SEDC
Smart Energy Demand Coalition

Explicit Demand Response in Europe

Mapping the Markets 2017

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Executive

Associate

Foreword

Dear Reader,

In 2017 we are on the cusp of a Demand Response breakthrough in Europe.

In the two years since our last Demand Response Map was published, we have seen improvements in almost all of the countries analysed, but progress has been gradual. Markets are slowly being opened where they were once closed, the role of aggregation is becoming more defined, and market product requirements are becoming more accessible for Demand Response. However, there is still much work to be done and flexibility potential to be realised across the continent.

The launch of the European Commission's Clean Energy Package in November 2016 marks the start of the large-scale unlocking of Demand Response potential in Europe. We are currently tapping in to around 20GW of activated Demand Response, but the Commission places the potential at 100GW, rising to 160GW in 2030.

As we see the further integration of renewable energies in the electricity markets, the need for flexibility is all the more crucial. Demand Response is the perfect partner for the decentralised and variable energy sources necessary for reducing carbon emissions and energy imports in Europe.

The SEDC has been at the forefront of advocating for Demand Response, and the necessary accompanying regulatory framework, in order to realise its potential in Europe. We welcome the proposed legislative package by the Commission on Electricity Market Design, but also other initiatives on the smartness of buildings. Such legislative initiatives should propel the countries at the lower end of our Map to truly activate Demand Response, and should push the more advanced countries to do even better. We have a momentous opportunity to deliver these proposals through the European Parliament and Council this year.

Let's make 2017 the year of Demand Response, and put consumers and flexibility at the heart of the energy system.

Brussels, this day 6th April 2017.

Jessica Stromback

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Executive Summary

There is growing consensus, among policy makers and market participants alike, that Demand Response is a critical resource for achieving an efficient and sustainable electricity system at a reasonable cost. Demand Response is now widely recognised as an important enabler of security of supply, renewables integration, improved market competition and consumer empowerment. This understanding has been reflected within the European Energy Efficiency Directive and Network Codes in recent years, and has finally led to the thorough inclusion of Demand Response in the European Commission's legislative proposals on Electricity Market Design within the Clean Energy Package, from November 2016.

Demand Response empowers consumers (Residential, Commercial, or Industrial) by providing control signals and/or financial incentives to adjust their use of demand-side resources at strategic times. These demand-side resources may include their consumption, use of distributed generation and/or storage capabilities.

To fulfil Europe's energy goals and political promises, the full range of demand-side resources, available at competitive prices, must be engaged, and all consumers must have the ability to benefit from their flexibility. This will require both Explicit and Implicit Demand Response.

The present analysis focusses on Explicit Demand Response, analysing the regulatory framework conditions in 18 European countries. In Explicit Demand Response schemes (sometimes called "incentive-based") the aggregated demand-side resources are traded in the wholesale, balancing, and, where applicable, Capacity Mechanisms. Consumers receive direct payments to change their consumption (or generation) patterns upon request, triggered by, for example, activation of balancing energy, differences in electricity prices or a constraint on the network. Consumers can earn from their consumption flexibility individually or by contracting with an aggregator: either a third-party aggregator or the customer's retailer.

In Implicit Demand Response (also called "price-based"), consumers react to dynamic market or network pricing signals. It is important to understand that neither form of Demand Response is a replacement for the other: it is necessary to enable both Explicit and Implicit Demand Response to accommodate different consumer preferences and to exploit the full spectrum of consumer and system benefits.

The information in this report was gathered through desk research, and expert interviews with TSOs, DSOs, retailers, aggregators, regulators, and technology providers. National market participants, who work with Demand Response, then reviewed the national reports. Therefore, the findings reflect the experience of the players on the ground.

Measuring the Frameworks for Explicit Demand Response

The country analysis graded markets according to four central criteria:

1. Demand Response access to markets

The first set of requirements assesses the possibility for demand-side resources to participate in European electricity markets. There is a striking contrast between the requirements of the European Energy Efficiency Directive and the effective means at the disposal of consumers wanting to access the day-ahead, intra-day, balancing or other markets.

First and foremost, participation of demand-side resources in all electricity markets should be authorised. This very basic condition is still not fully met in the majority of EU Member States. For example, in several markets demand-side resources are only allowed to participate in a small number of programmes and certain markets are as of today still entirely closed to Demand Response (such as balancing markets in Italy and Spain, or re-dispatching markets in Germany). It is evident that general market opening is a fundamental pre-condition for Demand Response to evolve.

At the same time, aggregated load must be allowed and encouraged to participate. For a significant quantity of demand-side flexibility resources to be available to the system, TSOs and market operators should open the markets to aggregated load. Most countries which have opened their product requirements to Demand Response have also enabled aggregated load to participate (e.g. France, Belgium, Switzerland, Great Britain, etc.). On the contrary, other European countries opened some of their markets to load participation, but not to aggregated load, therefore disqualifying all except the largest industrial consumers from accessing these markets (e.g. Slovenia, Poland).

2. Service providers access to markets

The second group of criteria assesses the conditions for healthy competition between the different market actors, both traditional and new, seeking to involve consumers in a range of Demand Response programmes. Enabling independent aggregation is important for the healthy growth of market competition around consumer-centric services. Evidence from markets around the world shows that for these services to be successful and lead to market growth, it must be possible for consumer flexibility to be unbundled from the sale of electricity to the same consumer.

The independent aggregator represents a new role within European electricity markets. Defining the role of the aggregator is not an end in itself and will lead to several positive outcomes. The introduction of this role into a market creates critical momentum around the growth of Demand Response, attracts private investment, and fosters competition between service providers[1].

To enable independent aggregators to enter the market at scale, it is critical that the role and responsibilities of these new entrants are clarified. In particular, it is important that the relationships between retailers, balancing responsible parties (BRPs), and independent aggregators are clear, fair, and allow for fair competition

1 For example, in some markets in the USA today, over 80% of demand-side volumes are provided through independent aggregators, even though suppliers are able to offer the same services. Similar patterns occur wherever independent aggregation is allowed, including Ireland, Western Australia, and New Zealand.

between market parties. A regulatory framework should be put in place that is proportionate to the challenges faced by aggregators, and ensures that they can access the market without depending on the agreement of the consumer's retailer. Such a framework should define standardised processes for information flows on a need-to-know basis, as well as volume and financial settlements between the different market parties, with a view to avoiding any significant distortive impacts on the retailers/BRPs.

3. Product Requirements

The third set of requirements against which the SEDC assessed the development of the regulatory environment for Demand Response in the different Member States is whether the participation requirements in the electricity markets enable access of a range of resources, including demand-side resources.

While genuine system constraints and security concerns must be respected, many different product/programme participation requirements were historically designed around what generators could conveniently deliver. Today these narrow criteria are no longer justifiable because they block low-cost demand-side resources, and hence artificially inflate procurement costs. For example, a system's physical need for reserves typically requires the resource to be available for between ½-2 hours. However, the market participation requirements for some reserve markets may state that load must be available up to 12 hours and up to 60 hours over the weekend. This suits coal-fired generation, which can operate for extended periods of time at minimal incremental cost once the start-up costs have been incurred, but it does not reflect the actual system need. This may not have been a problem in the past, but it is now, as it blocks consumer participation, since most consumers are unable to adjust their consumption for 16 consecutive hours. Markets should be designed in a granular manner, in order to enable the full range of resources to enter.

4. Measurement and verification, payments and penalties

The fourth set of criteria reviews the measurement and verification standards within a market, as well as the financing and penalty requirements.

Performance measurement, which is typically known as measurement and verification (M&V), is the process of quantifying and validating the provision of the service according to the specifications of a product. All resources should be held to the performance specifications established by the product. However, demand-side and generation-side communication requirements will usually need to be designed separately and made appropriate to the characteristics of each.

It is important that, in the case of aggregation (by independent aggregators or retailers), the communication protocols imposed are between the system operator and the aggregator. These protocols should not be mandated down to the individual customers. The latter communications should be at the discretion of the aggregator and his customer(s), so long as the aggregator is able to appropriately aggregate the data from his customer(s) and pass that data to the system operator according to specified protocols. This ensures that the system operator secures the data without additional special communications equipment and avoids the need for the system operator to further transpose the data between communications systems once received.

The volume of demand variation being sold into the market is assessed against a baseline. Volumes of demand-side flexibility are calculated as the difference between what the consumers normally consume (the baseline) and their actual measured consumption during the dispatch, measured using appropriate metering. The baseline cannot be measured directly, so it must be calculated based on other available measured data, using an agreed, robust methodology. Member States should adopt a small number of standardised baseline

calculation formulas, ideally the same across Member State boundaries.

Transparent and reliable methodologies have been put in place in different markets around the world and there is extensive literature available. However, if there is a lack of transparency concerning the methodology and its requirements, this acts as a strong barrier against the development of Demand Response programmes. It is therefore essential that the methodologies in place are made available to consumers and Demand Response service providers.

Finally, payment criteria, volumes, and values, should be transparent and based on open and fair competition. For similar services delivered to the system, which meet the requirements of the market, compensation for Demand Response services should be commensurate with those services delivered by generation.

The Status of Regulatory Conditions Today

The research shows that there has been an overall increase of interest in enabling Demand Response in almost of all the countries examined. Since the previous edition of the report, regulatory changes have been implemented or are planned in many of the analysed countries. Notably, in the countries where Demand Response has traditionally been almost non-existent, such as Estonia, Spain, Italy, there has been at least some regulatory interest in exploring its potential. The European countries that currently provide the most conducive framework for the development of Demand Response are Switzerland, France, Belgium, Finland, Great Britain, and Ireland. Nevertheless, there are still market design and regulatory issues that exist in these well-performing countries. Switzerland and France have detailed frameworks in place for independent aggregation, including standardised roles and responsibilities of market participants.

In France, a new draft decree being reviewed by the Conseil d'Etat in early 2017 could provide for a new financial settlement framework whereby a significant of the payment to retailers with curtailed customers would be charged to retailers rather than to demand response providers. However, issues persist around a standardised baseline methodology.

In both Belgium and Ireland upcoming legislation should help to increase the participation of Demand Response. New legislation addressing the role of the aggregator and independent aggregation will soon be put in place in Belgium, which will help to provide an equal footing for all market actors; a strong sign for the uptake of Demand Response. However, there are still some issues regarding measurement and verification that inhibit the growth of Demand Response. In Ireland, the new "Integrated Single Electricity Market" to be implemented in 2018, together with the DS3 programme, will open a range of markets for demand-side response, specifically the balancing market, and the wholesale market, as well as a newly designed Capacity Mechanism.

Great Britain continues to have a range of markets open to demand-side participation. Independent aggregators can directly access consumers for ancillary services and capacity products, and the country recently has started considering a framework for independent

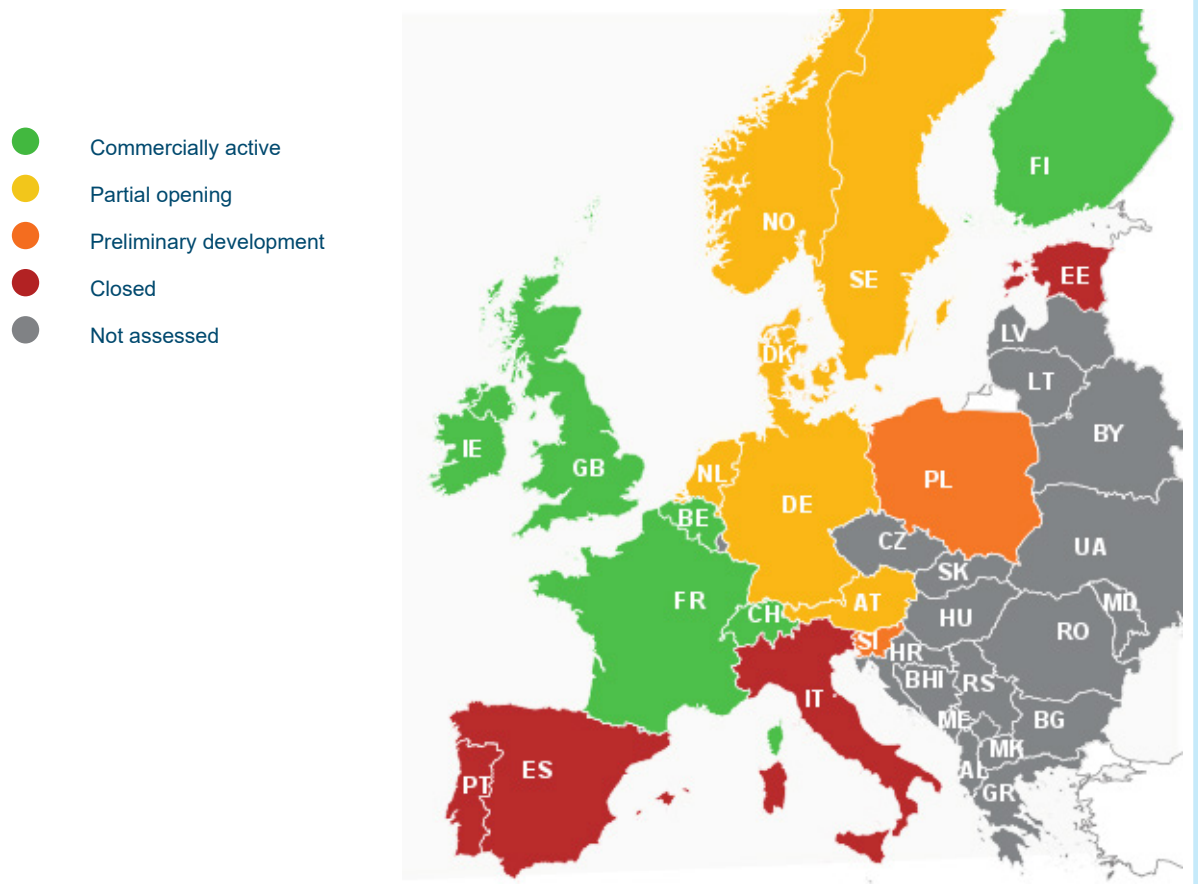

Figure 1: Map of Explicit Demand Response development in Europe today

aggregator access to the Balancing Mechanism.[2] Yet, with relatively burdensome measurement and verification procedures in place for Demand Response, it still has room to improve.

Finland stands out amongst the Nordic countries primarily as it allows independent aggregation in at least one of the programmes in the ancillary services, and due to its advanced provisions for measurement and verification. It will also be experimenting through pilot projects with independent aggregation in other parts of the balancing market starting in 2017.

Austria, Denmark, Germany, Netherlands, Norway, and Sweden are marked yellow as regulatory barriers remain an issue and hinder market growth. Although several markets in these countries are open to Demand Response in principle, programme requirements continue to exist which are not adjusted to enable demand-side participation. Furthermore, a lack of clarity remains around roles and responsibilities of the different actors and their ability to participate in the markets. However, Germany, the Nordic countries and Austria have started processes to find a standard solution for the role of independent aggregation. One

2 Consumer access for independent aggregators is possible today for most ancillary services and capacity products, but has remained closed for wholesale markets and the Balancing Mechansim.

of the notable differences in this year's mapping was that Germany has moved from orange status in 2015 to yellow in 2017. This is primarily due to the fact that product definitions have been updated or are about to be updated, and balancing reserve markets are about to be opened for independent aggregation

Slovenia, Italy, and Poland are coloured orange. In Slovenia and Poland, no major regulatory changes have been made within the past couple of years that would have allowed for further Demand Response participation. Notably, Italy has upgraded its status from red in the previous SEDC Demand Response Maps to orange today, as it has slowly started to take the regulatory steps needed for a solid framework for Demand Response. However, despite the gradual opening of markets, significant barriers still hinder customer participation. For example, major sections of the market are still closed off and they lack a viable regulatory framework for Demand Response overall.

Spain, Portugal, and Estonia are coloured red because aggregated demand-side flexibility is either not accepted as a resource in any of the markets or it is not yet viable due to regulation. Here, we see a critical disconnect between political promises and regulatory reality. Estonia may be an important country to watch in the future given that markets could open once they have disconnected from the IPS/UPS synchronous area.

Conclusions

Overall, the study revealed five overarching trends:

1. The regulatory framework in Europe for Demand Response is progressing, but further regulatory improvements are needed
While the EU Demand Response market is further advanced than it was a couple of years ago, it is still fragmented. Cooperation between Member states can be seen within different regions in terms of cross border trade on the wholesale and balancing market, which is a positive sign. However, more work needs to be done to accelerate the promotion of Demand Response across all Member States. There are still major barriers (such as penalties, product requirements, consumer access, etc.) that need to be addressed before the EU can reach a harmonised Internal Energy Market.

2. Restricted consumer access to Demand Response service providers remains a barrier to the effective functioning of the market
Competition of service providers is essential to create the necessary market dynamics to access the full Demand Response potential. Nevertheless, regulatory frameworks in the majority of EU member states do not yet acknowledge the role of independent Demand Response aggregators, or they require aggregators to conclude bilateral contracts with retailers/BRPs – whose business is often competing – in order to sell consumers' flexibility. France and Switzerland are still currently the only countries to have a clear framework on the status of independent aggregators and their role and responsibilities in the market, while the UK, Ireland and Finland enable aggregator access at least to some markets and products. Progress can be seen in Belgium and Germany, where the definition of frameworks is under development, and discussions have started also in Austria and the Nordic countries.

3. Significant progress has been made in opening balancing markets to demand-side resources
Relatively good progress has been made by most countries in giving demand-side resources access

to the balancing markets. There has been positive cooperation between stakeholders (new market entrants, regulators, TSOs, and retailers). Specific countries' balancing market programmes have been opened for pilot projects, while in others overall market design reform will open the whole market to demand-side resources. Discussion over how to improve the definition of baseline methodologies, measurement, and verification have also taken place in certain countries.

4. The wholesale market must be further opened to demand-side resources

The issue of access for independent aggregators to the wholesale market is prevalent across the majority of Member States. In most cases, the framework only allows for BRPs or retailers to aggregate and sell their own consumers' flexibility. At best, some large consumers and Virtual Power Plants can sell their electricity directly on the market. This, alongside the further opening of the balancing market and ancillary services, needs to be addressed in order to allow for further competition between market actors in the electricity market.

5. Local System Services are not yet commercially tradeable in European countries

With the exception of Great Britain, incentive structures for Distribution System Operators in Europe do not encourage the use of market-based flexibility resources today. Despite pilot projects, no effective market structures have been implemented in any of the analysed countries for DSOs to be able to source flexibility, including from Demand Response, for optimised local system operations.

To fully enable the cost-effective use of Demand Response across Europe, the European regulatory framework and national legislation needs to ensure that regulation is in the best interest of consumers and other market actors, and fit for the modern electricity market. Keeping old frameworks in place creates distortions and slows progress. It is imperative now more than ever that Member States deliver on their promise to deregulate their electricity markets, specifically to enable consumer services through market competition.

The European Commission's proposed revision of the Electricity Directive and Electricity Regulation, could provide a major step towards enabling a competitive market, including the full participation of Demand Response, in Europe.

The SEDC calls on the European Parliament, Member States, and Commission to promote the approval, specification and implementation of the overarching rules and detailed legislation necessary to create a viable market framework for Demand Response across Europe.

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List of Acronyms

AbLaV	Ordinance on Contractual Agreements Concerning Interruptible Loads
ACER	Agency for the Cooperation of Energy Regulators
AEEG	Autorità per l'Energia Elettrica il Gas
APG	Austrian Power Grid
APX	Power Spot Exchange
ARegV	Anreizregulierungsverordnung
BEIS	The Department of Business, Energy and Industrial Strategy
Belpex	Belgian Power Exchange
BMWi	Bundesministerium für Wirtschaft und Energie
BNetzA	Bundesnetzagentur
BRP	Balance Responsible Party
BSP	Balancing Service Provider
CAPEX	Capital Expenditure
CER	Commission for Energy Regulation
CHP	Combined Heat and Power
CM	Capacity Market
CREG	Commission for Electricity and Gas Regulation
CRM	Capacity Remuneration Mechanism

DA	Day-Ahead
DK1	Electricity Grid Price Area for West Denmark
DK2	Electricity Grid Price Area for East Denmark
DSR	Demand-side Resources
DR	Demand Response
DNO	Distribution Network Operators
DSBR	Demand-Side Balancing Reserve
DS3	Delivering a Secure, Sustainable Electricity System
DSM	Demand Side Management
DSO	Distribution System Operator
DSU	Demand Side Unit
EC	European Commission
EDF	Électricité de France S.A.
EDRP	Emergency Demand Response Program
EED	Energy Efficiency Directive
EEX	European Energy Exchange
ELES	Elektro-Slovenija
ENEL	Ente nazionale per l'energia elettrica
ENTSO-E	European Network of Transmission System Operators for Electricity
EPEX	European Power Exchange
ERDF	Électricité Réseau Distribution France
ESCO	Energy Service Company
FCDM	Frequency Control by Demand Management
FCR	Frequency Containment Reserve
FCR-D	Frequency Controlled Disturbance Reserve

FCR-N	Frequency Containment Reserve - Normal
FiT	Feed-in-Tariff
FRFS	Fast Reserve Firm Service
FRR	Frequency Restoration Reserve
FRR-A/aFRR	Frequency Restoration Reserve – Automatic
FRR-M/mFRR	Frequency Restoration Reserve - Manual
FSP	Flexibility Service Provider
GW	Gigawatt
GWh	Gigawatt hour
HV	High Voltage
HVDC	High Voltage Direct Current
HV Grid	High Voltage Grid
I-SEM	Integrated Single Electricity Market
ICH	Interruptible Contract Programme
ICT	Information and Communication Technologies
ID	Intra-Day
IGCC	International Control Cooperation
INC	Imbalance Netting Cooperation
IPS	Integrated Power System
kV	Kilovolt
kVA	Kilo (Volt X Amps)
kW	Kilowatt
kWh	Kilowatt hour
M&V	Measurement and Verification
mHz	MiliHertz

MR	Minute Reserve
MS	Member State
MW	Megawatt
MWh	Megawatt hour
NEBEF	Notification d'Échange de Blocs d'effacement
NRA	National Regulatory Authority
Ofgem	Office of Gas and Electricity Markets
OMIE	OMI -Polo Español S.A
OMIP	Operador do Mercado Ibérico de Energia
OPEX	Operating Expense
OTC	Over the Counter
PCR	Primary Control Reserve
PDBF	Daily Base Operating Schedule
PJM	Pennsylvania, Jersey, Maryland Market
PQ	Pre -qualification
PSE	Polskie Sieci Elektroenergetyczne
RES	Renewable Energy Sources
RK	Regulating Power
RKOM	Regulating Power Options Market
RPM	Regulating Power Market
RR	Replacement Reserve
RTE	Réseau de Transport d'Électricité
SBR	Supplemental Balancing Reserve
SCR	Secondary Control Reserve
SCADA	Supervisory control and data acquisition

SDR	Strategic Demand Reserve
SE1	Bidding area Luleå
SE2	Bidding area Sundsvall
SEM	Single Electricity Market
SGEM	Smart Grids and Energy Markets
SGR	Strategic Generation Reserve
SNL	Quickly Interruptible Loads
SOL	Interruptible Loads
SR	Strategic Reserve
STOR	Short Term Operating Reserve
STOR TR	STOR Tender Round
SwissIX	Swiss Electricity Index
TA	Transitional Arrangements
TNUoS	Transmission Network Use of System
TOR	Technical and Organisational Rules
ToU	Time -of -Use
TSO	Transmission System Operator
TURPE	Tarif d'Utilisation des Réseaux Publics d'Électricité
TW	Terawatt
TWh	Terawatt hour
UMIG	Utility Market Implementation Guide
UPS	Unified power system of Russia
USEF	Universal Smart Energy Framework
VOLL	Value of Lost Load
VPP	Virtual Power Plant

Introduction

Background: Why is Demand Response Important?

Demand Response leads to changes in electricity consumption by end-use consumers in response to effective market signals. Thanks to this mechanism, Demand Response is ideally suited to accommodate three fundamental characteristics of electric power systems:

- Electricity cannot yet be stored economically, so its supply and demand must be maintained in balance in real time.

- Grid conditions can change significantly from day-to-day, hour-to-hour, and even within seconds. Generation and/or consumption levels can also change quite rapidly and unexpectedly, causing mismatches in supply and demand which can threaten the integrity of the grid within seconds.

- The electric system is highly capital-intensive, and generation and transmission system investments have long lead times and multi-decade economic lifetimes.

Demand Response can increase the system's adequacy by substantially reducing the need for investment in peaking generation by shifting consumption away from times of extremely high demand. Crucially, it can act as a cost-effective balancing resource for variable renewable generation. Adding stability to the system, it lowers the need for must-run power plants that burn fuel continuously in order to be ready to supply power at short notice. It can decrease the need for local network investments, as it can shift consumption away from peak hours in regions with tight network capacity.

Apart from the indirect benefits that Demand Response delivers to society by lowering the costs and optimising the efficiency of the electric systems and markets, it can also provide direct benefits to consumers by paying them directly for the value of their demand-side flexibility. Finally, it encourages market competition between different flexibility resources and market players, allowing the participation of independent service providers (aggregators) and rewarding service-oriented retailers.

It is now clear to policymakers that Europe will not be able to achieve its energy policy goals in a secure and cost-efficient manner unless the energy system becomes more flexible. Demand Response and consumer empowerment are understood as integral parts of the Energy Union and the Clean Energy Package because they help to reach a competitive, secure, and sustainable economy. They do so by forming a natural partnership with renewable resources and energy efficiency. Each improves the performance and financial returns of the other, spurring increased investment and job creation.

Enabling both Explicit and Implicit Demand Response

Demand Response empowers consumers (residential, commercial, or industrial) by providing control signals and/or financial incentives to adjust their use of demand side resources at strategic times. These demand-side resources may include their consumption, use of distributed generation and/or storage capabilities.

To fulfil Europe's energy goals and political promises, it will not be sufficient to engage just one group of consumers, in one programme type, for one market. **The full range** of demand-side resources available (at competitive prices) must be engaged, and the full range of consumers must have the ability to benefit from their flexibility. This will require both Explicit and Implicit Demand Response.

In **Explicit Demand Response schemes** (sometimes called "incentive-based") the **aggregated** demand-side resources are **traded** in the wholesale, balancing and ancillary services, and where applicable in Capacity Mechanisms. Consumers receive **direct payments** to change their consumption (or generation) patterns upon request, triggered by, for example, activation of balancing energy, differences in electricity prices or a constraint on the network. Consumers can earn money from their consumption flexibility either individually or by contracting with an aggregator: this could be an independent aggregator or the consumer's retailer. **Implicit Demand Response** (also sometimes called "price-based") refers to consumers choosing to be exposed to *time-varying electricity prices or time-varying network grid tariffs* that reflect the value and cost of electricity and/or transportation in different time periods. They respond to wholesale market price variations or in some cases dynamic grid fees. Introducing the right to flexible prices for consumers (provided by the electricity retailer) does not require the role of the aggregator.

It is important to note that neither form of Demand Response is a replacement for the other. E**nabling both types of Demand Response is necessary to accommodate different consumer preferences and to exploit the full spectrum of consumer- and system benefits from Demand-Side Flexibility.**

The present analysis focusses on Explicit Demand Response. As there is typically only limited overlap with rules and regulations relevant to Implicit Demand Response, it requires a separate analytical approach and is not assessed in this study.

Benefits of aggregation

An aggregator is a service provider who operates – directly or indirectly – a set of demand facilities in order to sell the flexibility available from pools of electric loads as single units in electricity markets. The aggregator – a service provider who may or may not also be a retailer of electricity – represents a new role within European electricity markets. Most consumers do not have the means to trade directly into the energy markets and require the services of an aggregator to help them navigate the complexity and participate. Aggregators

pool many different loads of varying characteristics and provide backup for individual loads as part of the pooling activity, increasing the overall reliability and reducing risk for individual participants. Aggregation service providers are central players in creating vibrant demand-side participation and Demand Response. They negotiate agreements with industrial, commercial and residential electricity consumers to aggregate their capability to reduce (or increase) energy and/or shift loads on short notice. They create one "pool" of aggregated controllable load, made up of many smaller consumer loads, and sell this as a **single resource.** These loads can include fans, electric heating and cooling, water boilers, grinders, smelters, water pumps, freezers, etc.

It is important to recognise that the activity of aggregating consumers' loads requires a number of very specific competencies unique to this role. For example, the aggregator needs significant industry knowledge and experience to identify the flexibilities in various industries, technical assets and processes, and the limitations of those flexibilities, in order to match these to the requirements in a specific market. Consumers often do not know about their own potential for flexibility, so they need expert support. In addition, aggregators have the technical capability to physically connect the customers and integrate their load into their aggregated pool. These activities require a sophisticated communication infrastructure (hardware and software) and a central IT system capable of dealing with a wide variety of loads with different properties.

Aggregation can achieve performance levels that fulfil market requirements for reliability and can be comparable to, or better than, the performance of generation. The aggregation of diverse customers means that the system operator can use the aggregated demand-side capacity as a single, reliable resource. One of the key benefits of aggregation is the diversity of the aggregated portfolio (i.e. many small loads building one large resource), which ensures that the committed capacity will be delivered by the aggregator even when some individual consumers may not be able to perform[3].

The performance levels of Demand Response have been proven in existing markets in North America and Australasia, as well as in Austria, Belgium, Finland, France, Ireland and Great Britain. An example of the reliability of Demand Response can be seen in the table below. The table summarises the performance of Demand Response in the PJM market during the period 2015-2016.

3 The aggregator will also never bid his full resource into a market – for example if he has 100 MW of load available, he may only offer 70-80 MW into the market – ensuring that the aggregator can fulfil his reliability requirement with high reliability.

Zone	Committed ICAP (MW)	Reduction (MW)	Over/under performance (MW)	Performance (%)	Re-test (%)
AECO	131	144	14	111	6
AEP	1,737	2,051	314	118	1
APS	746	835	88	112	3
ATSI	1,046	1,451	405	139	5
BGE	762	1,611	849	211	1
COMED	1,603	1,813	210	113	0
DAY	175	219	44	125	0
DEOK	306	374	68	122	0
DOM	887	1,048	161	118	4
DPL	295	731	437	248	0
DUQ	171	210	40	123	0
EKPC	132	143	11	108	0
JCPL	173	200	27	116	1
METED	271	310	39	114	11
PECO	479	562	83	117	1
PENELEC	287	329	42	115	9
PEPCO	535	1,248	713	233	0
PPL	774	859	84	111	12
PSEG	384	429	45	112	1
RECO	7	9	2	125	0
Total	10,902	14,577	3,675	134	3

Table 1: PJM, Load Management Performance Report – 2015/2016. Load Management commitments, compliance, and test performance (ICAP). Zonal level results for all DR products combined

Demand Response aggregation can be provided by electricity retailers, as well as independent Demand Response Aggregators. Enabling both types of actors to exist and compete in the market is essential for the healthy uptake and growth of market competition around consumer-centric services. For example, the latest PJM Market Activity Report on Demand Response (from March 2017) shows that 80% of Demand Response capacity in PJM comes from independent aggregators[4]. The shares are similarly high in other jurisdictions that have mature Demand Response markets, such as Western Australia, New Zealand, or other US interconnections (e.g. New England and New York). An aggregator can **only** succeed when their customers succeed and benefit from Demand Response. While retailers can also offer aggregation services, to create the necessary market dynamics, it is important to have market participants for whom Demand Response is their **core business.** Even in highly competitive retail markets, aggregator access has been proven to be essential in spurring competition in Demand Response services for customers[5].

The following chapter outlines the existing provisions

4 PJM, 2017: Demand-Response Operation Market activity report March 2017, page 13; PJM calls aggregators Curtailment Service Providers (CSPs) Available at: http://www.pjm.com/~/media/markets-ops/dsr/2017-demand-response-activity-report.ashx (retrieved on 20 March 2017)

5 The example of Australia proves how enabling independent DR Aggregators has led to 12% dispatchable peak demand in the Western Australian wholesale market, while only some 2% of demand are estimated to be elastic in the Eastern Australian market. Both retail markets are highly competitive, but Eastern Australia does not allow Independent DR Aggregators. Source: EnerNOC presentation for the JRC, October 2015

for Demand Response at the EU level and analyses a set of regulatory requirements for truly enabling consumer participation in the electricity markets.

1

Regulatory Requirements for Enabling Demand Response

1.1 European Regulatory Framework for Demand Response

European policy makers have demonstrated strong support for Demand Response. This is reflected in several existing legislative texts:

The Electricity Directive – 2009/72/EC

The current Electricity Directive[6] of the Third Energy Package already defined the concept of "energy efficiency/demand-side management", acknowledging the positive impact on environment, on security of supply, on reducing primary energy consumption and peak loads. Article 25.7 requires network operators to consider Demand Response and energy efficiency measures when planning system upgrades. Article 3.2 also states *"In relation to security of supply, energy efficiency/demand-side management and for the fulfilment of environmental goals and goals for energy from renewable sources, [...] Member States may introduce the implementation of long-term planning, taking into account the possibility of third parties seeking access to the system".* This language was strengthened further within the Energy Efficiency Directive (EED).

The Energy Efficiency Directive (EED) – 2012/27/EU

The Energy Efficiency Directive (2012/27/EU)[7] constitutes a major step towards the development of Demand Response in Europe.

According to its Article 15.2, Member States were required to undertake an assessment of the energy efficiency potentials of their gas and electricity infrastructure, in particular regarding transmission, distribution, load management and interoperability, […] and identify concrete measures and investments for the introduction of cost-effective energy efficiency improvements in the network infrastructure, by 30 June 2015.

Furthermore, Article 15. 4 requires Member States to:

- *"Ensure the removal of those incentives in transmission and distribution tariffs that are detrimental to the overall efficiency (including energy efficiency) of the generation, transmission, distribution and supply of electricity or those that might hamper participation of Demand Response, in balancing markets and ancillary services procurement".*

- *"Ensure that network operators are incentivised to improve efficiency in infrastructure design and operation, and, within the framework of Directive 2009/72/EC, that tariffs allow suppliers to improve consumer participation in system efficiency, including Demand Response, depending on national circumstances".*

The most important part of the Directive is Article 15.8, which establishes consumer access to the energy markets, either individually or through aggregation. In detail the Article states:

- *"Member States shall ensure that national regulatory authorities encourage demand side resources, such as Demand Response, to*

6 Directive 2009/72/EC, concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC, 13 July 2009, art. 2 "Definitions".

7 Directive 2012/27/EU, on energy efficiency, amending Directives 2009/125/EC and 2010/30/EU and repealing Directives 2004/8/EC and 2006/32/EC, 25 October 2012.

participate alongside supply in wholesale and retail markets."

- *"Subject to technical constraints inherent in managing networks, Member States shall ensure that transmission system operators and distribution system operators, in meeting requirements for balancing and ancillary services, treat Demand Response providers, including aggregators, in a non-discriminatory manner, on the basis of their technical capabilities."*

- *"Member States shall promote access to and participation of Demand Response in balancing, reserves and other system services markets, inter alia by requiring national regulatory authorities […] in close cooperation with demand service providers and consumers, to define technical modalities for participation in these markets on the basis of the technical requirements of these markets and the capabilities of Demand Response. Such specifications shall include the participation of aggregators."*

The Network Codes

The Network Codes are a set of rules drafted by European Network of Transmission System Operators for Electricity (ENTSO-E), with guidance from the Agency for the Cooperation of Energy Regulators (ACER) and the oversight of the European Commission, to facilitate the harmonisation, integration and efficiency of the European electricity market. These Codes – some of which are still in the final drafting phases- will be critical for the development of Demand Response, because they describe the terms and conditions under which demand-side flexibility providers will be able to participate in the electricity markets.[8]

State aid Guidelines for Energy and Environment

In April 2014, the European Commission adopted new rules on public support for projects in the field of environmental protection and energy. Among other issues, the new Guidelines clarify under what conditions state aid to secure adequate electricity generation is permitted. This allows Member States to introduce so-called "capacity mechanisms", for example to encourage producers to build new generation capacity or prevent them from shutting down existing plants or to reward consumers to reduce electricity consumption in peak hours. Although the text still refers to "generation adequacy", it requests the primary consideration of "alternatives" to capacity mechanisms, such as Demand Response. The rules state that, once set up, the capacity mechanisms must provide adequate incentives to existing and future generation, Demand Response and storage. In detail, this is clarified in the following provisions:

- *(221) [...] Member States should therefore primarily consider alternative ways of achieving generation adequacy which do not have a negative impact on the objective of phasing out environmentally or economically harmful subsidies, such as facilitating demand side management and increasing interconnection capacity.*

- *(227) The measure should be open to and provide adequate incentives to both existing and future generators and to operators using substitutable technologies, such as demand-side response or storage solutions. [...]*

- *(232) The measure should be designed in a way so as to make it possible for any capacity which can effectively contribute to addressing the generation adequacy problem to participate in the measure, in particular, taking into account the following factors:*

    - *(a) the participation of generators using different technologies and of operators*

8 The most relevant codes for Explicit Demand Response are the Balancing Guideline and the Systems Operations Guideline, which are expected to be validated in the Comitology process in 2017, as well as the Demand Connection Code that entred into force in 2016.

offering measures with equivalent technical performance, for example demand side management, interconnectors and storage.

Given that a number of Member States have already introduced, or are considering introducing or revising capacity mechanisms, these rules will be vital to create the solid legal basis needed to ensure that, when state aid is permitted for guaranteeing system adequacy, it should be provided in such a way that demand-side resources are not excluded, and so the lowest cost combination of resources can be acquired. However, the real value of these guidelines in creating a level playing field between the different technologies depends on the Commission's resolve to apply them.

New legislative proposals in the Clean Energy Package

The European Commission launched the Clean Energy Package in November 2016; a number of legislative proposals including, most importantly for Demand Response, the revision of the Electricity Directive[9] and of the Electricity Regulation[10]. This could represent the most important change in the regulatory context ever seen in Europe, for Demand Response. For example, the proposed text **systematically includes Demand Response as a resource in the provisions for all organised electricity markets,** alongside storage and generation. It also requires that provisions for balancing and wholesale markets accommodate renewable energy sources and increasing demand responsiveness. Specific improvements of production definitions for balancing and wholesale markets are proposed, regarding procurement and minimum bid sizes respectively. Long-term hedging opportunities are also made tradable on exchange in an open and transparent manner and, where they exist, capacity mechanisms shall select capacity providers in a transparent, non-discriminatory and market-based process. Balancing and ancillary services, as well as dispatching, re-dispatch and curtailment, are generally to be market-based (exceptions are possible in some cases). In addition, the incentive structures for Distribution System Operators are to be adapted to encourage the market-based sourcing of system services at the DSO level. Eligible parties, including customers, retailers and aggregators, should be able to access relevant data based on the consumer's consent. Finally, the proposals include the obligation for all Member States to introduce a conducive legal framework for Demand Response aggregators to foster market participation of DR, including through independent aggregators, enable their access to the market, and define relevant roles and responsibilities.

Among other important aspects in the legislative package, these key proposals for Explicit Demand Response are complemented by further provisions essential to enabling Implicit Demand Response. If accepted and adopted by the European Parliament and Council, and fully implemented across the EU, these overarching provisions will play a significant role in removing the different barriers identified in this report.

9 COM (2016a): Proposal for a Directive Of The European Parliament And Of The Council on common rules for the internal market in electricity Available at: http://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52016PC0864R(01)&from=EN (retrieved 15 March 2017)

10 COM (2016b): Proposal for a Regulation Of The European Parliament And Of The Council on common rules for the internal market in electricity Available at: http://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52016PC0861R(01)&from=EN (retrieved 15 March 2017)

1.2 Regulatory Needs to Enable Demand Response

Based on its previous reports *Mapping Demand Response in Europe 2013 and 2015,* the SEDC has developed a set of regulatory requirements to enable Demand Response. The requirements are structured around four main criteria:

- ✔ Enable market access for Demand Response
- ✔ Enable different service providers to access the market
- ✔ Create viable products
- ✔ Develop measurement and verification requirements and ensure fair payments and penalties

1. Demand Response Access to Markets

The first set of criteria assesses the possibility for demand-side resources to participate in European electricity markets. There is a striking contrast between the requirements of the European Energy Efficiency Directive and the realities for consumers wishing to access the day-ahead, intra-day, balancing or other markets. This is mostly due to an incomplete regulatory environment in the majority of Member States. To enable consumer participation, a set of regulatory steps should be fulfilled:

Participation of demand-side resources in electricity markets should be authorised.

This very simple condition is still not fully met in the majority of EU Member States. For example, in several markets demand-side resources are only allowed to participate in a small number of programmes and certain markets are currently still closed to Demand Response (such as the balancing markets in Italy and Spain or the re-dispatching markets in Germany). It is evident that general market opening is a fundamental pre-condition for Demand Response to evolve.

Aggregated load should be allowed and encouraged to participate.

As described in the introduction, to make a significant quantity of demand-side side flexibility resources available to the system, TSOs and market operators have to open the markets to aggregated load. Most countries which have opened their product requirements to Demand Response have also enabled aggregated load to participate (e.g. France, Belgium, Switzerland, Great Britain, etc.). On the contrary, other European countries opened some of their markets to load participation, but not to aggregated load, therefore disqualifying all except the largest industrial consumers from accessing these markets (e.g. Slovenia, Poland).

2. Service Providers Access to Markets

The second group of criteria assesses the conditions for healthy competition between the different market actors, both traditional and new, seeking to involve consumers in a range of Demand Response programmes. As described in the Introduction to this report, enabling independent aggregation is important for the growth of market competition around consumer-centric services. Evidence from markets around the world shows that, for these services to be successful and lead to market growth, it must be possible for consumer flexibility to be unbundled from the sale of electricity.

The independent aggregator represents a new role within European electricity markets. Defining the role of the aggregator is not an end in itself; and will lead to several positive outcomes. The introduction of this role into a market creates critical momentum around the growth of Demand Response, attracts private investment and spurs competition between service providers[11].

To enable independent aggregators to enter the market at scale, it is critical that the role and responsibilities of these new entrants are clarified. In particular, it is important that the relationships between retailers, BRPs, and independent aggregators are clear, fair, and allow for fair competition between market parties.

Main principles and starting point of clarification of roles and responsibilities:

First principle of competitive market design: To promote demand-side flexibility, a market design should protect consumer interests and create a level playing field for all competitors. Consumers that wish to generate revenue from their flexibility should be able to choose freely between all market options and available service providers. They should not be restricted to using a service provider that is tied to or approved of by their retailer.

For this to happen, the aggregation service provider must be able to operate independently from the consumer's BRP/retailer, which is potentially its competitor[12]. Therefore, standardised frameworks and processes should be put in place to enable the smooth functioning of the market, and at the same time protect the customer-aggregator relationship. Below is a short overview of the structure of this standardised process between the consumer's BRP and the independent aggregator.

In principle, a standardised framework should:

- create a level playing field on which (small) new market participants can compete with (larger) incumbent companies, encouraging market competition, improved services and freedom of choice for consumers. This includes provisions that allow aggregators to offer Demand Response services to consumers independently of the consumer's BRP/retailer.

11 For example, in some markets in the USA today, over 80% of demand side volumes are provided through independent aggregators, even though suppliers are able to offer the same services. Similar patterns occur wherever independent aggregation is allowed, including Ireland, Western Australia, Texas and New York.

12 The French competition authority, in its opinion 13-A-19, declares that the prior agreement to be given by a BRP for the participation on a market by an aggregator was not compliant with article 14.6 of the directive "Services" 2006.123/EC (12 December 2006). This article prohibits *"the direct or indirect involvement of competing operators, including within consultative bodies, in the granting of authorisations or in the adoption of other decisions of the competent authorities, with the exception of professional bodies and associations or other organisations acting as the competent authority; this prohibition shall not concern the consultation of organisations, such as chambers of commerce or social partners, on matters other than individual applications for authorisation, or a consultation of the public at large".* It is also important to note that if the consumer's supplier owns generation assets, the consumer's demand side flexibility is also a competitor to the supplier's supply side generation.

- be cost efficient, allow for smooth market functioning, and allocate costs and rewards fairly amongst market parties.

- include processes for correcting the volumes in each affected balancing group where significant Demand Response volumes are shifted. Financial settlements between the market parties have to be defined, and provisions for information exchange should safeguard commercially sensitive information.

- establish a governance structure with an appeal process and appeals body, in case any issues need to be resolved.

Different adjustment mechanisms to address the above situation have been trialled or implemented in a few EU member states and some international markets. **It is important that any settlement procedures are fair, standardised and well defined by the regulator and the respective system operator, in order to protect the financial interests of all parties.**

3. Product Requirements

The third set of criteria against which the SEDC assessed the development of the regulatory environment for Demand Response is whether the participation requirements in the electricity markets enable access by a range of resources, including demand-side resources.

While genuine system constraints and security concerns must be respected, many different product/programme participation requirements were historically designed around the specific capabilities of the generators which provided those services at the time. Today these narrow criteria are no longer justifiable because they block low-cost demand-side resources, and hence artificially inflate procurement costs. For example, a system's physical need for reserves typically requires the resource to be available for between 30 minutes - 2 hours. However, the market participation requirements for some reserve markets may state that load must be available up to 12 hours and up to 60 hours over the weekend. This fits the capabilities of coal-fired generation, which can operate for extended periods of time at minimal incremental cost once the start-up costs have been incurred, but it does not reflect the actual system need. This may not have been a problem in the past, but it is now, as it blocks consumer participation, since most consumers are unable to adjust their consumption for 16 consecutive hours. Markets should be designed in a granular manner, so as to enable the full range of resources to enter and compete.

Product descriptions are historically oriented towards generation standards.

The following list summarises the most frequent hurdles with regards to product design, faced by demand-side resources in the different European markets:

- Over-sized minimum bids: a consumer or aggregator may need to provide up to 50 MW to participate – rather than the more standard 1 MW.

- Extended duration or availability requirements: some demand-side resources may not be available for extended periods of time or would present different availability characteristics from generation (difference between week days/week-end, business hours/night hours, etc.).

- Too frequent activations/short recovery periods: this is done when a TSO does not want to have to make multiple calls for resources but prefers to make a single call and then have the resources available. This is convenient for the TSO, but

reduces the ability of a range of resources – including demand and renewable resources – to participate.

- Symmetric bids: few consumers can increase and decrease consumption equally. A requirement for symmetrical bids acts as a significant market barrier to consumer participation. In Member States where the TSO is willing to enable Demand Response, asymmetrical bids are allowed.

The participation rules of the different products/ programmes should allow a range of technologies to participate, taking into account their different characteristics, while ensuring that the system's needs are met. In a competitive market, the regulator and system operators have the responsibility to enable a range of resources to compete on an equal footing, and not only selected forms of generation.

4. Measurement and Verification, Payments and Penalties

The fourth group of criteria reviews the measurement and verification standards within a market, as well as the financing and penalty requirements.

Performance measurement, which is typically known as measurement and verification (M&V), is the process of quantifying and validating the provision of the service according to the specifications of a product. The performance measurement process usually occurs at three stages:

- To qualify potential resources against product specifications as an entry gate to participation.
- To verify resource conformance to the product specifications during and after participation.
- To calculate the amount of product delivered by the resource as part of financial settlements.

Critical elements required to measure and verify a Demand Response activation are:

- baseline methodology metering configuration
- product delivery
- communication requirements
- frequency of interval readings
- accuracy standards
- timeliness of measurement data and
- communication protocols

Main characteristics of the performance measurement process:

All resources should be held to the performance specifications established by the product. However, demand-side and generation-side measurement and communication requirements will usually need to be designed separately and made appropriate to the characteristics of each. Measurement and verification protocols need to ensure reliable delivery of demand-side services in a manner that will still enable strong resource development.

The measurement and verification process should take place at the aggregated level:

It is important that, in the case of aggregation (whether by an independent aggregator or the consumer's retailer), the communication protocols imposed are between the system operator and the aggregator. These protocols should not be mandated down to the individual customers. The latter communications should be at the discretion of the aggregator and

his customer(s), so long as the aggregator is able to aggregate the data from his customers and pass it on to the system operator using specified protocols. This ensures that the system operator secures the data without additional special communications equipment and avoids the system operator having to further transpose the data between communications systems once received.

This distinction is necessary because services provided by aggregated load can involve communications with hundreds of remote customer sites: quite a different situation from centralised generation. Communication requirements that may seem reasonable for a large power station are often prohibitively burdensome when applied to hundreds of individual customers.

Fair and transparent baseline methodologies should be publicly available.

The volume of demand variation being sold into the market is assessed against a baseline. Volumes of demand-side flexibility are calculated as the difference between what the consumers normally consume (the baseline) and their actual measured consumption during the dispatch, measured using appropriate metering. The baseline cannot be measured directly, so it must be calculated based on other available measured data, using an agreed, robust methodology. Member States should adopt a small number of standardised baseline calculation formulas, ideally the same across Member State boundaries.

Transparent and reliable methodologies have been put in place in different markets around the world and there is extensive literature available. However, if there is a lack of transparency concerning the methodology and its requirements, this acts as a strong barrier against the development of Demand Response programmes. It is therefore essential that the methodologies in place are made available to consumers and Demand Response service providers.

Measurement and verification should be **accurate** enough to prevent free riding. Where possible, it should be **standardised**, taking into account that multiple standard baselines must exist to cover different types of Demand Response activations on a range of different consumption sites. This variety of standard baselines is common practice throughout the different balancing markets in which Demand Response currently participates. The existing baselines from these balancing markets should be a starting point to define standard baseline methodologies, although other markets have found that different methodologies are needed for programmes which have longer dispatches or longer notice periods. Depending on the market, these standards could be decided by the appropriate national authority within each Member State or by the TSO.

Dynamic tariffs and baseline methodologies: The baseline is the extrapolation of the actual behaviour of the consumer. This includes the customer's behaviour in relation to electricity prices. Existing baseline methodologies have the capability of capturing this behaviour and should do so, where and when appropriate.

The market should be transparent

Payment criteria, volumes and values should be transparent and based on open and fair competition. For similar services delivered to the system, meeting the requirements of the market, compensation for Demand Response services should be commensurate with those services delivered by generation.

In many European Member States today, generation resources have access to the markets at an embedded guaranteed cost through a longstanding bilateral agreement with the TSO or retailer. This can result in suppressing the price for new entrants, such as aggregators, to provide Demand Response services.

The market structures should reward and maximise

flexibility and capacity in a manner that provides investment stability

The market structures should value and pay for flexibility. Depending on the market and products, this will entail availability payments, a guaranteed number of activations during the year or some other form of reliable form of payment. These should create investment stability to allow for the new build of resources designed to be available at short notice and for short periods of time. Ideally, market participants should be paid according to the Pay as Cleared (PAC) principle, to allow for the most competitive outcomes. This is particularly important to encourage new entrants, as they will be competing against incumbents with far deeper market knowledge.

Penalties for non-compliance should be fair and should not favour one resource over the other.

Penalties are needed to ensure reliability, so both supply-side and demand-side resources should be penalised for non-compliance. That said, penalty calculations for each may need to be differentiated depending on the market. The calculation must be realised on risk for the system, related to the non-delivery product impact (different for each market). It is important that regulators do not use a one-size-fits-all model or they may unintentionally shut out consumer participation.

2

Member State Analysis

2.1 Methodology

Scope

The 2017 report covers the regulatory framework for Explicit Demand Response across a wide range of markets (i.e. day-ahead, intraday, balancing and Capacity Mechanisms).

Country selection

The paper reviews the regulatory structures of 18 European countries. The 2017 report examines all countries studied in 2015, plus Estonia and Portugal. The selection was based on a preliminary research, which identified the European countries where progress in Demand Response development has been identified. The countries researched are:

EU Member States			
 Austria	 Belgium	 Denmark	 Estonia
 Finland	 France	 Germany	 Great Britain
 Ireland	 Italy	 Netherlands	 Poland
 Portugal	 Slovenia	 Spain	 Sweden
Non-EU Member States			
 Norway	 Switzerland		

Information gathering

The information was collected through expert interviews with the respective National Regulatory Authorities (NRAs), TSOs, DSOs, retailers, aggregators, technology providers, consulting firms, and research organisations, and desk research of regulation and market results. National market participants (working with Demand Response) then reviewed the national reports. The findings therefore reflect the experience of the players on the ground.

Colour-coding and grading system used for the analysis

The countries assessed were given a colour code and number grade per assessed area. This was done in order to provide a visual analysis of each country's progress in the key areas required for enabling Demand Response. By combining the grades given to these four key areas, a map was created reflecting the status of Demand Response in Europe. The 4 key areas on which the assessment of incentive-based Demand Response development was measured are:

- Demand-side resources access to the markets
- Different service providers access to the markets
- Programme Description and Requirements
- Measurement and Verification, Finance, and Penalties

Area 1. Demand Response access to markets

This area includes to what extent demand is allowed as a resource within the different national electricity markets (i.e. wholesale, balancing, ancillary services, Capacity Mechanism, strategic reserves, etc.).

KEY	Demand Response access to markets
5	Aggregated load is accepted in a range of markets
3	Aggregated load is limited to a number of markets
1	Aggregated load is accepted only in one or two programmes
0	Load is not accepted as a resource in any market

Area 2. Service providers access to markets

This area involves the clarification of involved parties' roles and responsibilities, allowing for direct access of consumers to independent service providers, alongside the retailers. In particular, it focuses on progress towards fair and standardised arrangements between BRPs/ retailers and aggregators. A standardised relationship between independent aggregators and BRPs has been classified as a key market enabler. A standard framework should enable third-party aggregator access to the consumer independent of bilateral retailer consent and resolve risks to the BRP/retailer caused by Demand Response activations by an independent aggregator.

KEY	Service provider access
5	Standardised arrangements between involved parties are in place for all markets – aggregators do not depend on prior consent of the retailer/BRP
3	Independent third parties may access some parts of the market without consent of retailer/BRP
1	Lack of standardised arrangements between involved parties and aggregators must contract with retailer/BRP to access market.
0	No standardised arrangement between involved parties is in place and aggregation is illegal

Area 3. Product requirements

This area refers to the requirements of the different products/programmes (e.g. minimum bid limit, symmetric bid, maximum number of activations, notification time, duration, etc.), assessing whether these enable demand-side resources to participate.

KEY	Program requirements
5	Programme requirements enable a range of resources (supply and demand) to participate in multiple markets
3	Minor barriers to demand-side participation in market remain, however participation is still possible
1	Significant barriers remain, creating major competition issues for demand-side resource participation
0	Programme requirements block demand-side participation

Area 4. Measurement and verification, payments and penalties

This area refers to standardised and transparent regulation on how Demand Response events should be measured. It looks at the definition of baseline methodologies in a harmonised and fair manner. It covers questions such as whether the requirements for measurement are proportionate to small consumer capabilities, taking into account the associated costs. It examines whether the pool of loads can fulfil the measurement requirements as an aggregate, or if these take place individually at a per-consumer level. It also examines whether payments for providing demand-side flexibility are fair, transparent, and attractive. Apart from studying whether the financial conditions are healthy, including whether penalties for non-delivery are reasonable or discourage customer participation.

KEY	Measurement and verification, payments and penalties
5	Requirements are well defined, standardised, proportionate to customer capabilities, dealt with at the aggregated level, and Payment is fair and penalties are reasonable
3	Requirements are under development, but do not act as a significant barrier; Payment is adequate, but unequal per MW between supply and demand; Penalty structures create risk issues for service providers, but participation is still possible
1	Requirements act as a significant barrier to consumer participation; Payment structures seem inadequate, unequal pay per MW between supply and demand, penalty structures create high risk issues
0	There are no measurement and verification rules for Demand Response participation; Payment structure inadequate and non-transparent; penalty structures act as a critical barrier

Overall Grading

Once this initial analysis was completed, each Member State was given an overall grade according to the general status of Demand Response in the overall electricity market. This final grade consists of the total sum of the results in the four aforementioned criteria. It is important to note that the grading is relative to other markets, and even a green indication can mean that further improvements are still possible and necessary to make the optimal use of Explicit Demand Response.

KEY	Relative status of Demand Response
5	Commercially Active
3	Partial Opening
1	Preliminary Development
0	Closed

2.2 Member States Reports

Austria

Overview

Austria has made progress enabling Demand Response within the Balancing Markets. However, the overall structure remains complicated (and therefore expensive) to navigate. Business development in the area is also still slow. In 2014, several amendments were made to the preconditions for the prequalification to ease the aggregation of demand resources and, open the balancing market to Demand Response and new technologies. In addition to existing pooling possibilities, various measures were implemented in regards to technical entities. There have also been changes made to increase the participation of consumers.

However, a Demand Response provider still has to have a bilateral agreement with the BRP for the BRP's sourcing costs, which creates an obstacle for entering the market.

The most attractive markets for Demand Response are from a technical point of view the tertiary control (relatively low entering barrier due to low technical requirements) and from an economic point of view secondary control (high prices and a number of activations).

Currently the business case for Demand Response in Austria is relatively weak. Aggregators can only attract customers with large amounts of flexible load and/ or backup generation (e.g. industry) to contribute to a pool. Smaller resources are still reluctant to participate due to low revenue streams.

As such, a level playing field for all flexibility providing devices in all valuation mechanisms of flexibility (regardless of size and grid connection, e.g. DSO) is needed. The participation of new market players and new forms of demand units in existing and new pools, such as aggregators is an important factor for the observed reduction of Austrian balancing costs.

Further planned measures in Austria include the optimisation of (real time) data exchange between the DSO, TSO and other market participants (i.e. to support pooling of units from third-party aggregation); improvement exchange of data for more effective market operation such as the harmonisation of (aggregated) exchange of schedules for activation in other balancing perimeters; and the enhancement of market rules/grid codes (such as new arrangements on independent aggregation currently in contracts between market parties). Additionally, market processes for using measured values (Smart Meter measurement 15 Min/daily) for imbalance settlement are in preparation to support all forms of flexibility valuation (balancing, imbalance settlement, participation in ID/DA markets).

1. Demand Response access to markets

A. Markets overview

The only market open for DR is the FCR (Primary control). The following tables provide a detailed explanation of Demand Response access in the different markets.

Wholesale market

ENTSO-E's terminology	APG's terminology	Total Volume Traded	Load Access & Participation	Aggregated Load Accepted	Aggregated Generation
Day ahead	Day ahead	261 TW	✗	✗	✓
Intraday	Intraday	43.51 TW	✗	✗	✓

Balancing and ancillary services

ENTSO-E's terminology	APG's terminology		Tot. Capacity Contracted	Load Access & Participation	Aggregated Load Accepted	Aggregated Generation
FCR	Primary Control	+ / –	67 MW	✗	✗ *	✗
aFRR	Secondary Control	+	200 MW	✓ n/a	✓ *	✓
		–	200 MW	✓ n/a	✓ *	✓
mFRR	Tertiary Control	+	280 MW	✓ ✓	✓ *	✓
		–	170 MW	✓ ✓	✓ *	✓

* Pooled loads normally comprise distributed generation, backup generation, and Demand Response, as entry levels for Demand Response alone are too high.

Table 2: List of balancing market products, including volumes and load accessibility in Austria

B. Markets open to Demand Response

Balancing Market Aggregation is legal and enabled particularly within the Balancing Markets. Austria has also amended the existing framework for aggregation and Demand Response – specifically the grid utilisation charges (*Netznutzungsentgelt, NNE*) has been adapted to favour the contribution of Demand Response in Austria's balancing markets, as they do not punish deviation from initial forecasts to the same extent any longer.

Capacity Market. Austria has not discussed the implementation of a Capacity Mechanism. Existing instruments, such as congestion management, balancing market programs and the cross-border cooperation with Switzerland, Slovenia and Germany are estimated to be sufficient[13].

Wholesale Market. Currently, there is no Demand Response participation on the EPEX spot market from Austria, although in principle demand-side resources, can already participate in the day-ahead market.

Distribution Network Services. There have been several research and development projects in Austria, which are targeting the development of the future role of DSOs in providing flexibility to the grid. As an example, hybridVPP4DSO[14] is investigating the use of a VPP for commercial trading activities combined with the technical management of the distribution grid.

C. Restrictions related to distribution network operations

Grid tariff payments, in case of higher consumption, due to activation of negative balancing reserves can exceed the incomes gained from the participation in the balancing markets and as such participation might not be financially interesting. As a result, a new grid tariff was recently introduced where the amount of energy consumed due to activation by the TSO is charged through a reduced grid tariff[15].

2. Service Providers Access to Markets

A. Demand Response service providers access to consumer

Though several Balancing Markets are open to Demand Response, the BRP – Aggregator relationship does not allow for equal competition between aggregation service providers. This is visibly slowing market development in Austria as aggregators wait, sometimes over a year, for the basic contractual arrangement to be completed. Certain customers have given up and disengaged from any effort to enter the market due to these barriers.

However, since putting special focus on the level playing field for all forms of participation in the balancing market, it can be observed that the number of market participants has increased significantly. For instance, in the aFRR at the end of 2016 there were thirteen market participants (almost tripled from five in beginning of 2014); in the Manual Frequency Restoration Reserves, there were sixteen market participants (doubled from eight in beginning of 2014). This includes new market entrants from other sectors such as the telecommunication or industry, retailers, and independent aggregators. In total, there were seven players with no (or very view) own production assets, mostly independent aggregators with pooled units which they did not own or operate themselves.

The aggregator requires BRP's agreement prior to load management. An independent aggregator needs to inform and contract with the BRP/retailer in order to use the flexibility of Demand Response resources (for the balancing market). As an operational necessity, all

13 According to Martin Graf, Chairman of the Austrian regulator E-Control, available at: http://www.aggm.at/energy-news/e-control-energiemarkt-wandel-bringt-vernetzung (retrieved on 11th April 2015)

14 hybridVPP4DSO (2015): Homepage, Available at: www.hybridvpp4dso.eu (retrieved 12th April 2015)

15 E-Control (2017): "Verordnungen des Bundes zum Thema Strom", available at https://www.e-control.at/recht/bundesrecht/strom/verordnungen (retrieved 15 March 2017).

independent aggregators need to **bilaterally negotiate** with the respective BRP concerning consumer data, curtailed volumes and money exchange, which creates difficulties and conflicts of interest between parties. The following delays and increase in costs slows the deployment and lowers the participation of aggregated Demand Response in the balancing markets. Nevertheless, the TSOs with relevant parties try to harmonise these arrangements as far as possible to reduce the efforts on the side of BRPs.

In changes made to the market rules in Austria, the role of an independent aggregator was recently included. The details of the agreement that were developed in a group consisting of aggregators, retailers, BRPs and generators are now included in a model contract. However, the recent agreement is not yet binding; as a next step and for better transparency and unification the agreement will be included in the grid code/market rules[16].

3. Product requirements

A. Main product requirements

This section reviews the program descriptions in the different markets to ascertain if they enable consumers to participate.

Wholesale market

ENTSO-E's terminology	Marketplace	Minimum size (MW)	Notification Time
Day ahead	N/A	N/A	N/A
Intraday	N/A	N/A	N/A

Balancing and ancillary services

ENTSO-E's terminology	APG's terminology	Minimum size (MW)	Notification Time	Activation	Triggered (max. times)
FCR	Primary Control	+/-1 MW	< 30 Sec.	Automatic	No limit
aFRR	Secondary Control	5	> 30 Secs < 15 Min.	Automatic	No limit
mFRR	Tertiary Control	1	> 15 Min.	Manual	No limit

Table 3: Description of some main Product requirements concerning the balancing products accessible to DR in Austria

16 Oestrerreichs energie (2017): "Regelreserve: Abwicklungsvereinbarung," available at: http://oesterreichsenergie.at/branche/stromhandel-und-stromvertrieb/regelreserve-abwicklungsvereinbarung.html (retrieved 15 March 2017)

Balancing market and Ancillary Services. In 2014 the product requirements for the tertiary reserve were changed in order to better fit consumer capabilities. For example, the minimal bid size was reduced from 10 MW to 1 MW for fully automatised activations (*AutoMOT;* put into operation in 2014 Q4). Furthermore, the duration for activation was reduced from 16 to 4 hours, enabling participation for a range of demand resources. A 4-hour duration is a significant improvement over 16 hours and is possible for an aggregator to manage. Consumers can be fully engaged when the requirement is lowered to 1-2 hours. There, however, remain a few historic regulations in place which are not appropriate for consumers, these treat a single consumer as if they were a large generation unit, for example by requiring them to have a dedicated telephone line to the TSO in order to provide Demand Response services. This significantly increases the cost of participating in Demand Response for consumers, again shrinking the size of the market.

Primary control. Primary control is tendered on a weekly basis. Symmetric bids with a minimum size of +/- 1 MW are allowed. With recent changes made to the balancing market there is basically no minimal limit of capacity any more, there are just specific rules regarding the pool organisation[17].

APG cooperates cross-border on primary control with the Swiss TSO Swissgrid based on a TSO-TSO model. A part of the necessary primary control reserve can be procured via the neighboring partner-TSO. Surplus bids can be put at the disposal to the partner-TSO and will be transferred to the neighboring market if they are cheaper than the domestic bids.

Secondary Control. Secondary control is tendered on a weekly basis with 3 different time windows (weekday peak, weekday off-peak, weekend) for both positive and negative regulation. The separation of positive and negative regulation supports demand-side participation as does the 3-time windows, as this means a consumer/ aggregator is able to choose and bid into the time window that is appropriate for them. For the secondary control the weekly auctions were for some months complemented with daily auctions but these had to be stopped due to aFRR cooperation with Germany. This may change when the rules are changed all together in the coming year[18].

There are two cooperation agreements with neighboring countries in place for secondary reserves: The Imbalance Netting Cooperation (INC) with Slovenia and the International Grid Control Cooperation (IGCC) with Germany, which reduces the amount of activation of secondary control in Austria significantly.

Tertiary Control. Tertiary control is tendered on a weekly and daily basis, with separate tenders for weekdays and weekends, both split into 6 four-hour windows. It is also it possible to adapt the energy price for the following day. These changes have had a positive impact in particular on small BSPs and for units where forecast is important (wind, industry etc.)[19].

17 APG (2017a): "Tenders for Primary Control Power in the APG Control Area", available at: https://www.apg.at/en/market/balancing/primary-control/tenders (retrieved 15 March 2017)

18 APG (2017b): "Tenders for Secondary Control Power in the APG Control Area", available at: https://www.apg.at/en/market/balancing/secondary-control/tenders (retrieved 15 March 2017)

19 APG (2017c): "Tenders for Tertiary Control Power in the APG Control Area", available at: https://www.apg.at/en/market/balancing/tertiary-control/tenders (retrieved 15 March 2017)

4. Measurement and verification, payments, and penalties

A. Measurement & Verification

Prequalification. Prequalification is valid for 3 years, each balancing reserve program requires its own prequalification process. After successful completion of the prequalification process, providers can enter into a framework agreement (for each program separately) with the TSO, which allows them to participate in the bidding process for the respective programs.

The official prequalification process of APG takes usually min. 3 months – depending on the quality of the submitted papers and the complexity/novelty of the used aggregation system the process could also last longer (due to additional questions or the need for clarification).

In recent changes to the prequalification process, all technical requirements are now the same for demand and generation, as well as for DSO and for TSO connected units and for every kind of technology[20].

The length of the process, the fact that each program must be pre-qualified separately and the complexity of the paperwork, still add to the cost of each consumer's participation. This is an example of the process itself shrinking the size of the market, though it is still legally possible to consumers to enter.

Baseline methodology. The baseline definition is given in the Conditions for Pre-Qualification[21]. Specific details can be defined bilaterally with APG. The communication infrastructure used by APG in Austria for balancing power relies on well-established but relative old standards (e.g. IEC 101). Experience showed that – from the point of view of cyber security – the risk using the IEC 104 protocol is too high.

B. Availability/utilisation payments

The prices for capacity (€/MW/h) in Austria were relatively high in the past but saw a decrease in 2014. Like in Germany, the balancing markets in Austria saw a shift of revenue/prices from the capacity to energy prices. The cost of balancing power in Austria increased to about 203 million € in 2014. Specifically, there has been some Demand Response participation in the tertiary reserve has, which is expected to grow further in the future. The balancing and ancillary services are 'pay as bid'.

20 APG (2017d): "Conditions for participation in tenders for control energy", available at: https://www.apg.at/en/market/balancing/conditions-for-participation (retrieved 15 March 2017)

21 APG (2015): "Dokumentation zur Präqualifikation", available (only in German) at: https://www.apg.at/~/media/FA1843A24D1A4DDF92313BE5CE657F13.zip and https://www.apg.at/~/media/14AEB29A7F15493FB5126B085EE3FFDB.zip (retrieved 12th April 2015)

Balancing and ancillary services

Product	Category	Availability payments[22]	Utilisation payments	Access
Primary Control	+ / –	22,01 €/MW/h	Not provided	tender-based
Secondary Control	+ Peak	7,38 €/MW/h	119,03 €/MWh	tender-based
	+ Off Peak	9,75 €/MW/h		tender-based
	+ Weekend	7,82 €/MW/h		tender-based
	– Peak	6,72 €/MW/h	-123,09 €/MWh	tender-based
	– Off Peak	14,20 €/MW/h		tender-based
	– Weekend	20,28 €/MW/h		tender-based
Tertiary Control	+ Weekdays	3,22 €/MW/h	164,09 €/MWh	tender-based
	+ Weekend	1,01 €/MW/h		tender-based
	– Weekdays	5,45 €/MW/h	-63,98 €/MWh	tender-based
	– Weekend	11,53 €/MW/h		tender-based

Table 4: Overview of availability and utilisation payments in the balancing market in Austria

C. Penalties

In the case of under fulfilment according to the prequalification requirements, market participants are subject to a suspension of capacity and energy payment. It could also lead to the possible temporary exclusion from tendering. Any future unavailability under contract, could also potentially lead to temporary (or even permanent) exclusion from the tendering process.

Demand Response: Penalties include a time-limited exclusion from the participation in the balancing markets and also monetary penalties (amount not specified; it is within the discretion of the TSO). In the case of repeated non-delivery/under-performance, the prequalification process has to be repeated.

22 E-Control (2015): Market price overview, weighted average over the period of W22/2013 – W21/2014, available at: http://www.e-control.at/portal/pls/portal/portal.kb_folderitems_xml.redirectToItem?pMasterthingId=2417724 (retrieved 8th April 2015)

Belgium

Overview

Belgium has taken significant steps to open its ancillary services to Demand Response through a series of changes in the product requirements. Demand Response can participate in the Primary and Tertiary Reserves, as well as in the Interruptible Contracts programme, classified under the Tertiary Reserve. However, the Secondary Reserve is not yet open to Demand Response.

The main difficulty within the Belgian market is that, currently, aggregators need the prior agreement of the customer's retailer/BRP to contract with the customer. Product requirements generally enable Demand Response participation. Some improvements are still needed regarding measurement and verification, where some barriers block the full potential of Demand Response: for instance, local energy production cannot be isolated from the available flexible power potential, or the prequalification process required by the DSO for some programmes. Payments to provide ancillary services are quite attractive and penalties are considered reasonable.

The challenge for wider Demand Response participation is now to give customers access to the spot market. Participation in the spot market, Belpex, is currently limited only to a few large industrial consumers.

As of July 2017, the Belgium energy law is expected to be ratified and will formalise the role of the independent aggregator. This will establish the aggregator's right to access consumer's directly without the permission of the consumer's BRP or retailer. The Belgium regulator CREG will also be given permission to establish a standardised payment methodology for the retailer's sourcing costs.

1. Demand Response access to markets

Market overview

The following tables provide a detailed explanation of Demand Response access in the different markets.

Wholesale market

ENTSO-E's terminology	Market Place	Total Volume Traded (2015)[23]	Load Access & Participation	Aggregated Load Accepted
Day Ahead	Belpex	23.7 TWh	✔	✘
Intraday	Belpex	749 GWh	✘	✘

Balancing and ancillary services

ENTSO-E's terminology	Elia's terminology		Market size	Load Access & Participation[24]	Aggregated Load Accepted
FCR	Primary frequency control (R1)	R1-200mHz	28 MW	✘	✘
		R1-Down	27 MW	✘	✘
		R1-Load(Up)	27 MW	✔ 27 MW	✔
FRR	Secondary reserve (R2)	R2-Down	140 MW	✘	✘
		R2-Up		✘	✘
mFRR	Tertiary frequency control (R3)	R3-Prod	400 MW	✘	✘
		R3-DP		✔ 60 MW	✔
mFRR	Tertiary frequency control Interruptible clients (R3 ICH)		261 MW	✔ 261 MW	✔
RR	Voltage control and reactive power control		2700 MVAr	✘	✘
RR	Black start		n/a	✘	✘
RR	Strategic Reserve (SR)	SGR	750 MW	✘	✘
		SDR	97 MW*	✔ 97 MW*	✔

* Additional capacity has been contracted for the winter 2014/2015, as described below

Table 5: List of balancing market products, including volumes and load accessibility in Belgium

23 EPEX (2017): Press release, available at: https://www.epexspot.com/en/press-media/press/details/press/EPEX_SPOT_reaches_in_2015_the_highest_spot_power_exchange_volume_ever (retrieved on 15 March 2017)

24 Elia (2015a): "Required total volumes of ancillary services for year 2015, for R1, R2, R3 and R3-ICH", available at: http://www.elia.be/en/suppliers/purchasing-categories/energy-purchases/Ancillary-Services-Volumes-Prices (retrieved on 15th April 2015)

B. Markets open to Demand Response

Ancillary Services and Balancing Market. Primary and Tertiary Reserves allow Demand Response participation, whereas the Secondary Reserve does not. In addition, Demand Response represents about one tenth of the capacity involved in the Strategic Reserve. This reserve was introduced in 2014[25] to ensure a sufficient level of security of supply during the winter periods, in the particular context of an important reduction of nuclear power generation, due to the recent simultaneous breakdown of nuclear reactors. Finally, load flexibility is also provided through the Interruptible Contracts programme, which is dedicated to Demand Response.

DSO-connected consumers can participate in R3-DP (since 2014) and SDR since 2015-16. Other products might open to DSO consumers in the future, though the remaining issues with the lack of transparency concerning DSO blocking of a given consumer's access put this into question (see section 2 on *Measurement & Verification*).

The Secondary Reserve will open through a pilot that will be run starting in the summer of 2017. Assuming this pilot is successful, Elia will fully open R2 to Demand Response. This will take until 2019 to complete fully as it requires the TSO to update their SCADA systems. In addition, Demand Response represents about one tenth of the capacity involved in the Strategic Reserve.

Wholesale market. Wholesale markets are closed to Demand Response. This is likely to frustrate large industrial consumers in particular, who would want proper access to these markets in order to lower their own costs. They complain that capacity issues in Belgium make their energy costs a burden and they insist on the right to earn from their flexibility – without penalty.

Large single electricity consumers can enter demand bids with indication of price (not Demand Response) in the power exchange, Belpex Spot. Participation remains low, due to remaining prohibitive barriers, such as the requirement for aggregators to sign agreements with the consumer's retailer/BRP of the consumer or becoming a BRP. Furthermore, the share of the electricity traded in the spot market is still low in comparison with the total market volume as Belgium remains largely centralised. The participation of demand-side resources in Belpex Spot is limited to a few large industrial players, such as steel or chemical industries, or through some operators, that act as an aggregator for smaller consumers (e.g. greenhouses, pumping stations, cold stores, etc.).

The Belgian power market went through a year of volatile prices as a result of the uncertainty in regards to the availability of nuclear power. The day-ahead auction reached 23.7 TWh traded while the volumes on the Intraday market saw a slight decrease with 749 GWh in 2015[26].

Distribution Network Services. The Belgium DSOs do not use Demand Response themselves but rather focus, like many other DSOs in Europe, on Capex investments (copper), to maintain their own network security. The DSO cooperates operationally with the TSO in allowing consumers which are connected to their network to participate in Demand Response (although they reserve the right to block them at will without the legal requirement to justify why, if there is a capacity issue). Stakeholders report that the DSOs tend to take approximately 6 months to agree to allow consumers on their network to participate in whatever new program the TSO opened last. However, once the process is in place approval for individual consumers it is completed in a matter of weeks.

25 Belgian Government (2014): Law of 26 March 2014, art. 5, published on the Official Gazette n. 97/2014

26 EPEX (2017): Press release, available at: https://www.epexspot.com/en/press-media/press/details/press/EPEX_SPOT_reaches_in_2015_the_highest_spot_power_exchange_volume_ever (retrieved on 15 March 2017)

C. Restrictions related to distribution network operations

In Belgium, the federal regulatory authority sets the transmission tariffs and until recently has been in charge of setting the distribution tariffs. However, distribution tariffs are now the responsibility of the regional regulators. High voltage consumers (V > 26 kV) are charged a capacity payment in €/kW. Consumers connected to lower voltage levels are optionally charged a volumetric tariff with differentiation between peak and off-peak hours in addition to a capacity payment if they have peak measurement equipment[27].

2. Service providers access to markets

A. Demand Response service providers access to consumer

Every qualified participant can participate in the wholesale market if they meet the conditions (i.e. become a BRP or contract with a BRP, make an offer ≥ 1 MW to services opened to demand-side participation). Residential customers connected to the distribution grid cannot be their own access holders and thus cannot participate to the markets in an explicit way.

For balancing services and strategic reserve, the market is opened to final customers connected to high (380-150 kV), medium (70-30 kV) and low (<30 kV) voltage grids after a prequalification process and an approval of the DSO (for the low voltage grid) if they are equipped with quarter hourly meters. Sub-meters are also allowed. So far, residential customers cannot participate, neither directly nor through an aggregator.

The aggregator requires the BRP's agreement prior to load management. Selling load flexibility requires signing agreements with the consumer's BRP or becoming the consumer's BRP, except in the R3 ICH, where it is not required. Existing arrangements are in the form of bilateral contracts. As the situation stands now, customers do not have the ability to choose their aggregated service provider, since they have to obtain the permission of their BRP/retailer. The retailer has the legal right to refuse any cooperation with a different service provider or even renegotiate the consumer's contract for supply of electricity. For the moment, this creates significant entry barriers both for consumers and aggregators in an otherwise open market.

At the same time, it is difficult and expensive for an aggregator to become a BRP, because of the associated costs, bank guarantees and the high level of penalties, which might reach the value of 4.000 €/MWh in case of imbalance.

The issue is under review by the Belgian Regulator and the framework defining the relationship between third-party aggregators and retailers/BRPs was recently finalised. The new legal framework will allow independent aggregators to offer services in the frame of contracts signed with the TSO as long as they pass a prequalification process and so long as they respect the markets rules and products specifications. They will be able to participate in the FCR, mFRR and strategic reserve and a pilot project starting in 2017 which will allow them to participate in the aFRR market.

A legal framework recognising every end customer is entitled to exercise his flexibility without opposition from his retailer or his BRP and organising the transfer of energy is also in preparation. That draft federal law will

27 IndustRE (2016): "Innovative Business Models for Market Uptake of Renewable Electricity unlocking the potential for flexibility in the Industrial Electricity Use", available at: http://www.industre.eu/downloads/download/business-models-and-market-barriers (retrieved 17 March 2017)

introduce the new role of Flexibility Service Provider (FSP). This new role could be exercised by different market parties including independent aggregators.

Imbalance settlement after load management. BRPs may experience imbalances in a perimeter where Demand Response event took place. Two solutions are used at the moment for the existing balancing products open to Demand Response, based on consensus reached with market parties for a possible compensation of the balancing perimeter of the BRP:

(1) For the TSO-connected consumers in the interruptible contracts (R3 ICH) and in the Strategic Reserve demand-side (SDR) products, the curtailed energy is added back to the portfolio of the BRP (day-ahead nomination is used instead of the actual metering) and therefore the consumer pays for the energy curtailed;

(2) For R1-Load, R3-DP and SDR 2015-16, the latter for DSO-connected consumers, the portfolio of the BRP is not corrected. This means that the consumer would pay for the energy actually consumed and the BRP is paid imbalance prices, for the energy sourced, but not delivered to his consumers. In the specific context of the Belgian imbalance prices and by the fact that curtailment is only activated when the control area is short, this means the BRP is considered to get a more than adequate remuneration for his open energy position (typically significantly above day-ahead market price).

BRP-aggregator adjustment mechanism. For the R1-Load, R3-DP and for the DSO consumers for the SDR products, there is no payment between aggregators/ consumers and retailers. For the R3 ICH product, and TSO consumers in the SDR product, the consumer pays the energy curtailed to the BRP.

3. Product requirements

A. Main product requirements

The minimum bid size to participate in the programmes generally allows Demand Response participation, and the market conditions are in average in line with similar products. Tenderers have limited possibilities to take a speculative position in annual programmes tenders, therefore a significant up-front sales & marketing investment is required to secure customers with risks not to win a contract. This limits Demand Response potential. The following table contains an overview of the main programmes' technical requirements.

Wholesale market

Product	Market place	Minimum bid	Notification Time
Day Ahead	N/A	N/A	N/A
Intraday	N/A	N/A	N/A

Balancing and ancillary services

Product		Minimum size (MW)	Notification Time	Activation	Triggered (max. times)
R1-Load (Up)		1 MW	15s (50%) 30s (100%)	Automatic speed, rotation and frequency control system	No limit, but reasonable number of activations per year, about 80 min/ year
R3-DP		1 MW	15 min	Remote control	Max 40 times/year
R3 ICH		1 MW	3 min	Remote control	Not more than 4 times/ year
SDR	SDR_4	1 MW	6,5h (warm-up) + 1,5h (ramp-down)	TSO's website, day-ahead forecast + intraday correction	Max 40 times/year
	SDR_12	1 MW			Max 20 times/year

Table 6: Description of some main Product requirements concerning the balancing products accessible to DR in Belgium

Primary Reserve (R1-Load). Demand-side resources have to adjust their consumption only for deviations above 100 mHz, which has reduced impact on the industrial processes. The volume must be kept stable for at least 15 minutes, without interruption[28]. The TSO offers four different types of products:

R1-symmetrical 200 mHz (activated between -200 mHz, +200 mHz),

R1-symmetrical 100 mHz (between the range [-100, -200] mHz and [100,200] mHz,

R1-upwards (-200 mHz, -100 mHz),

R1-downwards (100 mHz, 200 mHz).

Demand Response is competitive, especially given that the up-regulation from generation is generally more expensive than the down-regulation. The combination of generation down-regulation and load curtailment is usually the best solution. This separation halves the number of the events for each regulation and the bandwidth required to offer the service.

Tertiary Reserve, (R3-Dynamic Profile). The duration per activation is limited to a maximum of 2 hours, with a minimum 12 hour-period between two interruptions, in order to ensure consumers do not to become

28 Elia (2002): Federal Grid Code, Arreté Royal 19 December 2002, F.2002-4675, section III, art. 242

overburdened by multiple activations[29]. The R3-DP is a Demand Response only product, but it competes with R3-Prod (generation): the 2015 tender, with a cap of 100 MW[30], ended with only 60 MW contracted, due to an aggressive bidding strategy of the largest players. The Demand Response product was challenged by non-Demand Response products, and for that reason discussions were ongoing to allow a bigger share of Demand Response in 2016. The results of which are unknown. The extra volume of Demand Response had the opportunity to bid into SDR additional volume in the 2015 auction.

Tertiary reserve – Interruptible Service (R3 ICH). The programme is the other facet of tertiary reserve (R3) off-take, and will be phased out over the coming years. There must be at least 24 hours between two interruptions. The TSO offers three possible levels of service, according to the maximum duration of an interruption:

- A4: 4 hours per call, 16 hours per year;
- A8: 8 hours per call, 24 hours per year;
- A2: 12 hours per call, 24 hours per year[31].

Strategic Reserve (SR). The 2014-2015 programme had a total capacity of 850 MW overall, where 750 MW of generation **(SGR)** constituted for a period of three years, and about 100 MW of Demand Response **(SDR)**, contracted for one year. On top of that, a significant extra volume was contracted for the winter of 2014/2015, among the non-awarded participants in the ICH and R3-DP tenders[32]. For the winter 2015-2016, the SR size was increased to 1500 MW, or up to 3500 MW[33] when the two missing nuclear power plants did not return to operation. In this context, at least 300 to 500 extra MW was reserved for generation in the two-year contract, and the rest was open for competition[34]. Regarding SDR, two sub-programmes are in place.

Programme	Maximum duration of one activation	Minimum duration of one activation	Minimum time between consecutive activations	Maximum cumulated duration in winter period
SDR_4	4 hours	1 hour	4 hours	130 hours
SDR_12	12 hours	1 hour	12 hours	130 hours

Table 7: Description of Strategic Reserves duration and activation characteristics in Belgium

Day Ahead and Intra-Day. Discussions to open the Day-Ahead and Intra-Day markets are expected in

29 Elia (2015a): "A specific tertiary offtake reserve: Dynamic Profile" available at: http://www.elia.be/~/media/files/Elia/Products-and-services/ProductSheets/S-Ondersteuning-net/S_Grid%20support_En.pdf (retrieved on 15th April 2015)

30 Elia (2014a): "Demand-side participation, Recent and Upcoming Developments", presented at SPF Economie / IEA-DSM Seminar, 10 June 2014

31 Elia (2015b): "Paid offtake interruption in order to preserve the grid", available at: http://www.elia.be/~/media/files/Elia/Products-and-services/ProductSheets/S-Ondersteuning-net/S4_F_INTERRUPTION.pdf (retrieved on 15th April 2015)

32 Elia (2015c) : "Rapport sur l'avancement du développement de la capacité d'interconnexion et de la gestion de la demande", art. 2.4.3 (published on 13th February 2015)

33 Elia (2015d): "Additional explanatory memo regarding the volume of the strategic reserve for winter 2015-2016" (notice of 11 th February 2015)

34 Belgian Government (2015) : "Réserve stratégique en électricité", available at : http://economie.fgov.be/fr/consommateurs/Energie/Securite_des_approvisionnements_en_energie/reserve_strategique_electricite/#.VOGvpfnF8dn (retrieved on 15th April 2015)

parallel with the set up an energy only bid ladder platform[35] where market players can offer all available flexibility for balancing purposes.

4. Measurement and verification, payments, and penalties

A. Availability/utilisation payments

Payments are attractive in the reserves markets. In R1 a single payment covers both the provision and the activation of the service. In R3, the auction process by the TSO sets the capacity payment, and in Interruptible Contract programme (ICH) an additional payment is rewarded per activation. SR remunerates for activation, warm up and utilisation periods. Balancing markets are pay as cleared in-line with the Network Codes.

In July 2017, the TSO will establish a pilot which tests an energy only auction called 'Bid-Ladder' which will provide the opportunity for consumers/aggregators to bid in resources on an hourly basis with no obligation to be available year around. This is the first of its kind and a significant step forward as it encourages both demand-side and distributed generation resources to participate. The table specifically shows average payments in the balancing services programmes and their respective tendering schedules.

Balancing and ancillary services

Product	Availability payments	Utilisation payments	Access
R1-Load	5-6 €/MW/h[36]	0	Monthly tender
R3-DP	3,07 €/MW/h[37]	0	Tender
R3 ICH	1,41 €/MW/h[38]	linked to the bid prices for upward activation, minimum of 75 €/MWh	Tender
SDR	Not public	68 €/MWh[39]	Yearly Tender

Table 8: Overview of availability and utilisation payments in the balancing market in Belgium

35 New programme under consideration by the TSO to allow extra generation or flexible demand to participate without the need to go through a traditional tender mechanism for reserves. Elia (2015): "Bin ladder platform", available at: http://www.elia.be/en/users-group/ad-hoc-taskforce-balancing/Bid-ladder-platform (retrieved on 10th June 2015)

36 Elia (2014c): Tender results for 2014, average range price, available at:, http://www.elia.be/en/suppliers/purchasing-categories/energy-purchases/Ancillary-Services-Volumes-Prices (retrieved on 15th April 2015)

37 Elia (2015e): Tender results for 2015, average range price, available at http://www.elia.be/en/suppliers/purchasing-categories/energy-purchases/Ancillary-Services-Volumes-Prices (retrieved on 15th April 2015)

38 Ibid. (retrieved on 15th April 2015)

39 Elia (2015f): Average utilisation payment, during a day with SR event http://www.elia.be/en/grid-data/data-download (retrieved on 19th March 2015

B. Measurement & verification

Measurement provisions currently do not enable full access of customer load to market. Since volatility of local energy production (e.g. from a locally installed wind turbines) at one site cannot be isolated from the available flexible power potential on that same location, a large amount of the available Demand Response potential remains inaccessible for aggregation. This is also the case for the volatility of non-flexible energy consumption within one site that cannot be separated from the available power flexibility. As such, there is a need for "meter behind meter" provisions in the settlement process within all reserves that demand can offer to a TSO (except R1). This issue therefore causes significant Demand Response barriers within the measurement and verification criteria. The UMIG 6.0 market design, expected to take place as of 2018, might lead to some changes.

Prequalification. For R3-DP and in the forecast for SDR 2015-2016, the prequalification process required by the DSO limits the available Demand Response potential and hinders Demand Response sourcing efficiency. This is due to the fact that the DSOs have difficulty evaluating the potential congestion issues linked to market driven behaviour of DSO consumers and therefore tend to be cautious and discriminatory towards allowing Demand Response. Currently the DSO is able to block or refuse consumer access to Demand Response without taking responsibility for the costs incurred by the consumer, aggregator and TSO, or even providing transparent measurement and risk calculation information used as a basis of the decision (in fact the DSO is not required to take accurate measurements of the risks involved). This lack of transparency and measurement requirements is a significant barrier to Demand Response development.

Baseline methodology. The baseline is required at least for the control of activation of the R3 ICH (TSO level) and SDR (TSO and DSO levels) products. For R3-DP, the use of the measure of a quarter hour before the event is used as baseline[40]. Specifically, R3-DP requires the installation of an AMR meter, with 15 minutes metering, and which needs to be validated by a distribution system operators or by the TSO. Sub-metering (meter behind the meter) was introduced for the SDR product for 2015-16, but for TSO consumers only. It was allowed for R3 in 2016, but again only for TSO consumers. Discussions to allow the participation for DSO-connected consumers are ongoing and could drive changes from 2017. Finally, R1 is evaluated a-posteriori by frequency-variation reports drawn up by the TSO, to verify the proper activation of the programme, as well as to analyse the process.

C. Penalties

The penalties are in line with the accountability of supplying reserves to a TSO and can be considerate acceptable. The availability penalty of R1-Load is the 130% of the remuneration price. R3-DP has a penalty of 130% of the capacity remuneration in case of missing power. R3-ICH has a penalty of 120% of the remuneration, in case of more than 3% of missing power reserve. SR requires a penalty of 130% of the remuneration in case of unavailability, and allows a period of unavailability without penalty, in case of needed reparation or scheduled inspections[41].

40 Elia (2014b): "Expert Working Group", available at: http://www.elia.be/~/media/files/Elia/users-group/Expert-WG-10122014_slides.pdf

41 Elia (2014d): "Procedure for constitution of strategic reserves", applicable for 2014 tender, art. 4.3.1

Denmark

Overview

The use of Demand Response in Denmark remains quite limited. Mainly because there is at the moment no significant demand for flexibility from TSOs or DSOs. This is due to sufficient capacity in Denmark and compared to other European markets, a well-functioning electricity market. Hence, today Denmark is able to handle the challenge of balancing the electricity market and price on flexibility products remain low.

However, with the increasing amount of variable resources (wind and solar power) not only in Denmark but in the entire region, investments today need to take flexibility needs into account to prepare for a future where the challenge of balancing production-side and demand-side will increase.

In theory, electricity consumers are allowed to participate in all the ancillary services in Denmark. However, due to a weak business case as well as a regulatory environment which makes it difficult for independent aggregators to develop innovative Demand Response businesses in the market, Demand Response participation within the markets remains limited. Demand Response aggregation takes place only through retailers, and there are no independent aggregators in the Danish market today. The balancing programmes are mainly designed around the characteristics of generators, leading to a situation where only the largest consumption units are able to participate. Tertiary Reserve is still the most accessible programme for demand-side participation.

In 2015 Energinet.dk, the Danish TSO, published a report on an energy market reform proposal named "Markedsmodel 2.0". The reform aimed at better integrating the large and growing share of Renewable Energy Sources through the use of flexibility and market coupling with the other Nordic countries. Introducing clear price signals was envisaged as one of possible enhancer of flexible demand[42] . Yet the recommendations from the project conclusions are still to be successfully carried out. The future of Demand Response overall is thus very dependent on the outcome of the market model discussions and its subsequent implementation. However, the hope is that the business cases for Demand Response will emerge more in the coming years.

Aggregation is legal in Denmark, however the way the roles and responsibilities between aggregators and BRP/retailers are defined represents an important entry barrier to independent aggregators. In order to contract with a customer, a third-party aggregator would need the prior agreement of the customer's BRP/retailers. As a result, only retailers/BRPs provide aggregation services, and in a limited manner, due to the remaining barriers. However, a revised market design is being discussed and carried out by the Danish Energy Association to develop a new market model for flexible consumption including the facilitation of independent aggregators. The recommendations are expected to be published by May 2017 followed by a consultations and implementation period.

42 Energinet.dk (2014), Market Model 2.0., Final Report, 21 October 2015, available at: https://www.energinet.dk/SiteCollectionDocuments/Engelske%20dokumenter/El/Final%20report%20-%20Market%20Model%202.0.pdf , retrieved on 28 Nov. 2016

Main enablers:

- Ancillary services are open to Demand Response;
- Prequalification is made at the aggregated pool level;
- Demand Response can participate in the wholesale market.

Main barriers:

- Payments in the wholesale market are too low to make a positive business case which besides rewarding the aggregator and customer of course also includes costs of taxation on electricity, costs of equipment and installation to measure the flexibility and monitor installations of heating etc. and varies fees to other market players (BRP, retailer and DSO);
- Product requirements are still largely generation-oriented and block demand-side resources;
- Bids from production and demand-side resources cannot be pooled;
- Some ancillary services still require symmetric bids and other generation-oriented requirements;
- Some markets require online measurement, and 24 hr service (a pilot on statistical measurement for homogeneous units are being tested on a V2G-project);
- Some markets have a volume demand of 10MW which makes it impossible for smaller pools of flexibility like heat pumps and vehicles to enter the market unless they have for example 5000 heat pumps;
- Other product terms like the contractual length, length of activation also hampers market development;
- The current market definition requires that independent / third-party aggregators must bilaterally contract with the consumer's BRP and retailer (if they only wish to sell flexibility and not energy) to provide Demand Response services.

1. Demand Response access to markets

Market overview

The Danish transmission system is divided into two areas (Western-DK1 & Eastern-DK2). DK1 is synchronous with Germany and the Continental grid, whereas DK2 is coupled with the Nordic grid. A connection exists between them, called "Storebælt HVDC" (the Great Belt Power Link). This situation influences the structure and use of Demand Response in Denmark as some programmes are separate for each area. The substantial share of Danish ancillary services are procured from the generation side. The main type of consumers participating in the markets are electrical heat boilers.

Wholesale market

ENTSO-E's terminology	Market Place	Tot. Volume Traded[43]	Demand Response Access & Participation	Aggregated Demand Response Accepted	Aggregated Generation
Day Ahead	Nordic and Baltic Day Ahead Market	391 TWh (2016)	✔	✔	✔
Intraday	Nordic, Baltic and German intraday market	5.1 TWh (2016)	✔	✔	✔

Balancing and ancillary services

ENTSO-E's terminology	TSO's terminology	Tot. Capacity Contracted	Demand Response Access & Participation	Aggregated Demand Accepted	Aggregated Generation
FCR	Primary Reserve (DK1)	23 MW	✔	✔ (23 MW[44])	✔
aFRR	Secondary Reserve (DK1)	≈100 MW	✔	✔	✔
FCR-N	Frequency-controlled normal operation reserve (DK2)	≈22 MW	✔	✔	✔
FCR-D	Frequency-controlled disturbance reserve (DK2)	37 MW	✔	✔	✔
mFRR	Tertiary (Manual) Reserve (DK1 and DK2)	≈868 MW	✔	✔	✔
RR		0 MW	✔	✔	✔
Functionality	Short-circuit power, reactive reserves and voltage control (DK1 and DK2)	✘	✘	✘	✘

43 NordPool Spot (2017): "Strong volumes foundation for expansion – Nord Pool 2016", available at: http://www.nordpoolspot.com/message-center-container/newsroom/exchange-message-list/2017/q1/strong-volumes-foundation-for-expansion--nord-pool-2016/ (retrieved on 15 March 2017)

44 Electrical boilers cover all demand for negative primary reserves (i.e. down regulation)

Other ancillary services if relevant (re-dispatch, voltage control)	×	×	×	×	×
Capacity mech. (if any)	×	×	×	×	×
Distribution network services	×	×	×	×	×

Table 9: List of balancing market products, including volumes and load accessibility in Denmark

B. Markets open to Demand Response

Balancing market and ancillary services. In the Tertiary Reserve, Demand Response participation is limited to electric boilers installed at local district heating plants. Currently, 45 units with a total capacity of 560 MW are installed in Denmark. Part of these (23 MW) also participate in the Primary Reserve as well as the regulating power market. This type of Demand Response is made possible by the complementary use of natural gas fired Combined Heat and Power plant's and relatively large heat accumulators, allowing for high flexibility in electricity consumption and production. The main types of aggregators participating are mostly the balancing responsibility parties. Currently, the TSO and various parties are involved in pilot projects testing the possibility of providing frequency controlled reserve (FCR).

- **DK1.** Secondary reserve in DK1 is fully contracted from Norway, thus there is no such market for Danish players. According to the TSO, a common Nordic market for Secondary Reserve is being discussed. In, "Energinet.dk's ancillary services strategy 2015-2017"[45] testing the feasibility of entering the Common market for FCR (primary reserve capacity) with Germany, the Netherlands, Switzerland and Austria as well as other potential cross border initiatives with continental Europe in both the a-FRR and m-FRR markets was supposed to be analysed. This process is still currently ongoing.

- **DK2.** There is a common market for Frequency-controlled normal operation reserve and Frequency-controlled disturbance reserve between DK2 and Sweden.

Wholesale Market. Consumers can trade their flexibility into the common Nordic wholesale markets (Elbas, Elspot). However, the traded volume is very limited, mainly due to low prices. A revised market design is being discussed and expected to be published May 2017 followed by consultations and implementation period. Lastly, approximately 85% of Danish electricity is traded on the Nord Pool Spot market.

Strategic Reserve. Energinet.dk decided against implementing a Capacity Mechanism and instead opted to assess the need for a strategic reserve, as it is a less

45 Energinet.dk (2015): "Energinet.dk's ancillary services strategy 2015-2017", available at: https://www.energinet.dk/SiteCollectionDocuments/Engelske%20dokumenter/El/Energinet.dk's%20ancillary%20services%20strategy%202015-2017.pdf (retrieved 15 March 2017)

extensive solution, for post-2025.[46] However this was rejected by the European Commission. As such, there is neither a strategic reserve nor a capacity mechanism in place within Denmark. This could be due to the fact that currently there is sufficient capacity in the country.

Distribution network services. Demand-side flexibility could represent an important tool for local congestion management. Several demonstration projects have been run by utilities focusing on the integration of intermittent energy into the grid. However, as mentioned in the introduction, the Danish DSOs for the time being have not encountered such high congestion similar to other countries. As such, there is almost no pressure to purchase flexibility. Although there are several R&D projects examining the issue and a specific task force at ENTSO-E examining this issue at a European level. There are a number of relevant projects in Denmark currently analysing the effective use of flexibility by DSO's, including EcoGrid and Ecogrid 2.0., iPower, and SmartNet.

In terms of investment management in general, regulatory schemes tend to favour investments in capacity (CAPEX) rather than operational costs, including costs related to the purchase of flexibility services (OPEX)[47]. However, the regulation is currently changing in Denmark, in terms of investment management. Currently DSO's are remunerated investment in CAPEX. But going forward, investments in DSOs assets that do not result in efficiency gains within the regulatory term of 5 years will result in a less attractive benchmark outcome for the particular DSO investing in new technology, and hence penalise the DSO financially. The expectation is therefore that DSOs will be less inclined to enter into new pilots of Demand Response going forward. Furthermore, there are no concrete mechanisms for the DSO's to buy demand-side flexibility.

C. Restrictions related to distribution network operations

A new network tariff regime is currently being discussed and amended both at the TSO and DSO level. Both projects are in the exploratory phase but one of many special attention points is the need of active Demand Response.

2. Service providers access to markets

A. Demand Response service providers access to consumer

The aggregator requires the BRP's agreement prior to load management. An independent third-party aggregator needs to inform and contract with the BRP/retailer in order to use the flexibility of Demand Response resource (for both the balancing market and wholesale market). All third-party aggregators need to **bilaterally negotiate** with the respective BRP concerning on consumer data, curtailed volumes and money exchange, which creates difficulties and conflicts of interest between parties. The following delays and

46 Energinet.dk (2014a): Market Model 2.0., Final Report, 21 October 2015, available at: https://www.energinet.dk/SiteCollectionDocuments/Engelske%20dokumenter/El/Final%20report%20-%20Market%20Model%202.0.pdf, (retrieved on 28 Nov. 2016)

47 Danish Energy Association (2016): "Winter package - Top 5 most important Distribution (DSO) issues", available at http://www.danskenergi.dk/~/media/EU/3_Distribution_issues.ashx (retrieved 15 March 2017)

increase in costs, slows the deployment and lowers the participation of aggregated Demand Response in the balancing markets. Furthermore, Demand Response and generation cannot be aggregated within the same bid. They have to sign up at as a Demand BRP or production BRP, respectively.

3. Product requirements

A. Main product requirements

Balancing Market and Ancillary Services. As mentioned above, Denmark is divided into two transmission areas (Western-DK1 & Eastern-DK2) influencing the structure of the market. The rules for ancillary services are mainly designed around generation-standards. For example, the requirement to have an online metering system constitutes a substantial cost for any entity willing to provide its services.

Primary Reserve. In DK1, the primary reserve is an automatically operated reserve for frequency containment. It requires very short delivery time and too frequent activations for traditional Demand Response to cope with – except for some MW-scale electric boilers.

In DK2 primary reserve, the TSO requires delivery of 50 % within 5 seconds and 100 % within the next 25 seconds. The frequency restoration reserve also requires symmetric bidding[48]. These requirements may change with the implementation of the European Network Codes, which is still ongoing.

Secondary Reserve. Today, the Secondary Reserve Market requires upward and downward regulation/ symmetrical bids. Furthermore, the whole volume of Secondary Reserve is currently contracted from Norway.

Tertiary Reserve. Common rules apply to both DK1 and DK2. The main barrier consists of a high minimum bid (10 MW), this reserve is still being manually operated. However, this will be changed to 5MW in 2017. The Tertiary Reserve is activated through a regulating market, which is common for Nordic countries. In addition, the participation in the Tertiary Reserves Market requires a control centre operating 24/7, which represents a cost barrier for a new aggregator[49].

Wholesale Market. In order to participate in the wholesale market, a Demand Response provider needs to sign an agreement with a BRP for both consumption and production.

48 A requirement for symmetrical bids acts as a market barrier to consumer participation. Consumers can rarely generate and consume in equal measure. In Member states where the TSO is willing to enable Demand Response asymmetrical bids are allowed.

49 EURISCO ApS (2013): "Activating electricity demand as regulating power. Flexpower – testing a market design proposal", p. 8, available at: http://www.eurisco.dk/images/1027_flexpower_activating_electricity_demand_as_regulating_power.pdf (retrieved on 10 June 2015)

Wholesale market

Product	Market place	Minimum bid
Day Ahead	EPEX Spot	0,1
Intraday	ELBAS/DK1-DE	0,1

Balancing and ancillary services

Product	Minimum size (MW)	Notification Time	Activation	Triggered (max. times per day)[49]
Primary Reserve (DK1)	0,3 MW	30 sec	automatic	~10-20%
Secondary Reserve (DK1)	1 MW	15 min.	automatic	~0,2%
Frequency-controlled normal operation reserve (DK2)	0,3 MW	150 sec	automatic	~0,1%
Frequency-controlled disturbance reserve (DK2)	0,3 MW	50% in 5sec, 50% in additional 25 sec	automatic	~10-15%
Tertiary (Manual) Reserve (DK1 and DK2)	10 MW (5MW Q2 2017)	15 min	manual	N/A. Heavily dependent of the price of the submitted bid. If low (competitive) the DR-asset is expected to be activated on a daily basis, if high only few times a year.

Table 10: Description of some main Product requirements concerning the balancing products accessible to DR in Denmark

4. Measurement and verification, payments, and penalties

A. Measurement & verification

Prequalification. Participation in frequency-based ancillary services requires local frequency measurement equipment with accuracy and sensitivity of measurement better than 10 mHz. Online metering

50 The actual numbers are not available and the best estimates are based on a load factor

is required by the TSO to participate in the Secondary Reserve, which is costly. By default, the local DSO is responsible for the metering and for online measurements. Moreover, the participation in the Tertiary Reserves Market requires a control centre operating 24/7. The high cost of participation is an issue in Denmark, where the majority of flexible loads are within the commercial sector, in relatively small sites. For this market to grow, these customers would need to be specifically enabled through low entry barriers and upfront costs. There is an ongoing pilot project testing the new framework for aggregation regarding; online metering, baseline, and verification.

Baseline methodology. There is no directly available baseline methodology, the lack of market transparency acts as another barrier to market entry. However, the baseline methodology is currently an issue being discussed under the new market model for flexibility.

B. Availability/utilisation payments

All payments are pay as cleared (marginal pricing). Payments are not attractive in Elspot, Elbas or in the Tertiary Reserve. Especially in Western Denmark (DK1), which is synchronous with Germany, the prices for RPM are low.

Balancing and ancillary services

Product	Availability payments	Utilisation payments	Access
Primary Reserve (DK1)	Range: 50,000 to 200,000 DKK/MW per month	Part of imbalance	Daily auction
Secondary Reserve (DK1)	Long term contract with Norway	NO	Long-term tender (5 years) Auctions if more is needed
Frequency-controlled normal operation reserve (DK2)	Range: 50,000 to 250,000 DKK/MW per month	Regulating power-price	Daily auction
Frequency-controlled disturbance reserve (DK2)	Range: 20,000 to 80,000 DKK/MW per month	Part of imbalance	Daily auction
Tertiary (Manual) Reserve (DK1 and DK2)	DK1 approx. 10,000 DKK/MW per month DK2: Long term contract with five different retailers	Both: Regulating power price.	Daily auction

Table 11:Overview of availability and utilisation payments in the balancing market in Denmark

C. Penalties

There are no specific penalties that discourage those from participating on either the balancing or wholesale market apart from the imbalance settlement procedures. Balancing costs are recovered by the market participant who has incurred the imbalance or cost depending on if they are consumption balance responsible or production balance responsible. The former entails a one price settlement whereas the latter applies a two-price principle. As such, the pricing incentivises the balance responsible to be in balance[51].

51 CEER (2016): "National Report Denmark 2016", available at: http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National_Reporting_2016/NR_En/C16_NR_Denmark-EN.pdf (retrieved 15 March 2017)

Estonia

Overview

The Estonian government and the TSO, Elering AS, have been intensely exploring the options to extend the use and application area of Demand Response during the last couple of years. Several background studies[52] have been commissioned[53].

Currently, the Estonian power system is interconnected with the IPS/UPS synchronous area which is planned to be desynchronized by 2025. Estonia has cross border electricity connections with Latvia (two 330 kV lines and additional 330 kV line under construction), Russia (three 330 kV lines) and Finland (via two HVDC cables with total capacity of 1016 MW). Two emergency reserve power plants were constructed in 2014 with total capacity of 250 MW by Elering.

There is no market for fast products (aFRR, FCR) since Estonia is part of the IPS/UPS synchronous and as such there is no need for these products in the frequency control. The existing reserve products are mFRR and emergency reserve, with 15 minutes' activation time and the duration of 1 hour. As Estonia is planning to desynchronize from IPS/UPS the need for additional products will arise soon and one of the options will be the development of further reserve products.

Demand Response aggregators currently do not have access to the market unless they have a direct bilateral agreement with the consumer's retailer.

Lastly, a regional process is ongoing aimed at opening markets to aggregated Demand Response which involves the other Baltic and potentially also Nordic countries, with regulatory proposals planned to be published next year.

1. Demand Response access to markets

Market overview

The Estonian Balancing and Wholesale markets are open to Demand Response in principle. However, explicit Demand Response participation is currently very limited to non-existent.

52 See: Tarbimise juhtimine [http://elering.ee/tarbimise-juhtimise-aruanne-3/] and Demand Side Response as Source for Flexibility [http://elering.ee/demand-side-response-as-source-for-flexibility-3/]

53 JRC (2016): "Demand Response status in EU Member States", available at: http://iet.jrc.ec.europa.eu/energyefficiency/sites/energyefficiency/files/publications/demand_response_status_in_eu28_member_states-online.pdf (retrieved 15 March 2017)

Wholesale market

ENTSO-E's terminology	Power Exchange	Total Volume Traded (2015)[54]	Load Access & Participation	Aggregated Load Accepted	Aggregated generation
Day Ahead	Nordpool	2016 Sell: 9,5 TWh 2016 Buy: 7,5 TWh	Data not available - should be procured from Nord Pool	Data not available - should be procured from Nord Pool	Data not available - should be procured from Nord Pool
Intraday	Nordpool	2016 Sell: 0,07 TWh 2016 Buy: 0,14 TWh	Data not available - should be procured from Nord Pool	Data not available - should be procured from Nord Pool	Data not available - should be procured from Nord Pool

Balancing and ancillary services

ENTSO-E's terminology	Elia's terminology	Market size	Demand Response Access & Participation	Aggregated Demand Response Accepted	Aggregated generation
FCR	-	0 MW	✗	✗	✗
aFRR	-	0 MW	✗	✗	✗
mFRR	-	1500 MW	0 MW	✓	✓
RR	-	0 MW	✗	✗	✗
Other ancillary services if relevant (re-dispatch, voltage control)	Emergency reserves	650 MW	✗	✗	✗
Capacity mech. (if any)	-	-	✗	✗	✗
Distribution network services	-	-	✗	✗	✗

Table 12: List of balancing market products, including volumes and load accessibility in Estonia

54 All information regarding the wholesale market provided by Elering, the Estonian TSO, 2017.

B. Markets open to Demand Response

Ancillary Services and Balancing Market. The market is open for both generation and demand-side resources originating from Estonia as well as from neighbouring countries. Currently there are no Demand Response providers participating in the balancing market in Estonia.

Wholesale market. There is no explicit exclusion of Demand Response from participating however there is a clear lack of a legal framework (i.e. definitions, responsibilities, and market functions) that prevents its ability to enter the market. At the same time, implicit Demand Response is used more widely with about a third of consumers buying electricity based on spot price.

Distribution Network Services. Demand-side flexibility could represent an important tool for local congestion management. Under the current legal framework, DSOs face congestion management issues given the impact of the integration of wind generation into the grid. As such, DSOs have been looking into flexibility projects as means to deal with congestion. They have also started to evaluate options for the use of DSR on the network[55]. Specifically, a pilot project between major DSO Elektrilevi OÜ and TSO Elering has been initiated to provide insight of possibilities regarding using DR to to mitigate grid congestion, among other things.

C. Restrictions related to distribution network operations

In Estonia, several DSOs provide different tariff regimes, some of which may incentivise flat consumption pattern. For instance, in Estonia some DSOs include a charge for the capacity of electricity to household and small industrial consumers while others have a simple flat energy tariff. However, DSOs also provide the option to choose a time-of-use-tariff (night/day) or base tariff for their energy component of the tariff[56]. As such, the danger of losing network tariff discounts depends on which tariff regime the consumer has chosen.

2. Service providers access to markets

A. Demand Response service providers access to consumer

In theory, all market players can participate in the balancing market in principle. However, **there is currently no aggregator model framework in place yet in the Estonian market.** The situation is dealt with through a case-by-case approach. The interaction between the aggregator and BRP/retailer (i.e. on correction of balancing perimeter, data, payments etc.) is agreed between both parties bilaterally as no legal requirements exist. The lack of rules for independent aggregators is strongly hindering the full potential of Demand Response participation and acting as the main barrier.

55 Elering (2015): "Demand-Side Response As Source For Flexibility" available at: http://elering.ee/public/Infokeskus/Demand_Side_Response_as_source_for_flexibility.pdf (retrieved 15 March 2017)

56 EC (2015): "Study on tariff design for distribution systems – Final Report" available at: https://ec.europa.eu/energy/sites/ener/files/documents/20150313%20Tariff%20report%20fina_revREF-E.PDF (retrieved 15 March 2017)

3. Product requirements

A. Main product requirements

The main enabler in terms of product requirements is that the minimum bid size was reduced to 1 MW to enable more providers to enter the market.

The following table contains an overview of the main programmes' technical requirements.

Wholesale market

Product	Market place	Minimum size (MW)
Day Ahead	Nord Pool	0,1
Intraday	Nord Pool	0,1

Balancing and ancillary services

Product	Minimum size (MW)	Gate Closure	Activation	Triggered (max. times)
mFRR	1	H-45 min	<15 min	0

Table 13: Description of some main Product requirements concerning the balancing products accessible to Demand Response in Estonia

4. Measurement and verification, payments, and penalties

A. Measurement & verification

Prequalification. The pool of loads in Estonia has to fulfil the requirements as an aggregate which means no minimum bid size and no technical requirements for a single unit. As such, the prequalification procedure does not in practice present any particular difficulties or challenges for Demand Response participation. For balance settlement and activation verification, the specific units should be known.

Baseline methodology. There is no methodology for baselines defined yet as Estonia is just in the process of developing frameworks for such services. At the same time, the TSO's Information and Communication technology is adapted to handle aggregation, for instance there is the capability to accept bids, activate the bids and receive data on the actual response of the activations.

B. Availability/utilisation payments

Balancing and ancillary services

Product	Availability payments	Utilisation payments[57]	Access
mFRR	Not applied	Pay-as-bid	Bi-lateral contract

Table 14: Overview of availability and utilisation payments in the balancing market in Estonia

57 When the common regional Baltic balancing market is implemented from 2018 then marginal pricing is applied (as foreseen to be requested by the EB NC).

Finland

Overview

Finland sources a significant share of its capacity needs from its neighbouring countries, such as Sweden, Norway, Estonia, and Russia. At the end of 2015, the amount of electricity transmission capacity that Finland sourced from these countries was around 5,250 MW[58].

Finland has completed several steps to allow Demand Response participation. In fact, active market participation of Demand Response and aggregation are possible in all markets, but limitations still exist. For example, independent party aggregators are only accepted in FCR-D markets. Moreover, aggregating resources from different BRPs' areas is only allowed in FCR-D markets, even if the aggregator is able to provide BRPs with the adequate information to mitigate their balancing risks. Additionally, Demand Response only exists in large scale form in the FCR-D and mFRR markets. There have however been some pilot projects for FCR-N that ended in January 2017, and a minor commercial participation from household loads (100 kW) has emerged recently in the FCR-N. Conversely, there is no participation in the aFRR market today. The minimum bid size limits the full potential of Demand Response for some products; aggregation rules are also an important barrier. Lastly, the payments are still quite attractive for the ancillary products.

Overall, there is an increasing trend in favour of business models for Demand Response today, covering most offerings in some reserve products and small-scale participation through aggregation.

58 CEER (2016a): "National Report 2016 to the Agency for the Cooperation of Energy Regulators and to the European Commission", available at: http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National_Reporting_2016/NR_En/C16_NR_Finland-EN.pdf (retrieved 15 March 2017)

1. Demand Response access to markets

Market overview

All the products are legally open to Demand Response. However, only some pilot projects participate in the Frequency Containment Reserve for Normal Operation (FCR-N), and currently there is no participation from the demand side in Automatic Frequency Restoration Reserve (aFRR).

Wholesale market

ENTSO-E's terminology	Power Exchange	Total Volume Traded[59]	Demand Response Access & Participation[60]	Demand Response Accepted	Aggregated Generation
Day Ahead	Nordic and Baltic day ahead markets	374 TWh (2015)	✔ 200-600 MW	✔	✔
Intraday	Nordpool	5 TWh (2015)	✔ 0-200 MW	✔	✔

59 CEER (2016a), Ibid.

60 Fingrid (2017): "Demand-side management", available at: http://www.fingrid.fi/en/electricity-market/Demand-Side_Management/Pages/default.aspx (retrieved on 31st January 2017)

Balancing and ancillary services

ENTSO-E's terminology	TSO's terminology	Market size	Demand Response Access & Participation[61]	Demand Response Accepted	Aggregated Generation
FCR	Frequency containment reserve for normal operation (FCR-N)	~140 MW[62,63]	✔ 1MW	✔	✔
	Frequency containment reserve for disturbances (FCR-D)	220-260 MW	✔ 240MW	✔	✔
aFRR	Automatic frequency restoration reserve (aFRR)	70 MW[67,68]	✘	✘	✘
mFRR	Balancing energy market, balancing capacity market and fast disturbance reserve (mFRR)	⊘	✔ 100-300 MW	✔	✔
	Strategic reserves	299 MW	✔ 10 MW	✔	✔
Other ancillary services if relevant (re-dispatch, voltage control)	⊘	⊘	⊘	⊘	⊘
Capacity mech. (if any)	⊘	⊘	⊘	⊘	⊘
Distribution network services	⊘	⊘	⊘	⊘	⊘

* Fingrid's Estimation

Table 15: List of balancing market products, including volumes and load accessibility in Finland

61 Fingrid (2017), Ibid.

62 Fingrid (2017a): "Reserves", available at: http://www.fingrid.fi/en/electricity-market/reserves/Pages/default.aspx (retrieved on 31st January 2017)

63 Fingrid (2014): "Tilannekatsaus varavoimalaitoksiin, nopeaan häiriöreserviin sekä kysyntäjoustoon (Status of fast reserves and elasticity of demand)", available at: http://www.fingrid.fi/fi/asiakkaat/asiakasliitteet/Kayttotoimikunta/2014/21.5.2014/Tilannekatsaus%20varavoimalaitoksiin%20nopeaan%20h%C3%A4iri%C3%B6reserviin%20kysynt%C3%A4joustoon.pdf (retrieved on 31st January 2017) * Fingrid's Estimation

B. Markets open to Demand Response

Balancing market and ancillary services. All ancillary services are in theory open to Demand Response. However, some limitations exist concerning aggregation. The aggregation of resources from different balancing groups is only permitted in FCR-D. This limits the full potential of Demand Response in other reserve markets.

Participation in the Frequency Containment Reserve for Normal Operation (FCR-N) is limited to some pilot projects of load curtailment. The other programmes have a wider participation. In the manual frequency restoration reserve (mFRR) Demand Response represents a significant share with approximately 100-300 MW[64] – about a quarter of the total capacity. The TSO has also run some pilot projects in different reserve markets[65]. There was a pilot project that focused on independent aggregator participation in FCR-N market which recently finished in January 2017. Currently Fingrid is tendering for an mFRR aggregation pilot project that will look into enabling aggregation from multiple balances and independent aggregator participation in the regulating power market. The aim is to start the pilot in 2017 and conclude it in 2018[66].

Wholesale Market. The Spot Market (day-ahead Elspot and intraday Elbas) is open to Demand Response and aggregation, but only directly from BRPs. Information related to consumers' bids into Nord Pool is not public, but Fingrid estimates that between 200 and 600 MW of consumers' flexibility participates in Elspot and up to 200 MW in Elbas.

Overall, and similarly to the other Nordic markets, a significant share of electricity is traded in the spot market. In 2015, the volume of electricity traded in the day-ahead markets was 374 TWh, and in the intraday market 5 TWh (this also includes Nord Pool intraday trading in Germany)[67].

Strategic Reserve. Finland has established a Strategic Reserve mechanism, which opened to Demand Response in 2013. A capacity of 10 MW was contracted for the winters 2015-2016 and 2016-2017 (in addition to the 285 MW contracted on the generation side for the same period). However, there has been no fixed amount of further flexibility that will be contracted for the foreseeable future in the strategic reserve mechanism. In February 2017, the Finnish Energy Authority announced that the needed peak load reserve capacity for the period from July 2017 to June 2020 will be 729 MW including 22 MW of Demand Response, the costs for which will be 14 M€/year.

Distribution network services. Demand-side flexibility could represent an important tool for local congestion management. The pilot project Smart Grids and Energy Markets (SGEM)[68] was run in 2014, to evaluate the potential of residential dynamic Demand Response, focusing on the following five areas: Smart grid architectures and distribution infrastructure, Intelligent management and operation, Active resources, Market integration, and New business models. In addition, there was also a FLEXE pilot project with one of its objectives to define flexibility requirements for planning and operation of integrated energy markets[69]. Direct

64 Fingrid (2017): "Demand Side Management", available at: http://www.fingrid.fi/en/electricity-market/Demand-Side_Management/Pages/default.aspx (retrieved on 31 January 2017)

65 Fingrid (2014a): "European Utility Week 2014 Amsterdam, Pre-conference seminar, November 3rd 2014"

66 Fingrid (2017b): "Fingrid is looking for partner to an aggregator pilot project in the balancing energy markets", available at: http://www.fingrid.fi/en/electricity-market/balancing-power/aggregator%20pilot%20project/Pages/default.aspx (retrieved on 31 January 2017)

67 CEER (2016a): "National Report 2016 to the Agency for the Cooperation of Energy Regulators and to the European Commission", available at: http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National_Reporting_2016/NR_En/C16_NR_Finland-EN.pdf (retrieved 15 March 2017)

68 CLEEN: "Smart Grid and Energy Market" project, available at: http://www.cleen.fi/en/sgem (retrieved on 15th April 2015)

69 http://clicinnovation.fi/activity/flexe/

load control of about 7000 electrically heated ToU partial storage houses in rural areas, showed a potential of about 10 MW, and dynamic load control capability was implemented in about 35 MW of full storage electrically heated houses, identifying a 14 MW potential for Demand Response[70].

However, at present there are no significant incentives for DSOs to procure Demand Response. The DSO's role in controlling flexibility is actually quite unclear. Moreover, in Finland, there are only incentives for OPEX; and OPEX incentives for R&D are approved as long as they do not exceed 1% of the allowed revenues. CAPEX for R&D and pilot projects are also treated as any other costs[71].

C. Restrictions related to distribution network operations

The network tariff regime offered by Distribution System Operators is a night / day time tariff which negatively impacts on the potential use of demand-side response on household levels (i.e. most flexible loads occur during night time when the tariff is lower, hence flexibility is not available during day-time when more needed in system). While this does not incentivise flat consumption, it still inhibits the increased use of Demand Response, and as such is a barrier to the further promotion of it in Finland.

2. Service providers access to markets

A. Demand Response service providers access to consumer

Demand Response consumers typically consist of large industrial consumers (e.g. forest and chemistry industry), partly also small industrial consumers / services (e.g. supermarkets) and households. The main types of aggregators that operate in the balancing market are resource owners and independent aggregators in the FCR-D reserve. Aggregation of generation in one balancing group is also quite common; most generation resources are aggregated and offered as one bid in the market, specifically in the mFRR. In Spring 2017, aggregated generation resources and loads under the same BRP will be allowed in the mFRR. Likewise, this is planned to be executed in the FCR-N in the second half of 2017.

Independent aggregators can only access the market in agreement with the consumer's retailer/BRP (except in FCR-D) and so the aggregator must be either the owner of the balancing resource, its retailer or BRP. In FCR-D, independent aggregators are accepted and so agreement with resource's BRP is not needed. Consequently, consumers do not have access to a Demand Response service provider of their choice in markets other than FCR-D. This lowers competition around consumer-centred services and significantly hampers demand-side development. As such, t**here is no specific framework governing the relationship between the BRP and an independent aggregator.**

Imbalance settlement after load management. The BRPs do not pay for imbalances due to reserve activations, as they are settled by the TSO. The TSO corrects the curve of the BRP's area taking into account the balancing orders and activations of automatic

70 VTT Technical Research Centre of Finland (2014): "Demand Response in the Nordic countries: Principles, barriers, Aggregation and Experiences", page 55

71 Eurelectric (2016): "Innovation incentives for DSOs - a must in the new energy market development" available at: http://www.eurelectric.org/media/285583/innovation_paper-2016-030-0379-01-e.pdf (retrireved 15 March 2017)

reserves. In FCR-D, reserve activations are not corrected due to low amount of activated energy.

3. Product requirements

A. Main product requirements

Ancillary Services. Some limitations still exist in the minimum bid size for some frequency reserves and for the strategic reserve.

Wholesale Market. Both day-ahead and intraday markets require a minimum size of 0,1 MW to participate. Smart meters have been almost fully deployed and retailers are legally required to make available tariffs based on hourly prices.

These tariffs enable consumers to lower their energy bills in the short to medium term. Firstly, the customers, by accepting volatility in prices, no longer pay the retailer's risk premium, which lowers retail energy prices when averaged over an extended period of time. Secondly, consumers have the opportunity to adapt their energy consumption over time to choose cheaper periods. That said, the Finnish programmes are not always directed toward providing consumer feedback or encouraging demand-side flexibility, which would require communication technology and/or some form of home/business automation. These automation offerings are currently being developed and deployed in limited areas, such as, but not limited to, the Helsinki region. In fact, it is possible to buy automatic controlling devices and services throughout the country but they are quite costly. It is for this reason that they are not yet widely spread across the country. Hourly priced tariffs on the other hand are quite popular already in Finland.

Wholesale market

Product	Market place	Minimum size (MW)[72]
Day ahead	Nordic and Baltic day ahead markets	0,1
Intraday	Nordpool	0,1

72 All pertinent data related to the wholesale market provided by Finnish TSO, Fingrid.

Balancing and ancillary services

Product		Minimum size (MW)[73]	Notification Time	Activation	Triggered (max. times)
FCR-N		0,1 MW	3 min	Automatic out of 49,90 - 50,10 Hz	Several times per hour
FCR-D	linear or partly linear	1	50% in 5s, 100% in 30s	Automatic < 49,9Hz	Several times a day
	on-off model	1	5s 49,7 Hz or 3 s 49,6 Hz or 1 s 49,5 Hz	Automatic < 49,7Hz or 49,6 Hz or 49,5 Hz	Several times a year
FRR-A		5	2 min	Automatic	Several times a day
FRR-M		10 (5 MW if electrical activation is used)	15 min	Manual	About once a year
Strategic reserves		10	15 min	Manual	0-2 times in winter
Balancing Market		10	15 min	Market based	Several times per day

Table 16: Description of some main Product requirements concerning balancing products accessible to DR in Finland

73 Fingrid (2017): “Demand-side management”, available at: http://www.fingrid.fi/en/electricity-market/Demand-Side_Management/Pages/default.aspx (retrieved on 31 January 2017)

4. Measurement and verification, payments, and penalties

A. Measurement & verification

Prequalification. The pool of loads has to fulfil all requirements, including pre-qualification, as an aggregated resource. This is a critical enabler of Demand Response as it allows the aggregator to act as mediator for the consumer, protecting them from onerous and complex technical pre-qualification measures. There is also no minimum required size for consumer participation and no technical requirements for the single unit.

Baseline methodology. Several practical questions remain around measurement and verification. Fingrid is still actively working with market participants to solve these issues.

B. Availability/utilisation payments[74]

FCR-D only provides availability payments while FCR-N provides both availability payment and utilisation payment based on net energy. There is also small scale DSR commercial participation in the FCR-N and large scale participation in the FCR-D. The prices have remained quite stable for the past three years. In the reserves where utilisation payments are provided, some issues regarding the aggregation of loads from different BRPs' perimeters still exist. In mFRR, the balancing power market provides only utilisation payment ('marginal pricing') while there are capacity payments in the strategic reserves market ('pay-as-bid').

74 Fingrid (2017c): market places, average data 2017, available at: http://www.fingrid.fi/en/electricity-market/load-and-generation/Demand-Side_Management/Market_places/Pages/default.aspx (retrieved on 15th January 2017

Balancing and ancillary services

Product		Availability payments	Utilisation payments	Access
FCR-N		13,00 €/MW/h[75] for yearly[76]	0[77]	Yearly Tender Hourly Market
FCR-D	standard	4,7 €/MW/h[78] for yearly[79]	0	Yearly Tender Hourly Market
aFRR		0[80, 81]	Hourly market + Market price[82]	Hourly Market
Balancing Energy Market (mFRR)		0	Marginal	Hourly bids
Balancing Capacity Market (mFRR)		Pay as bid	Marginal	Weekly tenders
Strategic reserves		Pay as bid	0[83]	Long-term contract

Table 17: Overview of availability and utilisation payments in the balancing market in Finland

C. Penalties

For Demand Response in the Balancing energy market and spot markets (Elspot and Elbas), penalties are based on the imbalance settlement price which corresponds to the Nordic balancing market price. In the balancing capacity market, reserve providers' availability affects the availability payment but the maximum penalty to forgo all availability payment, i.e. no pay back to the TSO. In the FCR the penalty is 100 % pay back to TSO for non-delivery. To register as a BRP, the fee is a reasonable € 200/month, but a bank deposit of minimum € 200.000 is required, in case of bankruptcy.

75 Fingrid (2017a): information, value for 2017
76 this is marginal price from the yearly tendering, marginal price is used also for hourly market
77 marginal price from balancing energy market is used, the net energy is compensated
78 Ibidem
79 this is marginal price from the yearly tendering, marginal price is used also for hourly market
80 pay as bid used for capacity price. In 2016 the average price for upward capacity was 23,4 €/MW,h and 19,7 €/MW,h for downward capacity
81 pay as bid used for capacity price. In 2016 the average price for upward capacity was 23,4 €/MW,h and 19,7 €/MW,h for downward capacity.
82 marginal price from balancing energy market is used
83 marginal price from balancing energy market is used, the net energy is compensated

France

Overview

Since 2003, large industrial customers have been participating in the balancing mechanism, and from 2007, the first pilots were run in order to introduce aggregated residential load to the mechanism. In 2014, for the first time an industrial consumer provided its energy reduction as a FCR or Primary Reserve[84]. This programme, together with Secondary Reserve (aFRR), has been accessible to load participation since 1 July 2014.

The NEBEF mechanism, which allows curtailed load to bid as energy directly into the wholesale electricity market was introduced in December 2013. The volume activated during the experimentation phase was quite modest (310 MWh in 2014), partially due to a mild winter. Since then the participation has been 1.522 MWh (2015) and 10.313 MWh (2016)[85].

The Capacity Mechanism, which started in January 2017, is open to Demand Response and is based on a 'decentralised market'; where market participants contract directly amongst themselves. The EPEX auction where capacity certificates are sold is centralized and anonymous.

In terms of upcoming regulatory changes that could impact Demand Response, a draft decree of the Energy Transition Law that is being scrutinised by the Conseil d'Etat (Court of administrative justice) could provide for a new financial settlement framework whereby a significant part of the payment to retailers with curtailed customers will be charged to retailers rather than to demand response providers.

Main enablers. Balancing mechanism and ancillary services are open to aggregated Demand Response. Loads can also participate in the Day Ahead and, since January 2017, in Intraday market via NEBEF. Demand Response is also allowed in the Capacity Mechanism. The French TSO has been adjusting programmes' requirements, to better fit the capabilities of the demand side. The relationship between aggregators and retailers/BRPs was regulated and a standardised framework put in place in 2013.

Main barrier. Participation in the automatic FRR is reserved to generators and only possible for Demand Response via a secondary market. Primary and Secondary controls activation are made on a pro-rata basis according to each generator's obligation. A merit order based for secondary control activation is being discussed but will not be put in place in the short term (targeted implementation date: January 2020). Some participation requirements (for reserves) are still unfavourable to Demand Response. Furthermore, introducing more baseline methodologies could enable more consumer participation.

84 RTE (2014) : "Les consommateurs industriels désormais fournisseurs de services pour la fréquence du système électrique français", available at : http://clients.rte-france.com/lang/fr/clients_producteurs/services/actualites.jsp?id=9693&mode=detail (retrieved on 20 May 2015)

85 RTE (2016): 'Volumes d'Effacement NEBEF, tous Opérateurs d'Effacement confondus, agrégés à la maille France', available at: http://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_effacements.jsp, retrieved Nov. 2016. Aggregated 'Chroniques' (delivered) values except for 2016, 'Programmes' values.

1. Demand Response access to markets

Market overview

The charts below show ancillary services and other mechanisms where Demand Response participation is allowed. On the wholesale market, the experimental phase of the NEBEF mechanism (2014) resulted in a load participation of 310 MWh. Since then the participation has been 1 522 MWh (2015) and 10 313 (2016)[86] The first auction of the French Capacity Mechanism was held in December 2016.

Wholesale market

ENTSO-E's terminology	Market place	Total bid volumes	Load Access & Participation	Aggregated Load Accepted	Aggregated generation
Day Ahead	EPEX Spot	106,4 TWh in 2015[87]	✔ through NEBEF (1,5 GWh in 2015, 10 GWh in 2016)	✔ (NEBEF)	✔
Intraday	EPEX Spot	5,43 TWh in 2015[88]	✔ through NEBEF (starting from Jan. 2017)	✔ through NEBEF (starting from Jan. 2017)	✔

86 RTE (2016), Ibid. Aggregated 'Chroniques' (delivered) values except for December 2016, 'Programmes' values.

87 CRE (2016) : 'L'Observatoire des Marchés de Gros du 4eme Trimestre 2015', available at http://www.cre.fr/marches/observatoire-des-marches, table 3, p. 13, (retrieved in November 2016)

88 CRE (2016), Ibidem

Balancing and ancillary services

ENTSO-E's terminology	TSO's terminology	Tot. Capacity Contracted[89]	Demand Response Access & Participation	Aggregated Demand Response Accepted	Aggregated Generation
FCR	Primary Control *(Réglage Primaire de Fréquence)*	600 – 700 MW	✔ (≈60MW) *though FCR cooperation*	✔ *though FCR cooperation*	✔ *through FCR cooperation*
aFRR	Secondary Control *(Réglage Secondaire de Fréquence)*	600 – 1000 MW	✔ Q3-Q4 2016, for around 10 MW	✔ *via **secondary** market*	✔
mFRR	Fast Reserve *(Réserves rapides)*	Max. 1000 MW	✔ (480 MW)	✔	✔
RR	Complementary Reserve *(Réserves complémentaires)*	Max. 500 MW		✔	✔
DSR - RR	Demand Response Call for Tender* *(Appel d'Offres d'Effacement)* **New Status in 2017*	2014: max. 850 MW 2015: 1200 to 1800 MW 2016: max. 2100 MW 2017: 750 to 1400 MW[90]	✔	✔	⊘
Other ancillary services if relevant (re-dispatch, voltage control)	⊘	⊘	⊘	⊘	⊘

89 RTE (2009), "Documentation Technique de Référence, Chapitre 4 – Contribution des utilisateurs aux performances du RPT, Article 4.1 – Réglage Fréquence/Puissance", available at: http://www.rte-france.com/uploads/Mediatheque_docs/offres_services/reftech/24-04-09_article_4-1__v3.pdf (retrieved on 10 June 2015)

90 RTE (2016a): 'Un potentiel d'effacement de 2,5 GW pour l'hiver 2017', available at: https://clients.rte-france.com/lang/fr/visiteurs/services/actualites.jsp?id=9759&mode=detail, (retreived 19 December 2016)

91 RTE (2017a): 'Niveau global de Garantie de Capacités', available at: http://clients.rte france.com/lang/fr/visiteurs/vie/meca_capa/meca_capa_nggc.jsp (retrieved on 17 March 2017)

92 RTE (2016b):'Lancement d'une consultation pour la réservation de capacités d'effacement pour l'année 2017', available at : https://clients.rte-france.com/lang/fr/visiteurs/services/actualites.jsp?id=9757&mode=detail (retrieved October 2016).

93 RTE (2016c): 'Un potential d'effacement de 2,5 GW pour l'hiver 2017', available at : http://clients.rte-france.com/lang/fr/visiteurs/services/actualites.jsp?id=9759&mode=detail (retrieved December 2016)

Capacity mech.	Capacity mechanism *(Mécanisme de capacité)*	89.7 GW[92]	✔ 2017: 1700 MW of certified exchangeable capacities and 800 MW of capacity obligation reduction from retailers[92,93]	✔	✔
Distribution network services	⊘	⊘	⊘	⊘	⊘

Table 18: List of balancing market products, including volumes and load accessibility in France

B. Markets open to Demand Response

Limit to aggregation: In the French market and balancing programmes, bids should include Demand Response only or generation only. One cannot aggregate both Demand Response and generation within the same bid. However, an experiment starting in January 2017 will allow the enabling of aggregated Demand Response together with on-site generation for primary control capacities (FCR)[94].

Ancillary services. These two programmes are open to Demand Response:

- Frequency Containment Reserves *(Réglage Primaire de la Fréquence)* is directly open to Demand Response through the FCR cooperation (with DE, AT, CH and NL)

- Automatic Frequency Restoration Reserves *(Réglage Secondaire de la Fréquence)* is still related to obligations for the major generators who can then sub-contract their provision in a secondary market.

Demand Response (including aggregated loads) participation has been legally possible since July 2014, but limited to sites located on the transmission network. The participation of consumers connected at the distribution level has been theoretically possible since January 2016. Simplified rules were put in place first in 2016 (with limitations such as only being able to provide symmetric valuation) with full 'normal participation' not enabled until 2017. Volumes and their origin are notified to RTE (without mention of price).

Another emergency service was created in 2013, to value interruptibility service through direct contracts between the TSO and electricity-intensive consumers. The total amount of these contracts was 1.500 MW for 2017[95].

Balancing Mechanism: Manual frequency restoration reserves (mFRR) and replacement reserves (RR) are open to Demand Response. For Demand Response, this includes consumers located at the distribution network level; RTE mentions in particular the important potential of the tertiary sector[96].

94 CRE (2016a): "Délibération de la Commission de régulation de l'énergie du 1er décembre 2016 portant approbation des Règles Services Système fréquence et des Règles Services Système tension" available at :

95 RTE (2017) : 'Résultats de l'appel d'offres Interruptibilité 2017' - 09/11/2017

96 RTE (2016d) : "Les résultats sont également marqués par la participation de nouveaux gisements, et notamment de sites du secteur tertiaire (par exemples hyper et supermarchés)- Un potentiel d'effacement de 2,5 GW pour l'hiver 2017 ", available at : http://clients.rte-france.com/lang/fr/

Wholesale Market. The test phase of the Demand Response mechanism called NEBEF *("Notification d'Échange de Blocs d'Effacement")* took place from December 2013 to December 2014 on the wholesale market. The rules of the NEBEF mechanism were issued on 19 December 2014 and continue to be developed[97]. Offers through the NEBEF mechanism were intensive at the end of 2016, due to high wholesale prices (mainly because of nuclear power plant unavailability, but also because of low temperatures). In the month of December 2016, the total volume traded was 4 GWh. The new rules for the NEBEF mechanism (NEBEF 3.0) have introduced amongst a variety of other aspects, Intraday and Day-Ahead market participation access.

Currently, activations of Demand Response programs are managed by the TSO based on the system requirement, providing rights to all retailers to offer variable tariffs. Depending on the tariff, the programs are activated by the TSO (for TEMPO; related to consumption forecast) or by EDF (for EJP; based on economic criteria). More generally, in the context of smart meter roll out, all retailers are able to provide non-regulated tariffs with the same type of options based on wholesale electricity market prices.

Capacity mechanism. The French capacity mechanism is a 'decentralised market' based on the obligation of the retailer to get a certain amount of capacity certificates depending on the consumption of its consumers' portfolio. Capacity resources (demand response and generation) have the obligation to be certified and provide certificates according to their expected availability. Demand response can also be valued as a reduction of the supplier obligation. The market, in place since January 2017, is open to generation and demand-side participation. The first rules were issued on 22 January 2015. Following the Commission inquiry on capacity mechanisms, modified rules have been published on 29 November 2016[98].The "capacity" will reflect only the availability of Demand Response in the market[99]. Its effective activation will be counted through the balancing mechanism or wholesale market.

A former DR Call for Tender, initially implemented as transitional mechanism before enforcement of Capacity Mechanism, was converted into a support mechanism to promote DR in France as of January 2017

Distribution network services. Demand-side flexibility could represent an important tool for local congestion management. Enedis[100] has 18 demonstration projects concluded or in progress. They aim to test programmes that could allow for better network management. The projects range from RES integration to evaluation of so-called active demand solutions[101]. Apart from these projects, DSOs in general are not able to contract flexibility for constraint management. The current regulatory framework that governs the incentive structure takes into account the performance of the DSO including its operating costs (OPEX)[102,103]. Provided it includes an incentive for cost reduction and

visiteurs/services/actualites.jsp?id=9759&mode=detail (retrieved on 15 December 2016)

97 the list of players participating in NEBEF Mechanism is available on the French TSO' website : https://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_operateurs.jsp

98 Ministère du Développement Durable (2016): "Arrêté du 29 novembre 2016 définissant les règles du mécanisme de capacité et pris en application de l'article R. 335-2 du Code de l'énergie", available at : http://www.developpement-durable.gouv.fr/IMG/pdf/Regles_du_mecanisme_de_capacite_-_Version_arretee_29_novembre_2016.pdf (retrieved November 2016)

99 To participate, the Demand Response operator will have to prove its ability to activate Demand Response programmes matching the capacity it claims for in its portfolio.

100 Enedis, former ERDF, is a branch of the EDF group and the French major DSO. It covers 95% of mainland France territory.

101 more information on ENEDIS's website, at the following address: http://www.enedis.fr/smart-grids-ou-reseaux-intelligents (retrieved on 10 June 2015)

102 EvolvDSO (2014): "Evaluation of current market architectures and regulatory frameworks and the role of DSOs" available at: http://www.evolvdso.eu/getattachment/70a9e337-5fb3-4300-a7d5-0b5b0b56ab1f/Deliverable-1-2.aspx (retrieved 15 March 2017)

103 EC (2015): "Study on tariff design for distribution systems – Final Report" available at: https://ec.europa.eu/energy/sites/ener/files/documents/20150313%20Tariff%20report%20fina_revREF-E.PDF (retrieved 15 March 2017)

alternatives to network investment,this could open the door to the purchase of flexibility services by the DSO.

C. Restrictions related to distribution network operations

France is one of very few – if any – examples in Europe where the tariff promotes a Demand Response programme based on critical peak pricing. Under the critical peak pricing scheme, the consumer is requested to reduce demand with a 1 Day notice signal for some given days a year[104].

The French regulator, Commission de Régulation de l'Energie (CRE), approved in November 2016 the introduction of a critical peak pricing scheme in the current distribution tariff (TURPE 4) from July 2017, for the medium voltage delivery point (above 1 kV and up to 50 kV, identified as "HTA" classification)[105]. In January 2017, the French energy and Environment Minister asked the CRE to revise this decision to go further and widen the critical peak pricing to low voltage (up to 1 kV, identified as "BT"). This request was rejected by the French Regulator[106].

2. Service providers access to markets

A. Demand Response service providers access to consumer

The main types of Demand Response consumers in France include mostly industrial consumers, i.e. large industrial consumers using electrolysis or similar processes that participate in primary and secondary control; more diverse industrial consumers that are involved into balancing products; as well as residential consumers (~ 10 000).

The aggregator does not require BRP's agreement prior to load management. Since 2014, consumers or aggregators have been able to provide their flexibility to the Balancing and NEBEF, without the need to contract bilaterally with a BRP. However, participation of Demand Response to aFRR is only possible through a secondary market. As such, consumers and aggregators have to sign bilateral contracts with producers to sell them their products. In the capacity mechanism, Demand Response can be valued without having to contract with retailers. The EPEX auction where capacity certificates are sold is centralized and anonymous.

Imbalance settlement after load management. The rules on the imbalance settlement are under evaluation within on-going discussions on the new law on energy transition. In the balancing mechanism, ancillary services and wholesale markets, the BRP perimeter is corrected by the TSO after the load management.

BRP-aggregator adjustment mechanism. The law from 15 April 2013 provides for the payment (i.e. compensation) by the aggregators to the retailers/BRPs for the sourcing costs of the supplied energy[107]. The set

104 EC (2016): "Impact assessment support study on: "Policies for DSOs, Distribution Tariffs and Data Handling"" available at: https://ec.europa.eu/energy/sites/ener/files/documents/ce_vva_dso_final_report_vf.pdf (retrieved 15 March 2017)

105 CRE (2016d): "Délibération de la Commission de régulation de l'énergie du 17 novembre 2016 portant décision sur les tarifs d'utilisation des réseaux publics d'électricité dans les domaines de tension HTA et BT" available at: www.cre.fr/documents/deliberations/decision/turpe-hta-et-bt/consulter-la-deliberation (retrieved on 15 March 2017)

106 CRE (2017): "Délibération de la Commission de régulation de l'énergie du 19 janvier 2017 portant décision sur la demande de la ministre de l'environnement, de l'énergie et de la mer, en charge des relations internationales sur le climat, d'une nouvelle délibération sur les tarifs d'utilisation des réseaux publics d'électricité dans les domaines de tension HTA et

107 Décret n° 2014-764 du 3 juillet 2014 relatif aux effacements de consommation d'électricité, available at: http://www.legifrance.gouv.fr/affichTexte.

of payment rules include a "regulated regime" where the TSO sets a price reflecting the cost of the energy component of the retail price, and a "contractual" and a "corrected" regime. The rules apply to electricity reductions that are bid into the wholesale market and into Balancing Mechanism. The existence of a mechanism 'per default', avoiding resource-consuming negotiations, is an important enabler for securing aggregator's access to the market, and therefore Demand Response development.

Details concerning the rules on imbalance settlement and financial adjustment for each type of market are provided below.

- **Ancillary services:** Participation was extended to consumer on the distribution network in January 2016, where load curves are corrected based on the energy curtailed, which is then invoiced by the electricity retailer at the retail price.

- **Wholesale market:** There are 3 different regimes for the BRP's remuneration / payment:

(1.) Contractual[108] regime: the payment is decided by a contractual arrangement between the DR operator and the retailer of the site.

(2.) Regulated regime: a financial transfer (in €/MWh) from Demand Response operator to the retailers of the curtailed customers (the settlement) is supposed to represent only the energy component of the retailer price for the customers participating in Demand Response programmes. The price scale is set by the TSO, and is differentiated for metered and profiled sites (as they have different kinds of supplies – i.e. market supply or supply based tariffs). This settlement price has been introduced to ensure that the retailer/BRP of curtailed customers maintains the injection of the energy that it has sourced for its customers.

(3.) "Corrected consumption" regime: initially provided for consumers connected to the transmission network, the consumer's retailer invoices the electricity related to the DR event to the aggregator/consumer. The current NEBEF rules 3.0 extend this regime to certain consumers connected to the distribution network.

- **Balancing mechanism:** At the transmission network level, consumers' load curves are corrected based on the energy curtailed, which is then invoiced by the electricity retailer at the retail price. At the distribution network level, up until 2014, electricity retailers were not compensated. Since 2014, either they are compensated:

(1.) By consumers, based on regulated scales approved by the regulator ("regulated regime"), with consumers below 36 kVA benefitting from reduced payment to the retailer[109], or

(2.)Decided by a contractual arrangement between the Demand Response operator and the electricity retailer ("contractual regime").

Additionally, the TSO has been investigating to what extent the possible shift or rebound effects caused by Demand Response could be taken into account in the settlement scheme. The report was published in March 2016[110]. A decree is currently being scrutinised by the Conseil d'Etat (supreme court for administrative justice).

- **Capacity mechanism:** In the French capacity

do?cidTexte=JORFTEXT000029190216&categorieLien=id (retrieved on 10 June 2015)

108 This has been mainly adapted to situations where aggregator and supplier belong to the same legal entity

109 For consumer under 36 kVA, the Energy Transition Law put in place a reduced payment for consumer where RTE contributes to the payment to the retailer. However this disposition has been criticised by the Competition Authority in a recent decision (Avis n° 16-A-22 du 22 novembre 2016 concernant l'effacement de consommation dans le secteur de l'électricité, available at: http://www.autoritedelaconcurrence.fr/pdf/avis/16a22.pdf)

110 RTE (2016e): "Évaluation des économies d'énergie et des effets de bord associés aux effacements de consommation", available at: https://clients.rtefrance.com/htm/fr/mediatheque/telecharge/20160401_Rapport_report_complet.pdf (retrieved on March 2016)

mechanism, the product reflects only the availability of Demand Response in the market. The effective activations are counted through the balancing or NEBEF mechanism, which include BRP compensation mechanisms.

3. Product requirements

A. Main product requirements

As a critical enabler, all main electricity markets are open to Demand Response. Moreover, the establishment of the capacity mechanism could provide a source of long-term investment stability for Demand Response.

The French TSO RTE has worked on a continuous improvement of products on the ancillary services market to be aggregation-friendly, i.e. to allow aggregation irrespective of the type of network, metering, electricity retailer, BRP, etc. Consumers with a curtailment clause in their retailer contract may participate in forms of Demand Response, so long as the Demand Response program is declared after the curtailment period, and if it is still technically possible to measure the level of Demand Response.

RTE does not accept mixed offers: bids should include (aggregated) generation only or aggregated demand only. Demand Response and generation cannot be mixed into a single VPP offer. This represents a barrier for the development of both resources in the future, as Demand Response could represent an interesting resource to balance renewable variable output.

Starting from 1 January 2017, Demand Response will be able to bid into the intraday market.

Wholesale market

Product	Market place	Minimum size (MW)
Day Ahead	EPEX Spot	0,1 MW
Intraday	EPEX Spot	0,1 MW
NEBEF (DA & ID)	EPEX Spot	0,1 MW

Table 19: Description of some main Product requirements in the wholesale market in France

Ancillary and Balancing services

Product	Minimum size (MW)	Notification Time[111]	Activation	Triggered (max. times)
Primary Control (FCR)	1 MW	< 30 s	automatic	Triggered continuously
Secondary Control (aFRR)	1 MW	< 400 s	automatic	Unlimited
Fast Reserves (mFRR)	10 MW	13 min	manual	Unlimited
Complementary Reserves (RR)	10 MW	30 min	manual	Unlimited
DR Call for tender (DSR – RR)	1 MW	2 h	manual (ongoing works on automation)	Up to 40 days/year

Table 20: Description of some main Product requirements in the balancing products accessible to DR in France

Wholesale Market. To participate as a provider within NEBEF mechanism, the Demand Response operator is required to sign a contract with the TSO. Declarations indicating available Demand Response volumes, are submitted by the providers between D-1 9h30 and D 22h.

Ancillary Services.

- **FCR** *(Primary Control)* **and aFRR** *(Secondary Control)*. Minimum quantities for FCR & aFRR are 1MW. FCR & aFRR are mandatory symmetrical products. Demand Response participation was opened to consumer sites located on the distribution network in January 2016.

- Allowing asymmetrical products (on the certification side, not on the market side since the TSO will continue to buy symmetric products) is planned for 2017; Demand Response participation from distribution grid and more aggregation-friendly conditions are coming in the near future.

- **mFRR** *(fast reserves)* **and RR.** The minimum bid was set at 10 MW for mFRR and RR om April 2014. Although this is not the 1-5 MW requirement achieved in most Demand Response friendly markets in Europe, it is a significant improvement over the earlier 50 MW requirement.

- Experimentation for 1-10 MW **Replacement Reserve** has been taking place since April 2015 for RR, and for mFRR in October 2015. As for the availability within mFRR, the RTE tender allows much flexibility: Demand Response is able to participate for certain days only (not requiring 24/7 availability).

The TSO activates bid volumes on the Balancing Mechanism (mFRR, RR, DSR-RR) by merit order. Generation and consumption are in competition on a level playing field. The dispatcher activates the most

111 The figures related to notification times are available on the French NRA's webpage, at: http://www.cre.fr/reseaux/reseaux-publics-d-electricite/services-systeme-et-mecanisme-d-ajustement (retrieved on 9 April 2015)

economic offer and also takes into account technical constraints when needed (e.g. the activation delay).

Since April 2015, several European countries have started the joint procurement of primary reserves (DE, NL, CH and AT)[112]. In January 2017, France will join this group of countries[113].

Capacity mechanism. Demand Response operators have two options to participate in this market:

- contracting with retailers and reducing the obligation of retailers through Demand Response programmes, or
- going through a certification process of loads and acting independently.

Demand Response operators can choose between the two options of participation and can switch from one method to another – from one delivery year to another. The peak periods both on the obligation side and on the certification side have been designed to allow Demand Response operators to participate.

Demand Response operators are able to go through the certification process closer to real time than generators. Existing generators need to be certified 3 years ahead whilst Demand Response operators need to be certified only 1 year ahead of the delivery year. Such a solution is useful for Demand Response operators as it can give them more flexibility as far as planning their development is concerned.

4. Measurement and verification, payments, and penalties

A. Measurement & verification

Prequalification. Prequalification has to be obtained in order to participate in some markets:

- in FCR, aFRR, mFRR, every portfolio has to be prequalified by the TSO by following a test procedure on the whole list of sites. After the prequalification process, the TSO validates the capacity (in MW) on the portfolio tested;
- for the NEBEF mechanism, prequalification is done to assess the ability of the aggregator to realise load management (no specific portfolio is tested);
- for DR RR: has to be qualified to participate to the balancing mechanism or to the NEBEF mechanism.

The pooled load has to fulfil requirements as an aggregate. This is a critical enabler of Demand Response as it allows the aggregator to act as mediator for consumers, protecting them from onerous technical pre-qualification measures and from costly duplication of procedures.

There are specific requirements according to the types of reserves, which can be difficult for the demand-side to meet. In addition, aggregation possibilities are limited. The TSO will start to experiment in enabling the

112 TransnetBW (2015): "Joint Procurement Of Frequency Containment Reserve", available at: https://www.transnetbw.com/downloads/strommarkt/systemdienstleistungen/international-cooperation-on-procurement-of-frequency-containment-reserve.pdf (retrieved on 6 December 2016)

113 CRE (2016e): "Délibération de la Commission de régulation de l'énergie du 1er décembre 2016 portant approbation des Règles Services Système fréquence et des Règles Services Système tension ", available at: http://www.cre.fr/documents/deliberations/approbation/regles-services-systeme4/ (retrieved December 2016)

aggregation of load management and on-site generation in 2017 for the primary control product (FCR).

Prequalification tests are designed by RTE independently for each market, and can be very different from one reserve to another depending on the necessity of the service provided for the system' security (more demanding for the mFRR than for the DR RR), which can hamper the participation of Demand Response assets. The same kind of prerequisites are also applied to generation resources.

Baseline methodology. The methodology is published on the RTE website, and requires the approval of the regulator. In the NEBEF and balancing mechanisms, three groups of baseline methodologies are available:

- Based on values just before and after the Demand Response event;
- "historical" values either declared by the aggregator or calculated using a statistical approach based on a longer period;
- specific case-by-case method for large portfolios (mainly residential)

The TSO also makes it possible for participant to propose new measurement processes.

In the FCR and aFRR, continuous activations require a different approach to measure and assess the performance of a pool. RTE sets a couple of parameters to continuously evaluate the performance as well as to specifically focus on major frequency deviation events.

For now, performance is always measured at the pool level, without taking into account that only some of the sites of the pool may be activated. While the measurement at pool level is generally favourable to Demand Response, the volatile consumption pattern of the sites can be an obstacle to validate the performance of a pool. Methods to assess the parameters have been adapted from historic assessment procedures used for generation assets and will have to be refined to fit to new Demand Response portfolios.

The new rules for the NEBEF mechanism (NEBEF 3.0) have also introduced a new baseline and a mutualized payment to the retailer in case of load curtailment that correspond to energy savings. However, the decree for application of the mutualized payment to the supplier has not been published yet.

B. Availability/utilisation payments

In France, generators and Demand Response providers can bid on EPEX Spot. This platform uses marginal price ('pay-as-clear') as clearing price.

Balancing and ancillary services

Product	Availability payments	Utilisation payments	Access
Primary Control (FCR)	According to bid	According to spot price	Weekly tender together with AT, DE, NL & CH TSOs (from 17 January 2017)
Secondary Control (aFRR)	160k€/MW/y for obligations. Free deals on secondary market.	Spot price	Obligation to provide (or contract a substitute) for generators, DSR participation through secondary market only; pro rata activation
Fast Reserves (mFRR)	24 k€/MW (2017)	Free bid price	Merit order based (energy)
Complementary Reserves (RR)	16 k€/MW (2017)	Free bid price	Merit order based (energy)
DSR-RR	12-20 €/MW/year[114]	100 €, 150 € or 200 €; or spot price based formula (min. 65 € and max. 500 €/MWh)	Merit order based (energy)
Balancing Mechanism	*Not available*	Free bids	Merit order based

Table 21: Overview of availability and utilisation payments in the balancing market in France

Activation of secondary control (aFRR): the activation of Secondary control reserves (aFRR) is made at the pro rata of the generator's obligation. Integration of DR is currently only possible through the secondary market, and with cooperation between generators and consumers.

Other: Explicit Demand Response in the residential sector (so called *"l'effacement résidentiel diffus"*) was in 2015 entitled to a premium, which has been cancelled by a decision from the Conseil d'Etat (supreme court for administrative justice) taken on the 16 March 2016[115]. Some provisions on residential Demand Response are still under discussion at this stage.

Capacity mechanism. The capacity mechanism is based on a decentralised market structure with an obligation for the retailer to buy capacity certificates up to the level of their portfolio peak consumption Demand response which is certified for the capacity mechanism has to be available during peak load periods ("PP2").

C. Penalties

The penalties in case of non-delivery/under-performance as well as for activation in the different parts of the market are detailed below.

Markets with availability payments come with specific penalties in case of non-delivery or underperformance.

- FCR and /aFRR: Penalties are not proportional to availability payment but to the spot price. An informal national secondary market (even though FCR

114 Average estimates based on global budget allocated by RTE for an auction. RTE does not disclose detailed results of auctions.

115 French Government: Actu-environnment, "Le Conseil d'Etat juge illégale la prime d'effacement" available at : http://www.actu-environnement.com/ae/news/conseil-etat-illegale-prime-effacement-26462.php4, (retrieved on 30 November 2016)

cooperation tender is cross-border, participants only have access to national capacities to hedge themselves) is available to cover unavailability. If unavailability is not declared but experienced by the TSO, the financial penalty is lower but prequalification of the portfolio can be rescinded.

- mFRR and /RR: Penalties are not proportional to availability payment but to spot price. The informal national secondary market is available to cover unavailability. It is lower when it is declared to the TSO rather than when experienced through availability control, or through missed activation. Random activations can be triggered by the TSO.

- DR RR: Penalties are proportional to availability revenues. It is lower when it is declared to the TSO rather than experienced through availability control, or through missed activation. Random activations can be triggered by the TSO. The 2017 DR-RR tender includes a mechanism where penalties are automatically deducted from availability payments.

For activation:

- On the Wholesale market: Over- or under- delivery leads to imbalances and therefore to the imbalance price.

- On the Balancing and ancillary services: a 20% tolerance on delivery is in place for small volumes (<50MWh activated). Penalties are set according the price set in the offer.

Generally speaking, balancing settlement prices are designed to avoid arbitrage with spot price (for sale of energy on the market instead of keeping it aside for the TSO).

Availability control by the TSO (between the availability that is declared and before an activation request occurs) cannot identify the unavailability of large portfolios where flexibility only represents a small amount of total consumption, or of back-up generation units.

Low liquidity and/or little visibility on the non-organized secondary markets create a high level of uncertainty regarding the possibility to hedge a portfolio and avoid penalties that can be very high.

Bank guarantees are also needed in all mechanisms and could be difficult for a small aggregator to secure. In 2015, RTE started allowing Demand Response operators to choose between a bank guarantee and regular deposits. RTE introduced a new mechanism in the DSR-RR that will allow the netting between fixed prices and penalties (known as conventional compensation) in 2017. The legal basis for such a mechanism remains unclear.

Germany

Overview

Today, there are important barriers that prevent the full potential of demand-side flexibility in Germany from being realised.

With the plan to achieve 35% of renewable electricity supply by 2020 and the phasing out of nuclear power by 2022 announced in 2011[116], the German energy system has started to integrate more and more decentralised energy generation (wind, solar, biomass and biogas) and has increased its needs in de-centralised flexibility. Situations in which variable generation from wind and solar plants supply a large majority of total demand in the grid are expected to happen more frequently in the coming years.

Currently, the German market regulation creates significant barriers to most forms of Demand Response programme types, including both those provided by retailers and independent aggregators. However, the German Federal Ministry for Economic Affairs and Energy (the BMWi) is aware of the current barriers and is addressing then by running a broad discussion forum and consultation on the policy conditions for the future of generation and supply of electricity, its use in heating, transport and industry, and the transport of electricity across the grids. This process is supposed to help inform policy decisions of the new government which will be elected in Sept 2017[117].

The current list of barriers includes:

- A number of markets are closed for Demand Response, either because legislation does not allow DR (e.g. network grid reserve), or by being closed in practice due to highly generation-biased product design (e.g. proposed design for a capacity reserve).
- The lack of a framework and incentives for DSOs to procure distributed flexibility as a service instead of investing in expansion/reinforcement of expanding their networks
- Pre-qualification requirements for balancing reserves are at the asset level (rather than exclusively at a pooled level);
- Network fees that are designed to incentivise a flat consumption pattern, and hence penalise those who provide flexibility to the system;
- The lack of a standardised role for third-party aggregators within the market model – requiring a multitude of contractual relationships between BRPs, Retailers and the third-party aggregators[118];
- The high share of taxes, network tariffs as well as

116 BMWi (2012): "Germany's new energy policy" available at: http://www.australien.diplo.de/contentblob/3459910/Daten/2512354/energiewende_bmwi.pdf (retrieved on 15 March 2017)

117 For more information, see http://www.bmwi.de/English/Redaktion/Pdf/weissbuch-englisch,property=pdf,bereich=bmwi2012,sprache=en,rwb=true.pdf; https://www.bmwi.de/BMWi/Redaktion/PDF/G/gruenbuch-gesamt-englisch,property=pdf,bereich=bmwi2012,sprache=de,rwb=true.pdf; http://www.bmwi.de/English/Redaktion/Pdf/electricity-2030,property=pdf,bereich=bmwi2012,sprache=en,rwb=true.pdf

118 There are ongoing discussions on an aggregator framework in Germany that will hopefully be put in place by the end of 2017.

other fees and levies included in the retail prices (50%-80%), which dilute the price signals of the wholesale market significantly.

1. Demand Response access to markets

Market overview

The following tables detail the markets in which Demand Response is accepted, however, the actual share of flexible demand-side loads in the overall participation is very hard to estimate in Germany.

Wholesale market

ENTSO-E's terminology	German TSOs' terminology	Tot. Volume Traded[119]	Demand Response Access & Participation	Aggregated Demand Response Accepted	Aggregated Generation
Day Ahead	EPEX Spot	235 TWh (2016)	✔	✔	✔
Intraday	EPEX Spot	41 TWh (2016)	✔	✔	✔

119 EPEX (2017): Press release, available at: https://www.epexspot.com/en/press-media/press/details/press/EPEX_SPOT_reaches_in_2015_the_highest_spot_power_exchange_volume_ever (retrieved on 15 March 2017)

Balancing and ancillary services

ENTSO-E's terminology	German TSOs' terminology		Tot. Capacity Contracted[120]	Demand Response Access & Participation	Aggregated Demand Response Accepted	Aggregated Generation
FCR	Primary control reserve	+ / –	830 MW[121]	✔	✔	✔
aFRR	Secondary control reserve	SCR +	1976 MW	✔	✔	✔
		SCR –	1907 MW	✔	✔	✔
mFRR	Minute reserve	MR +	1850 MW	✔	✔	✔
		MR –	1654 MW	✔	✔	✔
Interruptible loads	Immediately interruptible loads (SOL) – AbLaV[122]		750 MW	✔	✔	DR only programme
Interruptible loads	Quickly interruptible loads (SNL) – AbLaV		750 MW	✔	✔	DR only programme
Other ancillary services if relevant (re-dispatch, voltage control)	Re-dispatch (Winter reserve)		2016/17: 8300 MW[123,124] 2017/18: 7000 MW[125]	⊘	⊘	⊘
Capacity mech. (if any)	Capacity Reserve		2000 MW for October 2018 - September 2020	⊘	⊘	⊘
Distribution network services	[market for this does not exist– only bilateral deals between DSOs and generators/ loads][126]					

Table 22: List of electricity balancing market products with volumes and load accessibility in Germany

120 Regelleistung (2016): "Data for control reserve", available at: https://www.regelleistung.net/ext/data/ (retrieved on 6 December 2016)

121 The Participation of France as of Jan 2017, will increases capacity to ~ 1400 MW

122 Verordnung für abschaltbare Lasten

123 TransnetBW (2016): "Übertragungsnetzbetreiber rufen Winterreserve ab", available at: https://www.transnetbw.com/downloads/strommarkt/systemdienstleistungen/international-cooperation-on-procurement-of-frequency-containment-reserve.pdf (retrieved on 6 December 2016); https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/Versorgungssicherheit/Berichte_Fallanalysen/Feststellung_Reservekraftwerksbedarf_1617_1819.pdf;jsessionid=705F330F10BDAB757FA5F02866CA8651?__blob=publicationFile&v=2

124 Bundesnetzagentur (2016): "Bericht Feststellung des Bedarfs an Netzreserve fur den Winter 2016/2017 sowie das Jahr 2018/2019", available at: https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/Versorgungssicherheit/Berichte_Fallanalysen/Feststellung_Reservekraftwerksbedarf_1617_1819.pdf;jsessionid=705F330F10BDAB757FA5F02866CA8651?__blob=publicationFile&v=2 (retrieved 15 March 2017)

125 Bundesnetzagentur (2016a): "Netzreserve", available at: https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/Versorgungssicherheit/Berichte_Fallanalysen/Feststellung_Reservekraftwerksbedarf_1617_1819.pdf;jsessionid=705F330F10BDAB757FA5F02866CA8651?__blob=publicationFile&v=2 (retrieved 15 March 2017)

126 However, BMWi has started a process to create a legal framework for market activities in this area (14 a EnWG)

B. Markets open to Demand Response

Balancing market and ancillary services. The programmes in the balancing market are open to Demand Response resources.

Re-dispatch is closed for Demand Response: for both the continuous re-dispatch resources as well as the "winter grid reserve". These are generation-only, non-market based programmes. The TSOs contract power plants bilaterally without going through any public auction or tendering process. The regulatory oversight is performed by the Federal Network Agency (BNetzA) and the Federal Cartel Office[127].

Interruptible loads. Interruptible loads are defined as large consumption units which are connected to the medium, high and extra high voltage grid, nearly continuously consume a large volume of electricity and can, when called upon, reduce or interrupt their demand on short notice and for a fixed minimum duration. In Germany, such a programme was put in place in 2013 for an initial duration of 3 years, and was extended in 2016 until 2022. The changes that have taken place with the extension include a switch from monthly to weekly auctioning, and the minimum bid size being reduced to 5 MW (with the ability to pool loads).

Capacity mechanism. The draft rules (not yet finalised) for the new capacity reserve product allow Demand Response participation in principle, however rules are such that in practice this market is closed for Demand Response. For example, aggregation is not allowed, minimum bid size is 10 MW and opportunity costs are paid for generation but not for demand.

Wholesale Market. Day-ahead and Intra-day markets are open for consumers working with their electricity retailer (BRP) through implicit and explicit Demand Response. However, only retailers are currently able to seize those market opportunities. Independent Demand Response Aggregators are unable to do so for a number of reasons listed below.

In Germany, electricity is traded at the European Energy Exchange EEX in Leipzig (forward market, only financial futures) and the EPEX SPOT in Paris (day ahead and intraday market) and OTC (forward and day-ahead). The Day Ahead & Intraday Wholesale markets are not explicitly closed to Demand Response in Germany – i.e., there is no specific regulation prohibiting Demand Response from participating. However, there are several other reasons which prevent Demand Response from being active in the wholesale markets, for instance lack of standardized processes, network tariff design that discourages consumers from participating, and low market prices. Furthermore, day-ahead and intraday markets are closed for the participation of loads through independent third-party aggregators since there is no framework in place to define the interactions with the energy retailer and other market parties. Independent aggregation of distributed generation assets, like wind, biomass and biogas is however a viable business model, as the distributed renewable energy unit chooses a Balancing Responsible Party to market its generation.

Distribution network services. Demand-side flexibility could offer an important tool for local congestion management. As in most European countries however, the possibility for DSOs to invest in the ability to use Demand Response is very limited. Currently there are no market-based programmes operating on the distribution level. This is partly due to the fact that the incentive regulation favours CAPEX over OPEX, hence it is better from a DSO perspective to expand or enforce its network (and thus increase its capital base) than to contract with a Demand Response provider.

There are, however, traditional Demand Side

127 For further information on the reserve power generation directive, please see BMJ/juris (2015): Reservekraftwerksverordnung – ResKV, available only in German at: http://www.gesetze-im-internet.de/bundesrecht/reskv/gesamt.pdf (retrieved on 4th April 2015)

Management (DSM) measures in place in Germany. These stem from the pre-liberalization era and for the most part, cover domestic heating appliances (e.g. heat pumps or electric night-storage-heaters which are often quite load intensive). However, the current technical framework as well as the incentive scheme are both highly price-inelastic and thus, are not adequateto respond to the future system needs with high shares of renewable energy. These traditional schemes essentially need to be re-designed to work in a more flexible manner (e.g. allowing for the use of flexibility during day time). Today, substantial network fee reductions[128] steer the consumption patterns of these installations into the night hours (that traditionally used to have a low load profile). The steering mechanism (i.e., management based on ripple control) nowadays only works in relation to fixed restrictions given by the DSOs.

CAPEX vs TOTEX. In Germany, CAPEX vs TOTEX investment management (including "non -wire alternative services") is regulated by the Anreizregulierungsverordnung (ARegV = Incentive Regulation Ordinance). In early 2015, the German regulatory office for electricity (BNetzA) published an extensive evaluation report on the ARegV. This issue was discussed at length within the report and several changes were suggested by BNetzA. Many changes were included in the following legislative procedure to update the ARegV. However, the ARegV was debated extensively and many suggested changes were diluted or delayed by the legislators. Within the updated ARegV (which was adopted in September 2016), there has been some progress, but not enough to achieve significant change.

In terms of exploring mechanisms for DSOs to buy demand-side flexibility there has been a lot of discussion in Germany but little progress in practice. Different trade associations have proposed different mechanisms, but nothing has yet been implemented. For instance, some of the newly installed SINTEG projects (funded by BMWi) have started to explore this possibility. BMWi is also in the process of launching a regulatory proposal that would change and substantiate the current section 14 (a) of the Energy Industry Act. These changes would propose a re-design of the mechanism to work in a more flexible manner.

C. Restrictions related to distribution network operations

The DSO legally has to approve consumer participation in the balancing market, and, can limit or prohibit such involvement entirely. While in practice there has not been any unfounded refusal by DSO's, to date there have been significant delays in some projects caused by the discussions with the grid operators in order to get such approvals. Moreover, the DSO can prohibit consumers connected at the distribution level from participating in the balancing reserves without providing detailed justification; however, the consumer has the right to appeal such a decision to the regulator. But this would result in further delays.

Those consumers providing demand-side flexibility may face higher network fees if their provision increases peak load/feed-in; this can often removing any business case for Demand Response. The network charging regime aims at a high utilisation of existing grid infrastructure and hence incentivises consumers to maintain a regular, flat, standardised consumption profile, damaging the business case for flexibility. This is a major barrier in Germany, specifically for very large consumers. They typically get discounts on their network charges when they have flat consumption, which hampers Demand Response significantly. The charging regime also gives discounts to large consumers that remain above a certain "full load hour" level. Such consumers, when providing negative reserves (that is increasing electricity consumption), risk losing these discounts and paying significantly higher network charges, even

128 Codified in section 14a of the Energy Industry Act (Energiewirtschaftsgesetz - EnWG).

when the negative reserve energy is provided to the TSO for system balancing reasons. A similar effect can occur with the provision of positive reserves where the total consumption may fall below the required threshold, due to the provision of balancing services to the TSO. The structure of the network fees constitutes a severe barrier and restricts the participation of energy-intensive industrial consumers in the balancing market. This has been acknowledged in the BMWi White Paper in 2015[129], and changes to these rules were announced at the time, but so far no changes have been implemented. New rules on network tariffs have also been discussed but nothing has been implemented.

2. Service providers access to markets

A. Demand Response service providers access to consumer

In principle, Demand Response and aggregation are legally allowed to participate in German wholesale and balancing reserve markets. The types of consumers that participate in the markets include mainly large-scale industrial consumers (using more than 100.000 kWh/a), such as the paper and printing industry, vehicle manufacturing, the machine building industry, metal working industry, the food industry, the construction materials industry, and community sewage treatment plants. Generally speaking, the main actors on the market providing Demand Response include a wide range of aggregators and virtual power plants as well as some municipal utilities.

The aggregator-BRP requires retailer-BRP's agreement prior to offering consumption flexibility to the market. Third-party aggregation is currently very difficult in Germany, due to regulatory barriers that require independent aggregators to ask the bilateral permission of multiple parties – including the consumer's retailer/BRP, a potential competitor – prior to offering a consumer's flexibility into the market. In total, an aggregator operating in Germany has to negotiate three different contracts and a separate agreement with the DSO:

- Consumer (agreement on participation)
- TSO (prequalification (PQ), supply of reserve energy)
- DSO (agreement, report of non-availability, confirmation for PQ)
- Consumer's BRP (agreement on schedule exchange, BRP-approval for PQ, agreement on payments)

A particular difficulty is the requirement to reach a bilateral agreement on schedule exchange and compensation payments with the consumer's BRP and retailer. There are no standards for this, and the BRP and retailer often have no interest in working with the aggregator to reach such an agreement. The reason for this is that BRPs/retailers usually see the aggregator as a competitor: someone who is approaching their customer to offer services the BRP/retailer offer, or may intend to offer in future. The aggregator's dependency on the approval of a potential competitor is the single largest barrier for competition between service providers in Germany, as it effectively bundles flexibility services with electricity supply. In the new "Strommarkt" law the market was

129 BMWi (2015): "An electricity market for Germanys energy transition" available at: http://www.bmwi.de/Redaktion/EN/Publikationen/whitepaper-electricity-market.html (retrieved on 15 March 2017)

also opened to Secondary reserve customers meaning that BRPs have the obligation to issue this agreement like they have to do for MRL. Industry has put forward a proposal to overcome this issue in balancing markets that avoids the need for bilateral agreements and discussions on compensation[130]. At the time of publication of this report the proposals are with the German regulator for review and adoption.

Current status of imbalance settlement after load management.

After curtailment (as part of positive balancing reserve):

1. The aggregator sends information to the BRP, on the basis of the bilateral agreement.

2. The balancing group settlement is processed through a "day-after" schedule exchange.

3. The aggregator sells the curtailed energy to the TSO (as positive balancing energy).

4. The consumer's BRP sells the same amount of energy to the aggregator in order to correct both its own and the aggregator's balancing perimeter.

The aggregator must pay the BRP/retailer for the energy curtailed during a Demand Response event, on the basis of their commercial agreement. There is no standard or regulatory oversight of such agreements, so the retailer and BRP set the prices.

Discussions on future framework

In July 2016, legislation[131] was adopted to remove these barriers for balancing reserves in principle. Commissioned by the German Regulatory Authority, industry stakeholders developed a standardisation framework to put this in practice. This framework was handed over to the energy ministry and the regulator in December 2016 but still needs to be implemented into market rules and regulation. Part of this framework includes the standardisation agreements with a consumer's BRP and retailer. This standardisation will force the BRP and retailer to conclude agreements promptly (at the latest within 6 weeks) at the independent aggregator's request.

BMWi & BNetzA met in early 2017 to clarify the concrete needs and changes to be addressed in a subsequent formal regulatory proceeding and the process for carrying out such a proceeding. The current framework proposal for Demand Response developed by industry stakeholders is based on the "corrected model" (i.e. there is compensation for the energy) and (among other issues) includes:

- Standardisation of consumer's BRP agreement

- Standardisation of energy compensation (through the "corrected model" – the consumer pays the retailer for load reductions at his retail rate, the retailer pays the consumer for load enhancements at the agreed retail rate)

- A framework which allows for compensation of administrative efforts (aggregator has to pay the BRP) in the interim period (which will be replaced by the target model at the latest by 2020); though this provision is against the Commission's winter package proposals[132];

- Standards for information exchange that have been developed;

- And standards for schedule exchanges that have been developed.

130 BNE (2016): "Branchenleitfaden Regelleistungserbringung durch Drittpartei-Aggregatoren gem §26a StromNZV", available at http://www.bne-online.de/de/system/files/files/attachment/Branchenleitfaden%20Drittpartei-Aggregator.pdf (retrieved on 20 March 2017)

131 §26 a StromNZV

132 *This goes directly against the European Commission's Proposals found in their European Market Design Regulation*

3. Product requirements

A. Main product requirements

Balancing Market and Ancillary Services. Minimum bids for all balancing programmes were downsized in 2011 and 2012, making them more accessible for Demand Response[133]. As part of the energy market design discussion in Germany, the Ministry for Economic Affairs and Energy (BMWi) announced the opening up of balancing markets to new providers in its White Paper published in July 2015. A number of concrete measures were presented in the paper, including for example shortening the time blocks for the secondary balancing capacity. Currently, minimum bids do not exceed 5 MW. As a result, prices have been decreasing, which reveals the broader range of offers now available. However, with the changes underway, there will be exemptions which will grant smaller bid sizes.

Following the announcement of BMWi, the German Regulatory Authority (BNetzA) launched a formal regulatory proceeding to stipulate the auction rules for balancing capacity in order to permit new, flexible providers to participate. More details on the foreseen changes are given below.

Primary Control Reserve: Retailers of Primary Control Reserve need to prequalify with each TSO in whose area the prospected reserve will be offered. A prerequisite for completion of the Master Agreement is the successful prequalification of a unit with a performance at least equal to the minimum bid size. The current volume of 1250 MW includes 67 MW from the Netherlands and 25 MW from Switzerland, France, Belgium, Austria, and Denmark, who all bid in the same pool of PCR.

Secondary Control Reserve: Today, secondary reserves are tendered on a weekly basis, requiring a Balancing Service Provider to estimate available resources more than 10 days in advance. Additionally, response must be able to be sustained for up to 12 hours for Secondary Reserves and up to 60 hours over the weekend. German Demand Response participants do manage to operate in the reserves, by relying on larger pools and backup generation assets. However, partcipation remains significantly repressed due to these requirements. The major changes underway and discussed as part of the regulatory proceeding carried out by BNetzA include the shortening of secondary reserve products to 4 hour blocks (similar to the minute reserve), daily auctions for secondary reserve (like minute reserve), and allowing assets from 1 MW size to participate if the provider has no other assets in the respective control zone.

Minute Reserve: Today, minute reserves are tendered on a daily basis (working days only) for positive and negative regulation in 6 four-hour time windows for the following day. Two main challenges exist for the participation of Demand Response in the Minute Reserve programme: positive Minute Reserve faces a historical oversupply by 50-100%, although this figure seems to diminish with the overall decrease of residual load. Additionally, the response must be able to be sustained for 4 hours even though the service is normally only required for much shorter periods. Markets such as Austria, Belgium, the Nordics, and the UK have lowered the required activation period in order to allow demand-side resources to compete.

As part of the ongoing regulatory proceedings being carried out by BNetzA, there are some changes coming to the minute reserve, including for example a call

133 50Hertz/Amprion/TransnetBW/TenneT (2015): Minute reserve, available at: https://www.regelleistung.net/ip/action/static/ausschreibungMrl (retrieved on 18th April 2015)

for bids organized on a truly daily basis (on all days, including weekend and holidays). Minimum bid sizes, however, in general will not be reduced (threshold is still 5 MW for minute reserve). Exemptions (1 MW, 2 MW, 3 MW or 4 MW) are foreseen to simplify market access for new players (including DR), though there are tight rules for exemptions: each aggregator can only respond to the auction with one offer per control area/ balancing zone and per validity period. In addition, the introduction of a balancing energy market is planned (in line with the current draft of the Balancing Code), although most market participants are sceptical of this proposal and don't see a need for it as it will run in parallel to the already existing and liquid intraday market.

As of December 2016, the German government is finalising concrete text proposals, and after a final stage of consultation with market participants, these aforementioned changes to the balancing market product requirements will most likely become regulation over the course of 2017.

Interruptible loads (AbLaV). The AbLaV has been updated with a more open design. However, given that the regulator has previously tried to abolish its purpose, the design still needs to be further improved. The new design now includes a contracted capacity of 750 MW per product, aggregation (as long as all aggregated assets in one pool are below the same high voltage node), a minimum bid size of 5 MW, allowing participation by customers connected at medium voltage or higher and lastly, less strict availability requirements. Through the AbLaV, the legislator made it possible for TSOs to contract directly with interruptible loads that can help to maintain grid and system security[134]. The German TSOs issue a call for tender each month for the capacity of 750 MW of immediately interruptible loads (SOL), with a response time of less than 1 second, and an equal volume of quickly interruptible loads (SNL), with a response time of less than 15 minutes. Payments for availability are based on the outcome of a competitive auction and limited to max €500/MW per week, and payments for activations are limited to max €400/ MWh. This product (while improved) is not effectively designed, especially for newer market actors, and will be extended up to 2022.

Capacity reserve. The draft rules for the new capacity reserve product (which will open from October 2018) will de facto exclude Demand Response. The key barriers include:

- aggregation is not allowed;
- minimum bid size is 10 MW;
- there is no level playing field between DR and generation with regards to activation payments: generation gets paid their opportunity cost when activated, DR does not. At the same time, the product duration and frequency of activation is unlimited, putting a huge risk on DR assets;
- Only assets connected to the high voltage grid (110kV and higher) are allowed.

134 With the amendment of the Energy Industry Act (EnWG) of 20 December 2012 and by means of the "Ordinance on Interruptible Load Agreements (AbLaV)".

Wholesale market

Product	Market place	Minimum size (MW)	Notification Time
Day Ahead	EPEX Spot and OTC	1 MW for 1 hr	Auction at 12 am for the following day
Intraday	EPEX Spot	1 MW for 1 hr and 15 min	Gate closure 30 min

Balancing and ancillary services

Product	Minimum size (MW)	Notification Time	Activation	Max Product duration (= max. possible duration of activation)	Triggered (max. times)
PCR	1 MW	30 sec	Automatic	1 week	Up to several times per day
SCR	5 MW (1 MW if no other offer)	5 min	Automatic	12 hours' weekdays 60 hours over the weekend – this will likely change to 4 hours in 2017!	Up to several times per day
MR	5 MW (1 MW if no other offer)	15 min	Automatic activation by Merit Order List Server	4 hours	Up to several times per day

Table 23: Description of some main Product requirements in the balancing products accessible to DR in Germany

4. Measurement and verification, payments, and penalties

A. Measurement & verification

Prequalification. Prequalification is required at the asset level, which significantly limits participation. Many loads/assets that would provide valuable contributions to a pool through their specific capabilities, cannot pass the pre-qualification stage on their own. Given that it is the pool delivering the services to the TSO, it should be the pool that is pre-qualified, not the individual assets/ loads within the pool. Many neighbouring countries have moved to pool-level pre-qualification, including France, Switzerland and Austria.

Another major issue is that the balancing service providers must establish a separate 4 connections to each of the 4 German TSOs separately, in addition

to having to set up their pools 4 times, as there is no pooling across TSO zones. As the market structures in Germany are unified it is illogical that the pre-qualification results cannot be shared between the TSOs.

Therefore, the **pre-qualification process** can take many months, or in extreme cases up to a year at times when TSOs have limited resources to deal with (sometimes large amounts of) pre-qualification requests. This unpredictability makes it challenging for consumers and their service providers to develop a reliable business case. Recently, there has been a voluntary commitment made by the TSOs to work on each prequalification request within 2 months, but it has not resulted in any changes, as the TSOs have not in practice followed through on this commitment.

Baseline methodology. For balancing products, TSOs have defined a standardised baseline methodology that is publicly available. What is missing is a baseline methodology for DR in wholesale markets (day-ahead, intraday), to allow for explicit DR through independent aggregators.

B. Availability/utilisation payments

Balancing and ancillary services

Product	Availability payments	Utilisation payments	Access
Primary control reserve (PCR)	Based on auction outcome	None	Weekly Auctions
Secondary control reserve (SCR)	Based on auction outcome	Based on bids	Weekly Auctions – likely to be changed to daily in 2017
Minute reserve (MR)	Based on auction outcome	Based on bids	Daily Auctions
Immediately interruptible loads (SOL) – AbLaV[135]	Payments based on the outcome of a competitive auction (limited to max 500/ MW per week), and	Payments for activations are based on bids and limited to max 400/MWh	
Quickly interruptible loads (SNL) – AbLaV	Payments based on the outcome of a competitive auction (limited to max 500/ MW per week), and	Payments for activations are based on bids and limited to max 400/MWh	

The current primary reserve programme provides availability payments only. There is an EU consultation on the changes of this market currently ongoing. Secondary and Tertiary reserves programmes provide availability and utilisation payments. Bids are accepted following the merit order list of availability prices. During activation, the merit order list of utilisation prices applies. In particular, for the negative Secondary Control Reserve there is a wide range of accepted utilisation prices, of which the higher end is rarely called. All payments are issued pay-as-bid. The Day Ahead auction (hours) as well as the Intra Day opening auction (15 min) are pay-as-cleared; Intra Day is continuous trading and pay-as-bid.

The penalties are based on imbalance charges, plus the ultimate penalty of being excluded from the market by the TSOs.

135 Verordnung für abschaltbare Lasten

Great Britain

Overview

Great Britain (GB) was the first country to open several of its markets to consumer participation in Europe. Unfortunately, in recent years it seems that the stakeholder process between providers, BEIS (the Department of Business, Energy and Industrial Strategy), Ofgem, and National Grid has not been as effective as would be expected in a mature market. As a result, measurement, baseline, bidding and many other procedural and operational requirements are inappropriate for demand-side resources, noticeably reducing the number of demand-side MWs in the system even as national capacity continues to decline. Today:

- Almost all balancing services[136][137] are open to Demand Response and aggregated load is accepted, although the product design is not optimal for customer participation.
- The Capacity mechanism is also open to Demand Response, but not on comparable terms to generation.
- The Balancing Mechanism remains closed to independent aggregators.
- The wholesale markets remain closed to independent aggregators.

While National Grid has engaged in streamlining the participation requirements for balancing services and increasing transparency, DR still faces significant regulatory and operational challenges which limit the viability of the UK market for Demand Response providers.

The BRP and Aggregator issue is not yet resolved in GB. This means that aggregators are unable to access the Balancing Mechanism or wholesale energy markets – to do so would require bilateral agreements with each customer's retailer. Aggregators are able to access balancing services and the capacity mechanism, because there is no requirement for an agreement with the retailer/BRP. This means that the retailer (rather than the aggregator) is exposed to imbalance payments or costs resulting from the customer's actions. The effect on balancing services is highly debated. The effect on the capacity mechanism is much clearer: when the customer reduces demand during a system stress event, the retailer makes a windfall gain. This leaves independently-aggregated DR as the only resource in the capacity mechanism which does not receive an energy payment. This increases the minimum capacity price at which it can viably be offered – as it must cover all its energy costs from its capacity revenue – putting it at a unique disadvantage when bidding in auctions, and leading to less DR clearing than would be economically optimal. Also, participation to the CM implies important activations during stress events to fulfil engagement, whereas other CM split the availability engagement and

136 Note that there are no formal markets for balancing services in GB.. Rather, they're procured by National Grid through a mixture of tenders and bilateral contracts.

137 SBR is a generator-only programme. It was meant to be paired with DSBR, which was open to DR, but National Grid decided not to procure DSBR for 2016/17.

the activations on the market. With such rules, having no activation remuneration is even more impactful. In November 2016, the Government and Ofgem issued a call for evidence, asking whether a framework for independent aggregator access to the balancing mechanism should be introduced.

The capacity mechanism, introduced at the end of 2014, did not place demand-side resources on an equal footing with generation. In fact, only one demand-side aggregator, of the approximately 15 in the market, secured a contract within this new market in the first capacity mechanism auction. This design is in fact under question within the European Court of Justice [138], in the Tempus v European Commission case. There have been subsequent auction rounds in the capacity Market in 2015 and 2016 in which DR has been more successful, and growing numbers have secured contracts. The T-4 auction held in December 2016 saw 1400 MW of DR bids accepted.

In 2016 a Transitional Arrangement Auction (TAA) was held targeting specifically DR resources. The capacity mechanism was reviewed in a consultation in March 2016, and eligibility for the 2017 TAA was tightened to exclude any form of generation.

National Grid has also launched a new stakeholder-backed initiative called Power Responsive, with the goal of stimulating participation of flexible technologies in the electricity system. The program focusses on distributed generation, storage and DR from Industrial and Commercial users. As National Grid is under growing 'distress' because of the growth of embedded generation, interconnection and large transmission-connected renewables, and also DNOs encouraging more innovative products, the opportunity for Demand Response is in principle higher than ever. However, due to poor policy development and design choices, that opportunity has not yet been realised.

1. Demand Response access to markets

Market overview

Almost all ancillary services programmes in Great Britain are open to Demand Response, however comprehensive data is not available as to the share of Demand Response in the various programmes. This is a symptom of a general lack of transparency: many services are procured not through open markets, but through bilateral contracts, or through tenders in which the buyer, National Grid, has a great degree of discretion. This makes participation very risky for new entrants. Programmes dedicated specifically for Demand Response are the Demand-Side Balancing Reserve (not procured in season 2016/17), Demand Turn Up, a new service which is currently under trial, and Frequency Control by Demand Management. The total amount of demand-side flexibility participation within the balancing services, not including the balancing mechanism, amounted to 2,634 MW in the financial year 2015/2016[139].

138 Only 1 Demand Response provider was allowed to participate in the Capacity Market Design Committee, which met for over a year to design the market, while 13 generation representatives were included. Therefore, the design bias is not surprising.

139 National Grid (2016c): "Power Responsive Demand-side flexibility Annual Report", available at: http://powerresponsive.com/wp-content/uploads/2017/01/Power-Responsive-Annual-Report-2016-FINAL.pdf (retrieved on 15 March 2017)

Wholesale market

Product	Market Place	Market size (volumes traded)	Demand Response Access & Participation	Aggregated Demand Response Accepted	Aggregated generation
Day Ahead[140]	EPEX SPOT Day Ahead Auction	~5182 MWh/h	✗	✗	✔
Intraday[2]	EPEX SPOT Intraday in the UK	~1655 MWh/h	✗	✗	✔

Balancing and ancillary service

ENTSO-E's terminology	National Grid's terminology		Tot. Capacity Contracted	Demand Response Access & Participation (MW)	Aggregated Demand Response Accepted	Aggregated generation
FCR	Firm Frequency Response (FFR)[141]	Dynamic	~354.6 MW	✔ (data not available)	✔	✔
		Non-Dynamic	~0 MW	✔ (data not available)	✔	✔
FCR	FFR Bridging[142]		~10 MW	✔ (data not available)	✔	✔

140 Forecast based on APX 2014 annual report

141 All accepted tenders active in December 2016

142 FFR Bridging has been fully contracted for the short-term and is unclear if it will be contracted more in the future.

143 All accepted tenders active in December 2016

144 Data for STOR year 10 – weighted average capacity over all 6 seasons

145 National Grid (2016): "Supplemental Balancing Reserve (SBR) Operational Information" available at: http://www2.nationalgrid.com/UK/Services/Balancing-services/System-security/Contingency-balancing-reserve/Operational-Information/ (retrieved on 15 March 2017)

146 National Grid (2016): Ibid

147 National Grid decided not to procure DSBR for season 2016/17, because they had already procured sufficient capacity through SBR, which is only open to generators.

148 National Grid (2016c): "Power Responsive Demand-side flexibility Annual Report", available at: http://powerresponsive.com/wp-content/uploads/2017/01/Power-Responsive-Annual-Report-2016-FINAL.pdf (retrieved on 15 March 2017)

149 National Grid (2016c):, Ibid.

150 The Balancing Mechanism is what National Grid uses for normal balancing of the system. It's not capacity-based, but based on energy offers. This is an important market, and it's one in which there's essentially no DR participation (because the aggregator/BRP issue is unresolved). Ofgem/BEIS are currently analysing whether aggregators should have access to it.

151 Results from the December 2016 T-4 auction. National Grid (2016a): "Final Auction Results - T-4 Capacity Market Auction for 2020/21" available at: https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Final%20Results%20Report%20-%20T-4%202016.pdf (retrieved on 15 March 2017)

152 Capacity Market Register, 6 Dec 2016. Despite the TA being intended to develop the DR industry, sub-50MW generation was also eligible to participate, and cleared much of the capacity. The second TA auction (being held at the end of March 2017, for 2017/18 delivery) is open only to turn-down DR.

FRR	Fast Reserve*[143]	Non-Dynamic	60 MW	✔ (data not available)	✔	✔
RR	Short-Term Operating Reserve (STOR)[144]	Committed	~2494 MW	✔ (data not available)	✘	✘
		Flexible	~898 MW	✔ (data not available)	✔	✔
RR	STOR Runway		78 MW	✔ 78 MW	✔	✔
RR	Supplemental Balancing Reserve (SBR)		4,035 MW[145]	0 MW[146]		
RR	Demand-Side Balancing Reserve (DSBR)[147]		0 MW	✔ 0 MW	✔	✔
RR	Demand Turn Up (trial)		300 MW[148]	300 MW	✔	✔
FCR	Frequency Control by Demand Management (FCDM)		Not public	✔	✔	✔
FCR	Enhanced Frequency Response		201 MW[149]	✔ 0**	✔	✔
	Balancing Mechanism[150]		3,700 GWh of "bid-offer acceptances" (i.e. actual trades) (2017)	Minimal	✘	✘
Capacity mechanisms (if any)	Capacity Mechanism[151]		52,425.302 MW	~1411 MW***	✔	✔
	Transitional arrangements		~641 MW	✔ 328 MW[152]	✔	✔
Distribution network services (voltage control and congestion management)	⊘	⊘	⊘	⊘	⊘	⊘
⊘	Triad avoidance		Not applicable	✔	✔	✔
⊘	Red Zone Management		Not applicable	✔	✔	✔

* The very high frequency of activations (10-15 per day) makes it practically impossible for DR to participate

** The product is designed around the capabilities of battery storage, and only storage bids were accepted in the tender

*** Proven and unproven DR

Table 24: List of balancing market products, including volumes and load accessibility in Great Britain

B. Markets open to Demand Response

Balancing and Ancillary services. The programme with the greatest historical Demand Response participation is the STOR programme. Though STOR spurred Demand Response development in 2011-12, the STOR programmes are no longer attractive for Demand Response participation. Prices have fallen and those demand-side resources which cannot be available for the whole duration of the participation window (usually 11-13 hours per day) have been devalued in terms of their tendering competitiveness. Demand Response now represents a limited part of this reserve. For example, during the Season 8.3, load management represented less than 10% of the overall STOR participation. Two new variations, STOR Premium Flexible and STOR Runway, have been designed to provide better opportunities for Demand Response aggregation in STOR.

To provide reserves in advance of the Capacity Mechanism, National Grid introduced two Contingency Balancing Reserve services: Supplemental Balancing Reserve (SBR), which was only open to generation, and Demand Side Balancing Reserve (DSBR), which was only open to demand-side resources. The intention was that the services would be procured jointly, so that the supply- and demand-side resources could compete. However, splitting the contingency balancing reserve service into SBR for generation and DSBR for DR was not successful in its attempts to procure balancing reserve services from demand side resources. For the 2016/17 winter – the final season before the first full Capacity Mechanism delivery year, National Grid held an SBR tender earlier than the DSBR tender, and ended up procuring 4,035 MW of generation capacity and then later determined that it, having committed to that quantity of generation, had no need to procure any demand-side resources.

Fast Reserve Firm Service (FRFS), & Frequency Control by Demand Management (FCDM) allow for aggregated Demand Response participation, but its participation is limited mainly due to requirements that it is difficult for consumers to meet (see next chapter).

In October 2016, National Grid consulted with 115 flexibility providers in an attempt to simplify and provide clarity on the products in the Balancing services. The comments provided suggest the complexity and number of Balancing Services markets and adjustments act as a barrier to entry. As such, National Grid will work to address this issue, and focus on simplifying available balancing products as well as provide clear and understandable market information. The programme will be discussed with stakeholders through Power Responsive Steering Group and subgroups – the Demand Side Response Providers Forum and Storage Working Group as well as with energy and customer trade associations – so as to develop options to be implemented within a 12-month timeframe[153].

Wholesale market. Demand Response currently can only participate in the GB Day-ahead and Intraday markets in the form of flexibility of retailers and a few very large industrial customers that are already trading members. The markets are closed to independent aggregators.

Capacity Mechanism. Aggregated Demand Response has access to the Capacity Mechanism although participation rules are considered to be strongly biased in favour of generation. At the time of writing, the issue of State Aid approval of the Capacity Mechanism is in the European Court of Justice. Limited aggregation of generating loads is allowed, so long as separately metered units do not have a capacity of over 2MW. In addition, only generating units of the same type can be

153 National Grid (2016c): "Power Responsive Demand-side flexibility Annual Report", available at: http://powerresponsive.com/wp-content/uploads/2017/01/Power-Responsive-Annual-Report-2016-FINAL.pdf (retrieved on 15 March 2017)

aggregated[154].

National Grid runs the main T-4 auction annually, and purchases capacity for four years ahead of delivery. In the T-4 auction in 2015, around 450 MW of unproven DSR was contracted for delivery in 2019/20. There are also two further auctions in place; the T-1 auction (runs one year ahead of delivery) as a top-up to secure volume. The first "Early Auction", took place in January 2017, for delivery in Winter 2017/18. The second DSR Transitional Arrangements auction targets support to DSR to increase levels of participation for the years 2016–2018. In this auction around 475 MW was contracted for delivery in 2016/17[155].

Distribution network services. Demand-side flexibility could represent an important tool for local congestion management. Ofgem's approach to incentivising network innovation supports demand-side measures when these are cost-efficient:

- Under the 'TOTEX' approach to regulation in distribution price control 5 (2010-15), innovation measures are treated on a par with capital investment;
- Network Innovation Competitions, especially the Low Carbon Network Fund (about £500m over five years)[156];
- The current Distribution Price Control (2015-23), under the new regulatory framework RIIO-ED1, is based on innovation & specific outputs, obliging all DNOs to initiate or adopt Active Network Management.
- Recently implemented and continuously revised regulation mechanisms create the necessary incentives for network companies to introduce smart grid solutions, a dynamic that helped Great Britain attain thought leadership and become a frontrunner in levels of investments in this sector.

As a result, five out of the six DNOs are currently running Demand Response trials. Trials in the Thames River Valley and in Bristol involve a few dozen commercial buildings each, with a large scalability potential, but do not provide any payment to the end customer. Other trials involve the use of new commercial contracts for large customers (>100 kVA) or seek avoidance of network reinforcements through smart voltage control in major substations.

C. Restrictions related to distribution network operations

In Great Britain, for distribution tariffs, customers are defined by voltage (LV, HV, EHV) and by metering arrangements (half hourly, non-half hourly). Customers pay a fixed charge and a variable charge based on consumption (with some customers paying time-of-use), while customers with half hourly meters also pay capacity and reactive charges[157].

Furthermore, in several areas of the country there are experiments ongoing on DSO tariffs. As such, it is difficult to draw a full picture. Incidentally, the regulator just published a consultation which sets the direction of travel for the review of transmission and distribution networks charging arrangement on the 13th of March, which is expected to lead to changes in the balance of network charging between generation and demand and

154 British Government (2013): "Defining CMUs and Portfolios" available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/248885/Definition_of_CMUs_and_portfolios.pdf (retrieved on 15 March 2017)

155 National Grid (2016c): "Power Responsive Demand-side flexibility Annual Report", available at: http://powerresponsive.com/wp-content/uploads/2017/01/Power-Responsive-Annual-Report-2016-FINAL.pdf (retrieved on 15 March 2017)

156 Though the Low Carbon Network Fund has had some difficulty in attracting a satisfactory amount of commercially viable projects, partially due to the lack of payments to consumers for providing demand-side flexibility.

157 EC (2015): "Study on tariff design for distribution systems – Final Report" available at: https://ec.europa.eu/energy/sites/ener/files/documents/20150313%20Tariff%20report%20fina_revREF-E.PDF (retrieved 15 March 2017)

could create the market conditions for the development of storage. This consultation focusses on the residual charge element of network tariffs, which amounts to 80% of the transmission charges and at the distribution level they can be up to 50%[158].

2. Service providers access to markets

A. Demand Response service providers access to consumer

Aggregation is possible in ancillary services and is especially needed in those programmes with high minimum bid sizes. The majority of Demand Response customers are larger industrial and commercial sites. Traditional measures used for DR include diesel generators[159], interruptible processes in various industrial plants (e.g. cement manufacturing), CHP plants, gas turbines and engines, refrigeration, air-conditioning, pumping and lighting. A surprisingly high proportion of DR seems to come from diesel generators. This may be because the services that are open to DR participation tend to require quite frequent dispatches. For at least one product (FFR), DR and generation can be coupled within the same bid.

The aggregator does not require a BRP's agreement prior to load management. Aggregators are not required to ask for permission or to inform the retailer prior to load management and have direct access to consumers. However, they are unable to access the consumers' energy for wholesale market purposes or for participation in the Balancing Mechanism, or to obtain an energy payment when delivering for the Capacity Mechanism. For other purposes, such as the Capacity Mechanism or selling balancing services to National Grid, they may aggregate load from all over the country.

3. Product requirements

A. Main product requirements

Balancing Market and Ancillary Services. The tables below outline some of the key requirements for participation in the wholesale and balancing markets in Great Britain.

Wholesale market

Product	Market place	Minimum size (MW)
Day Ahead	EPEX SPOT Day Ahead Auction	0.1 MW
Intraday	EPEX SPOT Intraday	0.1 MW

158 Ofgem (2017): "Targeted Charging Review: A consultation", available at: https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-consultation (retrieved on 17 March 2017)

159 These feature heavily amongst "DR" resources as product designs tend to require long running hours which are relatively unattractive for load management. Even the CM does this: resources have to be tested 4x per year, and there's no merit order to ensure that high-short-run-marginal-cost/limited hours resources are dispatched only when necessary.

Balancing and ancillary services

Product	Minimum size (MW)	Notification Time	Activation	Triggered (max. times)
FFR	10 MW (1 MW from April 2017)[160]	Primary and High – 10 sec Secondary – 30 sec	Automatic	Pre-fault dynamic – continuous Post-fault static – around 11 times per year
FFR Bridging	1 MW (must be aggregated to 10 MW for combined responses)	Primary and High – 10 sec Secondary – 30 sec	Automatic	Post-fault static – around 11 times per year
Fast Reserve	50 MW	2 min	Manual	10-15 times per day
STOR	3 MW	4h	Manual	Up to several times per day
STOR Runway	1 MW	4h	Manual	Up to several times per day
Demand Turn Up	1 MW	10 min (sometimes requested day-ahead)	Manual	Up to several times per week
Enhanced Frequency Response	1 MW	1 sec	Automatic	Continuous operation
FCDM	3 MW	2 sec	Automatic	Around 11 times per year
Triad avoidance	Not applicable	Not applicable	Not applicable	Not applicable
Red zone management	Not applicable	Not applicable	Not applicable	Not applicable

Table 25: Description of some main Product requirements in the balancing products accessible to DR in Great Britain

Short Term Operating Reserve: The STOR Product requirements are challenging for consumers, as they require daily weekday participation, offering a fixed quantity for a window of 11-13 hours per day, in order to be paid at a competitive level. It is possible to choose a one-time window (morning/evening), but it involves an important devaluation of the resource, lowering revenues. National Grid hardly ever calls STOR Flexible: due to undercutting across several tender rounds, initially accepted flexible rates have turned out to be too high. STOR TR prices fall distinctly between TR-6 and TR-3, meaning that only tenders at least one

160 National Grid (2016b): "Firm Frequency Response (FFR)" available at: http://www2.nationalgrid.com/UK/Services/Balancing-services/Frequency-response/Firm-Frequency-Response/ (retrieved on 15 March 2017). Will Change from April 2017.

year ahead are really economically attractive. Another significant barrier is the long period of time between contracting a site and obtaining first payments. STOR Runway, a new option, will shorten this period, as National Grid will accept tenders for volumes that have not yet been fully "created" and qualified. This allows aggregators to "grow" their pool with financial guarantees, a positive step forward.

Firm Frequency Response. FFR is open to Demand Response providers, with a minimum capacity of 10MW, in both dynamic and non-dynamic profiles. Dynamic is where generation or consumption output will rise and fall automatically in line with the system frequency. Static is where an agreed amount of energy is delivered if the system frequency hits a certain trigger point e.g. 49.8Hz. From April 2017, the entry point to FFR will be reduced to 1 MW.

Fast Reserve. The FR Product requirements are very stringent, making it difficult for consumers to participate. It requires a 50 MW minimum bid size. Incremental additions are a minimum of 10 MW for each bidding unit. Coupled with a frequency of 10-15 activations per day, FRFS is not an attractive product for Demand Response.

Frequency Control by Demand Management. The FCDM programme is used to manage large deviations in frequency, such as those caused by the sudden loss of a large generating unit. FCDM is triggered at a static set point of 49.7Hz and therefore there are few events per year. There were nine events in 2013 and nine in 2014, always with a maximum duration of 30 minutes. The service is a route to market for demand-side providers, and is entirely managed through bilateral contracts between potential providers and National Grid.

Capacity Mechanism. Despite the fact that a special transitional system was introduced for Demand Response units and distributed generators, with two auctions in 2016 and 2017, the overall design of this market does not offer a level playing field. For example, new generators are eligible for 15-year capacity agreements, whereas new Demand Response resources are only eligible for one-year capacity agreements. In the first T-4 auction, a mere 0.4% of total capacity was awarded to Demand Response[161]. A legal case has been submitted to the European Court on the grounds that this market does not comply with the EU competition law.

Balancing Mechanism. This market is used by National Grid to balance supply and demand close to real time, by accepting bids or offers from generators or retailers to increase or reduce generation or consumption. Aggregators have no access to the Balancing Mechanism: to offer a customer's flexibility to National Grid through the Balancing Mechanism, an aggregator would require a bilateral deal with the customer's retailer, whereby the retailer would offer it on their behalf.

Triad Charges. Triads, are three half-hour periods on three different days separated by at least 10 days (the triad periods), that electricity demand is at its highest across GB. Transmission Network Use of System (TNUoS) charges recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and offshore on the basis of the share of demand during the triad periods. The triad days occur between November and end of February. Customers' average consumption in each network zone over the 3 triad periods is calculated, and then it is multiplied by the triad charge. This gives the total amount that supplier needs to pay to National Grid. Customers receiving pass-through charges pay their share based on average consumption during the three highest peak triad periods. This is an Implicit Demand Response scheme, as customers can avoid paying TNUoS to the extent to which they avoid consuming during the triad

161 British Government (2014): "Capacity Market: location of provisional results" available at: https://www.gov.uk/government/statistics/capacity-market-location-of-provisional-results (retrieved on 15 March 2017)

periods. Service providers may send triad warnings to their customers about 20-30 times annually, up to one day in advance, by e-mail, text message or other devices in order to warn them of a possible peak triad period. Lowering the triad charges brings good value for load flexibility, for those customers who are willing to respond so many times per year.

4. Measurement and verification, payments, and penalties

A. Measurement & verification

Prequalification. Prequalification takes place at the pooled assets level. Signing a STOR framework agreement can take between 2 weeks and several months. In the Capacity Mechanism, procedures seem straightforward, however the mandatory provision of a credit cover for unproven Demand Response poses a significant barrier to potential participants. DR units in the Capacity Mechanism need to complete a metering assessment before the delivery year, as well as a metering test if required, followed by a DSR Test before the delivery year and three "satisfactory performance days" during the delivery year. National Grid is currently undertaking a project to look into how the prequalification process for DSR providers can be updated, in particular in relation to frequency response services. However, the expensive testing regime does not seem to be open for reform.

FFR prequalification requirements currently lack transparency. National Grid has launched a review of the tests specs early 2017 in order to put more clarity, and make sure that proper tests specifications are implemented for DR assets, instead of the current copy/paste of generation test specifications.

Baseline methodology. Baseline methodologies vary by market and product. No one methodology works for all types of Demand Response, and under current rules, some methodologies favour customer generation over load management. In some other cases, the methodology does not accommodate certain types of Demand Response. Added to the programme structure issues described above, participation in Fast Reserves requires a new IT system adapted to Demand Response, which represents a high cost for aggregators.

B. Availability/utilisation payments

Wholesale market

There are two main power exchanges in Great Britain: EPEX (which recently acquired and integrated APX) and N2EX (Nordpool). A vast majority of electricity traded is still done through OTC contracts (~80% on average)[162]. The day-ahead markets use a clearing price mechanism, while the pay-as-bid pricing mechanism is used on the intraday markets. None of these markets are open to aggregators.

162 Ofgem (2015): "Wholesale Energy Markets in 2015" available at: https://www.ofgem.gov.uk/sites/default/files/docs/2015/09/wholesale_energy_markets_in_2015_final_0.pdf (retrieved on 15 March 2017)

Balancing and ancillary services

Product	Availability payments	Utilisation payments	Access
Short Term Operating Reserve (STOR)[163]	£5.6/MW/h Committed £1.83/MW/h Flexible	£158/MWh Committed £91.04/MWh Flexible	Tender-based
STOR Runway	£3.125/MW/h	£146.67/MW/h	Tender-based
Firm Frequency Response (FFR)[164]	£3.39/MW/h	£1.47/MW/h	Tender-based
FFR Bridging	⊘	⊘	Tender-based
Fast Reserve	£4.45/MW/h	£2.33/MWh (positional fee)	Tender-based
Demand Side Balancing Reserve (DSBR)[165]	⊘	⊘	Tender-based
Demand Turn Up	⊘	£ 60-75/MWh	Bilateral contracts
Enhanced Frequency Response	£7/MW/h - £12/MW/h	Not available	Tender-based
Frequency Control by Demand Management (FCDM)	~£4/MW/h	Not available	Bilateral contracts
Capacity Mechanism (CM)[166]	£22.50/kW/y	Not available	Auction
Transitional arrangements auction	£27.50/kW/y	Not available	Auction
Balancing Mechanism	Not applicable	Pay-as-bid, by generators and retailers only	Discretionary offer acceptance
Triad avoidance	Not applicable	Not applicable	Not applicable
Red zone management	Not applicable	Not applicable	Not applicable

* Providers can request Setup and Administration (for pools of more than 50 meter points) payments

Table 26: Overview of availability and utilisation payments in the balancing market in Great Britain

The imbalance (or 'cash-out') prices, which market participants have to pay when generating or consuming more or less electricity than they have contracted for, have been reformed to come closer to providing a marginal cost signal, and the price cap has been raised to £3,000/MWh and will rise further to £6,000/MWh in 2018.

Capacity Mechanism. Despite the fact that the Capacity

163 National Grid (2015): STOR results for TR 9 and 10, available at: http://www2.nationalgrid.com/UK/Services/Balancing-services/Reserve-services/Short-Term-Operating-Reserve/Short-Term-Operating-Reserve-Information/

164 Average prices for all accepted tenders active in November 2016.

165 Not procured for season 2016/17

166 T-4 auction result from December 2016, for 2020/21 delivery.

Mechanism included the Transitional Arrangements, intended specifically to help develop Demand Response in advance of the Capacity Mechanism, with year-ahead auctions in 2016 and 2017, the overall design of the Capacity Mechanism does not offer a level playing field[167]. There are some peculiar restrictions on the TA auctions: participation in the TAs is restricted to those Demand Response resources that have not participated in the Capacity Mechanism T-4 auctions, and customer loads that participate in the TAs are barred from the first two or three[168] T-4 auctions. This forced Demand Response participants to make choices on whether to participate in the uncertain TAs or forego the TAs and secure commitments in the Capacity Mechanism via the preferred T-4 auction mechanisms. It also means that Aggregators that take on an obligation in any of the first three T-4 auctions may face difficulty when populating the Demand Side Units, as customers who have participated in the TAs, even with another aggregator, will be disallowed.

C. Penalties

In STOR, failure to provide at least 90% of contracted capacity (defined in more particular terms as Events of Default) results in reduction of availability payments or eventual termination of a contract.

In the Capacity Market, penalties for underperformance are weak. The penalty for each hour of total non-delivery is 1/24th of the relevant auction's clearing price. A cap is set at 200% of a provider's monthly capacity revenues. An overall annual cap of 100% of revenues means participants cannot lose more than they are paid. These weak penalties mean that there is no strong incentive to perform reliably during system stress events. Conversely, the penalties for failing to perform in self-scheduled "satisfactory performance days" are severe: a resource that falls even 1 kW short of its capacity obligation in these tests will required to pay back all its annual revenues.

167 NERA Economic Consulting (2014), The Potential Impact of Demand-Side Response on Customer Bills, Prepared for EnerNOC, Kiwi Power and Open Energi, available at:http://www.nera.com/content/dam/nera/publications/2014/PUB_Anstey_DSR_0814.pdf

168 In response to protests, in 2016 the government relaxed the exclusivity between the first TA auction and the third T-4 auction. They have not yet done the same for the second TA auction.

Ireland

Overview

Demand Response participation has increased in Ireland in recent years. Having phased out its main Demand Response scheme in early 2013, Ireland's TSO, Eirgrid, modified the Electricity Market Rules to allow Demand Response providers to enrol as Demand Side Units (DSU) in the Single Electricity Market (SEM). Enrolment makes them eligible for capacity payments in the SEM. The first DSU became operational in July 2012; the second in December 2012.

There is room for improvement in the prequalification procedure for DSUs, whereas the interruptible loads programme STAR (Short-Term Active Response) is adequately designed. This programme will be replaced from October 2017 within the context of the "Delivering a Secure, Sustainable Electricity System" (DS3) Programme, a scheme seeking to develop new system services and grid codes that will enable Ireland to meet its target for 16% of the country's total energy consumption to come from renewable energy sources by 2020[169].

With the rapid expansion of wind energy and a target of 40% renewable energy in electricity generation by 2020, the system's need for flexibility is set to increase. Further business opportunities will be created with the opening of the balancing markets for DSUs in 2018 and with the launch of the Integrated Single Electricity Market (I-SEM) in 2018.

I-SEM is in its final phases of development by the Commission for Energy Regulation and the Utility Regulator of Northern Ireland. They have settled on a volume-based Capacity Mechanism using reliability options. Whereas the current SEM is an ex-post balancing market the I-SEM will comprise of two ex-ante markets for physical energy trading, Day Ahead and Intraday; an ex-post Balancing Market, a Capacity Mechanism, and two markets for energy related financial instruments, a Forwards Market and Financial Trading Right (FTR) auctions.

The new market arrangements are designed to integrate the whole island's electricity market with European electricity markets, enabling the free flow of energy across borders. According to the SEM Committee, this should "deliver increased levels of competition which should help put a downward pressure on prices as well as encouraging greater levels of security of supply and transparency"[170].

Within the context of transitioning to I-SEM, the opportunity for DSUs to offer ancillary services was introduced in October 2016. This will provide a significant growth opportunity for assets with appropriate characteristics, and will allow more diversity in the market. Furthermore, with the enabling of more participation in the I-SEM, demand-side participation will increase significantly through a more diverse product range.

169 Eirgrid (2014): "The DS3 Programme. Delivering a Secure, Sustainable Electricity System" available at: http://www.eirgridgroup.com/site-files/library/EirGrid/DS3-Programme-Brochure.pdf (retrieved on 28 November 2016)

170 SEM Committee is the peak decision-making body for the SEM, https://www.semcommittee.com

Main barriers and enablers for Demand Response in the different markets

Enablers. Aggregation is allowed, and the minimum bid size is 4 MW for DSUs (though due to the small market size a minimum of 1 MW would be a significant improvement over the current 4 MW requirement).

The STAR scheme has no minimum bid size, making it very accessible for consumption units. However, a careful cost-benefit analysis should be made for small units, as the installation costs for all equipment has to be covered by the unit's owner. The STAR scheme will end in October 2017 and be replaced with a new interruptible load programme (yet to be released).

Barriers. An ex-post pricing mechanism prevents the involvement of implicit demand-side measures given the lack of actionable price signals. Lack of different market products limits the level of participation. For now, participation is only available through Capacity Mechanism and ancillary services. I-SEM, which will go-live in 2018, will enable more demand-side participation.

1. Demand Response access to markets

Market overview

The ancillary market opened to Demand Side Units in 2016 under the "Interim Arrangements" which will lead to the launch of I-SEM in 2018. Demand Response, as well as other technologies, will be reviewed in 2017 Q1-Q3 through the DS3 Programme's "Qualification Trial Process" to enter the ancillary market as regular market players. This could mean a change in minimum entry size for aggregators, opening the market to new players.

A DSU consists of one or more individual Demand Response sites that can be instructed to dispatch by the TSO, as if it were a generator. Individual Demand Response sites may be aggregated in order to be operated as a single DSU. Eirgrid issues dispatch instructions at an aggregate level and the DSU aggregator then coordinates the response from the individual Demand Response sites. By being available for dispatch the DSU will be eligible for capacity payments in the Single Electricity Market (SEM).

The SEM today is effectively a balancing market in which DSUs can participate; the market comprises physical trading right (PTR) auctions, an ex-post spot energy market, and a capacity payment mechanism[171]. Currently, there is approximately 350MW of demand-side capacity active in the SEM.

The table below refers to the I-SEM. It is projected that DSUs will be able to participate in the Day Ahead and Intraday markets.

171 Eirgrid (2016): "Overview of the Integrated Single Electricity Market, I-SEM Project", available at: http://www.eirgridgroup.com/site-files/library/EirGrid/DS3-Programme-Brochure.pdf (Retrieved January 30 2017)

Wholesale market

ENTSO-E's terminology	Eirgrid's terminology	Tot. Capacity Contracted	Aggregated Demand Response Accepted	Aggregated Generation
Day Ahead	Day Ahead	⊘	✓	✓
Intraday	Intraday	⊘	✓	✓

Balancing and ancillary services

ENTSO-E's terminology	Eirgrid's terminology		Tot. Capacity Contracted	Demand Response Access & Participation	Aggregated Demand Response Accepted	Aggregated Generation
FCR	Primary Operating Reserve		50 MW (STAR)	Today only STAR ✗	✗	✗
FRR	Secondary Operating Reserve		50 MW (STAR)	Today only STAR ✗	✗	✗
RR	Tertiary Operating Reserve		⊘	Today only STAR ✗	✗	✗
RR	Replacement Reserve	Synchronised	⊘	✗	✗	✗
		De-Synchronised	⊘	✓	✗	✗
Interruptible loads	STAR		N/A To be replaced in October 2017	✓	✓	✗
Price-based capacity provision	DSU		7,046 MW[172]	✓	✓	✓
Other ancillary services if relevant (re-dispatch, voltage control)			1 Hour Ramping Reserve	✓	✓	✓
Capacity mech. (if any)				✓	✓	✓
Distribution network services				✗	✗	✗

Table 25: List of balancing market products, including volumes and load accessibility in Ireland

172 SEM Committee (2016): "Balancing Market Principles Statement Terms of Reference" available at: https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-16-058%20BMPS%20Terms%20of%20Reference%20Decision%20Paper.pdf (retrieved on 15 March 2017)

B. Markets open to Demand Response

Balancing market and ancillary services. Balancing Market Ancillary services opened to Demand Response on 1 October 2016 as part of the DS3 Programme "Interim Arrangements", following a multi-stage review of System Services by the TSOs in 2016. The decision was made to facilitate new technologies, including Demand Response, to enter the ancillary services market to increase competitive pressures on the long-term costs of the provision of ancillary services to the customer, through expanding the range of Service Providers[173]. The following ancillary services were opened under the interim arrangements:

Fast Frequency Response (FFR)
Primary Operating Reserve (POR)
Secondary Operating Reserve (SOR)
Tertiary Operating Reserve (TOR1)
Tertiary Operating Reserve (TOR2)
Replacement Reserve - Synchronised (RRS)
Ramping Margin 1 (RM1)
Ramping Margin 3 (RM3)
Ramping Margin 8 (RM8)

Wholesale Market. Demand Response participates in the wholesale electricity market from the point of view of bidding and dispatch, however Demand Response providers do not earn an energy payment for this.

Interruptible Contracts. Eirgrid's STAR scheme provides short-term reserves to the transmission grid, using under-frequency relays at industrial sites. Providers of this service can expect 10 to 20 unplanned and instantaneous interruptions per year for a typical duration of 5 minutes. However, the STAR programme is expected to end in October 2017, and will be replaced by a new programme (to be announced) under the DS3 programme.

Capacity Mechanism. A volume-based Capacity Mechanism does not yet exist in Ireland. Ireland has established a price-based capacity provision in the wholesale market, with a fixed cap of total payments being split across the year into half-hour windows. Prices per half-hour vary throughout the year, according to the loss-of-load probability, and eventual payments are then split between all capacity providers that subscribed their capacity for this particular half-hour. There is 80% accuracy in upfront capacity calculations, with wind forecasting having the strongest influence on uncertainty. Participation in the wholesale market is required to earn capacity payments in the Capacity Mechanism.

Distribution network services. Demand-side flexibility could represent an important tool for local congestion management. Currently there is not much activity on the distribution network level. However, this is likely to change in the near future with a strong involvement expected from DSOs.

There is currently no incentive scheme in place that encourages the DSO to invest in efficiency management (CAPEX vs TOTEX[174]), such as investing in "non-wires-alternative services". However, there are some monies for innovation approved by CER, the Irish regulator. At the moment, DSOs do not buy demand-side flexibility but are planning to offer smart energy systems including energy management to consumers. These projects are not fully market based.

173 For a detailed description of the Qualification Trial Process of potential ancillary services, see: Eirgrid/SONI (2016): "System Services Decision Paper on Qualification Trial Process", available at: http://www.eirgridgroup.com/site-files/library/EirGrid/DS3-System-Services-Decision-Paper-on-Qualification-Trial-Process-FINAL.pdf. (retrieved on 28 November 2016).

174 CAPEX: Capacity expenditure, infrastructure expenses, in opposition with operational expenditures (OPEX) services and maintenance expenditures. Total expenditure (TOTEX) = CAPEX + OPEX

C. Restrictions related to distribution network operations

Currently there is a 60% limit for wind generation in the system at any given time to protect the stability of the system. System operators can curtail generation if it exceeds this limit. The DSO has the right to limit the physical access of a site to Demand Response, but not the financial access. In other words, a site may be limited to curtailing load and/or using generators at certain times but not prevented from offering these services to the market. This means the customer is still paid for being available, even if the DSO deems that system constraints prevent them from being dispatched. There is no direct compensation from the DSO; the market pays the customer as if they were available. The DSO use “instructions sets” based on off-line analysis to limit the participation of DSR due to potential network congestion.

The tariff scheme in Ireland does not incentivise the provision of Demand Response services. The scheme is close to flat and does not reflect congestion or real time need. Even industrial tariffs do not have a significant effect on demand-side response activities.

2. Service providers access to markets

A. Demand Response service providers access to consumer

In the balancing market, a medium to large electricity users (> 4 MW) can participate in a Demand Side Unit (DSU) or an Aggregated Generating Unit (AGU). A Demand Side Unit is usually managed by a third-party company specialising in demand-side management, and consists of one or more individual demand sites. The main barrier service providers have to access to markets is the ex-post pricing system, which does not provide a good price signal for demand-side measures. This may change under the Qualification Trial Process, which takes place from January 2017 to September 2017, in preparation for the DS3 Programme. The Qualification Trial Process aims to prove and measure the effectiveness of potential ancillary services, including Demand Response, which opened in the balancing market under the interim arrangements in 2016. The Qualification Trial Process will enable new and existing Service Providers to demonstrate provision of services or measurement of a wide range of services in order to enable market access.

Additionally, the current market design of the SEM does not allow Demand Response and generation to be aggregated within the same bid. This is expected to change with the development of the DS3 programme and the introduction of I-SEM, to be launched in 2018, which will comprise of an Intraday, Day Ahead, Balancing Market, Capacity Mechanism, Forwards Market, and Financial Trading Right (FTR) auctions.

The aggregator does not require BRP’s agreement prior to load management; this may also change with the transition to I-SEM. All the data needed by Demand Response providers is provided by DSOs, as they own all the meters in Ireland. The Irish energy system is centralized and all the imbalances are controlled by the TSO. They distribute all the information regarding the balancing energy, volumes, and payments to all relevant parties. The aggregator thus works as a service provider for demand sites gathered to fulfil the DSU requirements. Aggregators do not have to ask for permission or inform the retailer or BRP prior to load management. They can aggregate load from anywhere in the country. Aggregators must report their availability to the TSO and are treated as a power plant that can be dispatched when needed. Retailers do not take

a position in advance and are not a BRP. All energy imbalances are settled ex-post.

Imbalance settlement after load management. Neither the BRP nor the aggregator is charged for the imbalances caused by the load management. The Irish electricity market is centrally dispatched, which means that the imbalances are covered by the TSO. When Demand Side Units are dispatched by the TSO, the demand site retailer has avoided costs (imperfections, capacity charges, Mechanism Operated Contacts) for the demand reduction quantity.

BRP-aggregator adjustment mechanism. There is no commercial loss for the retailer in the case of load management. As a centrally dispatched market, the Irish market does not require the retailer to plan demand in advance. No such adjustment mechanism is currently needed.

3. Product requirements

A. Main product requirements

Balancing Market. A DSU must have a Demand Reduction Capacity of at least 4 MW to participate. The TSO issues instructions to the DSU to reduce demand at an aggregate level, and the DSU has one hour to reduce its demand, and must be able to maintain this demand reduction for a minimum of two hours.

Demand sites typically use on-site generation, plant shutdown, or storage technology to deliver the demand reduction. An Aggregated Generating Unit is similar to a Demand Side Unit, the key difference being that it uses on-site generation only. The AGU partners with local organisations to provide emergency reserve generation to the grid are aggregated as one large unit[175].

This may also change under the Qualification Trial Process (described above), which will take place from January 2017 to September 2017, in preparation for the DS3 Programme. The minimum generation capacity for Demand Response providers in these trials is 1 MW instead of 4, indicating that new players may be able to enter the markets by 2018[176].

Capacity Mechanism. Once they have filled the Demand Side Unit (DSU) requirements, consumers or aggregators are treated like generators in the market. DSUs that are available for demand reduction are eligible for a capacity payment in the Single Electricity Market (SEM). They bid in prices and quantities for demand reduction and receive availability payments[177]. However, DSUs do not receive a utilisation payment. About €530 million was available in total in the Capacity Mechanism in 2013 for availability payments. DSUs participate in this market. The Energy market is valued at €3 billion annually[178]. Aggregators must provide a minimum of 4 MW bids, but there is no minimum size for individual units in the pool.

175 Eirgrid (2015): "Demand Side Management (DSM)" available at: http://www.eirgridgroup.com/customer-and-industry/becoming-a-customer/demand-side-management/ (retrieved on 15 March 2017)

176 Eirgrid (2016a): "DS3 System Services: Qualification Trial Process Decision Paper" available at: http://www.eirgridgroup.com/site-files/library/EirGrid/DS3-System-Services-Decision-Paper-on-Qualification-Trial-Process-FINAL.pdf. (Retrieved 28 November 2016).

177 The payments are based on 'value' of capacity (month, trading day and trading period). Payments are given for each ½ hour of every day (assuming availability) and vary significantly for a given trading period - from zero to €181.

178 SEM-O (2013): "SEM Market Overview, July 2013", available at: http://www.sem-o.com/Publications/General/SEMO%20Market%20Overview.pdf (retrieved on 10 December 2016) For data on 2016 market value, see homepage of SEM-O website. The market was valued at 2.9 billion in 2016. http://www.sem-o.com/pages/default.aspx for an up-to-date version - for 2016 the market was valued at roughly 2.9 billion.

Wholesale market. The TSOs are currently exploring an interim solution to Intra Day and Day Ahead Trading that will last until I-SEM TSOs join XBID – the European solution for cross-border intra-day continuous trading. The preferred solution is to establish 3 cross-border intraday implicit auctions and to facilitate continuous local trading with the possibility of local implicit auctions. Auctions should be implicit and based on half hourly products[179].

Product	Market place	Minimum size (MW)
SEM	SEM-O	Needs to be dispatchable >10 MW distinct sites or an aggregator at least >4MW

Balancing and ancillary services

Product	Minimum size (MW)	Notification Time	Activation	Triggered (max. times)
DSU	4 MW	1 hour	Manual	Unlimited
STAR	None	2 seconds	Automatic	10 – 20 per year
Powersave[180]	100 kW	30 minutes	Manual	Unlimited

Table 26: Description of some main Product requirements in the balancing products accessible to DR in Ireland

4. Measurement and verification, payments, and penalties

A. Measurement & verification

Prequalification. The individual units of each pool of loads must fulfil all technical and prequalification requirements. Thus, aggregators are not able to protect consumers from these technical and difficult prequalification procedures: each consumer is treated as if they were a large generation unit. This is a critical barrier to consumer participation as it forces providers to go through onerous technical pre-qualification measures, which they may not have the ability or knowledge to fulfil. This prequalification is also very costly and might even get worse in the years to come, with the opening of the balancing market programmes to Demand Response. Prequalification should be carried out at the pooled level to avoid this issue.

Baseline methodology. As of today, a meter-before/meter-after system is used and no common baseline methodology has been agreed upon. This is a major barrier for Demand Response. However, a group has been created to discuss the issue in cooperation with the TSO.

179 Eirgrid/SEM-O/SONI (2016): "Interim Intraday Market Solution for I-SEM Go-Live" available at: http://www.sem-o.com/ISEM/General/EG%20SONI%20NEMO%20Interim%20IDM%20Final.pdf (Retrieved 28 November 2016).

180 Eirgrid (2015a): "Powersave Scheme Rules 2015/2016", available at: http://www.eirgridgroup.com/site-files/library/EirGrid/Powersave-Rules-2015_2016.pdf (Retrieved 30 November 2016)

B. Availability/utilisation payments

SEM-O – the Single Energy Market Operator[181], is the only market platform currently available. The wholesale market is 'pay-as-clear'. For capacity mechanisms, every year a total cost and a minimum required capacity is set. Then total cost is divided to total available capacity. Note that the payments are reduced if there is more available capacity than needed. In case of repeated under-performance or non-delivery, a Demand Response aggregator faces license restrictions from the Commission for Energy Regulation (CER) and/or Utility Regulator of Northern Ireland.

Balancing and ancillary services

Product	Availability payments	Utilisation payments	Access
STAR[182]	Not provided	8,20 €/MWh*	Fixed
Powersave[183]	Not available	0.38 €/kWh (off-peak) 0.95 €/kWh (peak)	Fixed
DSU / capacity provision	59 €/kW/year[184]	Not provided	Tender-based

* Supplemental rates of 1.74 €/MWh – 6.97 €/MWh, depending on excess number of interruptions

Table 27: Overview of availability and utilisation payments in the balancing market in Ireland

181 SEM-O (2017): "The Single Electricity Market", available at: http://www.sem-o.com/AboutSEMO/Pages/default.aspx (retrieved on 10 December 2016)

182 Eirgrid (2015b): Payments and charges, available at: http://www.eirgrid.com/media/2014_2015_HarmonisedAncillaryServiceStatement%20_ofPayments_and_Charges.pdf (retrieved on 20th March 2015)

183 Eirgrid (2015a): "Powersave Scheme Rules 2015/2016", available at: http://www.eirgridgroup.com/site-files/library/EirGrid/Powersave-Rules-2015_2016.pdf (Retrieved 30 November 2016)

184 CER (2014): Total CPPS (Capacity Period Payment Sum) for 2015, available at: http://www.allislandproject.org/GetAttachment.aspx?id=229e36bd-411a-4a88-8140-f0a43068ad70 (retrieved on 20th March 2015)

Italy

Overview

In recent years, the Italian electricity market has been characterized by a rapid growth of renewable generation and by a decrease of electricity consumption. Italy relies mostly on hydro and gas for its flexibility needs, while the framework for consumer participation in the balancing market is not yet in place. The only exception is the interruptible contracts programme, which is a dedicated Demand Response programme separate from the balancing market.

The enrolment of interruptible loads is currently about 4 GW, with a minimum size of 1 MW to participate. Aggregation is not allowed. The payments are attractive and related mostly to availability payments rather than real utilisation. The programme has been called very few times during the last years, or in some cases never. Flexibility can access the day-ahead market, but only as demand bids with indication of price, as a balancing user (BRP). Although tenders to access the new Capacity Mechanism were expected to start at the end of 2015, the process has not been implemented yet. The regulation of the Capacity Mechanism envisages the participation of Demand Response.

The expected opening of balancing products to demand-side resources could lead to an increase of load participation. The potential progress is reflected in the new 2016 legislation[185], in which the Italian NRA (AEEGSI) defined the first phase of the Balancing Market Reform (RDE-1). The new agenda, whose implementation should start in 2017, will open the market to demand, distributed generation, RES, and high-performance co-generation. At the same time, it will regulate the access mechanisms of demand to balancing and reserve markets (including aggregation), reform balancing pricing, and revise geographic zone division.

1. Demand Response access to markets

Market overview

The following table details the electricity market product or sub-products and underlines where Demand Response and aggregation could participate, including related market sizes.

185 AEEG (2016): "Prima Fase Della Riforma Del Mercato Per Il Servizio Di Dispacciamento: Apertura Alla Domanda, Alle Fonti Rinnovabili Non Programmabili E Alla Generazione" available at: http://www.autorita.energia.it/allegati/docs/16/298-16.pdf (retrieved on 15 March 2017)

Wholesale market

ENTSO-E's terminology	TERNA's terminology	Market Size	Load Access & Participation	Aggregated Load Accepted	Aggregated generation
Day Ahead	MGP	195 TWh[186]	×	×	×
Intraday	MI	25 TWh[187]	×	×	×

Balancing and ancillary services

ENTSO-E's terminology	TERNA's terminology	Market Size	Demand Response Access & Participation	Aggregated Demand Response Accepted	Aggregated generation
FCR	Primary Frequency Control	1,5% of the total installed power[188]	×	×	×
FRR	Secondary Frequency Control	568,41 MW[189]	×	×	×
RR	Tertiary Reserve	3713,62 MW	×	×	×
Interruptible (Mainland)	Fast	3.300 MW[190]	3.300 MW	×	×
	Emergency	0 MW	0 MW	×	×
Interruptible (Islands)	Fast	145 MW Sicily 135 MW Sardinia[191]	145 MW Sicily 135 MW Sardinia	×	×
Capacity Mechanism (if any)	Not yet defined	Not yet defined	Not yet defined	Not yet defined	Not yet defined
Distribution network services	×	×	×	×	×

Table 26: List of balancing market products, including volumes and load accessibility in Italy

186 GME(2015):"RelazioneAnnuale",availaleat:https://www.mercatoelettrico.org/En/MenuBiblioteca/documenti/20160711RelazioneAnnuale2015.pdf (retrieved on 15 March 2017)

187 GME (2015), Ibid.

188 Terna (2008): "Partecipazione Alla Regolazione Di Frequenza E Frequenza-Potenza", available at: http://download.terna.it/terna/0000/0105/32.pdf (retrieved on 15 March 2017)

189 Terna (2017): "Stima della domanda oraria di energia e della riserva secondaria e terziaria", available at: https://www.terna.it/it-

190 AEEG (2015): "Aggiornamento Dei Corrispettivi Di Dispacciamento Per L'anno 2016", available at: http://www.autorita.energia.it/allegati/docs/15/658-15.pdf (retrieved on 15 March 2017)

191 Terna (2013): Results for the period 1 January 2013-31 December 2015, available at: http://download.terna.it/terna/0000/0257/61.pdf (retrieved on 15 March 2017)

B. Markets open to Demand Response

Balancing market. Primary Frequency Control is a mandatory service for non-intermittent generators bigger than 10MW that is potentially open to compensation[192]. Secondary Frequency Control and Tertiary Reserve are paid services, but not open to load management. However, there is upcoming new legislation that will bring significant changes to the balancing market.

With Consultation 298/2016/R/eel[193], AEEGSI opened a consultation aimed at allowing Distributed Generation, Demand Response, and non-programmable renewable sources to enter the market for the balancing service (MSD).

In the first phase of the reform, production and consumption units will be allowed to participate in the Balancing Market through their dispatching user as well as according to current technical conditions. The Balancing Service Provider (BSP) and the Balancing Responsible Party (BRP) will converge into a Dispatching User. The TSO will handle production and consumption units necessary to comply with its dispatching orders. Production and consumption units' will be able to access four types of resources within the Balancing Market: resolution of the programmed congestions, secondary power reserve, tertiary power reserve, and balancing services.

Interruptible Contracts. Participation is allowed for consumers with a minimum available curtailment potential of 1 MW, per site[194]. Interruptible Loads, managed by the Italian TSO are trigged after its order and have to react almost instantly (200 ms). Some conditions vary between mainland Italy and Sicily and Sardinia. Specifically, in mainland Italy, all capacity has already been contracted for 3 years, starting from 2015. New entrants are only provided access in case of some participants' withdrawal.

Wholesale market. Flexible consumers can access the spot market, in a single or aggregated form (as a balancing user), with demand bids and indication of price[195]. The context of raising economic constraints could explain the growing interest for limiting energy costs. Those who entered the market in 2015 offered 36,8 TWh, of which only 18,7 TWh was accepted[196].

In 2015, a significant share of electricity was traded on the wholesale market. Excluding bilateral contracts, almost 220 TWh of electricity was exchanged, 195 TWh in the day-ahead market and 25 TWh in the intraday market, which represent almost the 70% of the electricity consumption[197].

Capacity Mechanism. In 2014, the regulatory authority approved new regulation for the Capacity Mechanism in order to replace the previous temporary framework[198]. The initial aim was to hold the first auctions (with delivery period in 2017) in 2015 through an "implementation phase".

The supply for the Capacity Mechanism is envisaged to stem from operators of generation and demand-side capacities. Participation is voluntary; however, the TSO will decide on eligibility based on financial guarantees. Both new and existing capacities are thus in theory

192 Terna: "Allegato A15 Codice di Rete, Partecipazione alla regolazione di Frequenza e frequenza-potenza (Grid Code, Annex 15, Participation to frequency and to frequency-voltage control)", art.4, available at: http://www.terna.it/LinkClick.aspx?fileticket=TwRReqwHbvk=

193 Ibid.

194 Terna (2015): "Regolamento per l'approvvigionamento a termine delle risorse interrompibili istantaneamente e di emergenza nel triennio 2015-2017 (Regulatory framework for the period 2015-2017)", art.2, available at: http://www.terna.it/linkclick.aspx?fileticket=6Df1L3TCJsA%3D&tabid=663

195 Italian electricity market is divided into 6 market zones: North, Central North, Central South, South, Sicilia and Sardegna

196 GME (2015): "Relazione Annuale", availale at: https://www.mercatoelettrico.org/En/MenuBiblioteca/documenti/20160711RelazioneAnnuale2015.pdf (retrieved on 15 March 2017)

197 GME (2015), Ibid.

198 Italian Ministry of Economic Development (2014): GU 158/2014, 10 July 2014 (Italian Official Gazette), Decree 30 June 2014

eligible. Certain types are not eligible such as capacities subject to incentive schemes. Plans to include Demand Response exist, although the exact details on their participation are not yet in place.

Those interested in participating in the market must bid into either the day-ahead market or the ancillary services. The operators of contracted capacity must agree to pay back the difference between a contractually foreseen spot-market price and a pre-defined contractual "strike-price" if the difference is positive. The high penalties for failure to provide at critical system hours imply that it constitutes both a financial and a physical obligation to the participation of Demand Response.

The auction process is structured as several auctions with different lead times. The main auction is held four years prior to delivery, with a delivery period to be defined. The long lead-time of the main auction was chosen so that existing and new capacities can compete on equal footing[199].

Distribution Network Services. Demand-side flexibility could represent an important tool for local congestion management. As in most European countries, programmes run by the DSOs are still limited or in a pilot phase. Some pilot projects have started to evaluate the potential of Demand Response at DSO level. "Enel Info+[200]" was an energy efficiency pilot project carried out by e-distribuzione (previously ENEL Distribuzione). It was set up in some areas in Isernia and L'Aquila provinces from 2012 to 2015 and involved thousands of LV consumers. The participants received an energy monitoring kit including a specific device called "Smart Info"[201] which enabled easy access to energy consumption data and, at a later stage, facilitated involvement into Demand Response programmes.

Furthermore, an energy management system (EMS)[202] was implemented for the Universal Exposition 2015 by ENEL Distribuzione in partnership with Siemens, in order to offer advanced energy management services to the pavilions and exhibition areas. Consumption data was collected by Smart Info which allowed for the management of devices or information through user-friendly interfaces for energy managers and the visitors.

Other projects dealing with Demand Response were carried out such as "Address" or "Advanced" or are still ongoing, such as "FLEXICIENCY"[203]. There are other pilot projects run by other DSOs, such as "Smart Domo Grid[204]", by A2A Distribuzione.

Smart meters have been deployed in Italy starting from 2001, anticipating the mandates of roll-out that have been afterwards put in place at national and European level. A second generation of smart meters with increased functionalities and enhanced performance will be rolled-out starting from 2017.

The new smart meters developed by e-distribuzione have a dedicated communication channel towards the Home Area Network, based on a standard open communication protocol, that can provide customers with increasingly accurate information on consumption and open up the path to remotely managed domestic applications for energy efficiency and demand response.

Regarding incentives for investment in transmission and distribution networks, the Regulatory Authority

199 Norden (2016): "Regional Electricity Market Design", available at: http://www.ea-energianalyse.dk/reports/1551_Regional_Electricity_Market_Design.pdf (retrieved on 15 March 2017)

200 ENEL (2015a): "Enel Info+Infopiù", available at: http://eneldistribuzione.enel.it/it-IT/Pagine/enel_infopiu.aspx (retrieved on 10th June 2015)

201 This device can be plugged in any socket to collect the certified data managed by the smart meter through power-line. ENEL (2015b): "Smart Info", available at: http://eneldistribuzione.enel.it/it-IT/smart_info_domanda_attiva (retrieved on 10th June 2015)

202 ENEL (2015c): "Sistema Ems", available at: http://eneldistribuzione.enel.it/it-IT/sistema_ems_domanda_attiva (retrieved on 10th June 2015)

203 ENEL (2015c): Ibidem

204 A2A (2015): "Progetto Smart Grid Domo ", available at http://bilancio.a2a.eu/it/2012/bilancio-sostenibilita/la-responsabilita-sociale/i-clienti-cittadini-servizi/commercializzazione-elettricita-gas.html?page=7 (retrieved on 10th June 2015)

established that regulation must pay further attention to the potential benefits from the development of infrastructure projects (i.e. socio-economic benefits, service quality benefits, and the further integration of renewable sources), based on an output- based logic. In fact, the regulatory authority pointed out, how mechanisms adopted in 2004, and refined in 2011, revealed a rather inaccurate effectiveness for the system and, emphasized the need to update the regulation, which should gradually replace the input-based type schemes[205]. Therefore, after the completion of the pilots, and based on their results, the Authority published a new output-based framework aimed at incentivising operators' performance with focus – for the first application phase – on network observability and voltage control.

C. Restrictions related to distribution network operations

In Italy, the regulator issues the methodology for revenues, structure and connection charge and quality of service regulation after a consultation process with all stakeholders[206]. Distribution tariffs are set by the regulator based i.e. on data provided by operators.

Tariffs in Italy are geographically uniform. Legally it is required that the same network tariff for final customers is applied across the country. The retail market is liberalized since 2007 for all customers, while a residual price regulation ("maggior tutela") is still in place for residential customers and small businesses that did not switch to the free market . According to a draft decree, this residual form of price regulation will be phased-out in 2018. For household customers, the distribution tariff components used to be regulated through a progressive framework. As this progressive framework did not provide positive price signals and did not encourage energy efficient consumption patterns[207], the Authority introduced a gradual review of the structure of the network tariff in 2016, to be completed by 2018[208]. The new framework will provide a significant incentive in terms of energy savings; and will help to promote the achievement of energy efficiency targets, as it will incentivise the replacement of existing equipment (refrigeration, lighting etc.) with a new higher energy class and better performing models. It will also promote electrical applications from on-site renewable sources, which are currently heavily penalized by the current domestic tariff.

The components covering the network services (transmission, distribution and metering) are based on the costs of the services, so that all low voltage users have the same fee proportional to the energy drawn applied to the transmission component, while the distribution and metering components are based on capacity and standing charges respectively[209]. The new reform has no impact on non-residential types of users, while an upcoming tariff reform for non-residential customers has been announced by the regulator for next years.

205 CEER (2016b): "Summary Of The Annual Report To The International Agency For The Cooperation Of National Energy Regulators And To The European Commission On The Regulatory Activities And The Fulfilments Of Duties Of The Italian Regulatory Authority For Electricity, Gas And Water", available at: http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National_Reporting_2016/NR_En/C16_NR_Italy-EN_Summary.pdf (retrieved 15 March 2017)

206 EC (2015): "Study on tariff design for distribution systems – Final Report" available at: https://ec.europa.eu/energy/sites/ener/files/documents/20150313%20Tariff%20report%20fina_revREF-E.PDF (retrieved 15 March 2017)

207 https://ec.europa.eu/energy/sites/ener/files/documents/20150313%20Tariff%20report%20fina_revREF-E.PDF

208 http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National_Reporting_2016/NR_En/C16_NR_Italy-EN_Summary.pdf

209 http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National_Reporting_2016/NR_En/C16_NR_Italy-EN_Summary.pdf

2. Service providers access to markets

A. Demand Response service providers access to consumer

Aggregators are not allowed in any of the key markets. Demand Response does not have access to the balancing market and aggregation is no allowed. In the specific case of Interruptible Load Programme, to participate, a consumer is required to be a BRP or have an agreement with a BRP (*balancing user* in that case)[210]. Although participation is allowed for a 'Consortium', which is a legal association of private companies or public bodies (i.e. agricultural associations, associations of public bodies, etc.)[211]. The Consortium manages all energy needs for its members and could be interpreted as a form of aggregation. However, only two Consortiums were awarded tenders for the 2015-2017 period[212].

New regime of voluntary participation to the Balancing Market. According to the NRA proposal of reform of the ancillary services market, the TSO's network code will define the potential availability of Dispatching Users for ancillary services. The network code will also involve a pre-qualification procedure based on a remote test, to verify the effective ability of the Dispatching User. Similarly, the TSO will define a minimum limit for input/withdrawal capacity to access the Balancing Market, related to virtual production and consumption units (1 MW).

The geographic scope of aggregation cannot exceed the market zone but does not have to correspond to it. Furthermore, non-relevant production units willing to participate in the Balancing Market, will continue to be aggregated zonally, by Dispatching User, and by typology. Similarly, consumption units willing to participate in the Balancing Market, can be aggregated for each dispatching user: the geographic scope of aggregation cannot exceed the market zone but does not have to correspond to it (to be defined by the TSO).

On the other hand, those consumption units that are not willing to participate in the Balancing Market, will still be aggregated zonally (per Dispatching User), while aggregation between production and consumption units will not be allowed in the first phase of the reform.

3. Product requirements

A. Main product requirements

Balancing Market. As mentioned above, the requirements for participation in the balancing market do not explicitly take into consideration some particularities of aggregated Demand Response, although these may be under review in future. The current requirements give access only to generation units (e.g. symmetric bidding).

210 Terna (2015a): "Contratto tipo per la regolazione del servizio di interrompibilità istantanea (Framework Interruptible Loads)", premise (j), available at: http://www.terna.it/LinkClick.aspx?fileticket=79l33oECozE%3D&tabid=106&mid=468 (retrieved on 15th April 2015)

211 Terna (2015), ibid.

212 Consorzio Lattiere Virgilio Soc. agr. (agricultural) with 2MW, and Consorzio Toscana Energia Spa. (public bodies of Tuscany Region) with 211MW, Terna: "Auction results Fast Interruptible Contracts, period 2015/2017", Ibid.

Balancing and ancillary services

ENTSO-E's terminology	TERNA's terminology	Minimum Size (MW)	Notification Time	Activation	Triggered (max. times)
Interruptible contract (Mainland)	Fast	1 MW	200 ms[214]	After TSO request	No limit
	Emergency	1 MW	5 s	After TSO request	No limit
Interruptible contract (Islands)	Fast	1 MW	200 ms	After TSO request	No limit

Table 27: Description of some main Product requirements in the balancing products accessible to DR in Italy

Upcoming legislation will deal with major market issues such as product requirement barriers on the balancing market. The current consultation is specifically handling issues related to the criteria for the definition of aggregated load, definition of the capacity of injection and withdrawal of virtual units of production and consumption. It will also help provide clarity on the qualification process for voluntary participation, the definition of the relevant period for the purposes of settlement, and uplift payment for a qualified unit of consumption.

According to the current requirements, the network code both excludes all non-relevant units of production (<10 MVA) from non-programmable RES (objective requirements) and defines the necessary technical performance for units, in particular concerning the gradient (the power the unit is able to provide in minutes), the time of fulfilment after the TSO's request, and, only for Hydro units, a minimum duration of supply for the requested performance (functional requirements).

With the implementation of the first phase of the reform, the regulatory authority will ask the TSO to remove the constraint excluding non-programmable RES, and to allow the participation of non-relevant production units (<10 MVA) (including non-programmable RES) to the balancing market, so long as they comply with the geographic criteria.

The regulatory authority will also have the TSO provide new performance requirements. Until the definition of new contracts in 2018, units for Interruptible load services will be temporarily excluded from the Balancing Market, as well as production and consumption units in low-tension with no hourly metering (less than or equal to 55 kW).

Criteria for the definition of dispatching point for relevant unit of production from non-programmable RES and for Qualified Virtual Units (UVA). In RDE-1, relevant production units cannot be aggregated, they have to participate individually. However, non-relevant production units can be aggregated if they conform to Deliberation 111/06, Comma 8.2, Attachment A (both programmable and non-programmable).

Interruptible Contracts. In mainland Italy, the yearly volume for the period 2015-2017 was reduced from 3.900 MW to 3.300 MW[214]. Two sub-programmes are managed by the TSO: Fast Interruptible and Emergency Interruptible. The latter is triggered only in case of under

213 Terna (2012): "Prescrizioni Tecniche Integrative Per La Connessione Al Banco Manovra Interrompibili", available at: http://download.terna.it/terna/0000/0113/83.pdf (retrieved on 15 March 2017)

214 AEEG (2014): "Resolution 566/2014/R/eel" art.8, available at http://www.autorita.energia.it/allegati/docs/14/566-14.pdf

participation in the Fast-Interruptible tender. Different programme conditions apply for Sicily and Sardinia, where the previous scheme is still in force. Interruptions are called by the TSO, with no limit of activation. The number of calls is not public, but activations can be estimated at only few times per year.

Wholesale Market. Flexible consumers can make demand bids with indication of price. They should belong to the same market zone[215], and bid a minimum of 1 MWh. The participation fee is € 7.500, for the registration to the platform, and €10.000 as yearly fee, plus some variable costs over the electricity traded[216].

4. Measurement and verification, payments, and penalties

A. Measurement & verification

Prequalification. Participation in the interruptible contracts requires the compliance with the Grid Code, as well as a smart meter with a remote-control function, triggered by the TSO. The compliance with the requirements involves significant investments and the TSO can proceed with site-inspections, or documentation verification. However, the level of participation in the last tender by single consumers was positive, and fulfilled all available budget expected for the fast contracts.

Regarding the Balancing market, the possible participation of demand-side resources would require a control centre operating 24/7, which is a market entry barrier.

The upcoming RDE-1 reform will involve a new double qualification regime: a mandatory regime, for all the relevant units participating in the Balancing Market, and a voluntary regime, in which non-programmable RES units, non-relevant units (both production and consumption), and other relevant units, are currently not allowed to participate.

Baseline methodology. To participate in the interruptible contract, a consumer must have a minimum load equal to its bid load, corrected by a monthly factor. The correction factors, defined by the TSO, vary between 1 and 0,9 (for January, August, October and December) and were marginally increased for the period 2015-2017, in comparison with the previous rules.

B. Availability/utilisation payments and Penalties

Since 2015, the maximum bid values of the Interruptible Contracts was reduced by 10% in mainland Italy[217]. This change, combined with the programme size reduction, aimed to save about € 140 million per year according to the Ministry plan. Furthermore, a higher reduction occurred during the 2015-2017 tenders, when the results appeared to be significantly under the maximum bid price. The overall expenses are about € 300 million for the mainland, and about € 230 million for the islands. Payments for the Capacity Mechanism are not yet defined, but the availability payments are expected to be set at around 25.000 €/MW.

The agreement between the TSO and the Interruptible

215 Italian electricity market is divided into 6 market zones: North, Central North, Central South, South, Sicilia and Sardegna

216 GME (2015a): "Corrispettivi (Fees)", available at: www.mercatoelettrico.org/en/Mercati/MercatoElettrico/corrispettivi.aspx (retrieved on 15th April 2015)

217 AEEG (2014): "Resolution 566/2014/R/eel" art.8, available at http://www.autorita.energia.it/allegati/docs/14/566-14.pdf

Users is withdrawn in case of more than 3 failures of interruption during the period 2015-2017, or in the case where the consumer's load would be reduced under 70% of the contractual load[218].

Balancing and ancillary services

Product		Availability payments	Utilisation payments	Access
Interruptible contracts (Mainland)	Fast	89.899 €/MW in average[219] (135.000 €/MW, tender cap)	Extra 3.000 €/MW for each additional interruption, if the number of interruptions is >10, or paid back if the number of interruptions is <10[220,221]	Tender-based
Interruptible contracts (Mainland)	Emergency	No unassigned resource in the fast-interruptible contracts tender (90.000 €/MW, tender cap)		Tender-based
Interruptible contracts (Islands)	Fast	≈170.000 €/MW in average per year (170.000 €/MW, tender cap)	Extra 3.000 €/MW for each additional interruption, if the number of interruptions is > 20.	Tender-based

Table 28: Overview of availability and utilisation payments in the balancing market in Italy

218 Ibid., art.3.3

219 Terna (2015b): "Tender results, period 2015-2017", Ibid.

220 AEEG (2014a): "Resolution 301/2014/R/eel" 20 June 2014, art. 4, available at: http://www.autorita.energia.it/allegati/docs/14/301-14.pdf

221 Terna (2012a) "Contratto Per La Regolazione Del Servizio Di Riduzione Istantanea Dei Prelievi Di Energia Elettrica Di Cui Alla Delibera Dell'autorità Per L'energia Elettrica E Il Gas 513/2012/R/eel"

The Netherlands

Overview

The Netherlands presents an interesting model, as the TSO seems to have succeeded in enabling a considerable amount of demand-side flexibility with relatively simple market structures, namely clear and timely price signals – particularly to green-house owners. Further market development could be enabled through encouraging market competition between service providers.

Tennet, the Dutch TSO, estimates that currently up to 1.5 GW of Demand Response (including demand and behind-the-meter generation) might be present in the Dutch market. The total volume of balancing energy activated by the TSO per year still stands at 500 GWh.

The balancing market plays a central role in the Dutch electricity system. The main drivers for demand-side participation is imbalance management of BRPs for their own portfolios and so-called "passive balancing", which presents the advantage of simplicity, but prevents third-party aggregator to access consumers directly.

In 2015, a variation of Emergency Power programme, called "Omgekeerd Noodvermogen", was put in place[222] which allowed upward and downward regulation, and was accessible by loads. In total in 2015, 150 MW was procured in 2015. In 2017 so far 70 MW of emergency capacity has been tendered.

Main enablers:

- Demand Response can access the majority of ancillary services;
- Bidders are free to state condition for the activation;
- Minimum volumes in ancillary services are adequate for Demand Response capabilities.

Main barriers:

- The aggregators can participate in the market only through BRPs;
- The minimum contracted volume in the Emergency Power programme is 20 MW, which constitutes an entry barrier for potential providers.

The major change in the Netherlands is that more and more market actors including the DSO's, BRP's, and retailers are starting to look into the effective use of providing DR as a service so as to retain their customer base.

222 NL Noodvermoogenpool (2014): "Noodvermogen Afregelend", available at: http://nlnvp.nl/Nieuws (retrieved on 13 March 2015)

1. Demand Response access to markets

Market overview

Wholesale market

ENTSO-E's terminology	Market place	Total Volume Traded[223]	Demand Response Access & Participation	Aggregated Demand Response Accepted	Aggregated generation
Day Ahead	EPEX	42.7 TWh (2015)	✔	✔	✔
Intraday	EPEX	949 GWh (2015)	✔	✔	✔

223 EPEX (2017): Press release, available at: https://www.epexspot.com/en/press-media/press/details/press/EPEX_SPOT_reaches_in_2015_the_highest_spot_power_exchange_volume_ever (retrieved on 15 March 2017)

Balancing and ancillary services

ENTSO-E's terminology[224]	TSO's terminology	Tot. Capacity Contracted	Demand Response Access & Participation	Aggregated Demand Response Accepted	Aggregated generation
FCR	Primary Control *(Primäre Regeling)*	101 MW[225] (2016) (Dutch-German Auction; 29 MW via separate Dutch auction in 2015)[226]	✗	✗	✗
aFRR	Regulating Capacity *(Regelvermogen)*	300 MW, yearly procurement; Additional voluntary/ spontaneous bids per ISP (15 mins)	✓	✓	✓
mFRR	Reserve Capacity *(Reservevermogen)*	300 MW[227] Voluntary bids only, per ISP (15 mins)	✓	✓	✓
mFRR	Negative Emergency Power *(Noodvermogen + Omgekeerd Noodvermogen)*	350 MW[228], yearly procurement	✓	✗ (>230 MW industrial load and aggregated resources)	⊘
RR	Replacement Reserves	Traded on the intraday market	⊘	⊘	⊘
Other ancillary services if relevant (re-dispatch, voltage control)	⊘	⊘			⊘

224 Elia (2014): "Potential cross-border balancing cooperation between the Belgian, Dutch and German electricity Transmission System Operators", p. 4, available at: http://www.elia.be/~/media/files/Elia/users-group/141008_Final_report.pdf (retrieved on 14 March 2015)

225 Verpoorten Koen, et al.(2014): Market barriers for harmonised demand-response in balancing reserves: cross-country comparison, available at: https://lirias.kuleuven.be/bitstream/123456789/554390/1/Market+barriers+for+harmonised+demand-response+in+balancing+reserves.pdf (retrieved on 15 March 2017)

226 Frontier Economics (2015): "Scenarios for the Dutch electricity supply system", available at: https://www.rijksoverheid.nl/binaries/rijksoverheid/documenten/rapporten/2016/01/18/frontier-economics-2015-scenarios-for-the-dutch-electricity-supply-system/frontier-economics-2015-scenarios-for-the-dutch-electricity-supply-system.pdf (retrieved on 15 March 2017)

227 Ecofys (2014): "FLOW Dynamic Power Management WP2.2: Market Interaction", available at: http://www.ecofys.com/files/files/ecofys-2015-flow-dynamic-grid-wp2-2-market-interaction.pdf (retrieved on 15 March 2017)

228 Ecofys (2014), Ibid.

Capacity mech. (if any)	⊘	⊘	⊘
Distribution network services	⊘	⊘	⊘

Table 27: List of balancing market products, including volumes and load accessibility in the Netherlands

B. Markets open to Demand Response

In practice the passive contribution of BRPs is a low threshold means to enter in the balancing market. Many BRPs use this to include DSR. The biggest share of demand-side flexibility is used in "passive balancing/ passive contribution". In case of a short or long market, the BRPs can be rewarded for their imbalance – instead of being punished for it as it may happen in other countries – if their position contributes to the balancing of the whole network. Such a solution is possible due to publicly available near real-time imbalance positions and prices[229]. Whereas, aggregators typically pool demand-side resources from greenhouses, hospitals, small industries with CHP and load shedding capabilities.

Balancing Market and Ancillary Services. The TSO mainly uses aFRR to balance the system. There is also a scheduled mFRR product and a direct activated mFRR product (incident reserve). Demand Response and aggregation is only allowed in the manual frequency restoration reserves (mFRR). Primary Control does not allow load access and aggregation. Primary reaction is also tendered on a weekly basis. It is a symmetrical product and therefore the majority demand-side units are not able to participate. In the aFRR, demand-side resources are allowed but aggregation is not, thus making it difficult for DR to participate in reality. On the other hand, symmetry is not necessary[230].

In the Regulating/Reserve Power scheme, large electricity consumers (> 60 MW) are required to make their flexibility resources available to the TSO[231]. All other parties can do so on a voluntary basis. Bidders are free to state the conditions for activation. These include automatic activation or scheduled products, activation time and bid price. The TSO then accepts the bids according to its needs. Replacement Reserves are traded on the intraday market; they are not activated by the TSO.

Moreover, the TSO contracts complementary FRR in the Emergency Power scheme (manual, directly activated) annually, (350 MW) which can be utilised up to 40 hours per year and with a maximum of 8 hours for a single call[232]. Variation, allowing downward regulation, was added to the programme in 2015 and amounted to

229 "In the Dutch imbalance management system control area imbalance positions and imbalance price are made public in near real-time. Therefore, all market participants have the opportunity to voluntarily contribute to the TSO's efforts in maintaining the system balance. This so called 'passive contribution' is believed to result in a substantial reduction in the required control energy." TenneT (2011): "Imbalance Management TenneT Analysis report", p. 14, available at: http://www.tennettso.de/site/binaries/content/assets/transparency/publications/tender-of-balancing-power/imbalance-management-tennet---analysis-report.pdf (retrieved on 15 March 2015)

230 Verpoorten Koen, et al.(2014): Market barriers for harmonised demand-response in balancing reserves: cross-country comparison, available at: https://lirias.kuleuven.be/bitstream/123456789/554390/1/Market+barriers+for+harmonised+demand-response+in+balancing+reserves.pdf (retrieved on 15 March 2017)

231 Tennet (2012): "Implementation Guide", available at: http://www.tennet.org/english/images/120214%20SO%20SOC%2012-xxx%20Uitvoeringsregels%204%202%20%20UKclean_tcm43-19026.pdf (retrieved on 14 March 2015)

232 Ioannis Lampropoulos et al.(2012), "Analysis of the market-based service provision for operating reserves in the Netherlands", p. 3, available at: http://www.e-price-project.eu/website/files/EEM%5C'12%20-%20I.%20Lampropoulos%20et%20al.%20[31-03-2012].pdf (retrieved on 15

150 MW.

Recently a new opportunity was created in January 2017, allowing small connections, to be settled against the 15 minute meter readings values coming from the smart meter. This allowed for the unlocking of DSR for smaller connections with a smart meter through their retailer/BRP.

Wholesale Market. Demand Response offer can be bided into the wholesale market. The degree to which to it is available, however, is unknown.

Replacement Reserves. Reserves are traded on the intraday market; they are not activated by the TSO. In 2013, 48% of the total Dutch load was traded via Power NL Day-Ahead Market[233].

Congestion Management. The programme, introduced by Tennet in 2008, aimed at distributing limited amounts of transmission capacity. In case of expected congestion, a participant (generator) could offer to refrain from injecting electricity into the grid, in exchange for payments. However, the programme is not currently active and does not include the possibility for consumers to reduce consumption for the same payment.

Capacity Mechanism. The Netherlands have not introduced a Capacity Remuneration Mechanism (CRM).

Distribution network services. Demand-side flexibility could represent an important tool for local congestion management. There are few experimental projects run by DSOs, focused on electricity storage or use of smart technologies. For example, a pilot called Powermatching City[234] in Hoogkerk near Groningen aims at verifying smart grid functions in real-life circumstances. Households participating in the programme have access to different types of renewables, together with smart meters and smart household appliances. USEF (Universal Smart Energy Framework), was another project intended to provide access to smart energy systems to all interested parties through a market-based control mechanism[235].

The Congestion management programme was introduced by Tennet in 2008. In case of expected congestion, generators could offer to limit injections of electricity into the grid, in exchange for payments. However, the programme is not currently active and is not open to demand-side participation and moreover only provides network congestion management for high voltage transmission.

There is currently no incentive framework that allows for the DSO to invest in congestion management capabilities. The only incentive the DSO has is to make the grid as robust as possible. There are no mechanisms for DSOs to buy demand-side flexibility either, however there has been some growing interest in the form of pilot projects in the Netherlands.

C. Restrictions related to distribution network operations

The Netherlands uses a fixed tariff charge structure as well as charge the consumer based on their capacity amount. If consumers want to enter any other market they must go directly through the retailer, for instance it is not possible to have one retailer for your direct in feed another one that provides the electricity capacity. There is no incentive framework for DSOs in the Netherlands to do anything about the system status. Larger consumers also have no incentives to alter their consumption patterns, and must stay within their

March 2015)

233 APX Holding BV (2014): "Annual Report 2013", p 11, available at: http://www.apxgroup.com/wp-content/uploads/APX-Group-Annual-Report-20131.pdf (retrieved on 15 March 2015)

234 More information available at: http://www.powermatchingcity.nl/site/pagina.php?

235 More information available at: http://www.usef.info/Home.aspx

consumption contract. In fact, consumers are provided with a lower capacity charges if they are able to flatten their consumption.

A positive sign is that the Ministry of Energy and Economic Affairs announced that the netting structure, however, will be changed in the future and it is possible that it will be replaced by a Time of Use Tariff in the future.

The Netherlands has also started to study the effect of certain tariff structures on the willingness of Demand Response facilities to participate in flexibility and balancing markets. At this time, the results are unknown.

2. Service providers access to markets

A. Demand Response service providers access to consumer

Currently there are a minor amount of small scale aggregators participating in the market. The majority are generators, BRPs, or incumbent parties (such as integrated generators and/or retailers). The consumers are also mostly large industry, greenhouses, or those operating in the petrochemical intensive industries. There are a few pilots exploring the possibility of aggregating Demand Response and generation within the same bid but it is not currently possible in the regulatory framework.

Aggregators in the Dutch Market offer portfolio optimisation services to BRPs, through trading on the day-ahead, intraday and balancing markets. BRPs optimise imbalances through real-time dispatch and may act as balancing service providers. BRPs can act as aggregators or they can hire a third-party aggregator for this service. The offering is always bundled with the sale of electricity. Consumers must either reject the entire service or accept the aggregator's/BRP combined offer, or try to re-negotiate their entire retail contract with another retailer in order to access Demand Response services they required.

In this context, **a third-party aggregator is thus obliged to have an agreement with the consumer's BRP and with its retailer.** The aggregator can only work as the BRP's service provider. As in other Member States, this creates a market entry barrier for new entrants.

The need for an aggregator role in the Netherlands recently emerged due to several pilot project results which concluded that there was significant inflexibility in the current market model of the country. Therefore, a new market model framework was designed called USEF. The USEF framework is an add-on, on top of the existing market model, to enable a new market role called aggregator. It also incorporates a mechanism for the DSO to solve predicted congestions through a market based solution. Currently the investigation is ongoing of how to implement an aggregator role independent from the retailer/BRP.

At the same time, future developments are also being discussed between a group of key stakeholders (associations of suppliers/retailers, BRPs, DSOs, TSOs, Larger customers the ministry of economic affairs, regulators, etc.). This group is called the "Overleg Tafel Energievoorziening". Three future models have been discussed by the stakeholders:

- Model A: A new market role for an "(independent) aggregator";
- Model B: (And/Or) The separation of the retailer and BRP role for smaller connections;

- Model C: An independent choice for the customer of his BRP, retailer, and other service providers such as aggregators ESCO's etc.

The results of this are currently unknown.

Imbalance settlement after load management. Within the Frequency Restoration Reserve the TSO activates demand-side resources offered from BSPs. When load management is taking place, the TSO updates the BRP's balance status in order to avoid any imbalances caused by the requested volumes.

In the other balancing markets, aggregation is limited to the BRPs portfolio optimisation, therefore the settlement process does not require any adjustment. As it was already stated, most of Demand Response events are performed on the market (passive balancing – within the BRPs own portfolio) and will either result in a change of commercial schedules between BRPs (BRPs trading lack and excess of loads), or ultimately in imbalances to be settled with the TSO.

The imbalance settlement price is established every 15 minutes and acts as a real-time market signal which incentives BRPs to balance the system, and not only their own portfolios. This does not require the direct involvement of the TSO as the price acts as a balancing signal.

3. Product requirements

A. Main product requirements

Wholesale market

Product	Market place	Minimum size (MW)
Day Ahead	EPEX Spot	0,1 MW
Intraday	EPEX Spot	0,1 MW

Balancing and ancillary services

Product			Minimum size (MW)	Notification Time	Activation	Triggered (max. times)
FCR	Primary Reaction		1 MW	Max 30 sec	Automatic	Permanent
aFRR	Regulating Capacity		4 MW	30 sec	Automatic	Per 4 secs
mFRR	Reserve capacity	For balancing purposes	4 MW	Next ISP	Manual	Per activation
		For other purposes	4 MW	5th ISP	Manual	
mFRR	Emergency Power		20 MW	15 min	Manual	27 per year (2017)

Table 28: Description of some main Product requirements in the balancing products accessible to Demand Response in the Netherland

Balancing Market and Ancillary Services.

FCR. Primary Reaction is tendered on a weekly basis. It is a symmetrical product and therefore blocks most demand-side units from participating.

aFRR. Regulating Capacity is contracted through yearly procurement, spontaneous bids are also possible. Minimum size of a bid is 4 MW. Submitted bids are selected in a common merit order. The annual bids and the 4MW requirement mean that little DR is submitted[236].

mFRR. Reserve Capacity is procured through voluntary bids. It is divided into Reserve Capacity for balancing purposes and for other purposes; the latter serves for re-dispatch and is not a part of balancing market.

Emergency Capacity. Noodvermogen is contracted annually via tenders in May/June. Since 2014, it is procured separately for downward and upward regulation, allowing consumer loads to participate. The contracted volume has to be provided within 15 min., and shall be available nearly 24/7 (required availability amounts to 97 – 100%). The minimum contracted volume is 20 MW[237], it can also come in an aggregated form[238]. The Emergency Capacity is therefore difficult to enter for new entrants as the 20 MW minimal load required acts as a significant barrier to participation.

Replacement Reserves. Replacement Reserves are not used for balancing purposes and are self-dispatched, through the intraday market. This programme uses a pay-as-bid pricing system.

236 JRC (2016): "Demand Response status in EU Member States", available at: http://iet.jrc.ec.europa.eu/energyefficiency/sites/energyefficiency/files/publications/demand_response_status_in_eu28_member_states-online.pdf (retrieved 15 March 2017)

237 Tennet (2013): "Memorandum to Suppliers Emergency power", available at: http://www.tennet.eu/nl/fileadmin/downloads/About_Tennet/ENGELS-SO-SOC_13-056_Productinformatie_noodvermogen.pdf (retrieved on 13 March 2015)

238 Tennet, "Noodvermogen", available at: http://www.tennet.eu/nl/fileadmin/downloads/About_Tennet/Publications/Other_Publications/plugin-120521_Brochure_noodvermogen_tcm43-20672.PDF (retrieved on 14 March 2015)

4. Measurement and verification, payments, and penalties

A. Measurement & verification

Prequalification. The pooled load has to fulfil requirements as an aggregate. This is a critical enabler of Demand Response as it allows the BRP-aggregator to act as mediator for the consumer, protecting them from onerous technical pre-qualification measures, which they may not have the ability or knowledge to fulfil.

Baseline methodology. Baseline settlement depends on the contractual relationship between the end consumer, their BRP and their retailer. The absence of standardised requirements can act as a barrier as each contract must be negotiated individually. For TSO contracted FRR (manual) the BSP is required to supply measurements directly to the TSO[239]. The data regarding actual baselines is only required for aFRR (continuously, 4 seconds-based) and Emergency Power (checked ex post, taking into account the values 1 hour prior to activation to 1 hour after deactivation, with 5 min metering resolution).

B. Availability/utilisation payments

Portfolio management for the BRP is attractive, as it is both well paid and creates lower start-up costs than providing balancing products. Capacity price is a pay-as-bid price while energy prices resulting from daily auctions (for 15 minute periods) are uniform marginal prices. Larger consumers (> 60 MW) must bid available capacity into the reserve power system, while smaller market participant can choose whether they want to participate[240].

239 Metering is a liberalised market in the Netherlands, the meter data is managed by the meter data manager. The required metering equipment for important connections (superior to 3 * 80 A) is a telemetric meter, with (at least) 15 minutes resolution. For smaller connections there is no such obligation; allocation of realized volumes then will be based on profiling.

240 Frontier Economics (2015): "Scenarios for the Dutch electricity supply system", available at: https://www.rijksoverheid.nl/binaries/rijksoverheid/documenten/rapporten/2016/01/18/frontier-economics-2015-scenarios-for-the-dutch-electricity-supply-system/frontier-economics-2015-scenarios-for-the-dutch-electricity-supply-system.pdf (retrieved on 15 March 2017)

Balancing and ancillary services

Product			Availability payments	Utilisation payments	Access
FCR	Primary Reaction		Yes	No	Common platform Weekly
FRR	Regulating Capacity		Yes	€ 70/MWh over day ahead price	Yearly Call for tender + Voluntary bids
FRR	Emergency Power		Yes (payment value as bided)	€ 200/MWh or marginal + 10% if higher	Yearly Call for tender
FRR	Reserve Capacity	Balancing	No	€ 200 /MWh over day ahead price	Voluntary bids
		Others; redispatch, not relevant for balancing	No	Not available	Voluntary bids
RR	Replacement Reserves		No	Acc. to the Intraday wholesale market prices	Intraday wholesale market

Table 29: Overview of availability and utilisation payments in the balancing market in the Netherlands

C. Penalties

Non-availability of contracted Primary Reaction (FCR) volume is fined with a penalty equivalent to 10 times the bid price[241]. Verification of delivery of balancing energy occurs only for contracted products like the Regulating/ Reserve Power (FRR). Non-or insufficient delivery of contracted products may result in a penalty of 1/6th of the contractual fee, and ultimately in cancelling the contract. For Emergency Power the Balancing Service Provider has to supply measurements every 5 minutes to Tennet if the emergency power is deployed. Penalties also occur for non-or suboptimal availability.

241 Tennet et al. (2014): "Potential cross-border balancing cooperation between the Belgian, Dutch and German electricity Transmission System Operators", p.50,available at: http://www.tennet.eu/nl/fileadmin/downloads/About_Tennet/Publications/Technical_Publications/balancing/141008_Final_report.pdf (retrieved on 13 March 2015)

Norway

Overview

Norway has extensive hydropower resources. It represents about 95% of its electricity consumption and fills most of its flexibility needs. An important share of residential heating is covered by electricity. Norway has taken important steps to allow wider Demand Response participation. In fact, Demand Response and aggregation can now legally bid in all balancing markets. In order to place bids on the market, aggregators must be BRPs themselves or co-operate with a BRP which takes on the balance responsibility for them. While this framework might be pervasive across the Nordics, this model makes the concept of aggregation less appealing to market actors and thus implemented less, and in cases in Norway, technically unfeasible. There is currently dialogue between the Nordic NRAs and between the Nordic TSOs on how to improve demand-side flexibility in the Nordic market, and models for aggregation is a part of this discussion. While the major barrier to Demand Response in the Nordic markets and in particular Norway, is arguably not specifically the framework for a third-party aggregator, it still remains that, the discussion in finding a new regulatory framework for these market actors will play a considerable role in the future development of the retail market in the area overall.

In a report published by the Nordic regulators, the issue of independent aggregators is addressed. They believe in the importance of leaving the decision to intervene in the market to the competent national authorities after thorough impact assessments. When it comes to the role of aggregators, the Nordic regulators believe the most efficient setup for the retail markets is that aggregation services are developed by market competition through one integrated unit which has balance responsibility[242].

Demand-Side Resources mainly participate through the Regulating Power Market (the specific balancing market common to Nordic countries and operated by the power exchange, "NordPool Spot") and can participate in the spot market. The minimum bid size represents a barrier for Demand Response and several other technical requirements appear to be generation-oriented. However, changes are under discussion. Payments are quite attractive, but mainly in the Regulating Power Market. Currently, Norway is also running a pilot project in NO1 where they allow for the aggregation of small loads up to bids of 10 MW[243].

Traditionally, there is more participation from production in the reserve markets – today there is very little participation from demand in FCR and aFRR. Still, in mFRR (RKOM and RK) there is a substantial amount. Around 1000 MW in mFRR (RK and RKOM week), 543 MW in the mFRR season option market (RKOM) and up to 120 MW through bilateral agreements. In the future Norway expects more participation from demand-side resources in all markets.

242 NordREG (2016): "Discussion of different arrangements for aggregation of demand response in the Nordic market – February 2016", available at: http://www.nordicenergyregulators.org/wp-content/uploads/2016/02/NordREG-Discussion-of-different-arrangements-for-aggregation-of-demand-response-in-the-Nordic-market.pdf (retrieved on 15 March 2017)

243 Statnett (2017): "Prøveordning med unntak for NO1 i januar og februar 2017", available at: http://www.statnett.no/Global/Dokumenter/Kraftsystemet/Markedsinformasjon/RKOM/Pr%C3%B8veordning%20med%20unntak%20for%20NO1%20i%20januar%20og%20februar%202017.pdf (retrieved on 15 March 2017)

1. Demand Response access to markets

Market overview

The following table shows the electricity market product or sub-products and underlines where Demand Response can legally participate, including related market sizes.

Wholesale market

ENTSO-E's terminology	Market place	Market Size (MWh)[244]	Demand Response Access & Participation	Demand Response Accepted	Aggregated Generation
Day Ahead	Nordpool spot / elspot	391 TWh (2016)	✔	✔	✔
Intraday	Nordpool spot / elbas	5.1 TWh (2016)	✔	✔	✔

Balancing and ancillary services

ENTSO-E's terminology	TSO's terminology	Tot. Capacity / Energy Contracted	Demand Response Access & Participation	Demand Response Accepted	Aggregated Generation
FCR	Frequency controlled normal operation reserve (FCR-N)	214 MW[245]	✔ Since 9.03.2015	✔	✔
	Frequency controlled disturbance reserve (FCR-D)	353 MW[246]	✔ Since 9.03.2015	✔	✔
aFRR	Automatic frequency restoration reserve (FRR-A)	300 MW in the Nordics (105 MW Norwegian share)[247]	✔	✔	✔

244 NordPool Spot (2017): "Strong volumes foundation for expansion – Nord Pool 2016", available at: http://www.nordpoolspot.com/message-center-container/newsroom/exchange-message-list/2017/q1/strong-volumes-foundation-for-expansion--nord-pool-2016/ (retrieved on 15 March 2017)

245 ENTSO-E (2006): "System operation agreement", art. 4.1.2, available at: https://www.entsoe.eu/fileadmin/user_upload/_library/publications/nordic/operations/060613_entsoe_nordic_SystemOperationAgreement_EN.pdf

246 Ibid., art. 4.1.1

247 Statnett (2015): "Secondary Reserve", available at: http://www.statnett.no/Demand Responseift-og-marked/Markedsinformasjon/sekundarreserver/ (retrieved on 30th April 2015)

mFRR	Fast disturbance reserve (FRR-M)	RKOM week	0-1254 MW[248]	✔ 0- 1000 MW	✔	✔
		RKOM season	543 MW[249]	✔ 533	✔	✔ (Aggregated generation allowed when localized at the same central node)
		Bilateral agreement	136 MW[250]	✔ 120 MW[251]	✔	✔
	Balancing Market (RK)		≈ 1.700 MW[252]	✔ ≈1.000 MW	✔	✔
RR	Strategic reserves[253]		300 MW[254]	✘	✘	✘
	Energy Options (Strategic reserves in consumption) - Discontinued		✘	✘	✘	✘
Other ancillary services if relevant (re-dispatch, voltage control)	⊘		⊘	⊘	⊘	⊘
Capacity mech. (if any)	See RKOM					
Distribution network services	(see section B. below)					

Table 30: List of balancing market products, including volumes and load accessibility in Norway

248 Season 2016

249 Statnett (2015a): "RKOM", available at: http://www.statnett.no/Kraftsystemet/Markedsinformasjon/RKOM1/RKOM---sesong/ (retrieved on 13th January 2017)

250 Statnett (2017f): "RKOM-sesong", available at: http://www.statnett.no/Kraftsystemet/Markedsinformasjon/RKOM1/RKOM---sesong/ (retrieved on 13th January 2017)

251 Statnett (2015b):"RKOM – Bilateral", available at http://www.statnett.no/Kraftsystemet/Markedsinformasjon/RKOM1/Bilaterale-avtaler/

252 Statnett (2015c): "RKOM – RKM", available at: http://www.statnett.no/Demand Responseift-og-marked/Markedsinformasjon/RKOM1/Om-regulerkraftmarkedet-RKM/

253 However Norway is disinvesting in these turbines http://www.statnett.no/Media/Nyheter/Nyhetsarkiv-2015/Nye-nettanlegg-gir-besparelse-og-bedret-forsyningssikkerhet/

254 Statnett (2015d): "Reserve Power Plant", available at: http://www.statnett.no/en/Market-and-operations/Reserve-Power-Plants/ . Gas turbines

B. Markets open to Demand Response

Ancillary Services. Industrial consumers represent a significant level of participation in the balancing market.

- Primary Reserve (FCR-N and FCR-D) opened to Demand Response through a BRP in 2015.
- Secondary Reserve (aFRR) is legally open to Demand Response through a BRP, but participation is practically unfeasible due to unlimited activation time.
- The Norwegian TSO procures Tertiary Reserve (mFRR) through the balancing market (RK) and the mFRR option market (RKOM). The option market has seasonal or weekly tenders (RKOM). The TSO also has few bilateral agreements with demand resources that can be activated during the winter period, which require these parties to bid into the Regulating Power Market.

In a recent pilot project that concluded in 2015, Swedish and Norwegian TSO's explored the possibility of exchanging capacity between the Automatic Frequency Restoration Reserve (FRR-A). "The Hasle Project" ran for 8 weeks with the overall aim to contribute to the development of a Nordic market for FRR-A Capacity[255]. The results of the pilot project resulted in the decision to create a Nordic FRR-A capacity and energy market. The market will be 'pay as bid' with the bid size a minimum of 5 MW. Initially, the activation of will be performed "pro-rata", and the activation price will be determined based on the price set by the reserve activation in the mFRR market. Later, the Nordic FRR-A will be expanded with a Nordic Energy activation market, including voluntary bids, activation and pricing in accordance with a common merit order list, and real time congestion management. The market is intended to start operation in the second half of 2018[256].

Wholesale Market. There are, however, significant barriers to demand-side resources entry to the spot market such technical requirements that favour generation oriented energy. Overall and similarly to the other Nordic markets, a significant share of electricity is traded in the wholesale market, which represents almost the 100% of the electricity consumption in Norway.

Capacity Mechanism. The option market for regulating power (RKOM) is Norway's Capacity Mechanism. In addition, the TSO has four special tariffs for flexible demand connected to the central grid. These have a much lower grid tariff than the ordinary tariff and is coordinated with the DSOs for demand connected at distribution level. The reductions based on the accepted disconnection time of consumption (and partially the response time); 15 minutes, 2 hours or 12 hours[257].

Lastly, the assets from the previous strategic reserve mechanism that was in place since 2009, which consisted of two gas turbines (150MW), are also currently being sold off. Energy Options (Strategic reserves in consumption) was used up to the winter 2015/16 but is currently discontinued.

Distribution network services. Demand-side flexibility could represent an important tool for local congestion management. In Norway, there is currently an ongoing review of the network tariff regulation focussing on capacity mechanisms for all end users, which will

currently under considerations for potential disinvestment.

255 Statnett (2015e): "The Hasle-pilot project", available at: http://www.statnett.no/Global/Hasle%20report%20StGr_150317%20(3).pdf (retrieved on 15 March 2017)

256 Statnett (2016): "Nordic TSOs are preparing a Nordic aFRR capacity and energy market", available at: http://www.statnett.no/Documents/Kraftsystemet/Utvikling%20av%20kraftsystemet/Note%20on%20the%20aFRR%20market,%202016.11.01.pdf (retrieved on 15 March 2017)

257 Norden (2016): "Regional Electricity Market Design", available at: http://www.ea-energianalyse.dk/reports/1551_Regional_Electricity_Market_Design.pdf (retrieved on 15 March 2017)

greatly impact the DSO's investment structure and its ability to procure or invest in decentralised energy. At the moment, DSOs handle the shortage of grid capacity in the distribution grids via new grid investments, however there is only a few hours during the year in which the demand for grid capacity exceeds the total amount of capacity available in the grid[258].

There are also specific pilot projects that are targeting demand-side resources for DSO's but no permanent solutions or regulation in the area. Specifically, Agder Energi is running one pilot project targeting a grid substation which operates at 120 percent of its capacity a few hours each year. The project will use intelligent cloud-based smart grid technology to enable operators to better predict demand and engage distributed resources, reducing the demand on the substation and saving money that would otherwise be needed to upgrade. The pilot aim is to demonstrate how utilities fully automated can implement demand response technology to unlock a host of energy and sustainability benefits[259].

There have been many other pilot projects at city or local level too, such as the demo projects run by The Norwegian Smart Grid Centre[260]; Demo Steinkjer, led by NTE (dynamic tariffs in FP7-project e-GOTHAM and national project DEVID); Smart Energy Hvaler, led by FEAS (contracted capacity tariff tested in national project DEVID); Skarpnes Village, led by Agder Energi (aggregated households, FP7-project SEMIAH); Statnett pilot North, and the current RKOM Demand Response-pilot[261].

C. Restrictions related to distribution network operations

There are no active restrictions prohibiting consumers, at the distribution level, connection to the system or participating in the different markets.

The overall tariff regime does not incentivise consumption pattern supporting grid needs, however it is possible for DSOs to offer "load curtailment contracts" as a special tariff regime. Up to now it has not been possible to participate simultaneously in the option market for regulating power (RKOM) when on a load curtailment contract with Statnett. For the 2016/2017 season, they have been testing a pilot in NO1 where they allowed simultaneously participation[262].

258 NordREG (2015): "Tariffs in Nordic countries – survey of load tariffs in DSO grids", available at: http://www.nordicenergyregulators.org/wp-content/uploads/2015/03/Tariffs-in-Nordic-countries-survey-of-load-tariffs-in-DSO-grids.pdf (retrieved on 15 March 2017)

259 Powel (2016): "Microsoft and Agder Energi collaborate to build an intelligent grid powered by an intelligent cloud", available at: http://www.powel.com/news/microsoft-and-agder-energi-collaborate-to-build-an-intelligent-grid-powered-by-an-intelligent-cloud/ (retrieved on 15 March 2017)

260 The Norwegian Smart Grid Centre: "Demo Norge", available at: http://smartgrids.no/demo_norge/ (retrieved on 30th April 2015)

261 Statnett (2017): "Prøveordning med unntak for NO1 i januar og februar 2017", available at: http://www.statnett.no/Global/Dokumenter/Kraftsystemet/Markedsinformasjon/RKOM/Pr%C3%B8veordning%20med%20unntak%20for%20NO1%20i%20januar%20og%20februar%202017.pdf (retrieved on 15 March 2017)

262 Statnett (2017), Ibid.

2. Service providers access to markets

A. Demand Response service providers access to consumer

The aggregator requires BRP's agreement prior to load management. The aggregator in Norway must be a BRP or be BRP connected; independent aggregation as a direct party in the reserve markets is not permitted. That means that to participate in the balancing market, an aggregator would have to be the BRP for the loads/generation provided, or to enter an agreement with the BRP that is balance responsible for the loads/generation in question. In the latter option, the aggregator may work as a service provider for a BRP. He would then work only under the BRP's guidelines according to their commercial contract. There is currently no standard agreement for aggregators to use when entering agreements with their customer and other BRPs. The absence of standards in such agreements lead to a situation where such a configuration is not used today in Norway.

The Norwegian regulator and TSO are currently having national and Nordic dialogues with NRAs and TSOs on how to improve demand-side flexibility in the Nordic market, and models for aggregation in the future market is a part of this discussion. In Norway, the consumer has the ability to switch retailers, depending on the price agreement entered (variable versus fixed price). This means that an end-consumer could switch from one retailer to another providing not only electricity, but also flexibility services. However, there are a small amount of BRPs which also offer flexibility services.

As such, because the aggregator must enter into an agreement with an existing BRP (retailer/supplier), it is feasible that the BRPs may not wish to contract with the aggregator, given that it is possible that an aggregator may appear as the retailers/supplier's competitor. As the market develops further, it will be necessary to better regulate the mechanisms between retailers and aggregators.

In the Primary, Secondary and Tertiary Reserves, aggregation through a BRP is legally possible, but e.g. volume requirements (minimum 10 MW to participate in the regulating power market) can make it hard for the smaller loads to participate, and as such some market developments are required. Aggregation of production happens in practice, however, only under the same central node. Currently the TSO is conducting a trial scheme in NO1 for the winter of 2017 for RKOM in NO1 in which they are permitting the aggregation of demand-side resources within the same node area and for bids of 10 MW[263].

In addition to the balancing markets, aggregators can operate in the day-ahead (Elspot) and intra-day (Elbas) spot markets, by becoming a BRP, or with an agreement with the consumer BRP. The main types of consumers that typically participate in the market are mainly large industrial consumers. Moreover, Demand Response and generation are not able to be aggregated within the same bid.

Imbalance settlement after load adjustment. As mentioned before, the aggregator will either be the BRP or operate as a service provider for the consumer's retailer/BRP. Therefore, the retailer/BRP is the only one in direct relationship with the TSO. Given that the current framework in Norway does not allow for independent aggregators there is no specific mechanism that deals with imbalance adjustment between the two.

Activated reserves (FCR, FRR) are remunerated in the Regulated Power Market (or RK).

The imbalance settlement is common in the Nordic

263 Statnett (2017), Ibid.

Balance Market, and the imbalances are directly corrected by the TSO that takes into account its reduction order. As from 2017, the TSO's of Finland, Norway, and Sweden formed to create a separate entity that will directly deal with the operation responsibility imbalance settlement and invoicing for market participants amongst the three countries[264].

3. Product requirements

A. Main product requirements

Ancillary Services. The delivery time in the balancing market is 15 minutes, which is suitable for Demand Response units. The main remaining barrier in the balancing market is the 10 MW minimum bid size. The minimum limit is high, because this is still a manually operated market (meaning the TSO activates participants by telephone). However, there is an on-going evaluation in regards to bid size and product structure. Today's limit is under evaluation, and still they would need to introduce electronical activation before reducing bid size limit. Regarding the Primary Reserve (FCR-N and FCR-D), and the Secondary Reserve (FRR-A), the TSO can activate multiples of the MW block size (i.e. 5MW, 10MW etc.). On the other side, the Provider may deliver both FRR-A and FCR from the same station, or generator at the same time.

Wholesale Market. Both day-ahead and intraday markets require a minimum size of 0,1 MW to participate.

Wholesale market

Product	Market place	Minimum size (MW)
Day Ahead	Nordpool Elspot	0,1
Intraday	Nordpool Elbas	0,1

264 eSett (2017): "About", available at: https://www.esett.com/about/ (retrieved on 15 March 2017)

Balancing and ancillary services

Product	Minimum size (MW)	Notification Time	Activation	Triggered (max. times)
FCR-N	1	100% within 2-3 minute[265]	Automatic between 49,9-50,1Hz	Several times per hour
FCR-D	1	50% in 5s, 100% in 30s[13]	Automatic < 49,9Hz	Currently approx. 10.000 min/year outside normal operating band
aFRR[266]	5	2 min	Automatic based on Nordic frequency	No maximum
mFRR (RKOM / bilateral)	1[267]	15 min	Manual	According to the bid in RK
Balancing Market (RK)	10	15 min	Market based, manual activation	Several times per day
Strategic reserves	×	×	×	×
Energy Options	×	×	×	×

Table 31: Description of some main Product requirements in the balancing products accessible to DR in Norway

4. Measurement and verification, payments, and penalties

A. Measurement & verification

Prequalification. As the market rules stand today, it is impossible for an aggregator to pool load from different bidding zones. This limits the number and range of consumer sites available. Additionally, real time measurement is still a requirement for prequalification and as such, acts a barrier to access the Regulated Power Market (RPM), especially for small units. Furthermore, the RPM is still largely based on manual calls (using telephones), which restricts the potential of Demand Response, especially for small loads. Electronic activation was implemented in the Statnett system in 2014 and load retailers continue to support this functionality.

Anyone taking part in the aFRR also has to be prequalified by the TSO[268]

265 These are requirements from the Nordic System Operation Agreement, however there local needs for FCR response in Norway that may give variation in these settings

266 Statnett (2012): "Technical Product Specification For delivery of FRR-A to Statnett", Appendix 1 FRR-A, version January 2012, available at: http://www.statnett.no/PageFiles/2581/LFC%20Technical%20Product%20Specification.pdf (retrieved on 30th April 2015)

267 Min bid size is 1 MW , but you have to bid min 10 MW in RK – so in practice min 10 MW

268 Statnett (2014): "Vilkår - anmelding, håndtering av bud og prissetting i sekundærreservemarkedet til (Term of service, Secondary Reserve)",

Baseline methodology. The Norwegian baseline, measurement and verification criteria limit the potential for aggregated loads, and acts as a market barrier to service providers.

B. Availability/utilisation payments

Payments for Demand Response are attractive only in the balancing market. The level of the penalties for non-performance enables Demand Response participation.

The following table contains an overview of the programmes' technical requirements. All payments are pay as cleared (marginal pricing).

8 October 2014, art. 1.2, available at: http://www.statnett.no/Global/Dokumenter/Kraftsystemet/Markedsinformasjon/Frekvensstyrte%20og%20sekund%C3%A6re/FRRAVilk%C3%A5r%20TilH%C3%B8ring%20september2014.pdf (retrieved on 30th April 2015)

Balancing and ancillary services

Product		Availability payments	Utilisation payments	Access
FCR-N		Yes	Marginal cost for zone 1-40 €/MWh (hourly mkt)[269] 1,12-18 €/MWh (weekly mkt)[270]	Hourly market Weekly market
FCR-D		n/a	n/a	Hourly market Weekly market
aFRR[271]		Yes *Market based marginal cost*	Best price either mFRR or spot	Weekly market
mFRR	RKOM week	≈ 0,6-14 €/MWh[272]	RK*	Weekly market
	RKOM season	≈ 0,9 €/MWh[273]	RK*	Yearly tenders
	Bilateral	Yes	RK*	Long term agreements
Balancing Market (RK)		0	Marginal cost for zone Example NO1 2016 Up average 30 €/MWh Down average 25 €/MWh[274]	Hourly bids
Strategic reserves		0	0	Owned by the TSO
Energy Options		0	0	

*The utilisation payments from RKOM (options) are gained in the balancing market (RK), since RKOM is options only to secure sufficient volume of bids in RK.

Table 32: Overview of availability and utilisation payments in the balancing market in Norway

269 Statnett (2014a): "Price range 2016 in the hourly market, values", available at: http://www.statnett.no/Kraftsystemet/Nedlastingssenter/Last-ned-grunndata/ (retrieved on 15 March 2017)

270 Statnett (2014a), Ibid.

271 aFRR market is currently under discussion for redesign for a common Nordic market. Nordic capacity market is planned for spring 2018, and Nordic energy activation market for aFRR earliest Q4 2018.

272 Statnett (2014b): RKOM week, available numbers from the 2014 season, values available at: http://www.statnett.no/Drift-og-marked/Markedsinformasjon/RKOM1/RKOM-uke/

273 Statnett (2014c): RKOM, Bid price for the season 2014/2015 (8 NOK/MW/h), available at: http://www.statnett.no/Demand Responseift-og-marked/Markedsinformasjon/RKOM1/RKOM---sesong/

274 Historical market data Nordpoolspot http://www.nordpoolspot.com/historical-market-data/

C. Penalties

The level of the penalties for non-performance would enable Demand Response participation. A short summary is given below for the markets where penalties are described, while the full regulation can be found in the market rules for each market:

- aFRR, in case of failure of the service: suspension of the player to the market, reduced/cancelled capacity compensations, public blacklisting, decided case by case by the TSO.

- RKOM, in case of not fulfilling RKOM obligations in RK: two levels of penalties, depending on the quality of the resource, 25 x option price for a high-quality resource, or 2 x option price in case of a low-quality resource, with an upward limitation at total availability payment each week per actor and price zone. The option price is referred to the weighted average volume of the weekly option price, seasonal option price and possible special purchase prices in that period. Risk of suspension, if repeatedly in breaking rules.

Poland

Overview

In Poland, coal is the predominant source of energy. The share of hard coal and lignite in electricity production in Poland is close to 86%[275] and due to the high cost of alternative technologies the reduction of this share is relatively slow. The growing share of unstable renewable energy sources combined with low flexibility and high failure rate of conventional generation sources may constitute a risk to security of supply[276]. As power plants are located mostly in the south of the country, the transmission network might face congestion. Thus, Demand Response could add important flexibility resources in areas of the country suffering from transmission and/or generation capacity constraints.

The balancing market was formally opened for Demand Response in July 2014, but so far there have been no active bids. The issue of very stringent requirements for Demand Response participation has been slightly relaxed from 1 January, 2017. In the past couple of years Poland has seen a slight increase in contracted volume of Demand Response to approximately 200 MW.

Additionally, the Polish transmission system operator has the legal ability to curtail the electricity supply of medium to large commercial and industrial customers without compensation. In emergency situations, such curtailments have priority over the commercial emergency Demand Response programs. An example of such a threat was the emergency situation in August 2015 when as a result of several factors: heat wave, low levels of water level for cooling thermal power plants, a series of failures in the system power plants and the very low level of wind generation – the system, - , operator ordered the curtailments of energy supplies for about eight thousand of the largest industrial and commercial customers.

Furthermore, the development of Demand Response in Poland will require legislative changes, as today there is no legal role for the independent aggregator. Another important issue is the question of payments for Demand Response providers. Current regulations provide only for utilisation payments in the Balancing market. The TSO (PSE) plans to introduce availability payments for its next EDRP tender in 2017 and there are plans to open the Operational Capacity Reserves (OCR) to Demand Response in 2018 (this reserve is linked to the balancing market and includes availability payments).

Main enablers:

- Planned introduction of availability payments in EDRP, potential opening of OCR and future Capacity Mechanism to Demand Response;
- Emergency Demand Response programs

275 URE (2016): "Sprawozdanie z działalności Prezesa Urzędu Regulacji Energetyki", available at: https://www.ure.gov.pl/pl/urzad/informacje-ogolne/sprawozdania/2916,Sprawozdania.html (retrieved on 15 March 2016)

276 ENTSO-E (2015): "Winter Outlook 2015/2016 & Summer review December 2015" available at: https://www.entsoe.eu/publications/system-development-reports/outlook-reports/Pages/default.aspx (retrieved on 15 March 2017)

- Planned launch of announced new emergency Demand Response programs, one with payment for availability

- Balancing market
  - Slightly relaxed Demand Response participation requirements in January 2017

- Planned introduction of Capacity Mechanism with DSR as the one of eligible resource

Main barriers:

- Ancillary services are not accessible for Demand Response and not transparently contracted;
  - Complex verification and measurement requirements in the balancing market are considered as prohibitive along with no option for Demand Response
  - Remuneration much less attractive than in the intervention programs for generation

- Balancing market
  - Limited price volatility;
  - Lack of payment for availability in current emergency Demand Response programs;
  - The lack of DSR participation in the additional capacity reserves payments scheme (which is reserved for largest generators only);
  - Complex verification and measurement requirements in the balancing market are considered as prohibitive along with no option for aggregation (direct participation only);
  - Exact conditions for demand participation in the OCR and Capacity Mechanism still to be confirmed;
  - Higher than necessary requirements for participation in the balancing market: in particular, the accuracy of forecasting, penalties disproportionate to the possible benefits
  - Ancillary services are not accessible for Demand Response.

While there are many clear barriers to Demand Response, there is also quite strong potential for the business case for Demand Response, which is mostly driven by system needs and untapped flexible resources. But this will require the introduction of decent availability payments to take off. In the next 5-10 years, it is possible that the market will have taken off thanks to all markets being open to Demand Response (i.e. peak-shaving, Capacity Mechanism, reserves, ancillary services, balancing market).

1. Demand Response access to markets

Market overview

The table below gives an overview of the programmes used by the Polish TSO to balance the grid. It can be easily noted that possibilities for Demand Response to participate are limited.

Wholesale market

ENTSO-E's terminology	TSO's terminology	Market Size	Demand Response Access & Participation	Aggregated Demand Response Accepted	Aggregated Generation
Day Ahead	RDN	27,6 TWh (2016)	✔ 277	✔ 5	✔
Intraday	RDB	71 GWh (2016)	✔ 5	✔ 5	✔

Balancing and ancillary services

ENTSO-E's terminology	PSE's terminology	Tot. Capacity Contracted	Load Access & Participation	Aggregated Load Accepted	Aggregated Generation
FCR	Primary Reserve *(Regulacja Pierwotna)*	155~170 MW	✘	✘	✘
FRR	Secondary Reserve *(Regulacja Wtórna)*	540~500 MW	✘	✘	✘
RR	Automatic Voltage Control Reserve *(Automatyczna Regulacja Napięcia i Mocy Biernej)*		✘	✘	✘
-	Emergency Demand Response Programme *(Redukcja Zapotrzebowania na polecenie OSP)*	185 MW winter / 201 MW summer (2015)[278] 200 (2016)[279]	✔	✔ 280	✘
-	Cold Intervention Reserves	830 MW (for 2016-17)[8]	✘	✘	✘
Emergency reserve *(Praca interwencyjna)*	Individual agreements: - Pumped hydro storage - Gas fired generation	Approx. 1,7 GW	✘	✘	✘

277 Participation of Demand Response only trough modification of the supply/delivery portfolios

278 from 1 June 2015

279 PSE (2016): "Prognoza pokrycia zapotrzebowania szczytowego na moc w latach 2016 – 2035", (slide 5) available at: http://www.pse.pl/index.php?dzid=14&did=3215 (retrieved on 30 November 2016).

280 Min. aggregated demand 10MW, only industrial generation behind the meter allowed for aggregation

	Generation with overload	100 MW[6]	✗	✗	✗
-	Balancing Market		✓	✗	✓
-	Operational Capacity Reserve	3 451 MW (2016)[8]	✗	✗	✗
Other ancillary services if relevant (re-dispatch, voltage control)	Redispatching, blakstart		✗	✗	✗
Capacity mech. (if any)	Planned Capacity Mechanism Ongoing project		✗	✗	✗
Distribution network services			✗	✗	✗

Table 33: List of balancing and ancillary market products, including volumes and load accessibility in Poland

B. Markets open to Demand Response

Emergency Demand Response Programme (EDRP). Today, the EDRP is the only programme where Demand Response participates. The first contract was signed in March 2013 for 30 MW of capacity for summer and 25 MW for winter. In total 6 auctions were organised between 2012-2015 and cumulative power contracted by the operator for intervention to reduce exceeded 200 MW (0,8% of peak demand) in 2016. However, having only utilisation payments (190-300EUR/MWh) proved to be unattractive to customers and by the seventh tender in mid-end-of 2016 there were no participants. In addition, the transmission system operator was not satisfied with the level of reliability reductions and instead announced the launch of two new emergency DSR programs from Summer of 2017. It will include two options:

- A "guaranteed" option: with availability payments (and utilisation payment) and an obligation to bid and be available as per contract terms;
- A "current" option: with only utilisation payments and more flexible in terms of bids and availability.

Ancillary services. Other ancillary services are still reserved only for large generators.

Balancing market. The balancing market operated by the TSO, where the TSO acting as central dispatch can balance the system hour ahead. Generators and qualified active users may submit bids to the TSO. Active DR participation was allowed as of July 1st, 2014, but due to the very strict forecasting requirements, penalties and suspensions there is currently only one registered participant, and so far, they have never submitted a bid. From 2017 the requirement for active users have been slightly relaxed, but due to low price volatility the programme is still not expected to be very

popular. There are plans to review these rules for 2018 to allow demand to participate effectively.

The balancing market also includes "Operational capacity reserve" which could increase attractiveness of active user's participation. So far, this scheme provides availability payments as an incentive for the large generators to be available at peak hours. There are also plans to open this scheme to demand for 2018 but it remains unclear whether aggregation would be allowed.

Wholesale market. Demand Response can be traded on the Polish day ahead and intraday markets only as a part of a purchase or generation portfolio and due to low price volatility, the demand-side activity on the wholesale market is negligible. The wholesale market is liquid; the combined trade volume of the generation, trade and sales companies on Polish Power Exchange day ahead market (27 TWh) and physical future market (99 TWh)[281] is almost equal the country's consumption.

Strategic Reserve (Capacity Mechanism). Poland has created a temporary strategic reserve comprising 830 MW of generation capacity ('cold intervention reserve'). The reserve is intended to be transitional for two years starting in 2016, with the possibility to extend for a further two years beyond this[282]. It is a generation-only scheme, providing capacity (and utilisation) payments to maintain the availability of old power plants, already marked for decommissioning[283]. The hourly availability remuneration awarded in the tender is 19,51 - 22,38 PLN/MW/h (also in the off-peak hours), with utilisation remuneration is based on the justified costs.

The introduction of a Capacity Mechanism in Poland, is also being discussed given that the operational capacity reserve, implemented in January 2014 by the TSO, is considered as a temporary solution that could be in use until the establishment of the Capacity Mechanism. A market design, based on the same principles as the UK Capacity Mechanism, was submitted to public consultation in July 2016 and is now waiting for further progress. The plan was to have the Capacity Mechanism in place in 2017 for first delivery in 2021 (with four-year-ahead and one-year-ahead auctions). Demand-side resources are also supposedly going to be able to participate in this market along with generation on a level-playing field: Uncertainties remain on this, especially considering the proposal that much longer should be granted to generation than to demand. According to the project, the following resources would be eligible for participation a:

- generation resources with the gross capacity of at least 2 MW
- Demand Response resources with the net capacity of at least 2 MW
- aggregated Demand Response resources with the total aggregated net capacity between 2 MW and 50 MW

New generation units may be awarded 15-year contract, while modernised generation unit may be awarded 5 year contracts. The Ministry of Energy may set up the minimum capacity volume thresholds for new and modernised generation units, so those units will not only be awarded with the longer contracts, but also auctions for this units will probably end with higher prices then Demand Response.

Distribution network services. A Pilot Residential Demand Response project was conducted between 2013 and 2014 by Tauron (DSO) and PSE (TSO) on a small group of voluntary participants. Two groups of programs were tested: TOU tariffs and reduction on

281 www.tge.pl

282 EC (2016a): "REPORT FROM THE COMMISSION Final Report of the Sector Inquiry on Capacity Mechanisms" available at: http://ec.europa.eu/energy/sites/ener/files/documents/com2016752.en_.pdf (retrieved 15 March 2017)

283 PWC and ING Bank (2014): "5 Myths of the Polish Power Industry 2014", p.22, available at: http://www.pwc.pl/en_PL/pl/publikacje/assets/pwc_ing_5_myths_of_the_polish_power_industry_2014_report.pdf (retrieved on 10 June 2015)

demand[284]. The Time of Use programs did not change the consumption pattern, but slightly reduced the energy consumption. A two-hour reduction on demand was partially successful, however the only slightly lower peak was created just before or just after the reduction. Additionally, the average reduction decreased over testing time. The main reason for the limited output was the small saturation of controllable load: electric space heating and cooling are typically very rarely used in the residential sector. Only about 0.1% of detached houses in Poland have as electric heating[285] as the main heat source, and Time of Use tariffs are typically already in use with such customers.

There aren't any incentives to encourage the DSOs to invest in energy efficiency measures nor "non-wires-alternative services", nor buy demand-side flexibility. However, DSOs invest heavily in residential smart meters for future applications.

C. Restrictions related to distribution network operations

The Distribution Use of System Charges related to the maximum demand (customers above 40 kW) are not based on Time of use, so flat consumption is incentivised and may discourage off-peak use pattern.

2. Service providers access to markets

A. Demand Response service providers access to consumer

In order to take part in the balancing market as the active user, Customers or Balancing Service Providers must be a Balancing Responsibility Party. Only a few of the biggest energy users in Poland have BRPs other than a retailer, so usually the customer depends on the retailer; and aggregation is practically impossible. As the market currently stands, it is unlikely that a retailer will contract with a consumer outside of its own balancing area.

In order to ease the implementation of such agreements and acquire measurement data from DSOs, the TSO update transmission agreements between themselves and appropriate DSO and BRPs. The DSO is obliged to provide the metering data to the TSO and customer, but not to the aggregator. Many customers complain of irregularities and errors in the transmission of metering data

284 PSE (2014): "Doświadczenia z realizacji programu pilotażowego na obszarze TAURON, Wojciech Lubczyński", available at: http://www.pti.org.pl/content/download/4681/38622/file/PSE%20-%20Zachowania%20odbiorc%C3%B3w.pdf (retrieved on 30 November 2016)

285 IEE (2013): "Efektywność Energetyczna w Polsce, Przegląd", available at: http://www.iee.org.pl/?a=text&b=32 (retrieved on 15 March 2017)

3. Product requirements

A. Main product requirements

EDRP. In the previous tenders, the specifications provided for 24-month contracts (winter or summer seasons). The maximum number of activations during this period was 15, with a maximum of 1 per day and 3 per week. One "testing" activation was guaranteed otherwise activations were not. Each reduction could be 2, 3 or 4 hours long. The minimum bid size was 10 MW, and aggregation of individual units was allowed. The consumption units had to be equipped with at least hourly meters. The specification for the new EDRP tenders has not been disclosed yet and as such these conditions will change in Q1 of 2017. In the meantime, the PSE has tried to increase the penalties for under delivery, with no success.

Balancing markets. Some major barriers on the wholesale market include the minimum bid size (1 MW), the long response time of 50-60 minutes/hourly settlement, and the fact that active participation in balancing market is practically impossible for independent aggregators which are not the customer's BRP.

Furthermore, active participants have to create a separate DR scheduling unit in the balancing market. In addition, those interested in participating on the market have to be a balancing responsible party.

Although DSR providers may bid in freely during chosen peak hours between 7:00-22:00 during working days. The forecasting demand accuracy error may not exceed +/-10% for every consecutive three offered hours (before Jan 1st 2017 +/-5% for every three consecutive hours regardless from biding). Failure in forecasting accuracy will result suspension in the mechanism for at least 5 days (20 days before Jan 1st 2017) when the accuracy is tested in peak hours. If the suspension is over 90 days, it results in the termination of the contract.

In terms of remuneration for the activation, if activated energy is purchased but not consumed it will be sold to balancing market and there is no remuneration for reduced demand if it is not covered by the scheduled contracts.

In the planned Capacity Mechanism the maximum aggregation of Demand Response of 50MW and the pre-certification requirements for aggregators act as major barriers. Furthermore, aggregation of demand and local generation are not possible. There is also no separate category for storage in the planned Capacity Mechanism.

Wholesale market. Demand Response can participate in the Polish day ahead and intraday markets only as modification of the supply or purchase portfolio.

Wholesale market

Product	Market place	Minimum size (MW)
Day Ahead	RDN	1 MW/hour
Intraday	RDB	1 MW/hour

Balancing and ancillary services

Product	Minimum size (MW)	Notification Time	Activation	Triggered (max. times)
Primary Reserve *(Regulacja Pierwotna)*	-	-	-	-
Secondary Reserve *(Regulacja Wtórna)*	-	-	-	-
Automatic Voltage Control Reserve *(Automatyczna Regulacja Napięcia i Mocy Biernej)*	-	-	-	-
New Emergency Demand Response Programms (Planned)	*10 MW*	-	-	-
Past Emergency Demand Response Programms *(Redukcja Zapotrzebowania na polecenie OSP)*	*10 MW*	*6 h*	*Manual*	*Various in different past tenders, typically max 10 per 2 seasons (summer or winter)*[286]
Balancing Market	*1 MW*	*1,5 h*	*50 min*	-

Table 34: Description of some main Product requirements in the balancing products accessible to DR in Poland

4. Measurement and verification, payments, and penalties

A. Measurement & verification

Prequalification.

EDRP. New EDRP programs will be announced soon, the specification is not fully defined yet. Planned DR volume limit: min. 10MW max. 100MW, aggregation allowed

Balancing market. The pool of loads has to prequalify as an aggregate. There is no minimum size for an individual unit within the pool, but there are high requirements in terms of measurement and planning accuracy. If these technical requirements are not fulfilled, the participation is suspended.

Baseline methodology.

EDRP. According to the preliminary project, there will be 5 baseline methodologies, the most appropriate apply automatically, which may be very challenging for proper demand reduction volume forecasting. Historical approach: “X of Y”, whereby recent similar days are used.

286 will change in the upcoming EDRP tender awaited Q1 2017

Balancing market. Demand Response providers shall use their hourly consumption forecasts. In order to qualify for participation, the forecasting accuracy may not exceed 10% in each 3 consecutive hours (in peak hours).

B. Availability/utilisation payments

The table below presents payments available in the services and programmes, accessible for Demand Response. The most liquid wholesale market is the Polish Power Exchange Market (participation only through the brokerage house or retailer). Other market platforms include the Forward, day-ahead, and intraday operated by Polish Power Exchange Market; as well as the Balancing market and Ancillary Services operated by the PSE (TSO).

The day ahead, intra- day, and balancing market are pay-as-cleared and the offers in the balancing market as well as the ancillary services and interventional DSR are pay-as-bid.

Balancing and ancillary services

Product	Availability payments	Utilisation payments	Access
Primary Reserve *(Regulacja Pierwotna)*	-	-	✕
Secondary Reserve *(Regulacja Wtórna)*	-	-	✕
Automatic Voltage Control Reserve *(Automatyczna Regulacja Napięcia i Mocy Biernej)*	-	-	✕
EDRP (past tenders)[287]	No	~ 250 €/MWh (depending on accepted offers)	Tenders
Balancing market	No (only for generators)	~ 40 €/MWh	Bids

Table 35: Overview of availability and utilisation payments in the balancing market in Poland

Bids accepted in the latest EDRP tender round ranged from 950 PLN to 1450 PLN/MWh (220-333€), but customers were called very rarely. For instance, only 4 hour calls per 2 years were guaranteed and were executed. As such, this was insufficient to support market growth and did not reflect the payments available to generation assets.

For the balancing market, low price volatility, high participation requirements combined with lack of availability payments (Operational Reserve Scheme capacity payments are available for generators only) resulted in a lack of offers for active consumers.

Market players have been advocating for the introduction of availability payments similar to the payments for the Operational Capacity Reserve or cold reserves (mentioned above). These payments currently amount to: 144k PLN/MW/year (33k€/MW/year) for Operational Capacity Reserve (for the active

287 To change in 2017 tender

generators offering at balancing market in peak hours) and 210-240k PLN/MWh / year (50-55 kEUR/MW/year) for Cold Intervention Reserve (Strategic reserve from old generation plants).

In balancing market, prices are considered to be low. In 2014 they varied from approximately 70 to 1 470 PLN/MWh (13-360 €/MWh). However, the prices above 800 PLN/MWh (185 €/MWh) occurred very rarely except toward the end of the year, when Operational Capacity Reserve payment for generators were temporary not in place.

C. Penalties

In recent EDRP tenders, penalties have become stricter and have hindered growth considering the absence of availability payments. This should evolve again in the upcoming 2017 tender. The hourly penalties in the past EDRP programs were twice as high as the utilisation price for such hour, however the first 15% of the declared reduction volume could be omitted each hour without penalty.

Portugal

Overview

The electricity market in Portugal is characterised by a high generation capacity margin; network access tariffs are used by consumers with different time periods; telemetering of customers with a contracted power above 41.4 kW; combined with the existence of the interruptibility service for consumers with contracted power above 4 MW, makes Demand Response participation in the ancillary services market less appealing to market actors.

The regulator will carry out another regulatory review, which includes Demand Response. This may produce some opening of the market. Within this context, the upcoming electricity regulatory review process (Q1 2017), ERSE envisages the introduction of a series of revisions to give greater visibility to the possibility of Demand Response participation in the ancillary services market.

1. Demand Response access to markets

Market overview

Demand Response has not been defined in Portuguese law. ERSE, the Portuguese regulator, is aware that the structures for Demand Response have yet to be put in place, including measurement, definition and remuneration for consumption shifts. As a first step, Portugal is incorporating storage from pumped hydro plants in the balancing market, which might pave the way for Demand Response. Portugal is interconnected with Spain and shares the same wholesale market, the MIBEL, and balancing market structure.

Wholesale market

	Market Size	Load Access & Participation	Aggregated Load Accepted	Aggregated Generation
Day Ahead	5,66 GWh	✕	✕	✕
Intraday	0,406 GWh	✕	✕	✕

Balancing and ancillary services

ENTSO-E's terminology	TSO's terminology		Tot. Capacity Contracted[288]	Demand Response Access & Participation	Aggregated Demand Response Accepted
FCR	Primary Control		Not applicable	×	×
FRR	Secondary Control		2.559 GWh	×	×
RR	Tertiary Control		4.753 GWh	×	×
RR	Deviation Management		2.763 GWh	×	×
	Guarantee of Supply Constraints		4.085 GWh	×	×
	Technical Constraints (PDBF)		≈6.500 GWh	×	×
	Real-Time Constraints		≈1.800 GWh	×	×
RR	Power Reserve		2.109 GWh	×	×
	Secondary Regulation Band		1.197 GWh	×	×
	Interruptible Mainland[289,290]	5MW blocks	1.430-1.970 MW	1.430-1.970 MW	×
		90MW blocks	630-1.170 MW	630-1.170 MW	×
	Interruptible Islands		≈50 MW	≈50 MW	×
	Capacity Mechanism		≈2.500 MW	×	×

Table 36: List of balancing market products, including volumes and load accessibility in Portugal

B. Markets open to Demand Response

Balancing market & Ancillary Services. Currently, Demand Response does not have access to either the balancing market or the ancillary services.

Interruptible Contracts. The interruptible contracts programme does not allow aggregation and is limited to large industrial consumers, connected to the HV grid. It represents an available capacity of 2.000 MW of demand reduction in peak hours. Industrial energy consumers involved in this scheme are construction industries (steel, concrete, glass, etc.), or other material factories (paper, chemistry, etc.).

Wholesale market. Only generators with a production unit of at least 50 MW, can participate as a seller in the wholesale market. Flexibility resources can participate in the spot market, through demand bids with indication of price.

In 2015, a decrease was observed in the level of concentration in the wholesale market (due to unfavourable conditions for hydropower generation)

288 Red Electrica (2013): "The Spanish Electricity System", available at: http://www.ree.es/en/publications/spanish-electrical-system/spanish-electricity-system-2013, Red Electrica (2013): "Servicios de ajuste de la operacion del sistema, avance 2013", available at: http://www.ree.es/es/publicaciones/2014/02/servicios-de-ajuste-de-la-operacion-del-sistema-avance-2013 and Red Electrica (2015): "The Spanish Electricity System", available at: http://www.ree.es/sites/default/files/downloadable/the_spanish_electricity_system_2015.pdf

289 Spanish Official Gazette (2014):BOE-A-2014-10399, Spanish Official Gazette (2014): "Resolución de 10 de octubre de 2014", published on 14 October 2014, art.5, (mainland Spain), Red Electrica (2013), 'The Spanish Electricity System', Ibid. (insular Spain)

290 BOE-A-2016-9364, Spanish Official Gazette (2016): "Resolución de 7 de octubre de 2016", published on 12 October 2016. It should be noted that because Portugal shares a market with Spain, the data for these markets is the same.

and, an increase in the level of concentration in terms of installed capacity. This contributed to a very high level of participation of thermal plants in meeting demand.

Capacity Mechanism. The capacity mechanism allows for the participation of generation units only, providing both availability and utilisation payments[291]. From 2013, the availability payment has been reduced, and the programme duration extended[292].

Distribution Network Services. There are no DSO driven Demand Response programs.

C. Restrictions related to distribution network operations

Network access tariffs are charged to all electricity consumers for the use of the infrastructure. These tariffs are typically paid by retailers on behalf of their customers. They may also be paid directly by customers benefiting from Market Agent status, which means customers buying energy directly on the markets, and by those who are responsible for managing their programming imbalances[293].

In 2014, ERSE also conducted a regulatory review of network tariff codes (RT) in the electricity sector. The review focused on various matters, namely and of relevance, the broadening of the scope of the social electricity tariff approved by Decree-Law no. 172/2014; and the increase of bi-hourly and tri-hourly options, in the network access tariff, for power levels lower than 3.45 kVA. This increase of bi-hourly and tri-hourly options were also made available for end-customer tariffs in the Autonomous Regions and for end-customer social tariffs in Mainland Portugal and in the Autonomous Regions. Lastly, the regulatory review introduced rules for dynamic tariffs (pilot studies)[294].

2. Service providers access to markets

A. Demand Response service providers access to consumer

The role of independent Demand Response aggregators is not defined in Portugal and there is no regulatory framework describing roles and responsibilities, access rights and all other technical modalities required for creating a clear path for consumer participation. A BRP/ retailer may include consumers within their portfolio; however, there seems to be little interest from the retailers present in the market. This may partially be due to a large amount of capacity and the capped electricity prices, which slow market development.

The regulatory review taking place in 2017 may result in market development. However, the conclusions drawn from previous reviews indicate that there has been no input from experienced Demand Response players outside Portugal.

There are a few large consumers (such as steel mills), which act as their own retailer/BRP, and participate in the wholesale market.

291 BOE-A-2011-18064 (2011): "Orden ITC/3127/2011, 17 November 2011", published on 18 November 2011

292 BOE-A-2013-7705 (2013): "Real Decreto-ley 9/2013, 12 July 2013", published on 13 July 2013

293 ERSE (2016): "Annual Report On The Electricity And Natural Gas Markets In 2015 Portugal", available at: http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National_Reporting_2016/NR_En/C16_NR_Portugal-EN.pdf (retrieved on 15 March 2017)

294 ERSE (2016), Ibid.

3. Product requirements

A. Main product requirements

The following table contains an overview of the main programmes' technical requirements. However, Demand Response is not recognised as a product in these markets.

Wholesale market table here

Product	Market place	Minimum size (MW)[295]
Day Ahead	OMIP	0,1 MW
Intraday	OMIP	0,1 MW

Table 37: Overview of wholesale market in Portugal

Balancing and ancillary services table here

Product		Minimum size	Notification Time	Activation	Triggered
Interruptible Contract (Mainland)	5 MW blocks	Blocks of 5 MW	Three options: (1) Instantly execution, no notification, (2) Fast execution, 15min, (3) Hourly execution, 2h[296].	Automatic	Max 240 h/year and 40 h/month
	90 MW blocks	Blocks of 90 MW		Automatic	Max 360 h/year and 60 h/month
Interruptible Contract (Islands)		0,8 MW	Five options, from 2 hours to instantly	Automatic	Max 120 h/year

Table 38: Description of some main Product requirements in the balancing products accessible to DR in Portugal

295 EC (2016b): "Electricity Market Functioning: Current Distortions, and How to Model Their Removal" available at: https://ec.europa.eu/energy/sites/ener/files/documents/electricity_market_functioning_-_current_distortions_and_how_to_model_t.pdf (retrieved 15 March 2017)

296 Spanish Official Gazette BOE-A-2013-11461 (2013), "Orden IET/2013/2013, 31 October 2013", published on 1 November 2013, modified on 11 March 2014, art. 5

4. Measurement and verification, payments, and penalties

A. Measurement & verification

Balancing and ancillary services

Product		Availability payments[297]	Utilisation payments	Access
Interruptible contracts, Mainland	5 MW blocks	127.563 €/MW (2016) (260.000 €/MW maximum)	Balancing market, tertiary reserve	Tender-based
	90 MW blocks	289.125 €/MW (2016) (350.000 €/MW maximum)	Balancing market, tertiary reserve	Tender-based
Interruptible contracts, Islands		Not available	Not available	Not available

Table 39: Overview of availability and utilisation payments in the balancing market in Portugal

No rules are in place regarding baselining, measurement, pre-qualification and payment of Demand Response.

297 Red Electrica (2016): "InformacionSubastas TE2017", available at: http://www.ree.es/sites/default/files/informacion_convocatoria_subastas_te2017_v1.pdf (retrieved on 15 March 2017)

Slovenia

Overview

The Slovenian balancing market partially opened to aggregated Demand Response in 2014, for the Tertiary Reserve. The first tenders for aggregated Demand Response were organised by ELES, the Slovenian TSO, in 2014. The contracted volume was 20 MW in 2015.

The most significant barrier to enter the market is the limited number of accessible programmes and small volumes. According to ELES, there is a need for improvements as far as the quality of Demand Response is concerned, on both the TSO's and Demand Response providers' side, so that it can compete with conventional generation units. The Secondary Reserve was supposed to open for aggregated loads in 2016, however no operational data was available regarding this development at the time of writing of this report.

The TSO participated in several EU projects to promote Demand Response. These include FutureFlow, for secondary reserve cross border balancing market control, between Slovenia, Austria, Hungary and Romania; and eBADGE for developing an intelligent balancing mechanism between Slovenia and border countries.

Main enablers:

- Requirements for the participation in Tertiary Reserve (apart from the requirement of 24/7 availability) are appropriate for DR capabilities;
- TSO provides both utilisation and availability payments for the participation in the Tertiary; Reserve.

Main barriers:

- The Primary reserve is not accessible for aggregated load;
- The requirement of 24/7 availability in order to participate in the Tertiary Reserve;
- Wholesale market is closed to Demand Response participation;
- Limited business opportunity due to the small size of the market.

1. Demand Response access to markets

Market overview

Demand Response participation in Slovenia is possible in every reserve. Please see the tables below for a

better understanding of the degree of its participation in the different markets.

Wholesale market

Market	Exchange	Market Size[298]*	Demand Response Access & Participation	Aggregated Demand Response Accepted	Aggregated Generation
Day Ahead	BSP - Southpool	694 MWh	✗	✗	✗
Intraday	BSP - Southpool	26 MWh	✗	✗	✗

*Average hourly traded volumes on the wholesale market

Balancing and ancillary services

ENTSO-E's terminology	TSO's terminology	Tot. Capacity Contracted[299]	Demand Response Access & Participation	Aggregated Demand Response Accepted	Aggregated Generation
FCR	Primary Reserve	Not available	✓	✗	✗
FRR	Secondary Reserve	60 MW positive, 60 MW negative	✓	✓	✗
FRR	Tertiary Reserve	348 MW positive, 180 MW negative	✓	✓ (20 MW)	✓
Other ancillary services if relevant (re-dispatch, voltage control)	⊘	⊘	⊘	⊘	⊘
Capacity mech. (if any)	⊘	⊘	⊘	⊘	⊘
Distribution network services	⊘	⊘	⊘	⊘	⊘

Table 40: List of balancing market products, including volumes and load accessibility in Slovenia

298 BSP SouthPool (2016): "Day-ahead Trading Results", available at: http://www.bsp-southpool.com/day-ahead-trading-results-si.html (retrieved 15 March 2017)

299 Agencija za Energijo (2015): "Report on the energy sector in Slovenia for 2015", available at: https://www.agen-rs.si/documents/54870/68629/Report+on+the+energy+sector+in+Slovenia+for+2015/f1302ae0-7267-4ae7-b74d-7ce8c4323043 (retrieved 15 March 2017)

B. Markets open to Demand Response

Balancing market and ancillary services. Only the Tertiary Reserve service is open to Demand Response. Participation in the Primary and Secondary Reserves is limited to bilateral contracts between TSO and big industrial consumers, such as paper mills.

Wholesale. Demand Response cannot participate in the wholesale market.

Capacity Mechanism. For the time being, there are no plans to introduce a Capacity Mechanism in Slovenia.

Distribution network services. Demand-side flexibility could represent an important tool for local congestion management however there are currently no programmes aimed at the network management. Smaller distribution level consumers also do not participate in Demand Response. The broad DSO framework is incentive based and depends on achieving lowest possible costs; quality of supply; and lastly investments in smart grids. Thus, the incentives for the level of supply are determined by deviations in the achieved level of continuity of supply from the initial targets and results in reducing or increasing eligible costs[300].

C. Restrictions related to distribution network operations

To determine the network charge, the Slovenian Energy Agency uses a non-transaction postage-stamp method. This means that with respect to the network charge, the tariffs and average connection costs are uniform for the whole country and for all individual consumer groups[301]. The tariff structure also includes two time-of-use bands and is based on energy only for smaller customers. End users that want to increase their capacity must pay the DSO a network charge for their connection load. This cost depends on the connection voltage level (above 35 kV; 1-35 kV; commercial 0.4 kV and households)[302].

The system operator can refuse the connection if the user fails to meet the required conditions for connection, the connection would cause severe power disruptions, or if the system operator would incur disproportionate costs due to the connection[303].

2. Service providers access to markets

A. Demand Response service providers access to consumer

Traditional resources which participate in Demand Response in Slovenia are larger industrial consumers such as paper plants, glass plants and other process industries. Participation of these consumers in the Primary and Secondary Reserves is limited to bilateral contracts.

300 EC (2015): "Study on tariff design for distribution systems – Final Report" available at: https://ec.europa.eu/energy/sites/ener/files/documents/20150313%20Tariff%20report%20fina_revREF-E.PDF (retrieved 15 March 2017)

301 CEER (2015): "Report on the Energy Sector in Slovenia For 2014", available at: http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National_Reporting_2015/NR_En/C15_NR_Slovenia-EN.pdf (retrieved 15 March 2017)

302 EC (2015): "Study on tariff design for distribution systems – Final Report" available at: https://ec.europa.eu/energy/sites/ener/files/documents/20150313%20Tariff%20report%20fina_revREF-E.PDF (retrieved 15 March 2017)

303 EC (2015), Ibid.

Aggregated load is accepted only in the Tertiary Reserve. In general, Demand Response and generation can be aggregated within the same bid. The only entity that currently operates in the tertiary reserve in the form of an aggregator is a Virtual Power Plant that is managed by the retailer Elektro Energija and the DSO Elektro Ljubljana, with CyberGrid as the system provider.

The contractual rules regarding the relationship of the aggregator and the BRP are not clear. In general, a party interested in providing Demand Response services is required to obtain the consent of the BRP. However, in some cases the aggregator needs only to notify the BRP of the customer, and after the activation needs to provide a report with the details of the resources that were activated. After that, the TSO will take that information into account and make the estimates and calculations needed.

3. Product requirements

A. Main product requirements

There are annual tenders in the balancing market organised by the TSO. Demand Response providers have to ensure 24/7 availability, which can be difficult for many consumers to fulfil, and shrinks the possible pool of load. The response time is 15 minutes and the market participant must be able to deliver the service for a maximum 2 hours. The time between two activations must be at least 10h, with a maximum number of 2 activations per day. The minimum aggregated bid size is 5 MW.

Tertiary reserve. The biggest barrier for the tertiary reserve is the requirements to maintain non-stop availability for the provider.

Wholesale market

Market	Exchange	Minimum size (MW)[304]
Day Ahead	BSP-SouthPool	1 MW
Intraday	BSP-SouthPool	1 MW

Balancing and ancillary services

Product	Minimum size (MW)	Notification Time	Activation	Triggered (max. times)[3]
Tertiary Reserve	5 MW	15 min	Manual/Automatic	45 times in 2015

Table 41: Description of some main Product requirements in the balancing products accessible to DR in Slovenia

304 BSP SouthPool (2016): "Exchange Rules", available at: http://www.bsp-southpool.com/exchange-rules.html (retrieved 15 March 2017)

4. Measurement and verification, payments, and penalties

A. Measurement & verification

Prequalification. ELES's Information and Communication Technology systems are adapted to deal with aggregation. All potential Demand Response providers have to go through a thorough pre-qualification process. Having prequalification (EVORP) documents properly submitted, the TSO will carry out tests for each unit 7 days in a row, with a maximum of 10 hours of activation total. In addition to other requirements mentioned in Section 2, each Demand Response unit has to support real-time bi-directional communication with the national control centre.

Moreover, several legal and formal conditions have to be fulfilled (i.e. proper individual connection agreements, etc.). An aggregator must also submit a guarantee of 15.000 €/MW.

The Slovenian TSO does not contract and refund FCR. It is an obligation for all generators connected to the high voltage grid or units larger than 10 MW. Since it is not part of the balancing market, there are no specific pre-qualification criteria for FCR[6].

Baseline methodology. There is one officially used baseline (Baseline 1). It is based on Demand Response unit schedule, where actual reduction is determined as the deviation of 'reduced' consumption from the scheduled 'regular' consumption. The companies can use their own baselines if they are accepted by the TSO.

B. Availability/utilisation payments

Participation in the secondary reserve is mandatory and automatic for synchronous generators, and is not remunerated. BSP can access the tertiary reserve through a yearly tender. The tender is held in November of each year for the next year. Before the tender the BSP needs to pass a qualification test in order to participate. ELES, the TSO provides both utilisation and availability payments for the participation in the Tertiary Reserve.

Balancing and ancillary services

Product	Availability payments	Utilisation payments	Access
Tertiary Reserve	38000 EUR/MW	240 EUR/MWh	Tender

Table 42: Overview of availability and utilisation payments in the balancing market in Slovenia

C. Penalties

There are rather high penalties for non-availability. There is a 20% tolerance concerning under- and over-delivery. The penalty for non-deliverance of energy is 4.000 €/MWh, so many potential bidders choose not to participate. Additionally, the penalties grow exponentially in case of repeated failures in delivery[305].

Guarantee: An aggregator must submit a guarantee of 15.000 €/MW.

305 INCREASE (2016): "Increasing the penetration of renewable energy sources in the distribution grid by developing control strategies and using ancillary services", available at: http://www.project-increase.eu/cms_files/hofer/D5.2_Report_on_short-term_market_mechanisms_for_AS_provision.pdf (retrieved 15 March 2017)

Spain

Overview

Today, Spain relies mostly on hydro and gas for its flexibility needs. As Spain is evolving towards more distributed energy generation, the need for flexibility is expected to increase in the coming years. While Spain is the first country in the world where the default price for households is based hourly spot prices and could thus drive important progress for Implicit Demand Response, and even though some smart grid pilot projects are in place, the development of Explicit Demand Response is limited to industrial consumers.

Aggregation is still not legal in the Spanish electricity system and currently there is only one scheme allowing Explicit Demand Response: The Interruptible Load programme. The scheme, which is reserved only for large consumers, is managed by the TSO, Red Eléctrica de España. The programme acts as an emergency action, in case the system is lacking generation and there are insufficient balancing resources. Although annual tests are conducted, this programme has not been called on for several years.

Even though aggregators are not recognised in Spain, the role of "representatives" exists, which sell energy in the name of their "representees" and build balancing perimeters, thus minimising deviations from programme and resulting penalties[306]. It is, however, believed that the TSO and relevant stakeholders have started conversations for the future opening of these services to flexible demand[307].

1. Demand Response access to markets

Market overview

The following table presents the electricity market product or sub-products, and underlines where Demand Response and aggregation can participate, including related market sizes. While some of the markets are open for Demand Response in principle, in practice this applies only for large industrial consumers. Aggregated Demand Response is allowed only for Tertiary Control.

306 EC (2016c): "Survey on the implementation of Demand Response in Member States focusing on Art. 15 (8) EED 2012/27/EU"

307 IndustRE (2016):"Innovative Business Models for Market Uptake of Renewable Electricity unlocking the potential for flexibility in the Industrial Electricity Use", available at: http://www.industre.eu/downloads/download/business-models-and-market-barriers (retrieved 17 March 2017)

Balancing and ancillary services

ENTSO-E's terminology	TSO's terminology		Tot. Capacity Contracted[308]	Demand Response Access & Participation	Aggregated Demand Response Accepted
FCR	Primary Control		Not applicable	✗	✗
FRR	Secondary Control		2.559 GWh	✗	✗
RR	Tertiary Control		4.753 GWh	✓	✓
RR	Deviation Management		2.763 GWh	✗	✗
	Technical Constraints (PDBF)		≈6.500 GWh	✓	✗
	Real-Time Constraints		≈1.800 GWh	✓	✗
RR	Power Reserve		2.109 GWh	✗	✗
	Secondary Regulation Band		1.197 GWh	✗	✗
	Interruptible Mainland[309,310]	5 MW blocks	1.430-1.970 MW	1.430-1.970 MW	✗
		90 MW blocks	630-1.170 MW	630-1.170 MW	✗
	Interruptible Islands		≈50 MW	≈50 MW	✗
	Capacity Mechanism		≈2.500 MW	✓	✗

Table 43: List of balancing market products, including volumes and load accessibility in Spain

B. Markets open to Demand Response

Balancing market & Ancillary Services. Currently, aggregated Demand Response does not have access to the balancing market, nor to ancillary services. However, in 2015 a new regulation allowing the participation of generation based renewables in balancing markets was approved. As such, since 2016, decentralised and renewable energy resources (in particular wind generators) have been able to prequalify and participate in the tertiary reserve which is an important development in paving the way for aggregated Demand Response to participate in this market[311].

Interruptible Contracts. There is an available capacity of 2.000 MW of demand reduction in peak hours. In 2015 3,020 MW of interruptible load was assigned; while in the auction for 2016, 2,890 MW of interruptible demand was assigned, with a total cost

308 Red Electrica (2013): "The Spanish Electricity System", available at: http://www.ree.es/en/publications/spanish-electrical-system/spanish-electricity-system-2013, Red Electrica (2013): "Servicios de ajuste de la operacion del sistema, avance 2013", available at: http://www.ree.es/es/publicaciones/2014/02/servicios-de-ajuste-de-la-operacion-del-sistema-avance-2013 and Red Electrica (2015): "The Spanish Electricity System", available at: http://www.ree.es/sites/default/files/downloadable/the_spanish_electricity_system_2015.pdf

309 BOE-A-2014-10399, Spanish Official Gazette (2014): "Resolución de 10 de octubre de 2014", published on 14 October 2014, art.5, (mainland Spain), Red Electrica (2013), 'The Spanish Electricity System', Ibid. (insular Spain)

310 Spanish Official Gazette (2016): BOE-A-2016-9364 "Resolución de 7 de octubre de 2016", published on 12 October 2016

311 SmartNet (2016): "Ancillary service provision by RES and DSM connected at distribution level in the future power system", available at: http://smartnet-project.eu/wp-content/uploads/2016/12/D1-1_20161220_V1.0.pdf (retrieved on 15 March 2017)

of €503 million[312]. The requirements to take part in the interruptible demand service are defined by the Ministry of Energy. The National Regulatory Authority reports on the relevant legal disposition and overviews the related auction[313].

Depending on the notification time (from zero to two hours) and duration of the interruption (from one to twelve hours), there are five different types of contract. Interruptions can take place for up to 240 hours a year, with a maximum of one interruption per day and five per week.

Wholesale market. Only generators, with a production unit of at least 50 MW, can participate as a seller in the wholesale market. Flexibility resources can participate in the spot market, through demand bids with indication of price.

Regarding the total market size, in 2015, around 175.97 TWh was traded in the day-ahead market, and around 28.32TWh[314] in the intraday market.

Capacity Mechanism. The capacity mechanism allows for the participation of generation units only, providing both availability and utilisation payments[315]. In 2013, the availability payment was reduced, and the programme duration extended[316].

Distribution network services. Demand-side flexibility could represent an important tool for local congestion management. If needed, DSOs have the possibility to request from the TSO to call the use of the interruptibility service or as for redispatching and curtailmaint of generators. Furthermore, at DSO level, some pilot projects are on-going at city level, such as "Smart City Project" in Malaga, and the "Barcelona Smart City"[317].

C. Restrictions related to distribution network operations

For TSO congestion management, the TSO has the responsibility for grid curtailment. Curtailed generators are partially compensated (15% of day-ahead prices) for their loss of revenue in case of curtailment in real time operation. For planned curtailment, producers receive no financial compensation. All consumers are able to take advantage of Time-of-Use (ToU) contracts. These so called "access tariffs", recover both network and other regulated costs, and have time of use differentiation of up to 3 periods for households and up to 6 periods for large consumers. Subsequently, it is already possible for all consumers to shift consumption patterns in response to signals given that they have a degree of flexibility in their contracts.

All things considered, the current regulatory regime poses limited opportunities for Explicit Demand Response offerings in congestion management[318].

312 CEER (2016c): "Spanish Energy Regulator's National Report To The European Commisson 2016", available at: http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National_Reporting_2016/NR_En/C16_NR_Spain-EN.pdf (retrieved 15 March 2017)

313 European Commission (2016): "Survey on the implementation of Demand Response in Member States focusing on Art. 15 (8) EED 2012/27/EU"

314 CEER (2016c): "Spanish Energy Regulator's National Report To The European Commisson 2016", available at: http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National_Reporting_2016/NR_En/C16_NR_Spain-EN.pdf (retrieved 15 March 2017)

315 BOE-A-2011-18064 (2011): "Orden ITC/3127/2011, 17 November 2011", published on 18 November 2011

316 BOE-A-2013-7705 (2013): "Real Decreto-ley 9/2013, 12 July 2013", published on 13 July 2013

317 Smart city Malaga (2015), available at: http://www.smartcitymalaga.es/ (retrieved on 30th April 2015) and Barcelona Smart City (2015), available at: http://smartcity.bcn.cat/en (retrieved on 30th April 2015)

318 JRC (2016): "Demand Response status in EU Member States", available at: http://iet.jrc.ec.europa.eu/energyefficiency/sites/energyefficiency/files/publications/demand_response_status_in_eu28_member_states-online.pdf (retrieved 15 March 2017)

2. Service providers access to markets

A. Demand Response service providers access to consumer

Overall, there is no possibility for aggregated demand-side resources to take part in the Spanish electricity market. There are no standards at the moment defining their relationship with the BRP and the TSO.

Aggregators are not accepted in the market. As mentioned above, aggregated Demand Response does not have access to the balancing markets. Only consumers with contracted power above 5 MW have access to interruptible demand service managed by the TSO. The concept of aggregator for Demand Response does not exist in the Spanish regulation, however, individual customers can directly participate in the wholesale market[319].

There is no involvement of aggregation in the interruptible contracts programme, it is limited to large industrial consumers, connected to the HV grid. Industrial energy consumers involved in this scheme come from the construction industries (steel, concrete, glass, etc.), or other material factories (paper, chemicals, etc.) and desalinisation plants (in the Canarias Islands). The participants must have an ICT system, which links them directly to the TSO and not to the DSO where they may be connected. If, however, they are connected to the DSO's network, the DSO does not participate, and it is not even able to forecast it in advance. The retailer's imbalance is directly corrected by the TSO, taking into account its reduction order. The baseline is set individually and the available capacity is tested around twice a year. Lastly participants have to send the forecast to the TSO monthly for the following two months[320]. In 2011, there were 152 interruptible customers in Spain, offering reductions of about 2200 MW. In 2014, the assigning of interruptible capacity and the linked payments was done by the TSO through public auction, where customers satisfying the requirements for the service could participate. The load curve was registered during the whole interruption event in order to verify the fulfilment of the order, and penalties were applied when customers did not reduce their power by the agreed amount[321].

Imbalance settlement after load management. Participants in the interruptible load programme are directly in contact with the TSO via their ICT system. The retailer's imbalance is directly corrected by the TSO, which takes into account its reduction order, although as the programme has not been activated within the last decade, this provision is symbolic.

3. Product requirements

A. Main product requirements

Interruptible Load Programme: The interruptible load programme does not allow aggregated demand-

319 European Commission (2016): "Survey on the implementation of Demand Response in Member States focusing on Art. 15 (8) EED 2012/27/EU"

320 JRC (2016): "Demand Response status in EU Member States", available at: http://iet.jrc.ec.europa.eu/energyefficiency/sites/energyefficiency/files/publications/demand_response_status_in_eu28_member_states-online.pdf (retrieved 15 March 2017)

321 DRIP (2015): "Value pools and business models for Demand Response in the industry", available at: http://www.drip-project.eu/datas/DRIP_D_B1-2_20150123.pdf (retrieved 15 March 2017)

side resources to participate. In mainland Spain, the scheme was introduced in 2008, with a threshold of 5MW to participate[322]. In 2014, different conditions were introduced for interruptible loads bigger than 90MW[323]. In 2015, it was made possible to bid with blocks of curtailable load: 5MW blocks, or 90MW blocks. For the 5MW-block product, it is required to have a minimum hourly consumption of the assigned resource (i.e. 5MW for one 5MW block), while for the 90MW-blocks product it is required to have at least the 91% of the assigned resource (i.e. 81MW for one 90MW block)[324]. In the Canaries and Baleares, the old framework still applies, with a minimum size of 0,8MW to participate.

Wholesale market

Product	Market place	Minimum size (MW)[325]
Day Ahead	OMIE	0,1 MW
Intraday	OMIE	0,1 MW

Balancing and ancillary services

Product		Minimum size	Notification Time	Activation	Triggered
Interruptible Contract (Mainland)	5 MW blocks	Blocks of 5 MW	Three options: (1) Instantly execution, no notification, (2) Fast execution, 15min, (3) Hourly execution, 2h[326].	Automatic	Max 240 h/year and 40 h/month
	90 MW blocks	Blocks of 90 MW		Automatic	Max 360 h/year and 60 h/month
Interruptible Contract (Islands)		0,8 MW	Five options, from 2 hours to instantly	Automatic	Max 120 h/year

Table 44: Description of some main Product requirements in the balancing products accessible to DR in Spain

4. Measurement and verification, payments, and penalties

A. Measurement & verification

Prequalification. In the Interruptible Load Programme, participants must have an ICT system which links them

322 BOE-A-2007-14798 (2007): "Orden ITC/2370/2007, 26 July 2007", published on 3 August 2007

323 BOE-A 2012-15706 (2012): "Orden IET/2804/2012, 27 December 2012", published on 29 December 2012

324 Spanish Official Gazette BOE-A-2013-11461 (2013), "Orden IET/2013/2013, 31 October 2013",published on 1 November 2013, modified on 11 March 2014, art. 9

325 EC (2016d): "Electricity Market Functioning: Current Distortions, and How to Model Their Removal", available at: https://ec.europa.eu/energy/sites/ener/files/documents/electricity_market_functioning_-_current_distortions_and_how_to_model_t.pdf (retrieved 15 March 2017)

326 Spanish Official Gazette BOE-A-2013-11461 (2013), "Orden IET/2013/2013, 31 October 2013",published on 1 November 2013, modified on 11 March 2014, art. 5

directly to the TSO, and not to the DSO, where they may be connected. If they are connected to the DSO's network, the DSO does not participate in it, and it is not even able to forecast it in advance. The retailer's imbalance is directly corrected by the TSO, which takes into account its reduction order.

Baseline methodology. In the Interruptible Load Programme, the baseline is set individually and the available capacity is tested around twice a year. The participants have to send to the TSO each month the forecast for the following two months. In the absence of aggregated Demand Response, there is no regulation concerning single unit requirement or baseline definitions for aggregated loads.

B. Availability/Utilisation payments

Balancing and ancillary services

Product		Availability payments[327]	Utilisation payments	Access
Interruptible contracts, Mainland	5 MW blocks	127.563 €/MW (2017) (260.000 €/MW maximum)	Balancing market, tertiary reserve	Tender-based
	90 MW blocks	289.125 €/MW (2017) (350.000 €/MW maximum)	Balancing market, tertiary reserve	Tender-based
Interruptible contracts, Islands		Not available	Not available	Not available

Table 45: Overview of availability and utilisation payments in the balancing market in Spain

Interruptible Load Programme: The framework for Interruptible Contracts, in mainland Spain, aimed to achieve budget savings, through the introduction of an auction mechanism, with a tender-based price for the availability remuneration.

In Spain, the old framework still applies in the Canaries and Baleares with an availability payment only, limited to €20/MWh consumed. Payments are higher if the customer avoids consumption in peak hours.

In 2015, fees applicable to intermittent generators plants, as well as from retail consumers, funded the availability payments. The utilisation payment was sourced per the balancing market rules.

C. Penalties

Interruptible Load Programme: For the Interruptible Contracts in mainland Spain, the new scheme has defined stricter conditions in case of non-fulfilment of the project requirements. A penalty of up to 120% of the availability price applies for the first failure, and exclusion from the tender applies for a second failure[328].

In the Canaries and Baleares, the previous conditions still apply, with penalty of up to 100% of the availability price, even in case of two failures in the same year.

327 Red Electrica (2016): "InformacionSubastas TE2017", available at: http://www.ree.es/sites/default/files/informacion_convocatoria_subastas_te2017_v1.pdf (retrieved on 15 March 2017)

328 BOE-A-2013-11461 (2014), Ibid., art. 11

Sweden

Overview

Flexibility in Sweden comes mainly from hydropower plants in the north of the country (SE1 and SE2), while thermal plants are sometimes activated in the south of Sweden, in case of congestions or in case of peak demand. Demand Response participation and aggregation of demand-side resources are legally possible in Sweden. However, wider Demand Response participation could be triggered with the definition of appropriate roles and responsibilities between players, which would allow for consumers to freely choose their Demand Response service provider, while protecting all market participants.

Primary, Secondary and Tertiary Reserves are legally open to demand-side resources and in an aggregated manner. The participation is still limited and some regulatory changes are needed to fit better demand-side resource characteristics. Demand-side resources mostly participate in the Strategic Reserve and in the Regulating Power Market (RPM). An Independent third-party aggregator needs to be a BRP, and obtain a contractual agreement from consumers' retailer/BRP to participate in the market. This bilateral relationship between competitors hamper the market potential of demand-side resources.

Product requirements also limit the possibility for Demand Response to participate. In the Secondary, and Tertiary Reserve, the minimum bid size represents a significant barrier for wide participation. Demand-side resources also participates in the spot market, but it is not possible to have a clear market size.

As such, the main issues from market participants when it comes to Demand Response have to do with both access to and product requirements in the Primary and Secondary Reserves.

A lot of further development is still needed in Sweden, but change is coming. Together with the rest of the Nordics, Sweden is currently working on the issue of the role of independent aggregators participation in the balancing markets. From the TSO point of view, there is also a need for electronic systems at the RPM level in order to activate specific loads, as currently everything is done via telephone calls. However, this change is expected in 2017[329].

1. Demand Response access to markets

Market overview

The following table shows the electricity market product or sub-products and underlines where Demand Response and aggregated loads can participate, including related market sizes.

329 Ei (2016): "Åtgärder för ökad efterfrågeflexibilitet i det svenska elsystemet", available at: http://ei.se/Documents/Publikationer/rapporter_och_pm/Rapporter%202016/Ei_R2016_15.pdf (retrieved 15 March 2017)

Wholesale market

ENTSO-E's terminology	Market place	Market Size[330]	Demand Response Access & Participation	Aggregated Demand Response Accepted	Aggregated generation
Day Ahead	Nordic and Baltic Day Ahead markets	374 TWh (2015)	✔	✔	✔
Intraday	Nordpool Spot	5 TWh (2015)	✔	✔	✔

Balancing and ancillary services

ENTSO-E's terminology	SVK's terminology	Market size	Demand Response Access & Participation (MW)	Aggregated Demand Response Accepted	Aggregated generation
FCR	Frequency Containment Reserves for normal operating band (FCR-N)	230 MW[331]	✔ (100 KW Pilot)	✔	✔
	Frequency Containment Reserves for disturbances (FCR-D)	412 MW[332]	✔ ≈0	✔	✔
aFRR	Automatic Frequency Restoration Reserves (aFRR)	≈100	✔ ≈0	✔	✔
mFRR	Fast disturbance reserve (mFRR)	1.350 MW[333]	⊘	✔	✔
	Balancing Market (RPM)	1,6 TWh[334]	✔ ≈10 MW	✔	✔
RR	Strategic Reserve / Peak Load Reserve[335]	1.000 MW	✔ 334 MW	✔	⊘

Table 46: List of balancing market products, including volumes and load accessibility in Sweden

330 NordPool Spot (2017): "Strong volumes foundation for expansion – Nord Pool 2016", available at: http://www.nordpoolspot.com/message-center-container/newsroom/exchange-message-list/2017/q1/strong-volumes-foundation-for-expansion--nord-pool-2016/ (retrieved on 15 March 2017)

331 ENTSO-E (2006): "System Operation Agreement" Ibid. par. 4.1.1, available at: https://www.entsoe.eu/fileadmin/user_upload/_library/publications/nordic/operations/060613_entsoe_nordic_SystemOperationAgreement_EN.pdf

332 ENTSO-E (2006): "System Operation Agreement" Ibid. par. 4.1.2, available at: https://www.entsoe.eu/fileadmin/user_upload/_library/publications/nordic/operations/060613_entsoe_nordic_SystemOperationAgreement_EN.pdf

333 ENTSO-E (2006): "System Operation Agreement" Ibid. par. 4.2, available at: https://www.entsoe.eu/fileadmin/user_upload/_library/publications/nordic/operations/060613_entsoe_nordic_SystemOperationAgreement_EN.pdf

334 NordPool Spot (2014): RPM 2014 value, available at: http://www.nordpoolspot.com/Market-data1/Regulating-Power1/Regulating-Power--Area1/NO11/Norway/?view=table (retrieved on 30th April 2015)

335 Elforsk (2014): "Rapport 14:29, Demand Response in the strategic reserve, The Case of Sweden", p. 31, resources for the year 2014/2015, available at: www.elforsk.se/Documents/Market%20Design/projects/ER_14_29.pdf

B. Markets open to Demand Response

Ancillary Services. Although aggregation of Demand Response is legal within the ancillary services in Sweden. Demand Response mainly participates in the Regulating Power Market (RPM).

Wholesale Market. It is still not possible to have a clear picture of the size of the Demand Response's participation in the market. However, demand-side resources do represent a share in the Nord Pool Market, day-ahead (Elspot) and intraday (Elbas). In 2016, 391 TWh was traded in the day-ahead market (Elspot), and 5.1 TWh[336] in the intraday market (Elbas).

Strategic Reserve. Sweden has no Capacity Mechanism mechanism. A Strategic Reserve exists, where Demand Response can participate. The TSO can contract the necessary amount, with a cap defined by the regulation. The cap was gradually reduced in the period 2011-2020, from 2000 MW to 750 MW. The share of Demand Response was initially planned to increase up to 100%[337], and then softened to be at least the 25% of the contracted capacity[338]. With the most recent legislation passed on 1 July 2016, Sweden extended the strategic reserve to 2025, with a cap of 750 MW while maintaining the share of Demand Response at 25%[339].

Distribution network services. Demand-side flexibility could represent an important tool for local congestion management. Small electricity consumers are billed by retailers and by the DSOs according to their electricity subscription and use. Different network tariffs are in place for off-peak and peak hours, to penalize with higher rates consumption in peak hours, which are considered day hours in the winter period.

There have been some pilots in place, such as the Smart Grid Gotland[340], which was completed in December 2015 in Gotland Island, and includes Demand Response programmes.

There is no current mechanism in Sweden that allows for the DSO's to buy demand-side flexibility. However, in late 2016 the national regulatory authority in Sweden concluded a project[341] on the issue of DSO's procuring demand-side flexibility that was sent to the government before Christmas. As such, the results are not yet available. In general, Sweden is behind in incentivising DSO's to further invest in Demand Response and do not yet have a framework in place to adjust the investment structure in order to encourage this.

C. Restrictions related to distribution network operations

Legislation in Sweden requires that grid tariffs be objective, which implies that the customer receive a tariff that reflects the network cost[342]. Furthermore, there is no overall regulation for the tariff structure.

336 NordPool Spot, 2016 values

337 Svenskförfattningssamling 2003:436 and 2010:2004 (Laws 436/2003 and 2004/2010): "Constitution of Strategic Reserve, and Ministry of Enterprise, Energy and Communications Sweden (2012): "Experiences with the implementation of the strategic reserve in Sweden"

338 Svenskförfattningssamling 2014:213 (Law 213/2014)

339 Svenska Kraftnat (2015): "Network Development Plan 2016 – 2025", available at: http://www.svk.se/contentassets/c7ff3f2bb5ed4d4a8d7d6d0599a5426a/network-development-plan-2016-2025_webb.pdf (retrieved on 15 March 2017)

340 Smart Grid Gotland (2015), www.smartgridgotland.comhttp://www.smartgridgotland.se/about.pab (retrieved on 30th January 2017)

341 Ei (2016): "Åtgärder för ökad efterfrågeflexibilitet i det svenska elsystemet", available at: http://ei.se/Documents/Publikationer/rapporter_och_pm/Rapporter%202016/Ei_R2016_15.pdf (retrieved 15 March 2017)

342 Poyry (2015): "Mapping Of Tsos' And Dsos' Roles And Responsibilities Related To Market Design To Enable Energy Services", available at: http://www.nordicenergyregulators.org/wp-content/uploads/2015/03/Mapping-of-TSOs-and-DSOs-role-and-responsibilities_v200.pdf (retrieved on 15 March 2017)

Specifically, residential consumers typically receive a fixed tariff and energy charge (and in some cases have a capacity charge). Current charges are based on capacity over production and are significantly higher than its Nordic neighbours. Sweden, does however, provide the option for seasonal (time of use tariffs). Yet such a network regime disadvantages generation and incentivises a flat consumption pattern which negatively impacts the development of Demand Response, and can be especially disadvantageous for capacity with low load factors (such as wind power)[343].

2. Service providers access to markets

A. Demand Response service providers access to consumer

The main types of consumers that participate in the balancing market are paper mills, industry heat boilers, small industries in the Strategic reserves and paper mills and pumps at RPM. Furthermore, Demand Response and generation sources cannot be aggregated within the same bid.

The aggregator requires BRP's agreement prior to load changes. To operate in the electricity markets, an independent third-party aggregator would have to register as a BRP or sign an agreement with the consumer's retailer/BRP.

Registering as a BRP requires annual fee of about 2500 €/year, and the installation of an electronic reporting system connected to the exchange platform Ediel (or signing a contract with an agent that has such equipment).

Moreover, the relationship between the retailer and the aggregator can act as a market entry barrier as the consumer's retailer/BRP is unlikely to wish to cooperate with a potential competitor. In the Strategic Reserve, much of the responsibilities lie on the resource owner.

Currently there are no independent aggregators that are able to operate on the Swedish market

Imbalance settlement after load management. The BRP's imbalances are directly corrected by the TSO which takes into account its reduction order.

3. Product requirements

A. Main product requirements

Ancillary Services. With the current structure, Demand Response cannot cope with the product requirements for Primary (FCR-N, FCR-D) and Secondary (aFRR) Reserves. Demand Response could in theory participate with provisions that would make these Reserves more technically accessible (e.g. activation only for deviations above 100 mHz – which leads to limited times of activation, and thus to less impact in the industrial/commercial/domestic processes). In regard to the Tertiary Reserve (mFRR), the main barrier is the

343 Copenhagen Economics (2016): "Electricity Market Design for a Reliable Swedish Power System", available at: https://www.copenhageneconomics.com/dyn/resources/Publication/publicationPDF/0/370/1476950205/copenhagen-economics-2016-market-design-for-a-reliable-swedish-electricity-system.pdf (retrieved on 15 March 2017)

high minimum bid[344]. The Swedish TSO is currently in the process of managing a pilot project that will finish in May of 2017 that is aggregating 100kW from heat boilers in 100 households (small houses) for FCR. The results of the project will be used to update the rules and requirements for Demand Response in the primary reserves. The 0,1 MW minimum bid size for the day-ahead and intraday markets enables demand-side participation.

Wholesale market

Product	Market place	Minimum size (MW)
Day Ahead	Nord Pool	0,1 MW
Intraday	Nord Pool	0,1 MW

Balancing and ancillary services

Product		Minimum size (MW)	Notification Time[345]	Activation	Triggered (max. times)
FCR	FCR-N	0,1	63% in 60s, 100% in 3 min	Automatic when frequency is out of 49,9-50,1 Hz	Constantly
	FCR-D	0.1	50% in 5s, 100% in 30s	Automatic with frequency under 49,9 Hz	Approx.1 500 times/year
aFRR		5	2 min	Automatic	Constantly
mFRR (RPM)		10 (SE1, SE2,SE3), 5 (SE4)	15 min	Manual by a phone call	Every hour
Fast disturbance reserve		n-1	15 min	Manual and under frequency activation	Approx. 100 h/ year
Strategic reserves		5	15 min	Manually	Historically less than 10 h/year
Other ancillary services if relevant (re-dispatch, voltage control)		⃠	⃠	⃠	⃠
Capacity mech. (if any)		⃠	⃠	⃠	⃠
Distribution network services		⃠	⃠	⃠	⃠

Table 47: Description of some main Product requirements in the balancing products accessible to Demand Response in Sweden

344 Since 1st November 2011, the Swedish electricity market has been divided into four distinct price areas (i.e. S1, S2, S3, S4).

345 SVK (2014): "Balance Responsibility Agreement", available at: http://www.svk.se/siteassets/aktorsportalen/elmarknaden/balansansvar/dokument/brp-agreement-20150201.pdf (retrieved on 30th April 2015)

4. Measurement and verification, payments, and penalties

A. Measurement & verification

Prequalification. Prequalification is required for aFRR, for mFRR, and FCR products. The facilities also have to be qualified as "Regulation Object" by the TSO. It's currently also an issue to measure aggregated volumes. Measurement and verification for aggregated Demand Response will need further definition in order to ensure it delivers a reliable resource. FCR programmes also require a frequency measurement device installed at the location of the entity, with a certain level of accuracy.

There is also a project to establish a data hub in the pipeline which will help with measurement and verification in 2020 and subsequently also be useful for the increase in aggregation.

Baseline methodology. There is no publicly available baseline methodology.

B. Availability/Utilisation payments

The Swedish Ancillary Services are dominated by hydropower, due to the fact that it is a cost efficient and rapidly adjustable resource. However, Demand Response's participation is expected to grow, following the increasing share of intermittent generation into the network. Payments and penalties related to participation in the ancillary services are not public, but average prices are. The following table summarises the main participation conditions in the different programmes. All payments on the wholesale market are pay as cleared (marginal pricing). Imbalance prices for demand are set as Marginal price of the market and with a penalty of 0.49 Euro/MWh.

Balancing and ancillary services

Product		Availability payments	Utilisation payments	Access
FCR	FCR-N	Yes (Pay as bid) *(average prices are public)*	Yes (Marginal price at RPM). *Prices are public but not in real time*	Daily
	FCR-D	Yes *(average prices are public)*	NO	Daily
FRR-A		Yes *(prices are not public*	Yes (Marginal price at RPM) *Prices are public but not in real time*	Monthly
FRR-M Fast Disturbance Reserve		Yes *(prices are not public)*	Marginal price	Tender, procurement
FRR-M RPM		No (Voluntary Bids)	Marginal price	Hourly
Strategic Reserve		Yes *(prices are not public)*	Yes (Marginal price at RPM) Regulating bid	Tender, yearly procurement

Table 48: Overview of availability and utilisation payments in the balancing market in Sweden

Switzerland

Overview

After certain regulatory changes, which took place in 2013, Switzerland has opened itself up considerably when it comes to aggregated Demand Response. Technical barriers have been removed and, above all, Swissgrid allows BSPs to aggregate loads from anywhere in the country without the agreement of the customers' BRPs, settling imbalances directly with them. This regulation provides clear roles and responsibility for the BRP and BSP, while mitigating the costs and risks of both parties. It also establishes a critical set of processes under the TSO's supervision and could provide a model for the rest of Europe.

Some critical barriers still exist in the balancing market, however, such as that there are no tariff-related incentives, creating a conflicting interest with so called ripple steering technologies. There are also market-related challenges including poor transparency over real-time demand for flexibility; missing price signals; and a missing market opportunity for active trading. These problems show how Demand Response presently still has a limited financial value under the present market design[346].

Due to critical water scarcity, Demand Response might be an important source of flexibility in the future in order to compensate for a lowered level of hydropower. The phasing out of Swiss nuclear plants – planned for 2034 – will bring more intermittent energy in the Swiss electricity system. This may increase the need for Demand Response provision in ancillary service programmes.

Enablers. Aggregation was excluded from the market prior to April 2013, but a regulatory process has taken place after this date to remove the important technical barriers within ancillary services, which were preventing aggregators from entering these programmes. For example, the minimum bid size does not exceed 5 MW[347].

Barriers. Whereas the Tertiary control power programme is divided in 'positive' and 'negative', the Secondary control power programme still requires symmetric bids. The Primary and Secondary control power programmes require unlimited (24/7) availability. This challenge can be met by some industrial participants who may have loads such as cooling, heating etc., which can be aggregated and run at any time of day or night, but it remains an important barrier for commercial and domestic Demand Response as well as smaller industrial consumers[348]. Another critical issue in the product design of Secondary Control Power is that the dispatches are not according to a merit order list, but proportional to each unit's individual share in the programme. As a result, DR providers are being called upon frequently to deliver low volumes; the high frequency of dispatches deters customer participation.

346 Swissgrid (2015): "Contributions to the Market Design for the Swiss Energy Strategy 2050", available at: https://www.swissgrid.ch/dam/swissgrid/future/energy_strategy/consultation_paper_en.pdf (retrieved on 15 March 2017)

347 Swissgrid (2015a): "Basic principles of ancillary service products", available at: http://www.swissgrid.ch/dam/swissgrid/experts/ancillary_services/Dokumente/D150401_AS-Products_V9R0_EN.pdf (retrieved on 4th April 2015

348 Swissgrid (2015a), ibid

1. Demand Response access to markets

Market overview

All Swiss balancing market programmes are open to Demand Response. The following tables provide a detailed explanation of Demand Response access in the different markets.

Wholesale market

ENTSO-E's terminology	Total Volume Traded (2015)	Load Access & Participation	Aggregated Load Accepted	Aggregated Generation
Day Ahead	24.4 TWh[349]	✔	✔	✔
Intraday	1.44 TWh[350]	✔	✔	✔

Balancing and ancillary services

ENTSO-E's terminology	Swissgrid's terminology		Tot. Capacity Contracted[351] (2015)	Load Access & Participation	Aggregated Load Accepted	Aggregated Generation
FCR	Primärregelleistung		75 MW	✔	✔	✔
FRR	Sekundärregelleistung		378.23 MW	✔	✔	✔
RR	Tertiärregelleistung	Weekly +	232.58 MW	✔	✔	✔
		Weekly –	108.62 MW		✔	✔
		Daily +	433.58 MW		✔	✔
		Daily –	258.55 MW		✔	✔

Table 49: List of balancing market products, including volumes and load accessibility in Switzerland

B. Markets open to Demand Response

Balancing Market. Because of the regulatory developments that took place early in 2013 and a transitional period from May to October 2013, Demand Response has access to all of the Swiss ancillary services: including Primary, Secondary and Tertiary Control Power (positive and negative). Major regulatory

349 PEX (2017): Press release, available at: https://www.epexspot.com/en/press-media/press/details/press/EPEX_SPOT_reaches_in_2015_the_highest_spot_power_exchange_volume_ever (retrieved on 15 March 2017)

350 Abrell, Jan (2016): "The Swiss Wholesale Electricity Market", available at: http://www.nfp70.ch/SiteCollectionDocuments/2016_Abrell_Swiss_Wholesale_Electricity_Market.pdf (retrieved on 15 March 2017)

351 Abrell, Jan (2016), Ibid.

barriers have been removed and aggregators can bid into these programmes. Demand-side resources currently provide 3 MW of primary and 10 MW of secondary reserves (mainly coming from household boilers), whereas flexible loads from various industries (cement, chemical, paper, wood) provide about 49 MW of tertiary reserve.

Capacity Mechanism. A Capacity Mechanism for Switzerland is not being considered, as it is assessed to bring high administrative costs, inadequate liquidity and insufficient competition between individual power generators. Instead, Switzerland will continue to work more closely with its neighbours.

Wholesale Market. Currently there is no stand-alone Demand Response participation on the EPEX spot market from Switzerland. The total Swiss power being traded on the EPEX day ahead market increased in 2015 by 12% to a new record high of 22,913,735 MWh. The intraday market volume in 2015, where 15-minute trading is possible since 2014, also reached an all-time high of 1,674,835 MWh[352].

Distribution network services. Demand-side flexibility could represent an important tool for local congestion management. Currently there are only pilot programmes on the DSO level[353].

C. Restrictions related to distribution network operations

The standard tariff schemes in Switzerland consist of two components, reflecting the consumed electricity and the utilisation of the network infrastructure. All energy related costs are based on the volumetric time-of-use (ToU) principles[354].

2. Service providers access to markets

A. Demand Response service providers access to consumer

In the balancing markets, the aggregator (BSP) does not have any contracts with the Balance Responsible Parties of the areas where it operates. The BSP contracts directly with Swissgrid (the Swiss TSO) to access the market. BSPs can aggregate load from anywhere in the country. Neither the BRP nor the BSP are charged for the imbalance caused by the load management. Swissgrid corrects each BRP's balance group the day after the operation, taking into account all the operations that took place in its respective area.

A small number of third-party aggregators have started to offer Demand Response in the balancing market. Information on the exact volume of demand-side loads in the various programmes is not available.

Similar rules are not yet in place for demand-side offers into the wholesale market. However, the TSO is currently considering the advantages and challenges regarding the introduction of a new role for an independent aggregator[355].

352 EPEX (2016): Online data platform (retrieved on 25th April 2016)

353 See e.g.: Swiss Economics and Ecofys (2015) Zukünftige Energiemärkte und die Rolle der Netzbetreiber. Abschlussbericht im Auftrag des BfE, Bern, März 16, 2015. Available online at:http://www.bfe.admin.ch/php/modules/publikationen/stream.php?extlang=de&name=de_690889572.pdf; Consentec (2015) Koordination von Markt und Netz – Ausgestaltung der Schnittstelle. Untersuchung im Auftrag des Bundesamt für Energie. Abschlussbericht, Bern, Juli 9, 2015.

354 Markovic et. Al (2016): "The Future Role Of A Dso In Distribution Networks With High Penetration Of Flexible Prosumers", available at: http://www.cired.net/publications/workshop2016/pdfs/CIRED2016_0119_final.pdf (retrieved 15 March 2016

355 Swissgrid (2016): "Contributions to the Market Design for the Swiss Energy Strategy 2050", available at: https://www.swissgrid.ch/dam/

Imbalance settlement after load management. In the balancing market, Swissgrid corrects each BRP's balance group the day after the operation, taking into account all the operations that took place in its respective area.

BRP-aggregator adjustment mechanism. According to the framework agreement on aggregated loads, the added value caused by the provision of balancing services, is handed to the aggregator. However, the aggregator is obliged to compensate the BRP for the difference in consumed energy with a payment that is determined by the quarter-hourly day-ahead spot price of the Swiss Electricity Index (SwissIX). Such regulatory structure and clarity will be critical for the long-term stability and growth of Demand Response in Europe. However, it should be noted that if the day-ahead spot price is used for payment this will block Demand Response from participating in the day-ahead spot market now and in the future. The use of this price rather than a more complex but accurate sourcing price is questionable.

3. Product requirements

A. Main product requirements

Primary control power (Primärregelleistung). Primary control power is being procured by means of various weekly tenders. 46 MW are procured through an invitation to tender issued by Swissgrid, and a further 25 MW can be provided from France or Austria. The remaining share is procured in a joint tender together with the German transmission system operators.

Secondary control power (Sekundärregelleistung). Around 400MW of secondary control is being tendered for every week, with minimum bids of 5 MW. Secondary control power is dispatched "proportionally", rather than through a merit order list. This means that for every TSO dispatch of secondary control power, every BSP must respond, according to its overall proportion of the market. Unlike merit order dispatch, where offers are dispatched consecutively according to their price, the proportional system dispatches all BSPs every time secondary control is needed. This blocks industrial and a large share of commercial customers from participating in this market. Also, only symmetric bids are accepted, and only the capacity price is opened for bidding, with the energy price being based on the SwissIX hourly price. The symmetric bidding requirement remains a barrier to consumer participation as consumers' ability to adjust their consumption patterns is rarely symmetric.

Tertiary control power (Tertiärregelleistung). Tertiary control can be tendered asymmetrically, with minimum bids of 5 MW and a total volume of 100 MW. There are either 6 blocks of 4 hours opened every day or weekly tenders (00:00 Monday – 24:00 Sunday). The blocks of tenders and the asymmetrical bidding requirement both support the participation of consumers through providing the required flexibility in timing and bidding direction.

Wholesale market table here

Product	Market place	Minimum size (MW)
Day Ahead	EPEX Spot	0.1
Intraday	EPEX Spot	0.1

swissgrid/future/energy_strategy/consultation_paper_en.pdf (retrieved on 15 March 2017)

Balancing and ancillary services

Product[356]	Minimum size (MW)	Notification Time	Activation	Triggered (max. times)
Primärregelleistung	1 MW	30 sec	Automatic	Up to several times per day
Sekundärregelleistung	5 MW	200 sec	Remote-controlled	Up to several times per day
Tertiärregelleistung Weekly positive	5 MW	15 min	Manual (Email/phone)	Up to several times per day
Tertiärregelleistung Weekly negative	5 MW	20 – 35 min	Manual (Email/phone)	Up to several times per day
Tertiärregelleistung Daily positive	5 MW	15 min	Manual (Email/phone)	Up to several times per day

Table 50: Description of some main Product requirements in the balancing products accessible to DR in Switzerland

4. Measurement and verification, payments, and penalties

A. Measurement & verification

Prequalification. The consumer/prosumer (or VPP) unit has to fulfil requirements as an aggregate. This simplifies the prequalification requirements, as it allows the aggregator to stand in the place of the consumer. Prequalification at the aggregate level is therefore an important enabler of Demand Response. There is no minimum size and no technical requirements for a single unit. Virtual generation units appear as single feed-in/out node for the TSO.

The aggregator/BRP monitors and regulates its pool at its own cost (including installation and maintenance) and provides the monitoring data to Swissgrid. The prequalification process is usually completed within 2-3 months.

Baseline methodology. The baseline is defined as the measured value of the load before being influenced by the aggregator. Its measurement is then set at the pre-qualification stage.

B. Availability/Utilisation payments

Balancing and ancillary services

The Primary control power programme only provides an availability payment; currently prices are not attractive for Demand Response. Secondary and Tertiary control power – paid out with both availability and utilisation payments – supports a business case for aggregation and both receive an equal share in the aggregators' applications.

356 Swissgrid (2017): "Basic principles of ancillary service products", available at: https://www.swissgrid.ch/dam/swissgrid/experts/ancillary_services/Dokumente/D170214_AS-Products_V9R2_en.pdf (retrieved on 4th April 2017)

Bids are sorted in a merit order list by the availability price. Accepted bids are remunerated according to the "pay-as-bid" principle. The Swiss balancing services market has changed from a 'pay-as-cleared' system to a 'pay as bid' system in order to comply with ENTSO-E recommendations.

Balancing and ancillary services

Product			Availability payments	Utilisation payments*	Access
Primärregelleistung[357]	Weekly	Symmetric	19.67 CHF/MW/h	Not offered	Tender-based
Sekundärregelleistung[358]	Weekly	Symmetric	25.68 CHF/MW/h	Based on SwissIX	Tender-based
Tertiärregelleistung	Weekly[359]	Positive	5.45 CHF/MW/h	Based on SwissIX	Tender-based
		Negative	3.57 CHF/MW/h	Based on SwissIX	Tender-based
	Daily[360]	Positive	2.60 CHF/MW/h	Based on SwissIX	Tender-based
		Negative	2.18 CHF/MW/h	Based on SwissIX	Tender-based

* The agreement to reimburse based on SwissIX only applies to DR

Table 51: Overview of availability and utilisation payments in the balancing market in Switzerland

C. Penalties

There are two regimes of penalties.

- If the BSP fails to deliver the agreed curtailment, the penalty corresponds to the imbalance price of electricity.
- If the BSP has not reserved the power as planned in the bid and is directly responsible for it, the penalty is 10 times the price established in the bid. If indirectly responsible, (network constraints, works on power lines) the penalty is three times the price. This second type of penalty is rarely used.

However, it should be mentioned that when the BSP is not able to honour a contract, it has the possibility to pass it to another BSP, through a bilateral agreement.

357 Swissgrid (2016a): Primary Control Weighted average prices in 2015, available at: https://www.swissgrid.ch/swissgrid/de/home/experts/topics/ancillary_services/tenders/primary-control-power.html (retrieved on 4th December 2016)

358 Swissgrid (2016b): Weighted average prices in 2015, available at: https://www.swissgrid.ch/swissgrid/de/home/experts/topics/ancillary_services/tenders/secondary-control-power.html (retrieved on 4th December 2016)

359 Swissgrid (2016c): Weighted average prices in 2015, available at: https://www.swissgrid.ch/swissgrid/de/home/experts/topics/ancillary_services/tenders/tertiary-control-power.html (retrieved on 4th December 2016)

360 ibid: Weighted average price of all six 4-hour periods in 2015 (retrieved on 4th December 2016)

3

Overall Results

The SEDC Demand Response Map provides an overview of the current regulatory framework for Demand Response in the 18 countries examined. The research shows that there has been an overall increase of interest in enabling Demand Response in almost of all the countries examined. Since the previous edition of the report, regulatory changes have been implemented or are planned in many of the analysed countries. Notably, even in the countries where Demand Response has traditionally been almost non-existent, such as Estonia, Spain, Italy, there has been at least some regulatory interest in exploring its potential.

The Member State analysis reviewed markets according to the criteria described in the Methodology. These are: 1) Demand Response access to the markets 2) Service providers access 3) Product requirements 4) Measurement and verification, payments and penalties. The Map below indicates the overarching categorisation of different Member States. It is important to note, that frameworks are ranked in relation to each other – even for countries marked green, further improvements are still possible and necessary.

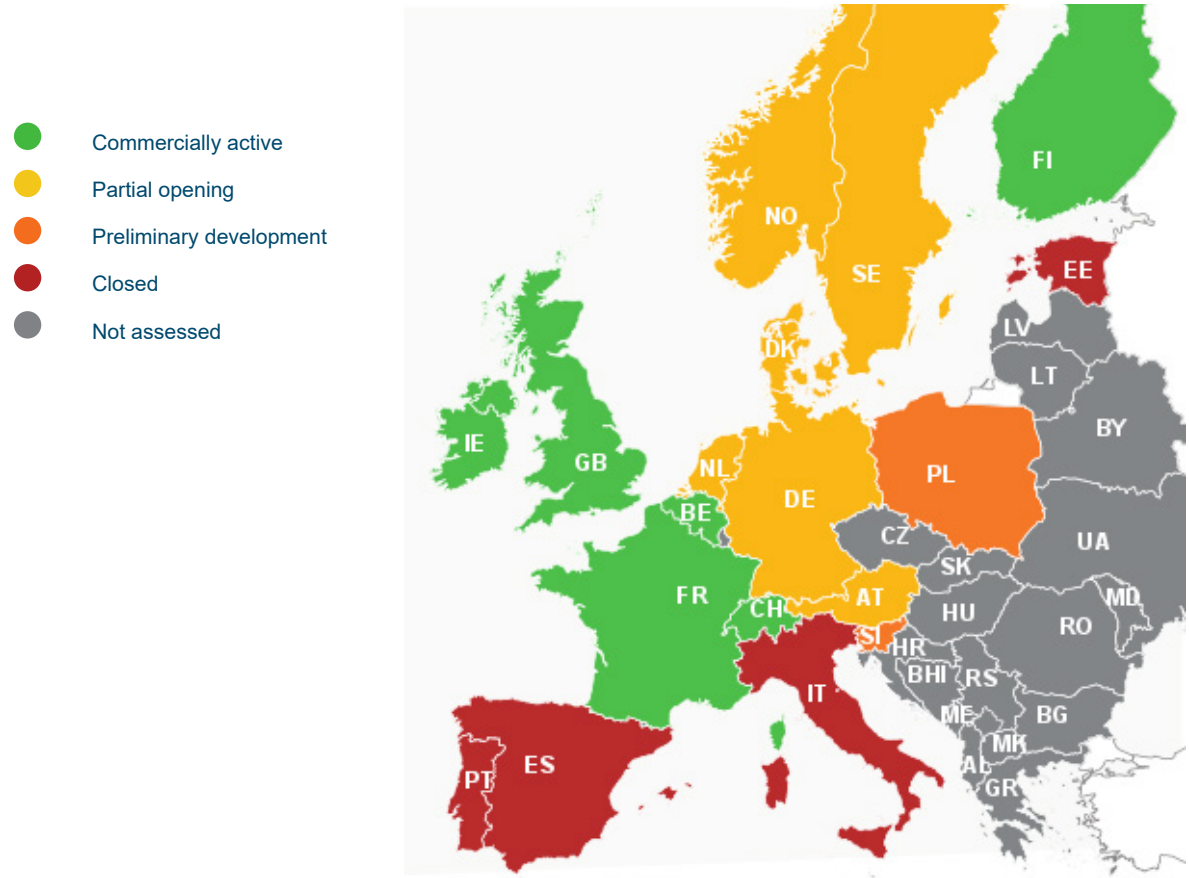


Figure 2: Map of Explicit Demand Response development in Europe today

The European countries that currently provide the most conducive framework for the development of Demand Response are Switzerland, France, Belgium, Finland, Great Britain, and Ireland. Nevertheless, there are still market design and regulatory issues that exist in these well-performing countries. Switzerland and France have detailed frameworks in place for independent aggregation, including standardised roles and responsibilities of market participants. In France, a new a decree related to payments to retailers is currently under review by the Conseil d'Etat which will provide further clarity on the relationship between independent aggregators and retailers/suppliers. However, issues persist around a standardised baseline methodology.

In both Belgium and Ireland upcoming legislation should help increase the participation of Demand Response. New legislation addressing the role of the aggregator and independent aggregation will soon be put in place in Belgium which will help to provide an equal footing for all market actors; a strong sign for the uptake of Demand Response. However, there are still some issues regarding measurement and verification that inhibit the growth of Demand Response. In Ireland, the new "Integrated Single Electricity Market" and DS3 programme, to be implemented in 2018 will open a range of markets for demand-side response, specifically the balancing market, and the wholesale market, as well as a newly designed Capacity Mechanism.

Great Britain continues to have a range of markets open to demand-side participation, such as the majority of the ancillary services. It has recently has started considering creating a framework for independent aggregator access to the Balancing Mechanism. Yet, with relatively burdensome measurement and verification procedures in place for Demand Response, it still has room to improve.

Finland stands out amongst the Nordic countries as it allows independent aggregation in at least one of the programmes in the ancillary services, and has advanced provisions for measurement and verification. Later this year it will also launch pilot projects looking at independent aggregation in other parts of the balancing market.

Austria, Denmark, Germany, Netherlands, Norway, and Sweden are marked yellow, as regulatory barriers remain an issue and hinder market growth. Although several markets in these countries are open to Demand Response in principle, programme requirements continue to exist which are not adjusted to enable demand-side participation. Furthermore, a lack of clarity remains around roles and responsibilities of the different actors and their ability to participate in the markets. However, Germany and the Nordic countries have started processes to find a standard solution for the role of independent aggregation, and Austria recently finished discussing the role of independent aggregation, which resulted in a non-binding model contract. One of the notable difference in this year's mapping was that Germany has moved from orange status in 2015 to yellow in 2017. This is primarily due to the fact that product definitions have been updated, and an improvement in market access for new actors is expected in the near future.

Slovenia, Italy, and Poland are coloured orange. In Slovenia and Poland, no major regulatory changes have been made within the past couple of years that would have allowed for further Demand Response participation. Notably, Italy has upgraded its status from red in the previous SEDC Demand Response Maps to orange today, as it has slowly started to take the regulatory steps needed for a solid framework for Demand Response. However, despite the gradual opening of markets, significant barriers still hinder customer participation. For example, major sections of the market are still closed off and they lack a viable regulatory framework for Demand Response overall.

Spain, Portugal, and Estonia are coloured red because aggregated demand-side flexibility is either not accepted as a resource in any of the markets, or it is not yet viable due to regulation. Here we see a critical

disconnect between political promises and regulatory reality. Estonia may be an important country to watch in the future given that markets could open once they have disconnected from the IPS/UPS synchronous area. The following table provide an at-a-glance overview of the analysis of Member States.

2017					
	Demand Response Access to Markets	Service Provider Access	Product Requirements	Measurement and Verification, Payments and Penalties	Overall
Austria	3	1	5	3	**12**
Belgium	3	3	5	3	**14**
Denmark	3	1	3	3	**10**
Estonia	1	0	1	0	**2**
Finland	5	1	3	5	**14**
France	5	5	5	3	**18**
Germany	3	1	3	3	**10**
Great Britain	5	3	3	3	**14**
Ireland	5	5	3	1	**14**
Italy	1	0	1	1	**3**
Netherlands	3	1	3	3	**10**
Norway	3	1	3	3	**10**
Poland	1	1	1	1	**4**
Portugal	0	0	1	0	**1**
Slovenia	1	1	0	3	**5**
Spain	0	0	1	0	**1**
Sweden	3	1	3	3	**10**
Switzerland	3	5	3	5	**16**
Overall	**48**	**30**	**47**	**43**	**168**
Max score	**90**	**90**	**90**	**90**	**360**

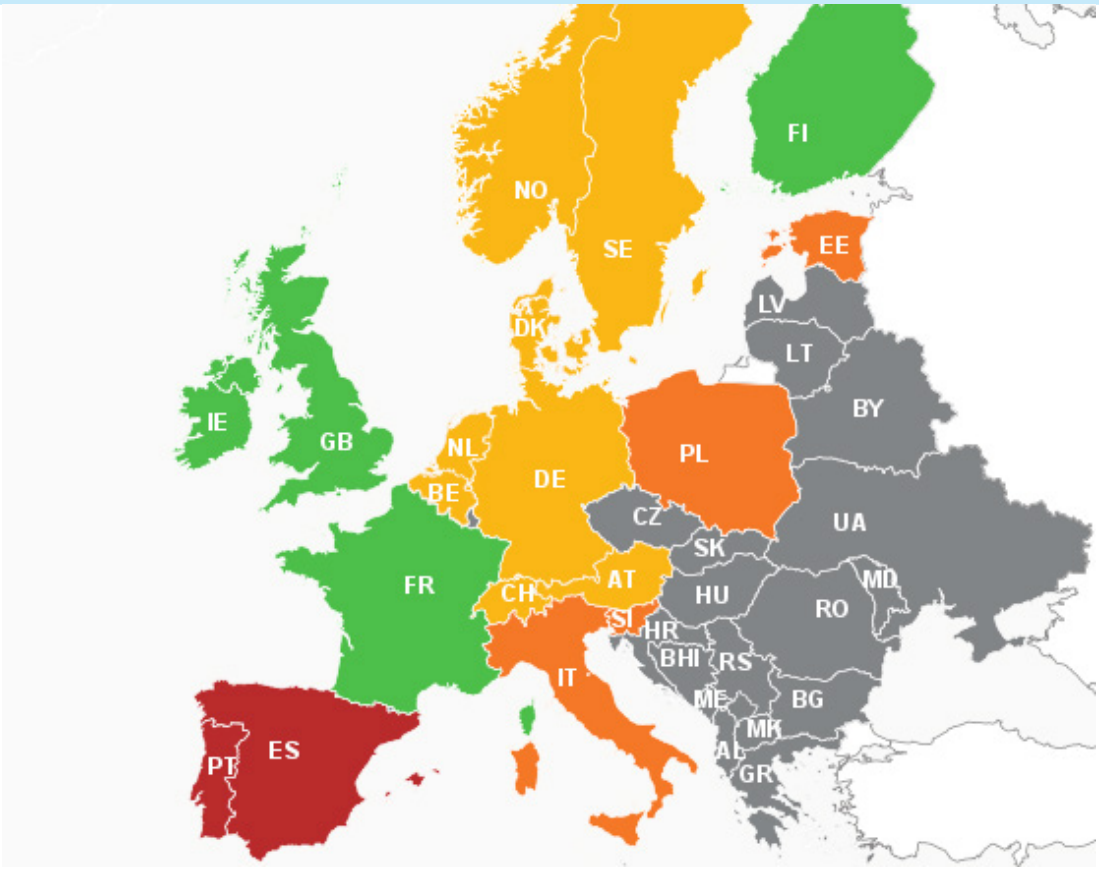
Table 52: Detailed grading of the countries assessed by the SEDC

To ease comparison and clarify differentiation between Member States, the four maps below describe the results per criteria.

3.1 Demand Response Access to Markets

In several national markets, Demand Response is either not accepted as a resource in the balancing, capacity or wholesale markets or is still limited to a couple of specific areas within the ancillary services.

Moreover, in the majority of the countries, the only way for Demand Response or decentralised generation to participate in the markets is by being sold directly through the retailer/BRP.



Key: see section 2.1 Methodology

Figure 3: Demand response access to markets in Europe

Demand accepted as a resource

Overall, there has been significant progress made since the previous report, in terms of opening, or planned opening, of markets to demand-side resources in certain Member States. These include Belgium, France, Finland, and Ireland even though most Member States continue to have certain markets where

demand-side resources are not accepted. However, Finland has recently started exploring the potential of Demand Response in multiple programmes in the balancing market. Slovenia has opened more than one programme in the balancing markets to aggregated demand-side resources. Spain also recently opened one of their balancing markets to decentralised and renewable energy resources. Italy is due to open all its markets to aggregated demand-side resources in the near future, after the recent passing of legislation aimed at market reform.

In many countries, Demand Response may not have access to the most valuable markets on an equal footing

In Poland, Demand Response participation has been limited to the Emergency Demand Response programme. However due to poor programme requirements involvement declined drastically, and by 2016 there were no participants. In the tender for Summer 2017 there will be two new emergency DSR programmes: one with both availability and utilisation payments and an obligation to bid, and the other with only utilisation payments and more flexibility in terms of bids and availability. In Spain, participation in different markets is still almost non-existent. In fact, Demand Response activity is restricted to industrial consumers in interruptible contracts.

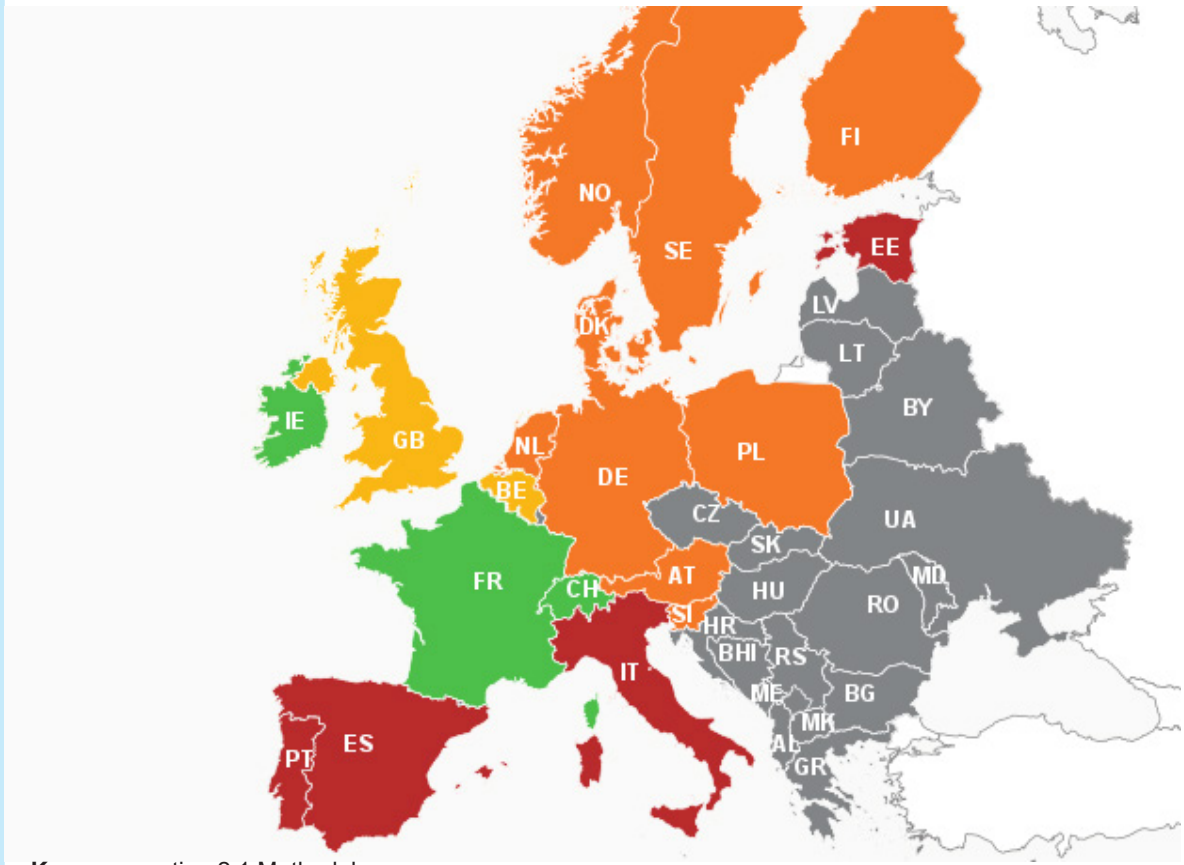
Since the publication of the last report there have been key developments in the emergence of Capacity Mechanisms. Italy, Poland, France and Germany have all recently agreed upon or are finalising the terms and conditions of Capacity Mechanisms that are to allow demand-side flexibility to compete with generation. Germany's capacity reserve draft rules (not yet finalised) are such that in practice the market is closed for Demand Response, aggregation is not allowed, and the minimum bid size is 10 MW. In Great Britain the Capacity Mechanism rules also heavily favour generation in practice.

In the Nordic countries, the effective use of strategic reserves has been much more prominent with fewer issues surrounding the participation of aggregated Demand Response in countries such as in Finland, Sweden, and Norway. Denmark, on the other hand, has no capacity market nor strategic reserve.

3.2 Service Provider Access

Consumer Access still appears to be one of the most problematic areas across the countries examined. This directly contradicts existing EU legislation, and in particular the Electricity Directive, Article 17.3a[361]. The European Commission's legislative proposal for the revision of the Electricity Directive – when adopted and properly implemented – should overcome this problem, stating that *"Member States shall ensure that their regulatory framework encourages the participation of aggregators in the retail market and that it contains at least the following elements: (a) the right for each aggregator to enter the market without consent from other market participants…".*

361 COM (2016a): Proposal for a Directive Of The European Parliament And Of The Council on common rules for the internal market in electricity available at: http://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52016PC0864R(01)&from=EN (retrieved 15 March 2017)



Key: see section 2.1 Methodology

Figure 4: Service providers access to markets in Europe

Today, the major hurdle remains the clarification on the roles and responsibilities of new market actors and their ability to participate in all markets.

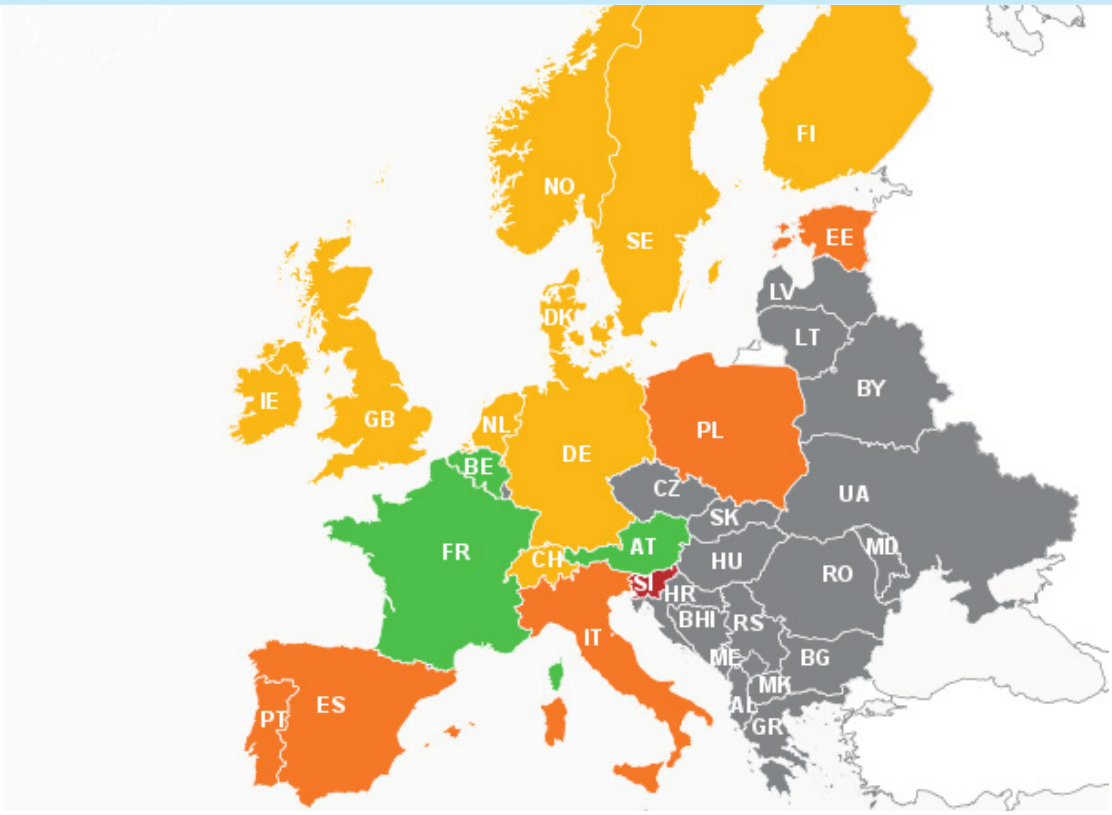
In the majority of European countries, market rules do not provide specific details on how independent Demand Response aggregators should engage with consumers, nor do they make it viable for them to access the market. They may allow these new service providers to participate in the markets, but they lack fair competition. In these Member States, independent aggregators must negotiate bilaterally with BRP/retailers to sell consumers' flexibility on the markets. This is a major disincentive for new market actors from attempting to enter the market, as the rules create a barrier to entry and result in retailers/BRPs being essentially the only actors providing aggregation services. The lack of a framework, in addition to the non-defined roles and responsibilities, increases the risk for all parties, and enables the abuse of consumer rights (including contractual arrangements and price stability).

When roles and responsibilities fail to enable the clear and direct access of consumers to aggregation service providers, free market competition around Demand Response services is hampered. The countries that have introduced detailed frameworks for independent Demand Response aggregators continue to be France and Switzerland, where rules are also in place to

ensure that the BRP is not penalised by a Demand Response event. Belgium and Germany are in the midst of establishing their own respective frameworks that will establish clear rules between the aggregator and retailer/BRP. Furthermore, Nordic countries will be discussing the future of the framework and are to announce the results of stakeholder discussions soon. Austria also recently finished discussing the role of the independent aggregator in meetings with stakeholders which resulted in a non-binding model contract, which is a strong step in the right direction. Ireland's system, by using a centrally dispatched model, does not have BRPs and makes the TSO the only one responsible for imbalances – therefore the entire issue is avoided. In Great Britain, the model allows independent aggregators direct access to consumers for most ancillary services and capacity products, but they are unable to utilise the energy for wholesale market purposes or for participation in the Balancing Mechanism.

3.3 Product Requirements

While several Member States have started to review regulation in terms of general market access for Demand Response, fewer have started to address the issue of product requirements, especially on balancing markets. Narrow product requirements continue block low-cost demand-side resources and artificially inflate the cost of balancing in several countries.



Key: see section 2.1 Methodology

Figure 5: Product Requirements in Europe

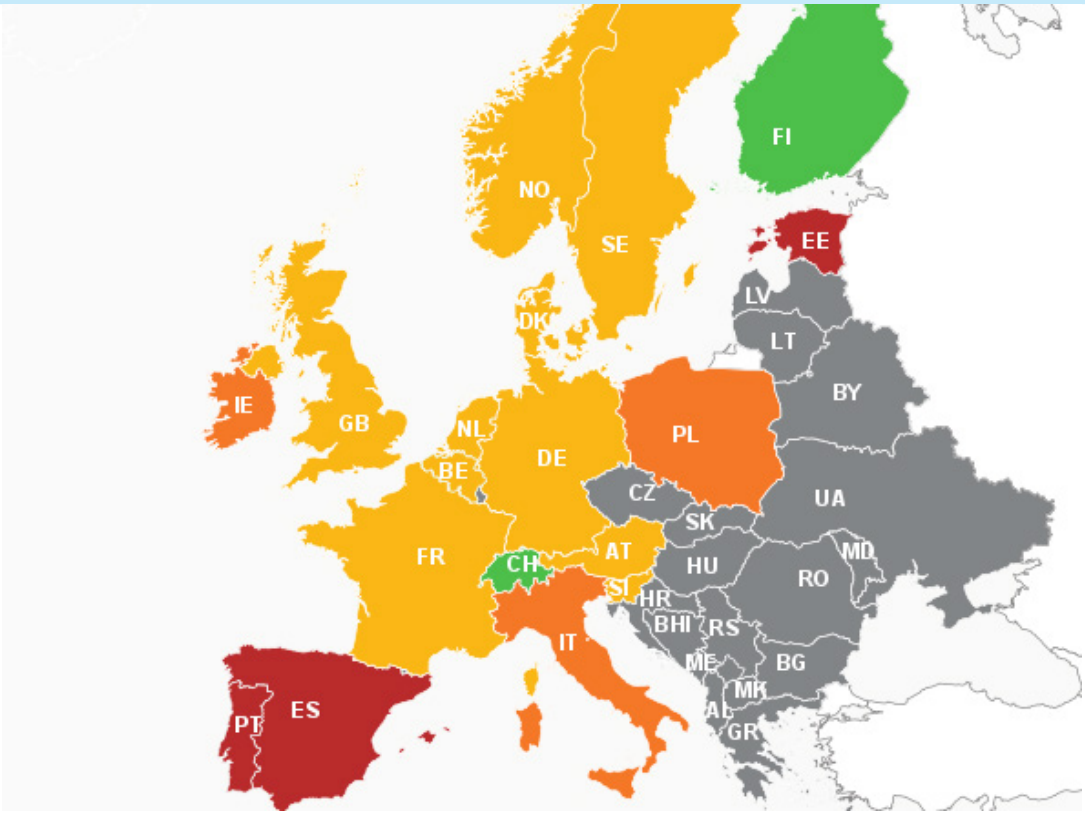
Although demand-side resources are more flexible and can react faster than most generators, large minimum bid sizes (over 5 MW), long event durations, high frequency of events, and short resting periods between events prevent larger consumer participation. For example, while consumers can participate quickly and provide a secure resource, they have difficulty providing availability 24/7.

On the positive side, Germany has made progress and recently the regulator included within its consultation document, the consideration to shorten the time blocks for the secondary balancing capacity to 4 blocks (similar to their minute reserve). The outcome of the consultation, however, is still unknown. In Great Britain, recent developments have removed barriers since 2015. One major change has been the entry point for the firm frequency response market in the ancillary services to be reduced to 1 MW from 10 MW in April 2017. In Belgium, major changes to the balancing market have made Demand Response quite competitive, specifically in the primary reserve with four different types of products, with minimum bid sizes of 1 MW. In Sweden, the TSO is in the process of managing a pilot project that will finish in May 2017 that is aggregating 100 kW from heat boilers in 100 households (small houses) for the FCR. The results of this will be used to update the rules and requirements for Demand Response in the primary reserves.

Dialogue and close cooperation with Demand Response providers, such as aggregators, retailers, and large consumers, have proven to be a critical element in moving the markets forward, for example in Germany, Austria, and Belgium.

3.4 Measurement, Verification, Payments and Penalties

The regulation concerning measurement and baseline methodologies is still progressing across the analysed countries. There has been some momentum towards establishing standardised prequalification rules and baseline methodologies. However, issues remain such as transparency, multiple baseline methodologies, and in some scenarios, there being no requirements for how energy consumption reduction is measure. These are major barriers to the uptake of Demand Response, and for new market actors accessing the markets. In Norway, Austria, Germany and Ireland the individual units of each pool of loads must fulfil all technical and prequalification requirements. This means that aggregators are not able to protect consumers from technical and difficult prequalification requirements and consumers continue to wrongly be treated the same as large generation units. Poland recently changed the prequalification measures and now a pool of loads can qualify as an aggregate, however, high requirements in terms of measurement and planning accuracy still make participation challenging.



...Key: see section 2.1 Methodology

Figure 6: Measurement and Verification, Payments and Penalties in Europe

Problematic measurement techniques act as disincentives for new market entrants.

In Denmark and Norway, the TSO requires real-time metering to participate in certain programmes. Such a high cost of participation is a major barrier especially when aggregating many relatively small loads within the commercial sector. Denmark is currently conducting a pilot project testing a new framework for aggregation, covering online metering, baseline, and verification. In Norway, the Regulated Power Market is still largely based on manual calls (through telephones). In Belgium, the DSO is able to block and even refuse consumer access to Demand Response, without taking responsibility for the costs incurred by the consumer, aggregator, and TSO. Furthermore, it does not provide transparent measurement and risk calculation information to justify its decision. This power provided to the DSO without transparency is a significant barrier to Demand Response.

In France and Great Britain, the pooled load is able to fulfil requirements as an aggregate, which is a critical enabler of Demand Response. However, there are still issues with prequalification in France such as the limited possibilities for aggregation and over-specific requirements on types of reserves. In Great Britain, the Capacity Mechanism has mandatory provision of a credit cover for untested Demand Response. Demand Response units in the Capacity Mechanism also need

to complete a metering assessment before the delivery year, as well as a metering test if required, followed by a Demand Response Test before the delivery year and three “satisfactory performance days” during the delivery year. This is overall a very expensive testing regime.

In Germany, each of the four TSOs may either establish their own criteria for a baseline methodology, or have no publicly published criteria. This is a major market barrier, as a consumer’s consumption adjustments may be measured as according to different standards depending on the TSO. Since the previous edition of this report Denmark, Sweden and Ireland, have not made any changes in creating a public and standardised baseline methodology. This issue will be discussed by the regulators in Denmark soon. In Poland, there are 5 baseline methodologies for the EDRP mechanism, which make it difficult for Demand Response participation.

Penalties.

Penalties for non-performance are generally acceptable, but fair and adequate payment for Demand Response is more problematic.

Availability payments are in most cases accessible for both generation and demand.

Availability payments are essential to secure investment in resource development. Most markets provide these payments to both generation and demand (assuming that the market is indeed open to demand).

Penalties appear generally proportionate overall.

In most cases, penalties seem to be proportionate. Severe penalties may occur in the market where they’re justified by the risk to the system (e.g. in primary control). However, they also play an important role in either encouraging or preventing market actors from participation. In Slovenia, significant bank guarantees are required from Demand Response service providers, which severely limits participation. There are also high penalties for non-availability: for instance, the penalty for non-deliverance of energy is 4,000 €/MWh, and as such, many potential bidders choose not to participate.

4

Conclusions

The detailed assessment of regulatory conditions for Explicit Demand Response in different European markets demonstrates measurable improvements and encouraging plans. Nevertheless, the overall result of the SEDC review still reveals multiple remaining barriers to the establishment of consumer centred Demand Response services. The study revealed five overarching trends:

1. The regulatory framework in Europe for Demand Response is progressing, but further regulatory improvements are needed.

While the EU Demand Response market is further advanced than it was a couple of years ago, and no longer in its early development phase, it is still fragmented. Cooperation between Member states can be seen within different regions in terms of cross-border trade on the wholesale and balancing markets, which is a positive sign. However, more work needs to be done in terms of accelerating the promotion of Demand Response across all Member States. There are still major barriers (i.e. penalties, product requirements, consumer access, etc.) that need to be addressed for the EU to reach the intended harmonised Internal Energy Market.

2. Restricted consumer access to Demand Response service providers remains a barrier to the effective functioning of the market.

Competition of service providers is essential to create the necessary market dynamics to access the full Demand Response potential. Nevertheless, regulatory frameworks in the majority of EU member states do not yet acknowledge the role of independent Demand Response aggregators, or they require aggregators to conclude bilateral contracts with a customer's retailer/ BRP – whose business is often competing – to sell a consumer's flexibility. France and Switzerland are still the only countries to currently have a clear framework on the status of independent aggregators and their role and responsibilities in the market, while Great Britain, Ireland and Finland enable aggregator access to at least to some markets and products. Progress can be identified in Belgium and Germany, where the definition of frameworks is under development, and discussions have also started in Austria and the Nordic countries.

3. Significant progress has been made in opening balancing markets to demand-side resources.

Relatively good progress has been made by most countries in providing access to demand-side resources to the balancing markets. There has been positive cooperation between stakeholders (new market entrants, regulators, TSOs, and retailers). In some countries, balancing market programmes have been opened for pilot projects, while in others overall market design reform will open the whole market to demand-side resources. Discussion over how to improve the definition of baseline methodologies, measurement, and verification have also taken place in certain countries.

4. The wholesale market must be further opened to demand-side resources.

The issue of access by independent aggregators to the wholesale market is prevalent across the majority of Member States. In most cases, the framework allows only for BRPs or retailers to aggregate and sell flexibility on the wholesale market, or at best, Virtual Power Plants and large consumers to sell their electricity directly on the market. This, alongside the further opening of the balancing market and ancillary services, needs to be addressed in order to allow for further competition between market actors in the electricity market.

5. Local System Services are not yet commercially tradeable in European countries.

With the exception of Great Britain, incentive structures for Distribution System Operators in Europe do not yet encourage the use of market-based flexibility

resources. Despite some pilot projects, no effective market structures have been implemented for DSOs to be able to source flexibility, including from Demand Response, for optimised local system operations in any of the analysed countries.

To fully enable the cost-effective use of Demand Response across Europe, the European regulatory framework and Member States' national legislation need to ensure that regulation is in the best interest of consumers and other market actors, and make sure it is fit for the modern electricity market. Keeping old frameworks in place creates distortions and slows progress. Now more than ever, it is imperative that Member States deliver on their promises to deregulate their electricity markets, specifically to enable consumer services through market competition.

The European Commission's proposed revision of the European Electricity Directive and Regulation, launched as part of the Clean Energy Package in November 2016, could provide a major step towards enabling a competitive market, including the full participation of Demand Response, across Europe.

The SEDC calls on the European Parliament, Member States and Commission to promote the approval, specification and implementation of the overarching rules and detailed regulations necessary to create a viable market framework for Demand Response across Europe.

The full potential of the European internal energy market will be only realised if consumers – households, businesses, and industry – are empowered to participate in the European Union's energy transition. This central goal of the market design will lead to a more efficient, cost-effective and sustainable energy system, with the consumer at its heart

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