Ref. Ares(2018)6668033 - 28/12/2018

Demonstration of **Inte**lligent grid technologies for renewables **Inte**gration and **Inte**ractive consumer participation enabling **Inte**roperable market solutions and **Inte**rconnected stakeholders

WP 7 – Update regulation target countries

Updated comparative analysis of regulatory frameworks in the target countries

D7.1

Topic	Demonstration of smart grid, storage and system integration technologies with increasing share of renewables: distribution system
Call	LCE 02 - 2016 - SGS
Grant Agreement Number	731218
Project Acronym	InteGrid
Document	D7.1 Updated comparative analysis of regulatory frameworks in the target countries
Type (Distribution Level)	☒ Public ☐ Confidential
Due Delivery Date	31.12.2018
Date of Delivery	31.12.2018
Status and Version	V1
Number of Pages	86
WP Responsible	Comillas
Deliverable Responsible	Comillas
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File Name	InteGrid_D7.1_Update of the existing regulation in target countries.docx

Document History

Version	Issue Date	Content and Changes
01	15.11.2018	First version
02	13.12.2018	Version for Internal Review
03	20.12.2018	Updated version after internal review by Ellevio
04	21.12.2018	Updated version after internal review by CyberGRID and Technical Coordinator

Acknowledgments

The following people are hereby duly acknowledged for their considerable contributions, which have served as a basis for this deliverable:

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Executive Summary

This document lies under the scope of Work Package (WP) 7 – "CBA, regulatory analysis and business models". It presents an update on the regulatory landscape, incentives and barriers in InteGrid's target countries. Therefore, it is a continuation of the work done within WP1, presented in the "Deliverable D1.3 - Current market and regulatory incentives and Barriers".

In this Deliverable D7.1, the Business Models that have been identified from within the HLUCs defined in WP1 are the guide for the discussion. Five business models, some of them split into several sub-categories, are analyzed in this report. These focus on four main types of actors, namely the DSO, the data service provider, the consumer and the retailer/aggregator. A summary of the business models, the main actor pursuing a given business model as well as a brief description is presented in the table below.

Business Model	Related HLUCs	Main Actor	Benefit	Short Description
BM1	HLUC03; HLUC04	DSO	Lower Interruption Indexes, reduced maintenance cost	The DSO invests in new sensors, monitoring devices and grid automation, improving continuity of supply and reducing maintenance cost
BM2	HLUC01; HLUC02	DSO	Lower operation costs, investment deferral	The DSO uses flexibility from DER to manage the grid. Operation costs are expected to be lower and some grid investments may be deferred
BM3	HLUC06	Data Service Provider	Revenue from services	The new agent "data service provider" can exploit the opportunities created by the gm-hub, a platform that centralizes metering data and acts as an interface for customers and third parties to trade data services.
BM4.1	HLUC08	Industrial Consumer	Reduced electricity bill	By improving electricity management, installing DG and possibly providing grid services, the industrial consumer can reduce its overall electricity cost.
BM4.2	HLUC09	Residential Consumer	Reduced electricity bill	Aided by new technologies such as the HEMS, residential consumers will be able to reduce their energy bill
BM5.1	HLUC10	Retailer	Reduced Imbalance Costs	The retailer uses the flexibility provided by consumers (residential and commercial) to reduce imbalance costs instead of adjusting its position in the intraday market
BM5.2	HLUC11	Platform Owner	Revenues from Ads or Subscription	The platform owner provides users information regarding their consumption, their neighbors' consumption other data that may engage them into better energy management. This is done through an online platform/app. Revenues come

				from subscriptions or ads, depending on the strategy adopted.
BM5.3	HLUC12	Aggregator - cVPP	Revenue from Ancillary Services for TSO	The aggregator provides ancillary services to the TSO (main balancing services) through the use of flexibility from multiple sources (DER, DG, industrial and residential consumers).
BM5.4	HLUC12	Aggregator - tVPP	Revenue from Local Services for DSO	The aggregator provides local services to the DSO (main congestion management) through the use of flexibility from multiple sources (DER, DG, industrial and residential consumers).

Based on each of the BMs, the most relevant regulatory topics for their implementation are mapped and discussed for the target country. In addition to the four countries analyzed in D1.3 (Portugal, Slovenia, Spain and Sweden), Austria was added to the sample.

The regulatory topics are compared, and barriers are identified for each business model. For several BMs, there is still a lack of regulation. Recent European Regulation such as the Network Codes and the Clean Energy Package are already stating the need for regulations that will be useful for InteGrid's objectives, but national regulatory frameworks do not reflect them as of today.

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Abbreviations and Acronyms

aFRR	Automatic Frequency Restoration Reserve
AMI	Advanced Metering Infrastructure
AS	Ancillary Services
BM	Business Model
BRP	Balancing Responsibility Party
BSP	Balancing Service Provider
CAPEX	Capital Expenditures
CBA	Cost-Benefit Analysis
cVPP	Commercial Virtual Power Plant
DAM	Day-ahead Market
DEA	Data Envelopment Analysis
DER	Distributed Energy Resource
DG	Distributed Generation
DoA	Description of Action
DSO	Distribution System Operator
EBGL	Electricity Balancing Guideline
EDC	Electricity Distribution Companies
ENTSO-e	European Network of Transmission System Operators for Electricity
EPEX	European Power Exchange
EXAA	Energy Exchange Austria
ESCO	Energy Services Company
FCR	Frequency Containment Reserve
FRR	Frequency Restoration Reserve
GDPR	General Data Protection Regulation
Gm-hub	Grid-market hub
HEMS	Home Energy Management System
HLUC	High-Level Use Case
LV	Low Voltage
mFRR	Manual Frequency Restoration Reserves
MOLS	Modified Ordinary Least Squares
MV	Medium Voltage
NRA	National Regulatory Agency
OPEX	Operational Expenditures
OTC	Over The Counter
PCR	Price Coupling of Regions
PV	Photovoltaic
RAB	Regulatory Asset Base
RPI-X	Incentive regulation mechanism based on the yearly adjustment of allowed revenues by adding the inflation (RPI) and subtracting an efficiency target "X".
RR	Replacement Reserve
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index

SOGL	System Operation Guideline (ENTSO-e)
SRA	Scalability and Replicability Analysis
TOTEX	Total Expenditures
ToU	Time-of-Use
TSO	Transmission System Operator
tVPP	Technical Virtual Power Plant
UoS	Use-of-System Charge
VPP	Virtual Power Plant
WACC	Weighted Average Cost of Capital
WP	Work Package
XBID	Corss-Border Intraday Market

1. Introduction: goals and scope

1.1. The InteGrid project

The way electricity is produced and consumed is changing fast. Consumers are being empowered with more data, enabling precise management of consumption, and more possibilities to participate in electricity markets. The concept of the producer is also changing. Now it includes not only the traditional large-scale power plant, but also the small generator connected to the distribution grid, storage, and Virtual Power Plants (VPP), through the aggregation of several users at the distribution level.

The creation of these new types of agents and the growing number of Distributed Energy Resources (DER) comes with the need of properly integrating them, both technically and from a regulatory perspective. They have the potential to contribute to the system with services that will enhance its performance and reliability, and potentially reduce operation costs.

A growing number of academic studies and research projects have been dedicated to the integration of a larger share of DER in power systems (GRID4EU[1], EvolvDSO[2], and SuSTAINABLE[3] projects, among others). Moreover, several pilot projects have been carried out by different DSOs in order to test the technical and economic viability of such integration (Prettico, Gangale, Mengolini, Lucas, & Fulli, 2016). One challenge to be explored yet, however, is how the new agents and technologies can be integrated considering the roles of different stakeholders, and their expectation, while enabling new business models given the current and future regulatory environments.

InteGrid's vision is to bridge the gap between citizens and technology/solution providers such as utilities, aggregators, manufacturers and all other agents providing energy services, hence expanding from DSOs distribution and access services to active market facilitation and system optimization services, while ensuring sustainability, security and quality of supply. The main objectives of the project are:

1. To demonstrate how DSOs may enable the different stakeholders to actively participate in the energy market and to develop and implement new business models, making use of new data management and consumer involvement approaches.
2. To demonstrate scalable and replicable solutions in an integrated environment that enable DSOs to plan and operate the network with a high share of DRE in a stable, secure and economic way, using flexibility inherently offered by specific technologies and by interaction with different stakeholders.

In order achieve the objectives mentioned above, the InteGrid project will carry three different demonstrations in Europe (Portugal, Slovenia and Sweden) to enable the various stakeholders to develop new business models as well as to bring new technologies to the market.

[1] https://cordis.europa.eu/project/rcn/103637_en.html
[2] https://www.edsoforsmartgrids.eu/projects/edso-projects/evolvdso/
https://cordis.europa.eu/project/rcn/109548_en.html
[3] http://www.sustainableproject.eu/
https://cordis.europa.eu/project/rcn/106534_en.html

Along with the physical demos, research will be conducted on the several topics surrounding the demonstrations and associated use cases. One of the correlated topics is the analysis of the current regulatory frameworks in the three countries where InteGrid partners are located, the impact of such frameworks, and recommendations for future regulation.

The regulatory analysis within the InteGrid project takes place in different stages. In the first one, a preliminary assessment of regulatory frameworks was carried within Work Package (WP) 1, under Task 1.3. The result of this analysis was presented in the Deliverable D1.3 (InteGrid Project, 2018).

This Deliverable D7.1 is the product of Task 7.1.1. The objectives of this task are to “to build on the activities of Task 1.3 in order to provide a comprehensive an updated review of existing regulatory frameworks in the target countries (Portugal, Spain, Sweden and Slovenia). This review will be used as the starting point for the subsequent critical analysis to identify existing barriers and propose specific regulatory recommendations”, according to the Description of Action (DoA). Therefore, this Deliverable D7.1 builds on the work presented in D1.3, updating the regulatory analysis for the four countries previously mentioned and incorporating a new country to the comparison, namely Austria, also a partner country in the InteGrid project.

A major difference from this D7.1 to D1.3 is the fact that we focus on InteGrid’s Business Models (BM) instead of the High-Level Use Cases (HLUC) to guide the discussion. Aiming the discussion towards BMs has the benefit of harmonizing the work done in other tasks of WP7 and possibly making the discussion and conclusions more accessible to the reader not so familiar with the technical aspects of the HLUCs. The Business Models, as well as their correspondence with HLUCs, are explained in detail in Section 2.

1.2. Work Package 7 and Regulatory analysis

This deliverable D7.1, along with the CBA plan presented in deliverable D7.3 are the first outcomes of WP7. The objective of this WP7 is to understand the potential business models enabled by InteGrid’s solutions, carry a cost-benefit analysis of these solutions, and research the regulatory layer underlying their implementation in the focus countries.

In this context, the WP7 was structured having the BMs in at the center of the discussion. In fact, the identification of disruptive business models is one of the core objectives of the InteGrid project. Therefore, in this deliverable D7.1, we use the preliminary Business Models to guide the regulatory discussion. We assess what are the current regulatory barriers and drivers for the implementation of these BMs.

This approach does not mean that the conclusions here presented are dissociated from the use case architecture of the project. There is a clear correspondence between BMs and respective HLUCs. Therefore, the regulatory implications for the individual HLUCs are easily identifiable. Moreover, we believe the BMs can be a more accessible approach for the external public, facilitating the dissemination of the regulatory discussion.

The Business Models used in this Deliverable D7.1 are preliminary, defined within InteGrid’s consortium. The Task 3 of WP7 will further analyze them, as well as submit them through a stakeholder consultation using the methodology already presented in the deliverable D1.4 (WP1). Deliverables D7.5 and D7.6 will present the Business Models in more details and presenting the view of stakeholders. Figure 1 illustrated the usage of the BMs within the research carried in WP7.

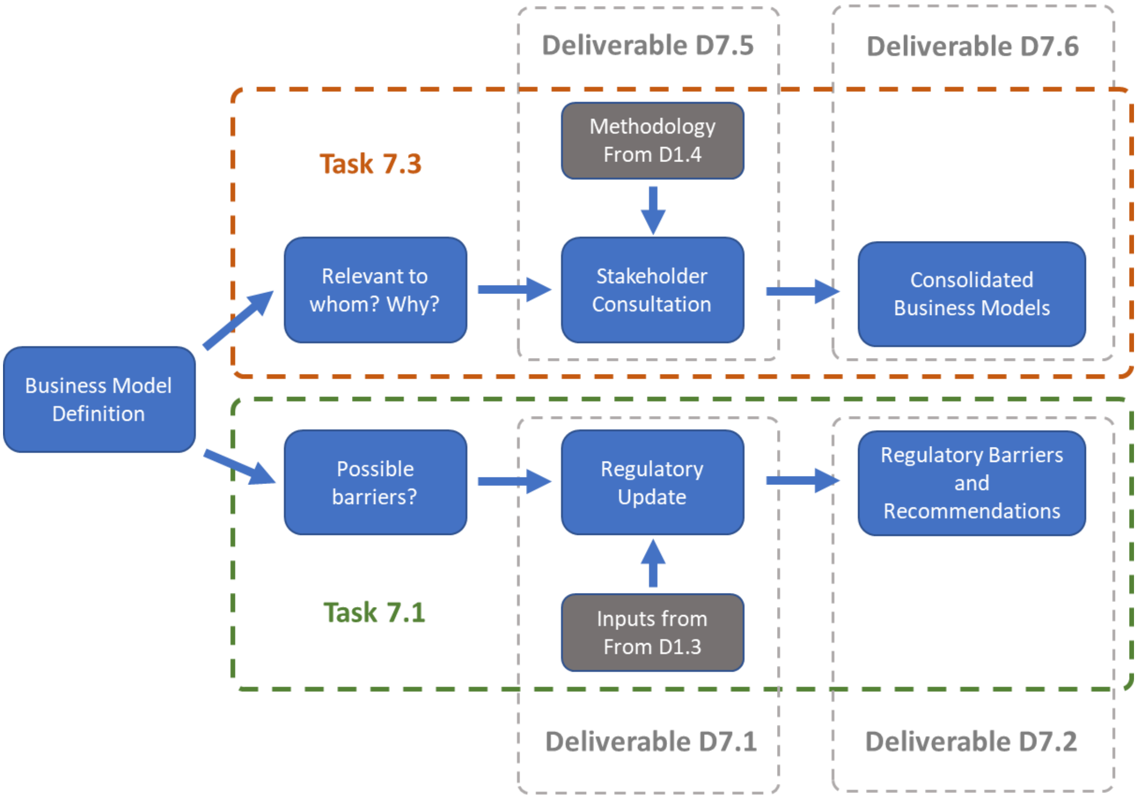

Figure 1: Business Models in Tasks 7.1 and 7.3

1.3. Document Structure

The remainder of this document is organized as follows. First, section 2 presents the preliminary Business Models and their correspondence with the HLUCs. Secondly, section 3 maps all relevant regulatory topics to Business Models and HLUCs. Section 4 goes through each BM, and for each one the most relevant regulatory topics are discussed. The five target countries are compared and a discussion on the barriers for each BM is made. Finally, section 5 concludes.

2. Business models in the InteGrid project

This section analyses the InteGrid Project architecture, its use cases and HLUCs, as well as the Business Models in order to identify the key regulatory topics relevant to the goals of InteGrid activities. These topics are mapped against the aforementioned Business Model, serving as the basis for the subsequent analysis of current regulation relevant to the realization of the InteGrid's goals.

2.1. InteGrid's HLUCs

The InteGrid consortium has identified 12 HLUCs, which are described in further detail in D1.2. These HLUCs have been classified into four different domains, namely: DSO-Grid Operations, DSO-market Hub, Grid Users, and Energy Services. The HLUCs and their corresponding domains are shown in Figure 2.

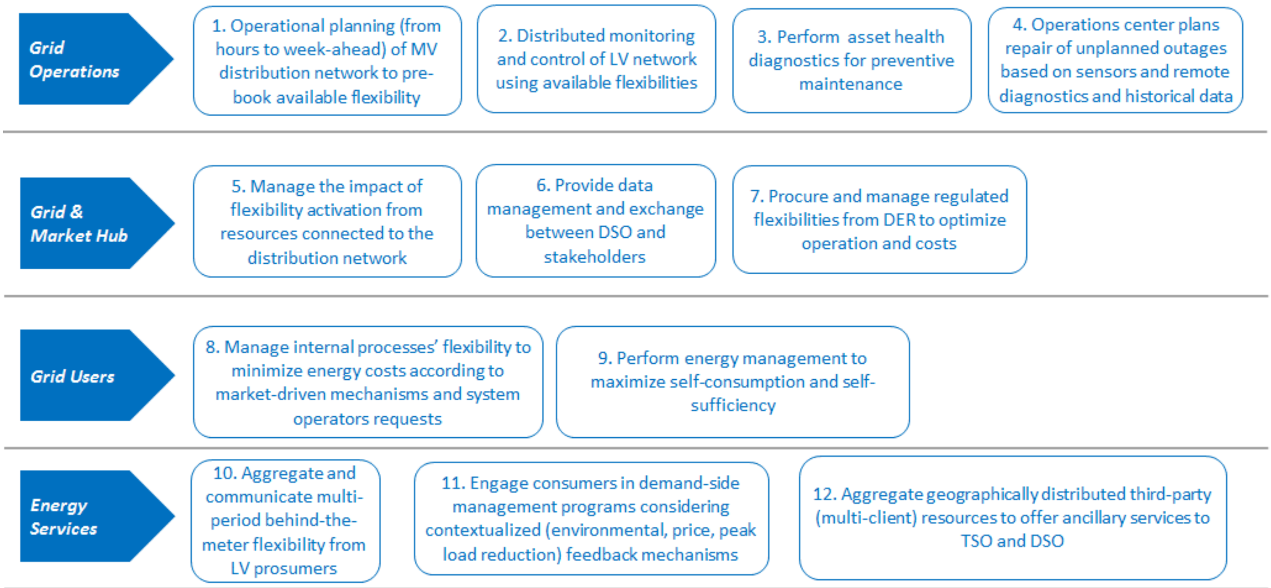

Figure 2: InteGrid HLUCs and corresponding domains

This categorization into four domains will be a key factor in determining the list of relevant regulatory topics and the subsequent cross-mapping. Firstly, some use cases are focused on the internal activities carried out by DSOs in their more **conventional role of network companies**, i.e. grid planning, operation and maintenance. The key innovation in this field lies in how smart grid solutions and the active participation of network users can support and enhance the efficiency of these operations. Consequently, the main regulatory topics for this set of HLUCs that requires analysis are those related to **the economic regulation of DSOs**, i.e. whether their regulation enables and/or encourages the deployment of these advanced solutions.

The second group of use cases constitute a more profound change in the role of DSOs. This is related to the interaction between DSOs and other stakeholders (network users, aggregators, VPPs, or energy services companies) for data exchange as well as the provision of services by DERs, both to the DSO itself (**DSO as a system optimizer**) and to other stakeholders and markets (**DSO as a market facilitator**). Hence, the key regulatory topics for this second group, besides DSO regulation itself (when it is the DSO who contracts these services), are those related to the deployment of **smart metering infrastructure**, key technology for data acquisition and monitoring the service provision, and the mechanisms enabling and governing the **interactions of DSOs with external stakeholders**.

The third group of use cases shifts the focus from the DSOs to the end-users, specifically industrial and residential prosumers. The two HLUCs identified in this category address the **management of internal end-user flexibilities** to minimize the energy bill (or any other goal important to the end user) and provide system services at different levels, if needed, through the intermediation of an aggregator or retailer. These flexible prosumers will respond based on their **retail tariffs** as well as the **market rules** for the provision of **frequency and non-frequency ancillary services**. Moreover, rules for **aggregation and allocation of balancing responsibility** are very important topics.

Lastly, the fourth set of use cases have as primary actors **stakeholders managing and providing flexibility services** in a competitive environment. These include any agent acting as flexibility operator or energy service provider, such as aggregators, retailers, VPPs, ESCOs, etc. These use cases comprise end-user engagement, flexibility management and service provision. Therefore, the major regulatory topics to take into account are those that determine the **capability and incentives for end-users to respond** (smart-metering, tariff design and market rules), as well as the **capability and incentives of flexibility operators and service providers** to deliver their services (aggregation rules, balancing responsibility allocation, market design, or non-frequency Ancillary Services (AS) provision).

2.1.1. From HLUCs to BMs

Business models can generally be understood as a way in which agents generate, perceive and capture value from a product or service. In fact, the literature on business models, although vast, is not precise in defining the concept. (Zott, Amit, & Massa, 2011) reviewed 103 business models publications and showed that more than one third do not define the concept of business model, "taking its meaning more or less for granted", around half of them define it or cite the main components, and only 19% refers to the definition of other authors.

In the context of the power sector, several research projects have used the business model framework to analyze the new business opportunities for utilities, distributed generation and smart grid-related services, as shown in the introduction of this internal deliverable.

In InteGrid, we take the definition used in the Horizon 2020 IndustrE[4] project as a starting point and expand it to fit the several agents considered in the HLUCs of InteGrid. The IndustrE project had the industrial consumer as the only agent. In InteGrid, we apply the same business model concept as in IndustrE, but also applied to System Operators, residential consumers, retailers, aggregators and others.

For the purpose of InteGrid, a business model can be understood as a set of business strategies chosen by a certain agent in order to generate economic benefit. These business strategies can combine multiple

[4] http://www.industre.eu/

instruments, and the economic benefits can be generated by different sources of revenue streams and cost reductions.

The instruments necessary to implement a business strategy vary and may include the provision of services, the selling of a product, or the implementation of a new internal process. The business strategies are then combined into an actionable framework, meaning that the main agent has a common final goal for all business strategies.

Following the above-mentioned definition, this report proceeds on evaluating the HLUCs, identifying business strategies and grouping them into business models. For each business model, a set of parameters is identified, namely main actor, involved actors (partners, customers, etc.), economic benefits for the main actor (revenue, savings), cost structure, etc. For each HLUC, a primary actor is identified. For some HLUCs, the primary actor is the same, and therefore we group them.

We notice, however, that HLUC05 and HLUC06 are not correlated to any BM. These HLUCs act as enablers for other solutions in InteGrid. HLUC05 mainly tests the concept of the Traffic Light System (TLS), which determines if the flexibility can participate in other markets due to congestion in the distribution network. In this sense, this HLUC describes a tool that will be used to enable other BMs[5], as it is the case of BM5 in which the technical VPP offers balancing services to the TSO. In the case of HLUC07, the procedure for the DSO to procure and activate the flexibility is described. It is a HLUC limited to an internal procedure of the DSO, that will enable BM2, in which the DSO uses the flexibility to manage their grid.

Figure 3 presents the five Business Models identified in InteGrid:

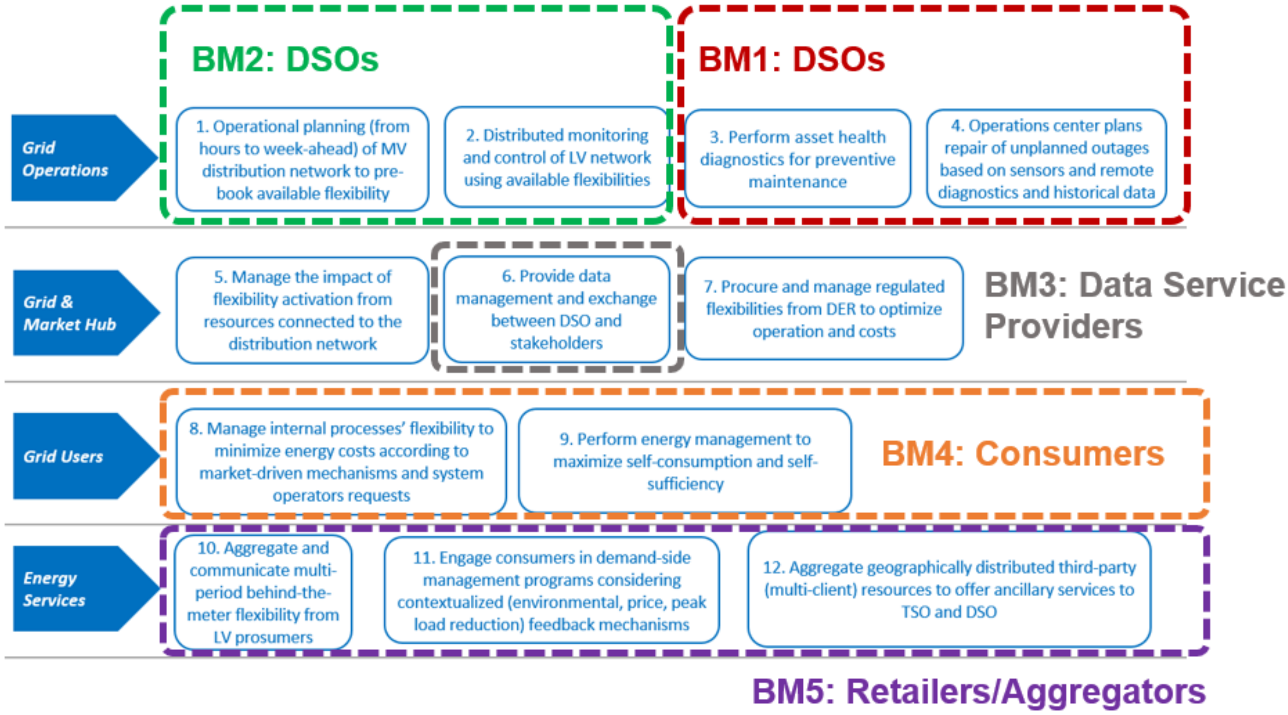

Figure 3: Business Models Mapping

[5] Note that this does not preclude a technology provider from developing and selling this piece of software as a product or service to a grid operator, similarly to other applications such as DMS or estate estimators. However, this is not an innovative business model facing regulatory constraints by itself, which is the focus on InteGrid and WP7 specifically.

Short description of BMs:

BM1 - DSO improves quality of service. The DSO is the main agent. The economic benefit is generated for the DSO in the form of cost reduction by reducing interruptions through improved fault location and improving asset management. The increase in quality of service may lead the DSO to higher incomes, depending on how regulation incentivizes it, and the improved asset management may reduce overall maintenance cost.

BM2 – DSO procures flexibility: The DSO is also the main agent. In this Business Model, the DSO generates economic benefit by procuring flexibility from resources connected at the distribution level. By doing so, costs for the DSO are expected to be reduced and investments to be deferred. Several agents will be involved in this business model, namely DER and consumers connected at the distribution grid.

BM3 – Data Services: In this BM, the Data Service Provider is the main actor. This BM encompasses businesses enabled by the implementation of the grid and market hub (gm-hub). Data service providers will be able to exploit the data in gm-hub for the benefit of consumers, DSOs, TSOs, and aggregators. These agents may pay Data Service Providers for providing analyses that may decrease the energy bill (in the case of consumers), reduce costs (in case of system operators), or increase revenues (for aggregators).

BM4 – Consumer reduces electricity bill: The Consumer is the main agent of this BM. The economic benefit to be generated in this BM is the reduction of the electricity bill for the final consumers. Two sub-business models are identified, one for the industrial consumer (BM4.1) and another for the residential consumer (BM4.2). Other agents will also be impacted by this BM, such system operators (DSO and TSO) that will profit from having additional resources to manage their grids.

BM5 – Creating of value through aggregation: In this Business Model, the Retailers and Aggregators are the main agents. They will be able to create value for end-users by reducing the electricity bill through aggregation and fostering the use of demand flexibility. This BM is divided into four sub-business models. The first one (BM5.1), centered in the retailer (or the BRP) that uses flexibility to reduce imbalance costs. In the second business model (BM5.2), a platform will foster demand-side management by the consumer. The third business model (BM5.3), in which the aggregator is the main actor, explores the idea of aggregation through the Commercial VPP concept. In this BM5.3, the aggregator profits from providing Ancillary Services to the TSO. In the fourth business model (BM5.4), the aggregator explores aggregation through the Technical VPP concept, in which local services are provided to the DSO by the aggregated flexibility.

Table 1: Summary of Business Models

Business Model	Related HLUCs	Main Actor	Benefit	Short Description
BM1	HLUC03; HLUC04	DSO	Lower Interruption Indexes, reduced maintenance cost	The DSO invests in new sensors, monitoring devices and grid automation, improving continuity of supply and reducing maintenance cost
BM2	HLUC01; HLUC02	DSO	Lower operation costs, investment deferral	The DSO uses flexibility from DER to manage the grid. Operation costs are expected to be lower and some grid investments may be deferred

BM3	HLUC06	Data Service Provider	Revenue from services	The new agent "data service provider" can exploit the opportunities created by the gm-hub, a platform that centralizes metering data and acts as an interface for customers and third parties to trade data services.
BM4.1	HLUC08	Industrial Consumer	Reduced electricity bill	By improving electricity management, installing DG and possibly providing grid services, the industrial consumer can reduce its overall electricity cost.
BM4.2	HLUC09	Residential Consumer	Reduced electricity bill	Aided by new technologies such as the HEMS, residential consumers will be able to reduce their energy bill
BM5.1	HLUC10	Retailer	Reduced Imbalance Costs	The retailer uses the flexibility provided by consumers (residential and commercial) to reduce imbalance costs instead of adjusting its position in the intraday market
BM5.2	HLUC11	Platform Owner	Revenues from Ads or Subscription	The platform owner provides users information regarding their consumption, their neighbors’ consumption other data that may engage them into better energy management. This is done through an online platform/app. Revenues come from subscriptions or ads, depending on the strategy adopted.
BM5.3	HLUC12	Aggregator - cVPP	Revenue from Ancillary Services for TSO	The aggregator provides ancillary services to the TSO (main balancing services) through the use of flexibility from multiple sources (DER, DG, industrial and residential consumers).
BM5.4	HLUC12	Aggregator - tVPP	Revenue from Local Services for DSO	The aggregator provides local services to the DSO (main congestion management) through the use of flexibility from multiple sources (DER, DG, industrial and residential consumers).

3. Mapping regulatory topics

The previous subsection has described the four domains in which HLUCs have been classified as well as the associated BMs. Hereafter we map regulatory topics and Business Models, and consequently HLUCs. This exercise is a continuation of the mapping presented in D1.3. Based on that report, three steps were taken in order to reach the updated mapping presented in Table 2.

- **Revisited relevance scoring**: based on the on-going work, not only of WP7, but also the demos and the enhanced understanding of each proposed solutions, some “regulatory topics/HLUCs” pairs were re-evaluated. The re-evaluations were made based on the recent development of the project and a deeper understanding on the specific implementation for each HLUC. For example, balancing and intraday market design was deemed very relevant for HLUC08, but now it is understood that these HLUC, and consequently BM 4.1 will have a greater focus on processes happening behind the meter than the direct provision of energy and services to the grid.
- **Consideration of Business Models**: besides the HLUCs, the BMs are also shown, considering that they will guide the discussion in this Deliverable.
- **Assignment of regulatory topics to the most relevant BM**: In this exercise, the most relevant BM was identified for each sub-group of regulatory topics. In Section 3, each regulatory topic will be discussed within the relevant Business Model. When a regulatory topic is considered relevant for multiple BMs will fallow. As shown in Figure 1, there is a clear correlation between BMs and HLUCs.
- **Exclusion of Business Model 5.2 from the regulatory analysis:** As mentioned in Section 2.1.1 and in Table 1, Business Model 5.2 is based on engagement platform developed in HLUC11. This BM has a very different nature from the others, being mainly a digital business rather than an energy business. The proposed platform shows relevant information to the consumer about his to promote engagement in energy savings. An example of an existing company operating a similar business is the American company Opower. Founded in 2007, the company started by sending “reports and alerts, via mail and email, that compare consumers’ energy use to their neighbours’ and provide targeted energy saving recommendations” (United States Securities and Exchange Commission, 2014). Revenues are generated by selling subscriptions of the software to utilities. In this sense, business under BM5.2 is mostly digital. The most relevant regulatory topic could be data protection, under the discussion of data management. Therefore, in this report we do not present a specific discussion on regulatory topics for this BM5.2. For further details on this BM, please refer to Deliverables D7.5 and D7.6 (upcoming).

In section 4, each BM is presented, the regulatory topics are discussed and a discussion on the possible barriers is made. Therefore, we describe hereafter the reasons for assigning each regulatory topic to each Business Model.

- **DSO Economic Regulation**: This group of regulatory topics is clearly linked to the BM developed by the DSO, namely BMs 1 and 2. On one hand, revenue regulation will play an important role for BM2, as DSOs may substitute grid reinforcement investments for flexibility procurement. On the other hand, output-based regulation and incentives for innovation are key for the development of BM1, as in this BM the DSO aim to improve continuity of supply, often incentivized by regulation through output-based mechanisms.

- **DSO as a system optimizer and market facilitator**: The regulatory topics in this group are mostly relevant for DSO's business models as well. In BM2, the network charges, connection schemes and DER provision of ancillary services are discussed. For the success of BM2, DER has to be able to provide their flexibility. Network charges and connection schemes will set rules and incentives for DER, while the regulation on DER providing ancillary services (both frequency and non-frequency AS) will determine if the DSO will be able to procure such services in the first place. Nevertheless, these topics are also relevant for BM4 and BM5. The only topic of this group discussed outside the two DSO's BMs is the DER aggregation and VPPs, clearly suitable for discussion under BM5.
- **Retail Tariffs and Metering**: This group of regulatory topics can be divided into two, one being mostly relevant for consumers (BM4) and the other relevant to several different BMs. For consumers, the design of regulated tariffs and self-consumption regulation is key. Tariffs will determine the types of price signals the consumer will be able to react to, while self-consumption regulation will set the limits and for DG installation. Smart meters deployment, on the other hand, is a topic that concerns almost all BMs (except BM1), as it is a fundamental requirement for nearly all solutions proposed by InteGrid. Nevertheless, we decided to discuss it in BM4, which addresses end users aspects. Data management regulation is also important across different BMs. However, it seems clear that it will have most implications within BM3, which deals precisely with the use and treatment of metered data.
- **Aggregation and Market Design**: This group of topics is entirely treated under BM5. All the topics concerning aggregation will impact both the retailer that aggregates to reduce imbalance costs, and the VPP that offers services to grid. The design of balancing and intraday markets are important for both BM5.1 (retailer) and BM5.4 (commercial VPP).

Table 1 provides a visualization of the mapping described above. The values given to each pair of HLUC/Topic follow the same logic adopted in D1.3: 0 - No relation; 1 - Indirect (or implementation-dependent) relation; 2 - Direct relation. Dashed lines indicate sections that were reviewed from D1.3 and change values. Solid-colored lines are a visual aid to help locate the most relevant topics for each Business Model.

Table 2: Mapping relevant regulatory topics to InteGrid HLUCs
(0 - No relation, 1 - Indirect (or implementation-dependent) relation, 2 - Direct relation)

			Most relevant BM	Functional Domain								
				DSO Domain - Grid Operations				gm-hub	Grid Users		Energy Services	
				HLUC01	HLUC02	HLUC03	HLUC04	HLUC06	HLUC08	HLUC09	HLUC10	HLUC12
				BM2		BM1		BM3	BM4.1	BM4.2	BM5.1	BM5.3/5.4
DSO Economic Regulation	Revenue regulation	Remuneration formula	BM2	2	2	2	2	0	1	1	1	1
		CAPEX-OPEX treatment		2	2	2	1	0	1	1	1	1
		DER-driven costs		2	2	0	0	0	0	0	0	0
		Regulatory benchmarking		2	2	1	1	0	0	0	0	0
	Output-based incentives	Continuity of supply	BM1	0	0	2	2	0	0	0	0	0
		Energy losses		1	1	0	0	0	0	0	0	0
		Others		1	1	1	1	1	0	0	0	0
	DSO incentives for innovation	Existence of incentives	BM1	2	2	2	2	0	0	0	0	0
		Design of incentives		2	2	2	2	0	0	0	0	0
DSOs as a system optimizer and market facilitator	Network charges for DER	Connection charges for DG	BM2	2	2	0	0	1	1	1	1	1
		Use of system charges for DG		1	1	0	0	1	0	0	0	0
	Connection schemes	Size limitations per voltage level	BM4	2	2	0	0	0	1	2	1	0
		Single-phase/three-phase LV connections		0	2	0	0	0	0	2	1	0
	DER provision ancillary services	Distribution non-frequency AS	BM2	2	2	0	0	0	2	1	2	2
		DSO-TSO interaction		0	0	0	0	0	2	1	2	2
	Business models for DER	DER Aggregation and VPPs	BM5	1	1	0	0	0	1	2	2	2
		Storage ownership		1	1	0	0	0	1	2	0	1
Retail tariffs and metering	Smart meters	Functionalities	BM1	1	1	0	2	2	2	2	1	1
		Roll-out model		1	1	0	2	2	1	2	1	1
	Data Management	Metering activity responsibilities	BM3	1	2	0	2	2	1	2	1	1
		Metering data management		1	2	0	2	2	2	2	1	1
	Design of regulated tariffs	Power system cost break-down	BM4	0	0	0	0	1	2	2	1	0
		Regulated tariff structure		0	0	0	0	1	2	2	2	0
		Tariff design responsibilities		0	0	0	0	1	1	1	0	0
	Self-generation regulation	Self-generation scheme	BM4	0	1	0	0	1	2	2	2	0
		Other limitations or conditions		0	1	0	0	1	2	2	2	0
Aggregation and market design	Aggregation	Aggregation rules	BM5	0	0	0	0	0	1	1	2	2
		Balancing responsibility		0	0	0	0	0	1	1	2	2
	Balancing/Intraday market design	Market scheduling	BM5	0	0	0	0	0	1	0	2	2
		Gate-closure		0	0	0	0	0	1	0	2	2
		Balancing product definition/pricing		0	0	0	0	0	1	0	2	2
		Imbalance settlement		0	0	0	0	0	1	0	2	2
		Market access rules		0	0	0	0	0	1	0	2	2
		Open for demand/storage		0	0	0	0	0	1	0	2	2

4. Update on current regulation

In this chapter, an update is made of the existing regulation in five target countries of this report, namely Austria, Portugal, Slovenia, Sweden and Spain. Compared to the countries analyzed in D1.3, Austria is added to this report, as it is also a country hosting an InteGrid partner.

For the completion of this analysis, a questionnaire was circulated among the partner DSOs and research institutions of the project. The questionnaire used was a continuation of the one used in D1.3, with the addition of questions and the revision of the questions previously answered for Task 1. A blank copy of the questionnaire is included as an annex of this report.

Additional sources of information were also used when necessary, as results from previous European projects like GRID4EU, evolvDSO, and SuSTAINABLE, as well as reports and publications from NRAs, DSOs, associations, EU institutions and academia.

This chapter is structured following the order of Business Models. For each BM, a description of the BM is presented, followed by the analysis of the main regulatory topics for that BM.

4.1. Business Model 1 - DSO improves quality of service

In BM1, the DSO is the main agent, and the main economic benefit for the DSO is the reduction of maintenance cost and the improvement in the continuity of supply indicators. The DSO achieves these objectives by improving fault detection and asset monitoring and maintenance. This BM is carried out inside the premises of the DSO with reduced interaction of external stakeholders, and it is derived from HLUC03 and HLUC04.

The goal of HLUC03 is to increase the distribution grid reliability, avoid fatal errors, reduce maintenance costs, and postpone unnecessary local maintenance tests by using big data analytics with event-driven maintenance for self-monitored equipment. Vital information for important network assets (e.g., the historical oil temperature of transformers, number of short-circuits sustained, number of changes in control) is collected using the advanced metering infrastructure and processed through tools that can diagnose and assess the current technical conditions and trigger probabilistic alarms to schedule maintenance actions.

The main objective of HLUC04 is to schedule the repair actions of unplanned outages based on pre-fault data collected from sensors, on remote equipment diagnostics, and on historical data collected from smart secondary substations. The expected result is a reduction in the outage time and, consequently, an improvement in the SAIDI and CAIDI indexes. Information collected from multiple sensors is used to schedule repair actions supported by intelligent tools and that aim at improving the relationship with consumers.

Therefore, for the development of this BM, regulation should provide the appropriate incentives for improvement in continuity of supply indexes. Otherwise, DSOs may see little incentive to deploy the required technologies. Nonetheless, output-based mechanisms with performance-based rewards and penalties with respect to the base allowed revenues seem to be a common type of incentive for this purpose. To incentivize quality of supply, for instance, many European countries adopt a combination of rewards and penalties (CEER, 2016a). Additionally, DSOs may also be incentivized through special mechanisms to deploy innovative assets, such as the enhanced monitoring and automation devices required for this BM (at least on a temporary basis for learning purposes). Finally, in addition to grid monitoring devices, smart metering data could be potentially used to improve fault location processes in this BM1[6]. Additionally, the deployment of smart meters, the DSO role, and the meters functionalities could be a relevant issue for a similar BM (please refer to Section 4.4.3).

4.1.1. Output-based Incentives

The incentive-based regulation provides a stronger incentive for cost reduction if compared to cost-plus remuneration method (also called cost-of-service regulation, or rate-of-return regulation), the most traditional mechanism before the liberalization of power sectors. It is now the standard among European DSOs, at least for OPEX regulation. A recent survey with 24 EU Member States showed that only 4 uses a Rate-of-Return regulation for electricity distribution (CEER, 2017a). Nevertheless, incentive regulation is also expected to evolve from a completely input-based model to one that also includes output based indicators (Cambini, Croce, & Fumagalli, 2014). While pure input-based regulation usually focus only on setting dynamic targets on OPEX or TOTEX (mechanism also known as RPI-X), output-regulation also considers indicator in different categories such as safety, reliability, conditions of connection, environmental impacts and others.

These output indicators may be used simply for monitoring purposes, to evaluate the impact of DSO investment plans, or directly to set reward/penalty schemes based on the DSO performance with respect to the corresponding indicators. Conventionally, output regulation at the distribution level has mainly focused on continuity of supply and energy losses.

In fact, it can be seen that this is common practice in the target countries. On the one hand, Spain, Portugal and Sweden expose DSOs to a bonus-malus mechanism based on targets for different continuity of supply indicators such as SAIDI, SAIFI not have a specific economic incentive defined as a reward/penalty scheme. Instead, reliability-related target indicators are defined in the regulation. These levels may be considered as minimum desirable reliability levels that DSOs should comply with, without specific incentives and penalties associated. Nonetheless, regulators do monitor and publish these indicators following a consistent methodology.

Apart from energy losses[7], none of the five countries reported having other relevant output-based mechanisms, except for innovation, as described below.

[6] Smart metering is mainly used for enabling advanced tariff schemes, provision of consumption information for end-users, and billing purposes. However, smart meters may also provide event-based information that could be helpful to locate grid faults. This is commonly known as the “last gasp” function, which essentially consists in each smart meter sending an alarm in case no voltage is observed by the meter.

[7] Despite the fact that energy losses are a relevant performance indicator for DSOs, loss reduction is not a main goal within this BM. Therefore, it is not discussed in further detail herein.

4.1.2. DSO incentives for innovation

The main aim of innovation incentives is to promote the deployment of experimental technologies that have the potential, usually yet unproven, to enable a more efficient grid planning and operation. These mechanisms intend to be temporary until the referred solutions can be seen as an additional tool for DSOs on the same level as conventional grid investments or “copper-and-iron” solutions, which will still be the backbone of distribution systems. As the expected benefits from innovation can be only seen after a certain time period, regulators should set incentives considering the long-term efficiency brought for consumers (CEER, 2018).

Incentives for innovation and smart grid deployment are extremely important for BM1, as they will determine if implementing new asset monitoring technology is economically interesting for the DSO or not, at least until the performance of such technologies is proven.

Spain does not have dedicated incentives for that matter. However, smart grids are subject to a regulatory life of 12 years, and this accelerated depreciation period can be considered an incentive. In Portugal, a dedicated scheme gives the DSO the minimum between an extra WACC of 1.5% on top of the regular regulatory WACC for a period of six years and 50% of the benefits that the innovative project delivers to the Electricity System. The DSO needs to submit an application to the regulator to have the project accepted as innovative. The project is considered innovative if it meets some of the requirements, such as promote energy efficiency, reduce losses, or promote demand-side management among others.

In Slovenia, if the DSO realizes the investments in smart grids that meet the requirements set out in the methodology, a single incentive is acknowledged amounting to 3% of the current value of the asset in the year in which the asset was put into service (Agencija za energijo, 2017).

In Sweden and Austria, no special incentives differentiating between regular and “smart” expenditures are identified. Thus, R&D and smart expenditures would be considered as operational costs with efficiency demands on them annually.

4.1.3. Drivers and Barriers

In the core of this Business Model are HLUCs 03 and 04. The former one focus on asset management in MV/LV and HV/MV substation equipment, in particular the definition of preventive maintenance planning of network assets based on health indicators constructed from monitored data. The latter focus on the improvement of fault location, reconfiguration and repair actions of unplanned outages using sensor data, historical information and remote equipment diagnostics. In both cases, the main aim is to enhance grid reliability through the deployment of innovative monitoring and automation technologies. Therefore, for the future implementation of Business Model 1, it is key that DSOs have the specific incentives to carry the necessary investments. These incentives comprise both those related to the investment in innovative equipment and those related to the improvement of continuity of supply.

The literature and the experience in some countries show the expected benefits of moving from a complete input-based regulation (e.g. RPI-X) to one that contains more output-based incentives for specific objectives. The UK was the first country to clearly adopt a more output-based regulation with the RIIO[8] scheme in 2010 (Ofgem, 2010). This scheme identified outputs to be measured and controlled for six categories, namely customer satisfaction, safety, reliability and availability, conditions for connection, environmental impacts, and social obligation. In order to incentivize these objectives, several tools are available under RIIO, and an assessment for each output is carried so a tailor-made incentive is set. For instance, an output incentive may be symmetric or not, as it is the case for several countries in InteGrid. In RIIO, incentives may be also marginal or not, meaning that rewards/penalties may vary according to the size of the incremental variation from the performance level predefined. Additionally, revenue incentives may be applied automatically or not, in this case following an assessment to verify if the delivery of outputs at a performance level different to that assumed in the price control (or not) are consistent with long-term value for money before making any potential changes to revenue. Finally, output incentives may be set as financial incentives (considering the characteristics above) or reputational. For distribution companies, RIIO is still in its first regulatory period (2015 to 2023) (Ofgem, 2013). The outputs reported by the DSOs are reported online, side-by-side, by the regulator Ofgem[9].

Another country that also adopted a more output-based regulation is Italy. Similar to Spain and Portugal, Italy has adopted an output-based mechanisms focus on the continuity of supply through a bonus-malus mechanism (ARERA, 2015). The incentive over the SAIDI was first introduced in the year 2000. Considering the long existence period, (Cambini, Fumagalli, & Rondi, 2016) study how the quality-related incentives has impacted on cost-efficiency and performance of companies, and conclude that a regional differentiation is necessary. Otherwise, regulation may be used more to reward good quality performance than allocate resources where quality improvement is hard to achieve, as the authors show to be the case in Italy (Cambini et al., 2016).

Regarding innovation incentives, a key discussion in Italy was how to move "*from input-based demonstration to output-based deployment*". This implied how to go from a system based on an extra WACC remuneration (+2% for 12 years) for pre-approved demonstration projects towards a regulatory framework where DSO remuneration was affected by the performance with respect to a wider range of output indicators, such as observable DG capacity or increased hosting capacity for DG in the MV grid (Schiavo, 2018).

In this context, in the five focus countries of this report, most of them already have some form of output-based incentive in place, mainly on quality of supply. This is positive thing considering the implementation of Business Model 1. If DSOs have specific incentives to improve quality of supply, they will feel more inclined to carry the necessary investments in innovative asset management technology. On the other hand, it is also important to provide DSOs with incentives for innovation. To this end, Portugal and Slovenia are already providing such incentives directly.

Beyond the implementation of output-based incentives for reliability and the existence on incentives for innovation, a further analysis should be on the fitness of these incentives for the implementation of the activities of Business Model 1. A similar reason provided by (Cambini et al., 2016) for the Italian incentives has to be carried out for the countries of InteGrid so recommendations can be derived from. This implies

[8] RIIO stands for Revenue using Incentives to deliver Innovation and Outputs
[9] https://www.ofgem.gov.uk/data-portal/network-indicators

assessing whether the incentives seen by DSOs are strong enough to drive a change and whether these are aligned with the final goal that is pursued.

Table 3: Summary of Output-based incentives and incentives for innovation

	Output-based incentives	**Specific Economic Incentives for Innovation**	**Description of the Economic Incentive for Innovation**
	Losses, Quality of Supply	Extra remuneration	Minimum between an extra WACC and 50% of the benefits that the project delivers to the Electricity System. The extra WACC is 1,5% of the project's value, for a period of 6 years.
	No specific output-based incentive. Nevertheless, the DSO is obliged to purchase losses, whereas they are only compensated for a reference level of losses, acting as an output-based incentive.	Extra remuneration	3% of the current value of the asset in the year in which the asset was put into service
	Losses, Quality of Supply	Accelerated depreciation	12 years of depreciation
	Quality of Supply	No dedicated incentives for innovation	N/A
	No specific output-based incentive. Nevertheless, the DSO is obliged to purchase losses, whereas they are only compensated for a reference level of losses, acting as an output-based incentive.	No dedicated incentives for innovation	N/A

4.2. Business Model 2 - DSO procures flexibility

This BM encompasses business strategies from HLUC01 and HLUC02. The main aim of this business model is to reduce DSO's investment costs thanks to a more active grid operation, i.e. by using the flexibility provided by resources connected to the distribution grid for grid management purposes. More specifically, this BM focuses on the operational planning stage, when available flexibilities are booked, as well as the remedial actions and flexibility activation when this is needed in real-time.

For the development of this BM, several regulatory topics are relevant, as shown in Table 2. In this section, we focus on three of them, considered essential for this particular BM, namely revenue regulation for DSOs, network charges for DER and DER provision of ancillary services:

- Revenue regulation is essential to determine to what extent DSOs are encouraged to resort to distributed flexibilities in order to defer grid investments or, on the contrary, whether they have strong incentives to increase their asset base as this will result in higher profits. The remuneration method (WACC or others) and the remuneration level play an important role in setting these incentives.
- Network charges, and more specifically grid connection charges, are an important topic when incremental investments would be driven by the connection of new grid users. Being this the case, the applicants for connection may be forced to cover the full expenses of the connection, thus eliminating any potential gain from the use of flexibility.
- Lastly, in order to contract flexibility from resources at the distribution network, regulatory mechanisms enabling DER to provide ancillary services to TSOs and DSOs need to be in place.

It is clear that DSOs will assume new roles in the coming years and will conduct a more active management of the grid. As detailed above, this BM is basically the DSO that buys flexibility from DER and actively manages the grid using these services. In some sense, the DSO will get closer to the way TSOs manage their grids. DSOs may no longer over-invest in networks, also known as the "fit-and-forget" approach in distribution, or the "copperplate" approach in transmission. Instead, DSOs will balance network investment with local service acquisition in order to reach a more efficient grid cost. Figure 4 illustrates this shift.

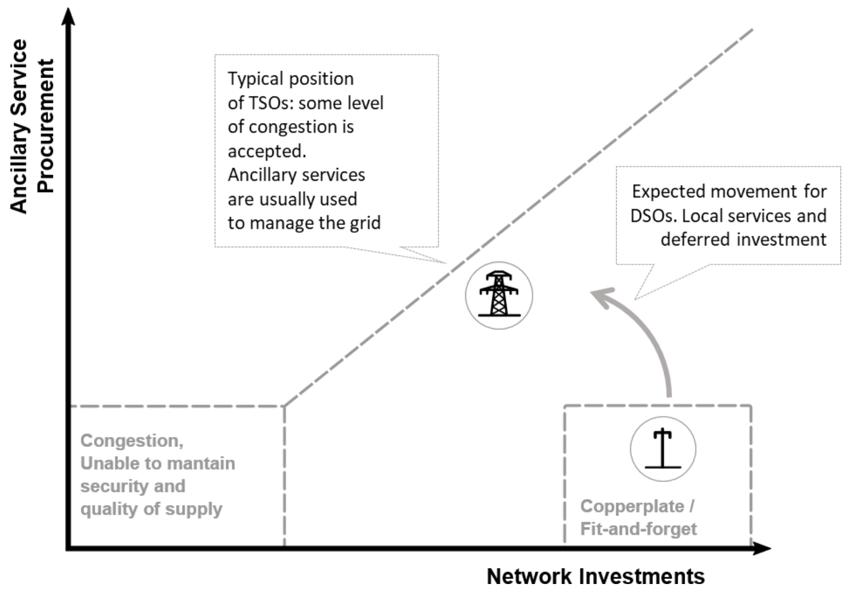

Figure 4: Expected movement for DSOs

In this context, regulation has an important role on allowing DSO to carry these changes in the way the grid is managed. For instance, the "Network Investment" axis of Figure 4 is heavily determined by the incentives provided by revenue regulation. On the other hand, the movement on the "Ancillary Service Procurement" axis will depend on how the regulation is set for DERs to provide their flexibility to the grid. Apart from that, other topics concerning the incentives for DER also apply, such as network charges, connection schemes and, potentially, smart meters roll-out (addressed in section 4.4.3).

4.2.1. Revenue Regulation

As discussed above, this BM requires DSOs to resort to flexibilities at the operation stage (increase in OPEX) in order to reduce investment costs (decrease in CAPEX), provided this is more efficient over the long-term or when grid reinforcement would be very hard to carry out or take a long time. Most of the incentives for DSOs to invest or not in new assets come from revenue regulation. This includes, among others, aspects such as the remuneration formula, the treatment of CAPEX-OPEX, and regulatory benchmarking.

As shown in D1.3, all four focus countries in InteGrid are under the paradigm of incentive regulation for their distribution companies. This is also true for Austria, the newly included country in this analysis. Table 4 shows the form of price control in the five countries, as well as how CAPEX and OPEX are treated and the method used for calculation of the rate of return. It can be seen that all the focus countries, except for LV in Portugal, treat CAPEX and OPEX separately. This, together with the absence of mechanisms enabling DSOs to purchase flexibility services (see section 4.2.4), hints that current regulation may still not be fully fit to promote this BM. On the other hand, most regulators apply the WACC methodology to remunerate the return on grid investments, being Spain the only exception among target countries[10].

Table 4: Remuneration Characteristics

	Form of price control	**Treatment of CAPEX and OPEX**	**Method used for Calculation of the Rate of Return[11]**
	Price Cap	Separately for the High and Medium Voltage concession. TOTEX (equal) approach with price cap for Low Voltage	WACC
	Revenue Cap	Separately	WACC
	Revenue Cap	Separately	No WACC is used. RoR is determined as the 10-year maturity State Bond plus 200 basis points (2%)
	Revenue Cap	Separately	WACC
	Price Cap	Separately	WACC

[10] Network regulation was changed in 2013 within a wider effort to reduce regulated costs in order to tackle the tariff deficit problem faced by the Spanish system.

[11] (CEER, 2017a)

The length of the regulatory periods instead differs from country to country, ranging from 3 to 6 years, as shown in Figure 1.

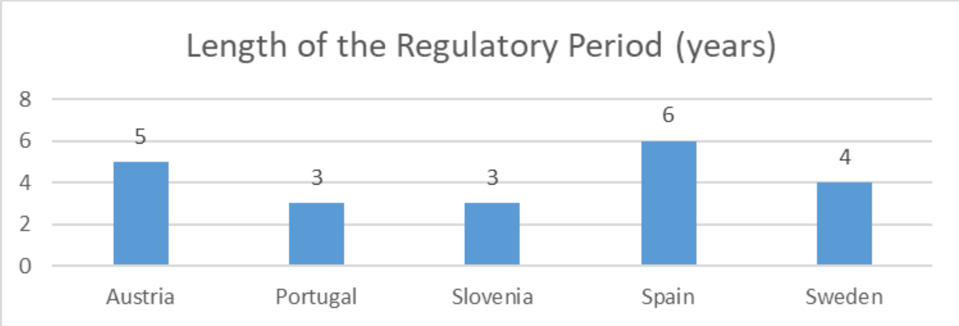

Figure 5: Length of the Regulatory Period (years)

In principle, longer regulatory periods should be desirable to encourage DSOs to adopt a long-term vision necessary to defer grid investments using flexibilities, assuming that the overall revenue regulation also follows a long-term perspective and avoids frequent changes that may cause regulatory uncertainties. Nonetheless, this topic should be considered jointly with other regulatory details such as whether DSOs are mandated to submit forward-looking investment plans or how often the regulatory asset base (RAB) is updated. Table 5 presents a summary of the need for DSOs to present investment plans and how the RAB is updated.

Table 5: Investment Plans and RAB update. Source: Regulatory Questionnaire and (CEER, 2017a)**.**

	Do DSOs have to submit investment plans?	**Is the RAB adjusted during the regulatory period?**	**If the RAB is adjusted during the regulatory period, how often (e.g. Annually).**	**Does the adjustment affect net book values by accounting for new investments and/or depreciation?**
	Yes. Investment plan must be submitted and approved by the Portuguese government.	Yes	Annually for the allowed revenues for year t, after 2 years the real values are considered in the adjustment of the allowed revenues for year t.	Yes. Each year the RAB allowed for year t is adjusted in order to consider new investments, write-offs and depreciation.
	Yes. Investment plans are required and must be approved by the Ministry of Infrastructure	Yes	Annually	Yes

	Yes. DSOs should submit investment plans yearly.	Yes	Annually, with a 2 years delay (please refer to the box below)	Yes. New assets are valued at the average of actual costs and unit standard costs set by regulation
	Yes, but investment plans submitted by the DSO are a prognosis.	Yes	Twice annually	Yes for ICT, but norm costs are used for all other CAPEX.
	No, DSOs do not submit investment plans.	Yes	The investment factor updates CAPEX (also RAB) annually on book value basis, t-2 time lag. However, a recalculation method takes care of the time-lag.	Yes. Net book values will change due to new investments and depreciation. Investment factor uses recent book values.

To determine efficiency targets in the remuneration formulas, regulators can opt to use some sort of regulatory benchmarking. In the case of the five analyzed countries, benchmarking is used in three of them. In Portugal, efficiency targets applied to the HV/MV OPEX and to the TOTEX of LV networks are determined by the use of Data Envelopment Analysis (DEA) and Malmquist index. Sweden also makes use of DEA to set part of the efficiency target applied over OPEX[12]. Benchmarking is also used in Sweden to set continuity of supply targets. In Austria, both DEA and Modified Ordinary Least Squares (MOLS) techniques are used to set the individual productivity targets for DSOs. In all these cases, frontier-benchmarking models based on historical data are used to assess the efficiency of DSOs. Whilst this is common practice across regulators, it is arguable whether such an approach would be enough to promote innovative practices from DSOs such as the one considered in BM2.

Table 6: Use of Benchmark to set efficiency targets

	Use of Benchmark to set efficiency targets	**Technique**	**Sample**
	Yes	DEA and Malmquist index	International
	No	NA	NA

[12] A "building block" approach is used in Sweden, and therefore OPEX and CAPEX are remunerated differently. Controllable costs are subject to an "efficiency requirement". Since the beginning of the second regulatory period, this factor is the sum of a general factor for all DSOs (1%) plus a benchmarking-based specific factor for each DSO (from 0 to 0.82%).

	No	NA	NA
	Yes	DEA	National
	Yes	DEA and MOLS	National

4.2.2. Network Charges for DG

If revenue regulation influence the incentives DSOs have to carry investments (the X-axis on Figure 4), it is also important to consider the incentives DER will have to provide services to the grid. This aspect is key for the implementation of BM2, particularly in the case of connection charges, since it determines the extent to which DSOs would be encouraged to count on the provision of services by DER (the Y-axis in Figure 4). This is because in case new grid users have to pay the full costs of connection, DSOs would not benefit from a reduction in connection costs. Moreover, carrying out significant reinforcements may hamper the profitability of new DG projects and delay the time of grid connection. Hence, alternative mechanisms, together with a more flexible grid access as discussed in section 4.2.4, can enhance the value of this BM.

As shown in D1.3 (InteGrid Project, 2018), all four countries then analyzed applied a deep[13] connection charge for DG, meaning that the user being connected may have to the pay the reinforcement to the grid if these are needed[14]. Regarding Use-of-System (UoS) charge, half of the countries have reported to apply it to DG. Table 7 presents the update information for the four countries previously presented in D1.3 and Austria. For the latter country, it is important to notice a difference in the concept of deep charge for connection. In Austria, users are charged a “system provision” cost, which reflects the cost of power deployment of the DSO (as for the reinforcement of the grid), and a “system admission” costs, relative to the connection itself. The former is set and published by the regulator, while the latter is set and negotiated by the network operator (REF-E, Mercados, & Indra, 2015). In this sense, in Austria users pay a deep connection charge, but the reinforcement cost is not relative to the new connection specifically but is a share of all expected reinforcement costs due to new connection.

For the countries in which UoS is paid by DG, an important aspect is the type tariff used, as the different types will provide different incentives for producers. Tariffs are usually set as flat-tariff, Time-of-use (ToU) tariffs, or dynamic tariffs. Table 7 also presents the type of tariff used by countries.

[13] Connection charges are usually classified into three categories: shallow, shallowish and deep. In a shallow regime, the user is exempted of any grid cost. In the shallow scheme, user should bare the cost of the connection from the user’s premises to the connection point. In the deep model, users have to pay the equipment to the connection point plus any reinforcement that is necessary upstream due to the new connection (Pérez-Arriaga, 2014).

[14] Although connection costs are defined as deep by the regulation, it could be possible that some governments subsidize part of them for some or all grid users.

Table 7: Network charge for DG

	Connection Charge		Use-of-System for DG		
	Type of Connection Charges	Calculation	Applicable for DG?	Metric	Type of tariff
	Deep	Case-by-case	No	N/A	N/A
	Deep	Standard formula	No[15]	N/A	N/A
	Deep	Case-by-case	Yes	Energy	Flat-tariff
	Deep	Case-by-case[16]	Yes	Energy and Capacity	ToU and Flat-tariff
	Deep (provision and admission)	Standard for provision and case-by-case for admission)	No[17]	N/A	N/A

Regarding the type of tariffs applied to DG, in Portugal, network Time-of-Use tariffs are applied to generators connected at Distribution level, but they only pay transmission charges. In Austria, the flat-tariff refers only to the network losses and ancillary services are charged for generators over 5MW of installed capacity.

4.2.3. Connection schemes

Regarding connection schemes, two aspects were compared among the five countries, namely size limitations per voltage level and single-phase/three phase requirements for LV connection. These topics were selected due to their relevance when determining the impact of new users on the grid. Deliverable D1.3 detailed both topics for Portugal, Slovenia, Spain and Sweden. It showed also that this topic is fairly harmonized across the four countries. In general, there are no explicit size limitations for connection per voltage level[18], but rather a decision of the DSO based on the conditions of the local grid.

From the publication of D1.3 to date, rules have not changed in the four countries. In Austria though, the size limits for each voltage levels are clearly established:

- < 100 kW: LV level
- > 100 kW: directly connected at transformer station MV/LV
- > 400 kW: MV level (10 to 30 kV)
- > 5 MW: HV level (110 kV)

[15] DGs connected directly to the grid are exempted of UoS. UoS is paid only for the energy withdrawn from the system, therefore only the consumption of a prosumer is charged.
[16] In Sweden, connection charges are calculated by the DSO, but consumers can ask a revision by the regulator if they think the calculated charge is not appropriate.
[17] No network UoS are applied to DG in Austria. Although, for DG with a capacity of more than 5 MW, network losses and ancillary services are charged.
[18] In Spain, however, there are limits. In the LV level, for instance, the upper limit is 100 kW. For more detailed information, please refer to D1.3.

- > 200 MW: EHV level (220 to 380 kV)

There are no differences between generators and consumers in terms of size in Austria.

Regarding the type of connection, if three-phase of single phase, no relevant changes happened since the publication of D1.3. In general, small users connected at the LV level have a single-phase connection, while bigger users have a three-phase connection. In Spain, for instance, this limit is 5kW for DG. In Austria, usually new LV connections are three-phase, with a maximum asymmetry of 3.68 kVA is permitted

4.2.4. DER provision of ancillary services

A crucial aspect for DSOs to be able to procure services from DER is foremost if regulation actually allows it or not. The review of the situation in the target countries reveals that DER provision of ancillary services is yet new, and mostly there are no specific regulation, especially for non-frequency ancillary services provided to the DSO.

DER provision of services for TSOs (frequency ancillary services) is already done in some countries. In Spain, in principle, the TSO can procure services connected to the distribution grid, if they are technically approved by the TSO. However, there is a minimum power to be offered for frequency regulation, for instance. Participation in the frequency regulation markets in Spain is aggregated, meaning that a company offers the frequency restoration capabilities of several generating units. The minimum per company is 10MW. Therefore, the TSO could procure services at the distribution grid in case of a big installation or an aggregator.

Similarly, in Austria and Slovenia the TSO can procure/use services from all voltage levels. In Austria, before the TSO will procure a service (independent of the voltage level) a service provider must complete a prequalification procedure (unique and repetitive) and in this prequalification procedure the DSO is included.

(Gerard, Rivero, & Six, 2016) shows that AS procurement from DER is also possible in other countries such as Belgium and Finland. These are balancing services, that in most countries there are no restriction on which kind of generator can participate, making possible for DER offer services in such markets.

Figure 6: Procurement mechanisms for AS provided by DER. Source: (Gerard et al., 2016)

Although TSOs are able to procure services from DER in several countries, it is important to highlight that this procurement is mostly limited to DG and it is not open to demand in all countries. This topic is treated in section 4.5.4, on the regulation for aggregation.

If TSOs are already able to procure services from DER, for DSOs, however, the provision of services is much more limited. The Deliverable D1.3 already informed that distribution non-frequency AS provision is still very incipient in InteGrid's countries. Still after this update and including Austria in the sample, none of the countries have local markets for DSOs to procure services from DER. Voltage control, for instance, that could be treated as a service, is treated only as a technical requirement. Local congestion management is still not a service in none of the five countries.

Interruptibility contracts, which may be seen as the simplest mechanisms besides mandatory provision, are not used by DSOs either[19]. These contracts can be seen as long-term procurement of flexibility and are already used by some TSOs to procure flexibility from large-size consumers. Under the terms established in the contract, the network operator can curtail supply and would, therefore, provide a remuneration to the consumer. Such type of contract could be used similarly by DSOs. In fact, (Meeus & Noucier, 2018) inform that in Belgium and Germany DSOs can procure flexibility with interruptibility contracts. These contracts provide a reduced network fee in exchange for the unit to be controlled by the DSO. In addition to the options on how to procure the flexibility, DSOs may also decide on who can provide flexibility. Different eligibility criteria such as size, location, technology, response times, aggregation, verification and measurement methodology (baseline), and others may impact the profitability of the BM.

4.2.5. Drivers and Barriers

For the proper implementation of Business Model 2, two key elements are necessary. Firstly, DSOs must have the incentives to procure services from local resources and defer investments. Secondly, DSOs must be able to procure flexibility from DER, and therefore the proper regulation must be in place so DER can provide these services. Thus, the two biggest barriers for this BM seem to be: i) lack of appropriate incentives for DSOs to defer grid investments and ii) the provision of local services by DER.

The former topic has started to be addressed in some instances through the use of forward-looking investment plans (e.g. in Portugal or Spain) that need to justify the efficient provision of distribution services, as well as an interest in moving towards TOTEX regulation as opposed to regulated OPEX and CAPEX separately. In fact, Article 32 of the Electricity Market Directive included in the Clean Energy Package will presumable mandate DSOs to submit network investment plans every two years (with a horizon of 5-10 years) that include these possibilities. On the other hand, the latter topic is still especially incipient, and besides the push for local non-frequency ancillary services given by the Clean Energy Package, no practical solutions are implemented yet[20].

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[19] Interruptibility contracts are understood here as a way for DSOs to contract flexibility for grid management purposes. Usually, DSOs may request the TSO for a DG curtailment through CECRE, but these curtailments are done for security reasons.

[20] The Article 31 (5) of the proposal for Energy Directive states that "unless justified by a cost-benefit analysis, the procurement of non-frequency ancillary services by a distribution system operator shall be transparent, non-discriminatory and market-based ensuring effective participation of all market participants including renewable energy sources, demand response, energy storage facilities and aggregators".

More advanced mechanisms to be explored in subsequent stages include the following:

- Interruptibility Contracts (non-firm network access): flexibility providers sign a contract in which they can be curtailed or have their power limited in certain conditions as in the case of network congestion.
- Non-frequency ancillary service (local) markets: the DSO can create a local market in which flexibility can be procured to satisfy DSO's needs.
- Administrative prices for non-frequency ancillary services: instead of creating a market, the DSO can set prices administratively and activate flexibility according to their needs. Resources have to agree on providing these services.
- Mandatory provision under pre-defined conditions: under certain conditions (e.g. security reasons) the DSO can activate the flexibility available. Resources should be remunerated accordingly.

And for each of these possible mechanisms, questions may arise. For local markets, for instance, liquidity may be a problem. For administrative prices, the methodology to remunerate DER has to be defined, as well as who should participate in the provision of the service.

4.3. Business Model 3 - Data Services

BM3 is centered on the "data service provider" agent. This agent is expected to use the data produced by InteGrid's solutions to provide services to other agents, such as retailers, DER owners, aggregators, consumers etc. The data to be used is the one stored in the Grid-Market Hub (gm-hub), which is mainly metering data. Therefore, this BM3 is a product of HLUC6.

In HLUC06, the DSO (or, potentially, any metering data manager) provides anonymized and pre-processed metering data available to external stakeholders in order to promote new data-driven services provided by market entities with benefits for distribution grid users and market actors such as:

- provision of data regarding ToU / dynamic network tariffs to customers, suppliers, aggregators, inducing end use flexibility;
- provision of information to LV consumers about their peak demand in order to increase threshold if necessary;
- provision of basic efficiency tips based on customer consumption profiles (e.g. comparison to peers average);
- provision of data (e.g. load diagram) to customers or 3rd parties (e.g. suppliers, ESCOs) with explicit consent from customers (acting also as authorization manager);
- Information regarding new distributed resources connection may also be provided (e.g. inform new DRES facilities in the moment of network connection request about the number of hours per year that may be curtailed).

Based on this information made available through the grid-market hub, a new type of market agent may be developed. One that will exploit the data and transform it into services to consumers and other market agents, respecting all privacy requirements.

Several different services can be envisioned for the new data service provider. Hereafter some examples are listed:

- Forecast provision: load and generation forecast based on anonymized data stored in the gm-hub. The forecasts can be used by DSOs, TSOs, Retailers, Aggregators, etc.
- DER sizing: information for consumers/prosumers on the best size of storage and PV panels.
- Electricity usage intelligence: for end-users (industrial and residential consumers). Information on how and when to offer flexibility and how to improve consumption pattern according to price signals.
- Portfolio management: analysis for aggregators on the best mix of resources to compose a portfolio. Analysis may consider past load and generation data, complementarity between DER profiles, locational specificities and forecasts.
- Customer engagement strategies: retailers may be offered services based on anonymized data to improve their customer engagement strategies

One can also notice that the Data Service Provider can be an independent agent, but can also be part of a previously existent business. ESCOs, Retailers and even the DSO can possibly offer one or more data service. In fact, in some countries, this is already happening. Several data services are already being offered to consumers by retailers, for instance.

For this BM, it is also important to notice that some regulatory barriers may exist, mainly on data access restrictions. In some countries, consumption data can only be accessed by certain players (only retailers in Portugal for instance).

Additionally, the model chosen for data access and management may also be a barrier for this business model. For the data service provider provide services, an efficient data access must be in place, so that data can be accessed efficiently and the necessary consents from consumers can be equally managed efficiently.

4.3.1. Data Management

The core of Business Model 3 is the use of metered data collected by DSOs (or the corresponding metering data manager). In this context, data management regulation is crucial for the future implementation of the solutions proposed by InteGrid's grid and market hub (hereafter referred simply as gm-hub)[21]. Therefore, here we analyze both the metering responsibility and the data management model adopted by countries.

In the Deliverable D1.3, a preliminary assessment of the metering responsibility is presented. Table 8 presents the updated status of metering infrastructure ownership and responsibility. For the five countries, the equipment belongs to the DSO, although this may not be a strict requirement. In Austria, assets could be owned by third parties. However, this situation does not happen, and it is not expected to happen. In Austria, consumers pay a fixed fee for the metering service (regulation determines the maximum fee – e.g. 2,4€ per month for a 3-phase meter; 1€ for a single-phase meter – but the DSO can also charge less) and a part of the costs for smart metering will be paid by network-tariffs. The billing activity is done by either the DSO or the supplier, as shown in Table 8.

[21] Naturally, the deployment of smart metering infrastructure is a key enabler for this BM. For a discussion on this topic, the reader is referred to section 4.4.3.

Table 8: Metering responsibility and meter ownership

	Ownership	Meter reading and billing
	DSO	The DSO reads the meters, while the supplier bills the customers.
	DSO	Reading is done by the DSOs, billing by the suppliers
	DSO	Reading is done by the DSOs, billing by the suppliers
	DSO	DSO
	In principle open, but mostly owned by DSOs	DSO

In fact, according to the data published by the European Commission, only in the UK smart meters are the responsibility of the supplier and in Germany there is the meter operator. Apart from the two countries, all the other member states assigned the deployment and ownership of smart meters to DSOs.

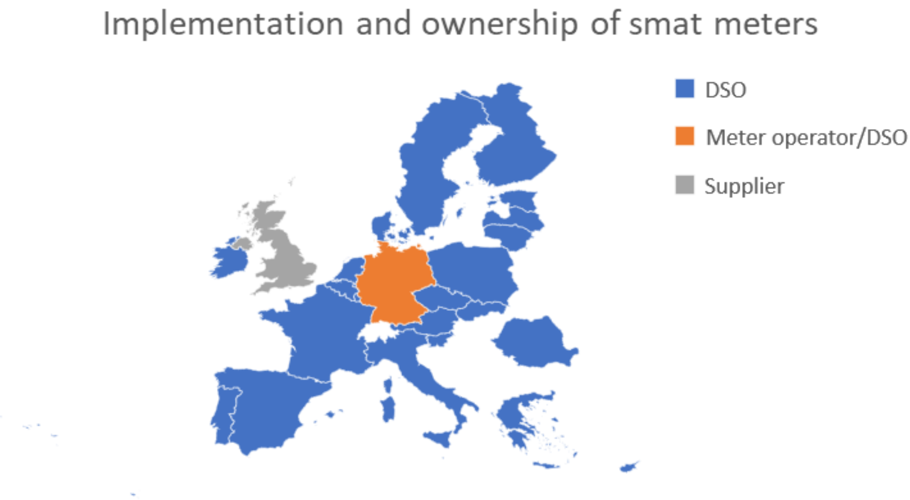

Figure 7: Implementation and ownership of smart meters. Data from: (EC, 2018)

On the data management model adopted by countries, four of them assigned the DSO as the responsible to give access to metering data. Only Sweden is planning to implement a central data hub in early 2021 that will be operated by the TSO. In other European countries, we can see a division between the Central Hub and the DSO model, as shown in Figure 8.

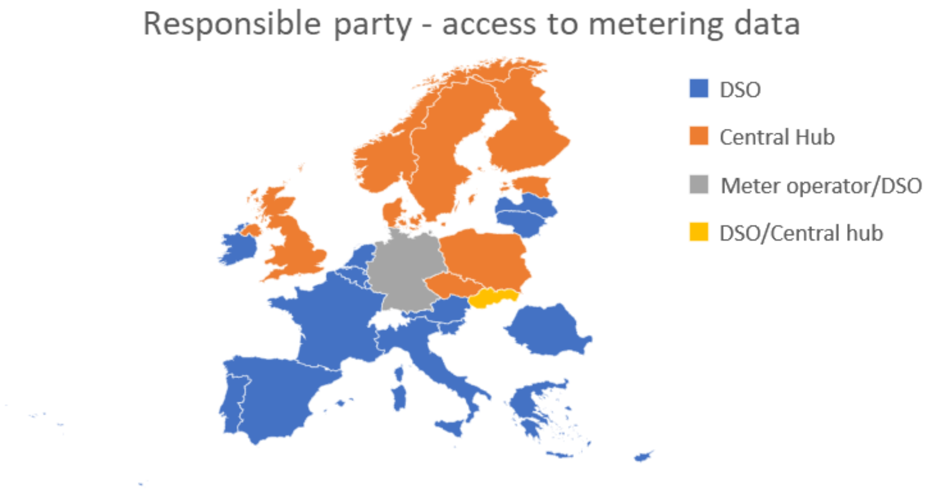

Figure 8: Responsible party for giving access to metering data. Source: (EC, 2018) **and** (Nordic Council of Ministers, 2017)[22]

4.3.2. Drivers and Barriers

According to (CEER, 2016b), data access and management could be classified into three groups:

- A fully centralized model is the one in which all data is retrieved, validated, stored, protected, distributed and accessed by a single actor, the data hub.
- A partially centralized model involves the centralization of some aspects, such as distribution and access to data. The storage, validation and protection, however, would be organized at different locations within the DSOs systems and metering points.
- A decentralized model is the one in which the DSO is responsible for all the data activity through non-standardized procedures. In this model, all agents would have to interact and request data to the DSO in different ways, depending on the data.

In InteGrid, BM3 is envisioned under the concept of the gm-hub, a centralized data platform. Therefore, the decentralized model can be seen a barrier for the development of this BM in the future. The decentralized model may impose difficulties for the data-services provider to access data, especially if data access is not harmonized. The necessity for an efficient data access and management model is even more important with the enforcement of the General Data Protection Regulation (GDPR), as security over the protection of personal data of natural persons is enhanced.

According to a survey conducted by (CEER, 2016b), regulators expect a change of their national data management models moving from more decentralized to more centralized models. Additionally, (CEER,

[22] Apart from Finland and Sweden, all other countries shown the data presented in (EC, 2018). The two mentioned countries were updated to reflect the central data-hub being implemented in the Nordic Countries. In 2016, the Swedish regulator (Ei) appointed the TSO (Svenska kraftnät) to establish and operate a data-hub for all electricity market data (Svenska kraftnät, 2017). This initiative follows a regional policy, as other Nordic countries are also implementing centralized data-hubs, namely Denmark, Finland and Norway (Nordic Council of Ministers, 2017). As of today, however, the DSO is still managing metering data, while the data-hub is not operational.

2016b) presents five guiding principles and seven recommendations for the design of data management models. Table 9 presents a summary of the principles and recommendations.

Table 9: Guiding Principles and Recommendation on Data Management Models. Source: (CEER, 2016b)

Guiding Principle	Recommendation
Privacy and Security	1. Customer meter data should be protected by the application of appropriate security and privacy measures.
Transparency	2. How data is accessed and managed should be made public 3. "In order to achieve energy efficiency benefits and other potential benefits, the relevant bodies in each country should take active steps to build customer confidence in sharing customer meter data. Those bodies could be the NRAs, the DSO/metering operator, public authorities, data protection authorities, and consumer organizations. Active steps to be taken might include information campaigns." 4. European harmonization on standards for data format and exchange should be pursued.
Accuracy	5. Regulation for data accuracy should be in place, and consumers should be aware in case of any inaccuracy.
Accessibility	6. "The customer (or a market participant acting on behalf of the customer) should have easy access to customer meter data. This information should, where reasonable, be made available through an adequate channel of the customer's choosing (e.g. an in-home system or by means of a gateway)"
Non-discrimination	7. Non-discriminatory access to information should be ensured.

Considering the principles suggested by CEER, we highlight that recommendations one, three and six are very important for the development of BM3, especially recommendation three. If consumers do not have the confidence in sharing meter data, most of the envisioned data services cannot be provided. This task, however, comes with the challenge of combining transparency and privacy, now enforced by the GDPR.

In summary, the main barriers for the BM3 are two. Firstly, a robust data management model has to be implemented in the focus countries for efficient data access by third parties. Secondly, consumers should feel confident in sharing their meter data so services can be provided, given that personal data protection is ensured at all times.

4.4. Business Model 4 - Consumer reduces electricity bill

In this BM4, the main agent is the consumer, and the main strategy is the reduction of the electricity bill by modifying consumption patterns in response to price and/or environmental signals. Note that this BM does not address energy conservation measures by changing lighting systems or insulation. As industrial and residential consumers may follow different strategies to achieve this objective, this BM4 is divided into two sub-BMs. BM4.1 is devoted to the strategies for the industrial consumers, while BM4.2 focus on residential consumers.

For both of them, the regulatory topics with bigger impact are the design of tariffs and the regulation on self-consumption. On one hand, tariff design will set the price signals to which consumers will be able to react. On the other hand, regulation on self-consumption will determine what are the alternatives in terms of production (or "presumption") of electricity. Consumers may opt for the installation of DG to reduce overall electricity expenditure, and therefore regulation will say what taxes apply, if exceeding energy can be sold to the grid, if net-metering is allowed etc. Lastly, the deployment of smart metering is essential for this BM as most advanced strategies for cost reduction as well as an efficient billing of the energy self-generated requires this technology.

Apart from these three topics, if a consumer wants to offer services to grid, through an aggregator or individually (in the case of an industrial consumers), this possibility has to be defined by regulation as well. This topic, however, is not treated in this BM, but in BM5, that concerns the aggregator, as the provision of grid services is not in the core of this BM4.

The following two subsections detail the strategies industrial and residential consumers may adopt to reduce electricity expenditure.

4.4.1. Business Model 4.1: Industrial Customers Minimizing Energy Cost

Industrial consumers can adopt different strategies to minimize electricity cost:

- Energy Price response: industrial consumers can adapt their consumption according to energy prices. For energy-intensive industries such as metals (steel, aluminum, copper), paper, chemicals and textile may make sense to reduce production if electricity price goes above a certain level.
- Network tariff response: The same reasoning exposed above for the electricity price is also valid for the network charges, in case they are designed in a dynamic or time-dependent way. Two network charge design options that may enable this response are:
    - Dynamic tariff response
    - TOU network tariff response
- Installation of DER and self-generation: Industrial consumers can also own generators (directly connected to their facilities or not) and battery storage. If DER is installed on the industrial facility's premises, self-generation is also a possibility.
- Participation in closed distribution systems. Regulation already foresees the possibility of closed distribution system (3rd Energy Package). This initiative allow industrial consumers to operate a closed network jointly and possibly reduce network costs. One possibility could be balancing the consumption on the same node.
- Provision of balancing services to TSO: Industrial consumers can also provide flexibility to the TSO.

- Provision of non-frequency AS services to the DSO: Flexibility can also be offered to the DSO. The viability of this option depends on how flexibility is offered and procured by the DSO. These options are listed in BM2.
- P2P trading. Industrial consumers may also be able to trade energy services among themselves through the use of peer-to-peer technology.

4.4.2. Business Model 4.2: Residential Customers Minimizing Energy Cost

As the industrial consumer, the residential consumer can also reduce electricity costs by improving energy consumption management and by offering flexibility to DSO, TSO, retailers and aggregators. The main strategies for residential consumers are:

- Energy Price response: residential consumers can also react to electricity prices. New technologies like the HEMS may enable more possibilities for demand response.
- Network tariff response: As for electricity prices, consumers can also react on network tariffs, if they are designed in a usage reflective way. This tariff design alternatives include:
    - Dynamic tariff response
    - TOU network tariff response
- Installation of DER and self-consumption (possible third-party ownership/leasing models): Residential consumers can also opt to install DER and profit from self-consumption. Several technologies are available such as PV, small wind turbines and batteries. Apart from that, consumers can also opt among several financial schemes to install the DER like leasing and financing.
    - PV, Wind
    - Storage
- Participation in "Energy communities": Introduced by the Clean Energy Package, the Energy Communities are also a possibility for residential consumers. Although it is still not clear in the regulation the scope of these communities, they are expected to allow consumers to manage electricity consumption and therefore reduce costs jointly.
- Provision of flexibility to different players: As for the industrial consumers, residential consumers can also provide flexibility to the DSO and the TSO, and additionally they can also offer flexibility to retailers and Independent aggregators. Retailers would want to buy flexibility for their internal balancing management, and aggregators would resell the flexibility to SOs.
- Energy Performance Contracts: Retailers may offer contracts based on demand-side management indicators.

- Renting the energy from a second residence: Customers that own more than one residence and have DER in the second property may rent the use of these resources when the residence is not being used (e.g. a summer house with solar panels installed).

The implementation of this business model depends on all regulatory topics that influence the capacity of consumers, both industrial and residential, to efficiently manage their electricity consumption, install DER such as batteries and EV, and eventually sell energy and provide grid services.

In this section, we focus on retail tariffs. We analyze the three relevant topics for demand-side management, namely smart metering deployment, the design of regulated tariffs and the self-generation regulation. Nevertheless, other regulatory topics are also relevant for this BM.

Although this BM focus on the actions downstream the meter, the possibility for DER to provide ancillary services may be also relevant for this BM. This regulatory topic is discussed within BM2 and BM5.

4.4.3. Smart Meter Deployment and Characteristics

Table 10 presents an update on the roll-out of smart meters and their characteristics in the analyzed countries. As of today, this is still a challenge for some of the countries, mainly Portugal.

Table 10: Roll-out and characteristics of smart meters

	Roll-out status	Expectation of conclusion	Minimal Functionalities	Responsible for Deployment
	Limited	The target would be 80% by 2020[23]	No specific set of functionalities for smart meters because their rollout has not been set by the Government yet.	DSO
	52% (2017)	92% by 2022, and 100% by 2025 (legal obligation)	Remote reading, remote on/off control, and events	DSO
	98% (2018)	100% by 2018	Remote meter reading, automatic disconnection in case of surpassing contracted capacity and remote connection/disconnection due to billing and contracting reasons.	DSOs
	100% (2009)	Ended in 2009[24]	Remote reading on a monthly basis and if the customers want to have hourly values, the DSO has to supply hourly values. New functional demands as of 2025 that most likely will mean daily hourly values read.	DSO

[23] (USmartConsumer, 2016)
[24] (Commission, 2014)

	12% (2017)	80% by 2020 and 95% by 2022	A specific regulation sets the functionalities required for the Smart Meters, including readings every 15 minutes, bidirectional communication and remote connection/disconnection	DSO

The decision to roll-out smart meters is subject to a national cost-benefit analysis at the national level. This is the reason why deployment levels are so different, not only among the five target countries of this report, but across all European countries. The current European target for smart meter deployment is the one set by the 3rd Energy Package, that states that 80% of total consumers should be equipped with smart meters by 2020. The Clean Energy Package provides further guidelines on the deployment of smart meters. In the case of a negative CBA, for instance, although the Member State does not have to carry out the roll-out, they have to review periodically the CBA[25] and consumers should be entitled to a smart meter if requested (in this case, the consumer bears the cost of the smart meter)[26]. Minimum functionalities are also defined in the Clean Energy Package[27].

4.4.4. Design of default and regulated tariffs

In this section, we cover the design of both default tariffs and regulated tariffs. By default tariffs it is understood the tariff set by regulation that the consumer can opt to pay instead of contracting a retailer. In some countries, this type of tariff is allowed only for vulnerable consumers, in some to all consumers, and in others this tariff does not exist, and consumers can only procure electricity from retailers. On the other hand, and equally important for the development of BM4, are the regulated tariffs, meaning the regulated part of the electricity cost. These charges are present in every country, and are usually divided into an energy component and a capacity component. The share of each one matters for BM4 as they set the possibilities of cost reduction by load shifting and/or self-consumption.

From the survey among the five countries, we observe that two countries still offer a default tariff to their household consumer, as shown in Table 11.

Table 11: Existence of default Tariff for household consumers

	Existence of Regulated Tariffs for household consumers
	Yes, and consumers can opt-out for regulated tariffs
	No
	Yes, and consumers can opt-out for regulated tariffs

[25] Electricity Regulation, Article 19 (5)
[26] Electricity Regulation, Article 21 (2a)
[27] Electricity Regulation, Article 19 (3)

	No
	No

For these two countries, we can say that the liberalization of the retail market is not complete, as many consumers may still resort to default tariffs. This possibility, although protects consumers, may also reduce the incentive for an active management of the electricity consumption.

A report published by CEER in 2017 (CEER, 2017b) shows how that a few countries in Europe still have default tariffs in place, as shown in Figure 9.

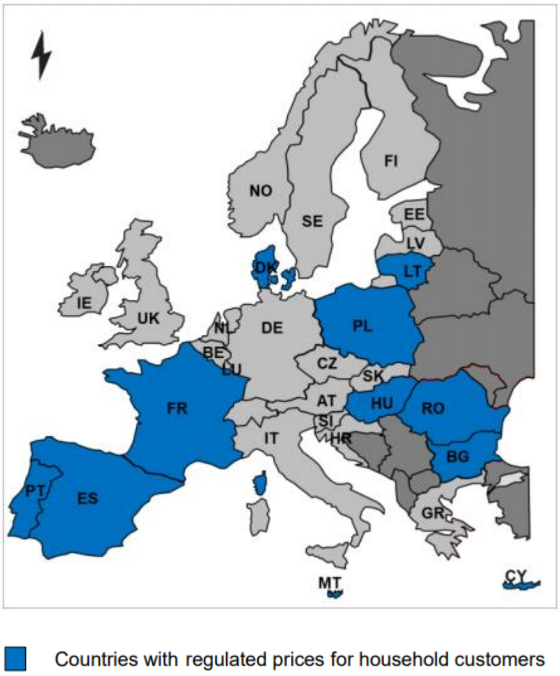

Figure 9: Countries with regulated prices for household customers. Source: (CEER, 2017b)

Although the default tariff may not offer the same incentives for customer engagement as liberalized tariff, it is important to note that consumers being supplied under this type of tariff are not the majority. In Portugal they account for 26%, while in Spain they are 43% (CEER, 2017b). Switching from one type to other also favors the retail market. In 2016 in Portugal, 8.5% of consumers left the regulated tariff in order to have a liberalized retail contract. The opposite movement is much rarer. In fact, the highest percentage of consumers going back to regulated tariffs happened in Spain (0.93% in 2016) (CEER, 2017b).

Default tariffs can also be designed in such a way that gives price signal to consumers. In Spain, for instance, the consumer can opt for a more stable tariff (that still fluctuates according to the prices in the wholesale market) or for a dynamic tariff with different prices for different time periods[28], as shown in Figure 10.

[28] It can be considered something in between a ToU tariff and dynamic tariff. Certain time periods are defined having different price levels, while within the time periods some variation is observed, reflecting the prices in the wholesale market. For more details, please refer to D1.3.

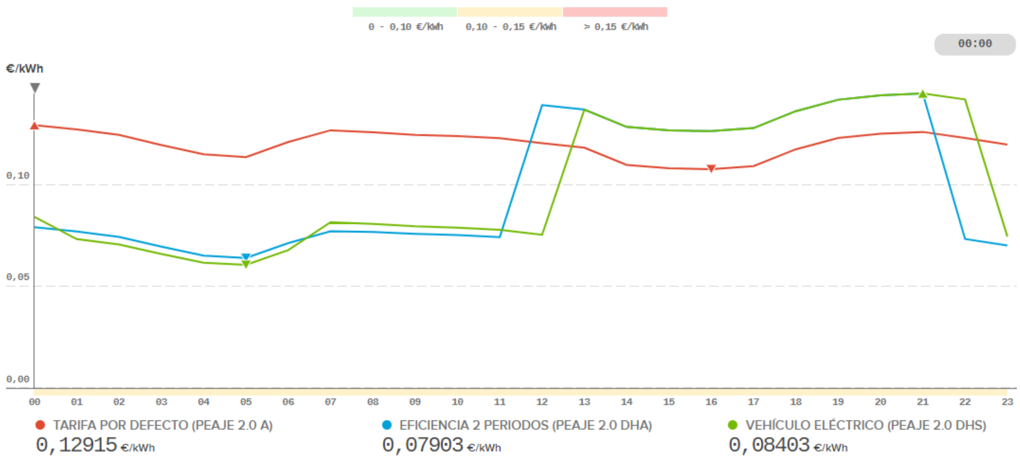

Figure 10: Regulated price in Spain for one day

Besides the regulated electricity tariffs existent in Portugal and Spain, the regulated part of the electricity bill in all countries can also be designed in a way the price signals are given to users. In particular, grid tariffs can be dynamic or ToU tariffs to reflect the usage of the network. D1.3 informed that Spain uses a ToU tariff for network charges, and that Portugal is developing pilots for the use of dynamic tariffs.

Figure 11 presents a comparison of tariff[29] breakdown for the four countries, based on the information provided by (ACER & CEER, 2017).

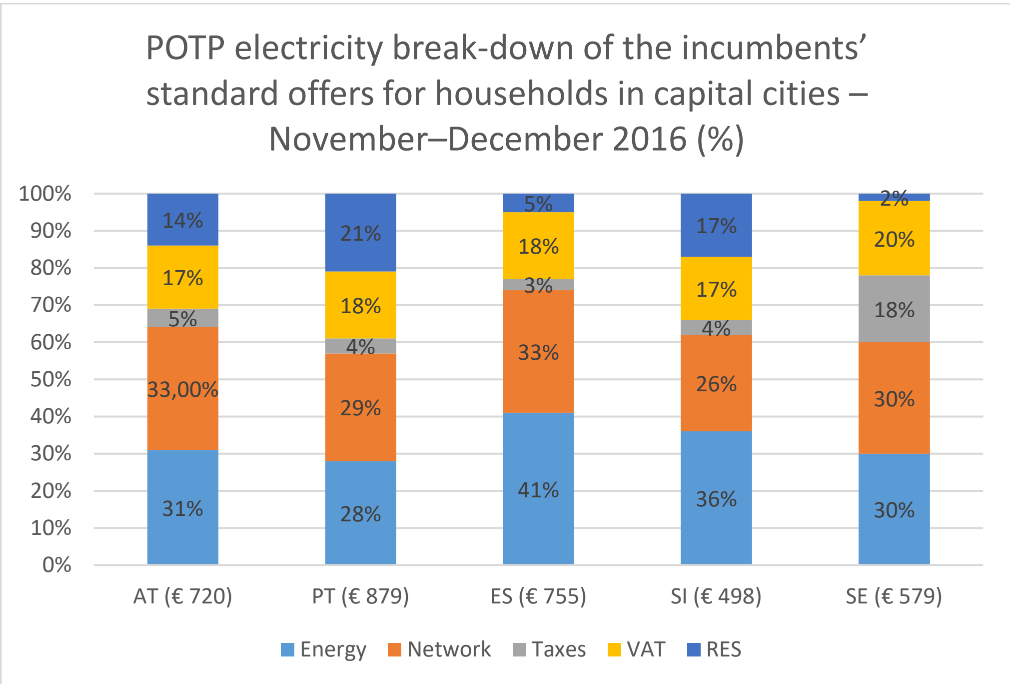

Figure 11: Electricity Post-Taxes Total Price (POTP) breakdown of incumbents' standard offers for households in EU capitals – November– December 2016 (%). Source: (ACER & CEER, 2017).

[29] Breakdown of the EU electricity post-taxes total price (POTP), index calculated by ACER and CEER that reflects the total cost of electricity for the final consumer. More details on (ACER & CEER, 2017).

4.4.5. Storage Ownership

Ownership models for distributed storage can also impact the possibility for consumer. Below, Table 12 summarizes the approach in the five analysed countries.

Table 12: Storage integration

	Is connection of storage to distr. networks regulated?	Is storage allowed behind the meter?	Can storages provide services to the DSO?	Are DSOs allowed to own and operate storage?
	No	There is no specific regulation regarding storage[30].	Prosumers can inject energy surplus, which could come from storage	Only in pilot projects
	No	Yes, if technical requirements are respected	No regulation on the issue	No legal limitations
	No	Yes, if technical requirements are respected	No regulation on the issue	No legal limitation, but it is assumed[31] that DSOs cannot own storage
	No	Yes, if technical requirements are respected	Yes	No legal limitations
	No, treated as a generator	Yes, if technical requirements are respected	There are no different/specific rules for storage	Utilities with more 100.000 customers are not allowed to own storage (only if required for grid operation)

4.4.6. Self-Consumption

Self-consumption is another central topic for the implementation of BM4. Besides reacting to price signals of electricity and network charges, users may also opt for the installation of DG for self-consumption. D1.3 showed that self-consumption is already allowed in the four countries previously analyzed. In Austria, self-consumption is also allowed, and net metering applied. Energy surpluses decrease the energy bill. There

[30] It also means that there is no explicit restriction regarding storage behind the meter.

[31] The assumption comes from the expectation of future European regulation on the matter. The Clean Energy Package, for instance, already proposes that "Distribution system operators shall not be allowed to own, develop, manage or operate energy storage facilities."

are no specific "prosumer requirements" and/or rules. When a grid user becomes a producer or a prosumer, they are treated as producers.

In Spain, in 2018, a major regulation in the power sector was approved, and among the main changes is the self-consumption. The Royal Decree (RD) 15/2018 abolished the so-called "tax on the sun". Before, the amount of energy that was self-consumed was subject to a specific regulated charge, popularly known as the "tax on sun". This charge allegedly aimed to recover the fixed system costs included in the volumetric component of the regulated charges. Albeit this was never applied for installation below 10kW (most residential ones) due to lack of development of the required secondary legislation, it effectively acted as a major perceived barrier for self-generation installations.

Another novelty is that prosumers with generation units below 100 kW now may be entitled to receive the same remuneration as any other generator (provided they register as such). Before, these small prosumers could not receive any remuneration for eventual energy injected into the grid. The RD also says that a simplified mechanism may be created for these prosumers, in other to reduce bureaucracy. It is still not clear how this remuneration mechanism will take place.

The "shared self-consumption" is also recognized by the new RD. How the self-consumption community will work is still not completely clear. The RD mentions that prosumers should be physically next to each other. Finally, several registration procedures were simplified in order to foster self-consumption.

4.4.7. Drivers and Barriers

A first barrier that can be observed is the limited success on the liberalization of the retail market. Some countries as Portugal and Spain still have regulated tariffs and no plans to phase it out. Although it is not a barrier for the development of BM4, it limits the potential reach of the BM. As seen in the country comparison though, regulated tariffs can offer price signals to consumers if designed as ToU or dynamic tariffs. On the regulated part of tariffs such as network charges, ToU and dynamic tariffs may also be used and increase the potential savings for consumers.

Dynamic pricing can be used on a higher or lesser degree to stimulate consumer's reaction to prices. The higher the "dynamics" of the mechanism, the more consumers will be rewarded if they react, and penalized otherwise. According to (Meeus & Noucier, 2018), there are three main possibilities for dynamics pricing, namely Static ToU, Critical peak pricing and Real-time pricing. The difference among them is on the granularity of the period during which consumption is metered separately and the degree of change in prices, as Figure 12 Illustrates.

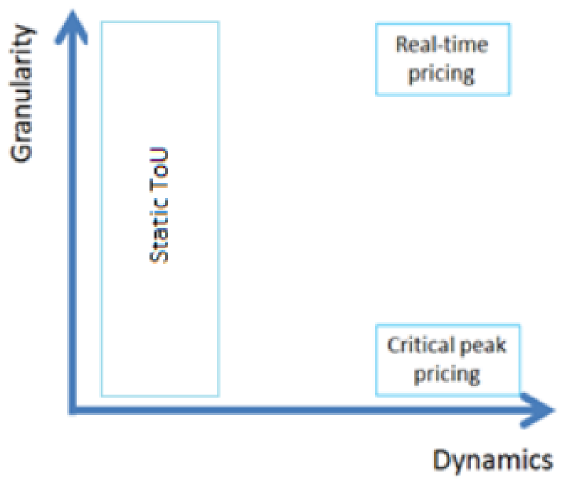

Figure 12: Methods of Dynamic Pricing for Electricity. Source: (Meeus & Noucier, 2018)

On the self-consumption side, barriers like the "tax on the sun" in Spain are being lifted. Additionally, the Clean Energy Package is expected to lift barriers on the prosumer's access to markets, as shown in Figure 13.

	PRODUCTION	WHOLESALE MARKET COMMODITY		WHOLESALE MARKET SERVICES		RETAIL MARKET	
		DIRECT	INDIRECT (AGGREGATOR)	DIRECT	INDIRECT (AGGREGATOR)	DIRECT	INDIRECT (AGGREGATOR)
3RD ENERGY PACKAGE	✓	✗	✗	✗	✗	✗	✗
EU CEP	✓	✓	✓	✓	✓	✗	✓

Figure 13: EU Clean Energy Package impact on prosumers' Market Access. Source: (Meeus & Noucier, 2018)

Smart meter deployment, as shown in Table 10, is still very heterogenous among countries. While Sweden has finished its first deployment almost a decade ago, Portugal is still starting. Although European targets exist on the matter, and countries are expected to meet them, this is still an important barrier as smart meters are the backbone of not only BM4, but almost all InteGrid's solutions.

4.5. Business Model 5 - Creating value through aggregation

This Business Model combines strategies for retailers and aggregators[32]. These agents may profit from aggregating DER's flexibility, reduce their costs through an enhanced management of their portfolio, or offer services that allow the final consumer to reduce their electricity bill. Therefore, this business model is divided into three different sub-business models. In the first one (BM5.1), the retailer (or the BRP) reduces imbalance costs by using client's flexibility instead of trading in the intraday market or paying imbalance

[32] As mentioned in section 3, in this report the BM5.2 is not covered. In this BM, the platform developer/owner is the main agent.

charges. The other two business models (BM5.3 and BM5.4) are related to the VPP concept (commercial and technical respectively).

Therefore, the key regulatory topics for this BM5 (and sub-business models) are the ones related to aggregation rules, demand-side access to balancing markets and ancillary services at distribution level or non-frequency ancillary services (already discussed in section 4.2.4). Additionally, market design also plays an important role, as retailers in BM5.1 are impacted by rules of imbalance, balancing market designs and intraday markets, and cVPPs will bid into balancing markets.

4.5.1. Business Model 5.1: Explore flexibility from HEMS

In this BM, the Balance Responsible Party is the main agent. The most interested BRP for this BM is the retailer, who can use the flexibility provided by its customers to manage imbalances. As of today, retailers have to manage imbalances by either trading in the intraday market or face imbalance penalties. With the development of aggregation and the use of advanced technology such as the HEMS, retailers will be able to use the flexibility from their clients to reduce imbalances and therefore reduce the costs associated with imbalances.

This BM5.1 imposes several questions on the strategy retailers should adopt:

- Which agents to consider: Retailers can choose the best customers to provide flexibility and therefore maximize the effectiveness of the BM.
- How to remunerate flexibility providers: For the customers that agree on offering their flexibility to the retailer, a remuneration strategy will be necessary. It is important to notice that customers will also be able to offer their flexibility to other players. Therefore, remuneration must be competitive.

Possible side-effects of this BM have yet to be evaluated. For instance, the use of flexibility to reduce imbalances may reduce liquidity in the intraday markets.

4.5.2. Business Model 5.3: Explore flexibility through the Commercial VPP

In this BM, the independent aggregator is the main agent. They use aggregated flexibility and provide ancillary services to the TSO, mainly balancing services (frequency regulation). This type of aggregation is defined as the commercial VPP.

Main strategies for the Commercial VPP are:

- Portfolio management: which resources to consider
    1. Type of flexibility (residential, industrial, voltage level)
    2. Location in the grid (although location is not greatly important for balancing services, except in case of congestions)

- Share of portfolio dedicated to cVPP and to tVPP
- How to remunerate the flexibility

For this BM, several regulatory topics are important, such as TSO-DSO coordination, if aggregated demand is allowed in AS markets, measurement and verification methodology (baseline) and the current status (legal and practical) of the independent aggregator (SEDC, 2017).

4.5.3. Business Model 5.4: Explore flexibility through the Technical VPP

This business model is similar to previous one. The difference being that in this BM, the independent aggregator offers the flexibility to the DSO, for grid management purposes[33] (non-frequency ancillary services). This type of aggregation is defined as technical VPP. In this BM, the independent aggregator faces the similar strategies as the cVPP, as shown below.

Main strategies for the Technical VPP:

- Portfolio management: which resources to consider
    1. Type of flexibility (residential, industrial, voltage level)
    2. Location in the grid
- Share of portfolio dedicated to cVPP and to tVPP
- How to remunerate the flexibility

4.5.4. Regulation on Aggregation

Aggregation is at the center of Business Model 5. In Business Model 5.1, a retailer or a Balance Responsible Party (BRP) may use aggregated flexibility to reduce imbalance costs, while in Business Models 5.3 and 5.4 aggregation is used to provide services for both the TSO and the DSO.

In all five countries, aggregation is permitted somehow, but its presence still limited. In Portugal, no specific regulation regarding aggregation exists, and therefore no independent aggregator or VPP is active in the Portuguese market. The situation in Spain is similar. Aggregation is allowed in the sense of aggregated bids by companies in the different markets, but the figure of the independent aggregator, as defined by the European regulation (e.g. Clean Energy Package) is still not active. Recently an association was created to foster aggregation in Spain[34]. In Sweden, independent aggregators are still not active either.

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[33] It is, in some sense, the other side of BM2, in which the DSO reduces costs by using flexibility to manage the grid.

[34] https://elperiodicodelaenergia.com/nace-entra-la-primera-asociacion-para-la-agregacion-y-flexibilidad-en-el-mercado-electrico-en-espana/

The countries that already have active aggregators are Austria and Slovenia. In Austria, the aggregators offering services for load frequency control are listed at the website of the Austrian TSO[35]. Aggregators are mainly aggregating flexibility from the industry and wind power. Like all ancillary service provider, also aggregators and their pool and/or generation units must also pass a prequalification procedure. In Slovenia, aggregation is permitted, and there are at least two active aggregators presently offering tertiary reserve (mFRR)[36] to the TSO.

An important topic for the development of BM5.3 and the concept of the cVPP is if aggregated demand is allowed to participate in ancillary services. From the five target countries, Austria and Slovenia are the ones that already allow aggregated demand to participate in AS. In both, however, participation is not allowed for Primary Reserve (FCR)[37]. In Slovenia, there is no market for FCR, because the provision of this service is mandatory for generators above 5MW and it is not remunerated. In Austria, this is not possible due to the fact that offers have to be symmetrical (both values for upward and downward regulation).

In Sweden, Demand Response participation in AS markets and the aggregated participation are legally possible, but not practical. A high minimal bid size and the in definition of the independent aggregator are still barriers for the participation of aggregated demand in the Swedish AS markets (Bertoldi, Zancanella, & Boza-Kiss, 2016). Portugal and Spain still do not allow the participation of demand, but progress initiatives are being made to open the participation. In Spain, the participation of demand is expected to start in 2019. In Portugal, the participation of demand in ancillary services is legally allowed since the end of 2017[38], but practically not feasible because of lacking definitions. A recent public consultation start a pilot-project allowing consumers to provide Tertiary Reserve, respecting a minimum capacity size of 1 MW (ERSE, 2018).

Table 13: Is aggregated load accepted in AS? Source: (Bertoldi et al., 2016)

	FCR	FRR	RR
	✗	✗	✗
	✗	✓	✓
	✗	✗	✗
	*	*	*
	✗ (required to be symmetrical)	✓	✓

[35] https://www.apg.at/de/markt/netzregelung

[36] ENTSOE defines mFRR as reserves that are able to restore the frequency within 15 minutes for continental Europe. As the Slovenian definition of the tertiary reserve product is a reaction time under 15 minutes, which false under this definition of ENTSO-E (Slovenian Energy Agency, 2017).

[37] The operational reserves defined by the SOGL differ slightly from what the reader may be used from ENTSO-E CE Operational handbook. In the Network Codes, Frequency Containment Reserve (FCR) is equivalent to the Primary Frequency Regulation. The Automatic Frequency Restoration Reserve (aFRR) is equivalent to the Secondary Regulation. The Manual Frequency Restoration Reserve (mFRR), together with the Replacement Reserve (RR) are equivalent to the Tertiary Reserve.

[38] Regulation n.º 621/2017 of ERSE, from 18 of December.

4.5.5. Balancing/Intraday Market Design

The market design in the four countries analyzed in Deliverable D1.3 has not change.

In Austria, power producers can trade their production either in organized power exchanges or over the counter (OTC). There are two power exchanges in Austria to which producers and trade, namely the European power exchange (EPEX) and the Energy Exchange Austria (EXAA). The EPEX is the most relevant power exchange and concentrates most of the short-term electricity in Austria. Due to the high capacity of cross-border lines, the Austrian day-ahead market was (until October 2018) closely tied to the German market area. However, price splits between Austria and Germany became more common.

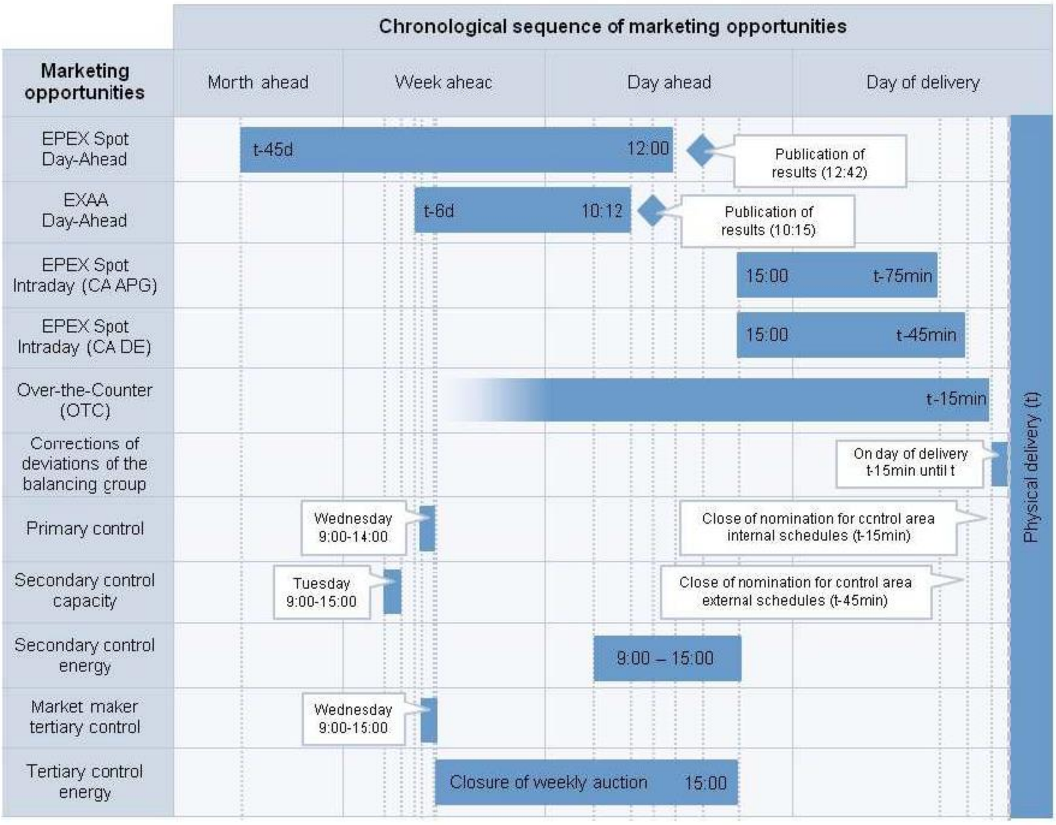

Figure 14: Scheduling of electricity markets in Austria. Source (E-control, 2014)

For the day-ahead, the order book for an auction is opened 45 days before physical delivery. Orders can be placed until noon one day before delivery. The minimum volume per single hour or block order in the day-ahead market is 0.1 MW, and the minimum price increment is 0.1 €/MWh. The intraday market in Austria is organized by continuous trading. The book of orders opens 15h of the day before and closes 75 minutes before the physical fulfillment (E-Control, 2014).

In all energy and balancing markets in Austria, no distinction is made between DER and conventional generation. As long as the technical and economic requirements set by the corresponding market rules are met, these resources can potentially participate in all markets, directly or through aggregation as discussed in the previous section.

Balancing products in Austria are divided into primary control, secondary control and tertiary control. Table 14 presents the characteristics of balancing products in Austria. However, these characteristics are expected to change as the Network Codes are implemented.

Table 14: Balancing products in Austria. Source: (E-Control, 2014)

	Primary Control	Secondary Control	Tertiary Control
Activation time	< 30 seconds	< 5 minutes	< 10 minutes
Biding volume	At least 2 MW, after that increments of 1 MW	At least 5 MW, after that increments of 5 MW	10 MW to 50 MW for a supplier's first bid, afterward 25 MW to 50 MW, only full MW can be offered
Delivery period	1 week	1 week	Mon-Fri Sat+Sun
Tendered Products	Weekly product (Mon-Sun: 00.00-24.00), capacity only	Peak (Mon-Fri: 08.00-20.00) Off-Peak (Mon-Fri: 00.00- 08.00 and 20.00-24.00) Weekends (Sat-Sun: 00.00-24.00) Each for positive and negative control	6 time slots for every 4 hours, each separated for positive and negative regulation

An important change since the publication of D1.3 is the entry into operation of Cross-Border Intraday Market Project (XBID). This platform harmonizes an intraday market across Europe under the mechanism of continuous trading.

4.5.6. TSO-DSO Coordination

Another topic especially relevant for the development of commercial VPP is the coordination between TSO and DSO. In InteGrid, the Traffic Light System is being tested as a tool to bridge the two system operators and promote and efficient operation under the condition that DER provides AS to the TSO. In general, this coordination is still incipient, limited to planning activities and security on operation. There is still no joint procedure for the procurement of flexibility, for instance.

In Portugal, there are interruptibility contracts for some large consumers that can be activated by the TSO. In Spain, the same situation exists, and the TSO can also procure services from DG connected to the distribution grid. Besides that, the TSO has the priority over the operation of generating units connected to the distribution network with an installed capacity of more than 50MW. Nevertheless, the DSO can request to the TSO the curtailment of generating units in case the DSO has problems in the network.

In Sweden, the TSO can also procure resources connected to the distribution level and have real-time data exchange for some nodes with the DSO. Sweden have interruptible contracts for some large customers on DSO level. In Austria, the TSO can procure/use services from all voltage levels. Before the TSO will procure a service (independent of the voltage level) a service provider must complete a prequalification procedure (unique and repetitive) and in this prequalification procedure the DSO is included. The TSO offers real time data of activation on request of the affected DSO.

4.5.7. Drivers and Barriers

Independent aggregation is still limited in the five countries analyzed. In Sweden, Portugal and Spain, no active aggregators are in operation. In Austria and Slovenia, where aggregation already happens, it is mostly restricted to large industrial or commercial customers and large DG.

This may be due to incipiency in the usage of flexibility from DER, but also due to the lack of specific regulation for aggregation. In most countries, aggregation still exists in a regulatory "grey area". On one hand, the participation of these agents is not forbidden, but as no specific regulation exist, they must comply with several market rules that may make the aggregation still not attractive. Aggregation business (especially in the case of small DER) is expected to work on a low mark-up, similarly to the retail business. If uncertainty exists over aggregation, it may receive little attraction by investors.

Another barrier for aggregation is the inexistence of clear regulation on independent aggregators, and sometimes even the prohibition of this type of agent (as in Spain). However, this landscape is expected to change in the coming years as the Network Codes and the Clean Energy Package are implemented by Member States. The EBGL declares in recital (8) that a level-playing field should be in place for all market participants, including demand-response aggregators and assets located at the distribution level, to offer balancing services. The Clean Energy Package goes further and devotes Article 13 of the Electricity Directive to set rules on the consumer contracting an aggregator. It establishes that the final consumer that enters into to a contract with an aggregator should not require the consent of its supplier, among other rules. Article 15 also states that "final customers are entitled to generate, store, consume and sell self-generated electricity in all organized markets either individually or *through aggregators* without being subject to disproportionately burdensome procedures and charges that are not cost reflective".

The Electricity Directive also makes a clear distinction between the aggregator and independent aggregator. This directive states that "Member States shall ensure that transmission system operators and distribution system operators when procuring ancillary services, treat demand response providers, including independent aggregators, in a non-discriminatory manner, on the basis of their technical capabilities" and that "Member States shall ensure access to and foster participation of demand response, including through independent aggregators in all organized markets".

Regarding the market design, an important barrier being lifted is the opening of Ancillary Services for aggregated demand. The two countries that still do not allow participation (Spain and Portugal), are actively promoting this opening, and it is expected to take place already in 2019. In Sweden, although legally aggregated demand is already allowed to provide AS, there are still practical barriers to be overcome. This barriers are also related to the definitions of roles and responsibilities of aggregators, as mentioned above.

Regarding product requirements at ancillary services markets, intraday and DAM should be open to a range of resources, including demand-side resources, distributed generation and storage systems. While genuine system constraints and security concerns must be respected, product requirements have been historically designed largely around what conventional generators could conveniently deliver (e.g. response time, duration of activation, ramp-up times, etc.). As new potential service providers grow, conventional criteria ought to be revised in order to create a level-playing field and remove barriers of entry for potentially low-cost flexibility resources, and which would otherwise artificially inflate procurement costs (BRIDGE, 2018).

In terms of measurement and verification, as well as associated payments and penalties, the volume of demand variation sold in markets is assessed against a baseline. The lack of transparency concerning the methodology and requirements for such assessment can be a strong barrier against the development of flexibility aggregation. Likewise, the lack of transparency in the payment and settlement criteria or biases in favour of conventional service providers (i.e. centralized generation) can also hamper the development of these BMs. Moreover, on a transnational scale, in spite of the progress made in the integration of energy markets (PCR or XBID), ancillary services markets are still largely unharmonized, thus hampering cross-border provision of flexibility services (BRIDGE, 2018).

In summary, aggregation is still very incipient. In some countries, as in Austria and Slovenia, aggregation exists but it is limited to large consumers/producers. Independent aggregators still not active and national regulation on the matter is still very limited, putting aggregation into a "grey area" of regulation. This is expected to change, as the new European regulations (namely the Network Codes and Clean Energy Package) try to lift the barrier impeding independent aggregation and aggregation of small DER to participate in markets.

5. Conclusions

This Deliverable D7.1 presented an update on the relevant regulatory topics for the solutions developed within the InteGrid project. As a continuation of the first assessment carried out in D1.3, the regulatory landscape has not changed dramatically in the four previously analyzed countries (Portugal, Spain, Slovenia and Sweden). The addition of Austria enriched the sample by bringing examples that could bridge some gaps in other InteGrid countries, as in aggregation, for instance, that is already more advanced in the latter country.

Differently from D1.3, this report puts the Business Models in the center of the discussion. The five business models identified focus on four main actor that ultimately will implement and profit from InteGrid's solutions, namely the DSO, the data service providers, the consumer and the aggregator (independent or not). Besides the technological barriers, these actors will also face several regulatory obstacles that will have lifted in the coming years.

For DSO, proper incentive for innovation has yet room from improvement in the five countries. This type of investment may be seen as not efficient in short-term, but is expected to bring important gains, especially for consumers. Out-put regulation can be further explored, the same way it is already used for quality of supply in most of the countries. The data service provider will only be possible with a robust data management model and consumer confidence to share data. The aggregator still lacks specific regulation, making its business model too uncertain to be viable (especially considering aggregation of small DER). What also lacks proper definition is the provision of local services by flexible DER. This is barrier that affects several of the actors in several BMs. It is necessary for the DSO that procures flexibility, for the DER that sells it, and for the aggregator that aggregates and offers to the DSO.

The barriers so-far identified in this report are mostly due to the lack of regulation than due to regulation on the wrong direction. Additionally, most of this regulatory barrier are being treated in the most recent European regulations such as the Network Codes and the Clean Energy Package. Table 15 presents the main biggest gaps between the current national regulations in the target countries and the Clean Energy. Therein, it can be seen that the Clean Energy Package proposals, when transposed and implemented, are bound to affect all the Integrid BMs. On the other hand, the Network Codes would mainly affect BM5, and specifically BM5.1 and 5.3. More specifically, the electricity balancing (EB) network code approved in November 2017[39] will affect balancing products definition, gate closure times for balancing markets, allocation of balancing responsibility, imbalance settlement, or the roles of BSPs and BRPs. As more progress is made with the implementation of the EB network code, further harmonization across countries is to be expected.

As a continuation of this Deliverable D7.1, Deliverable D7.2 will further explore the barriers identified in this report and will provide recommendations to overcome them. This recommendation will be done not only based on the result of this Task 7.1.1, but also on the results of the cost and benefit analysis (CBA) and the results of the scalability and replicability analysis (SRA). These recommendations will be specific to the target countries. Nevertheless, the potential applicability to other EU countries will be assessed as well.

[39] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2017.312.01.0006.01.ENG&toc=OJ:L:2017:312:TOC

D7.2 will also look at the standardization issues in the target countries. This topic was not covered in this D7.1, considering that it deviates slightly from the regulatory approach here proposed.

Table 15: Gaps between current national regulation and the Clean Energy Package

Business Model	Regulatory Topic	Regulation in the target countries	What does the Clean Energy Package say?
BM1 - DSO improves quality of service	Incentives for Incentives / Output regulation	Output-based regulation is not widely used by target countries, while incentives for innovation are also shy.	Regulatory authorities shall provide incentives to distribution system operators to procure services for the operation and development of their networks and integrate innovative solutions in the distribution systems. For that purpose regulatory authorities shall recognise as eligible and include all relevant costs in distribution tariffs and introduce performance targets in order to incentivise distribution system operators to raise efficiencies, including energy efficiency, in their networks.
BM2 - DSO procures flexibility	DER Provision of Ancillary Services	Procurement of local services by DSO is still not a practice in the target countries. The revenue regulation does not consider this type of expenditure either	MS shall incentivise DSOs to procure services in order to improve efficiencies in the operation and development of the distribution system, including local congestion management. Distribution system operators shall be adequately remunerated for the procurement of such services in order to recover at least the corresponding expenses.
BM3 - Data Services	Data Management	Data management models vary among target countries. In general, they are decentralized. In Sweden, however, a centralized hub is being implemented. In general, rules for data access are not transparent yet	Independently of the data management model it is important that Member States put in place transparent rules under which data can be accessed under non-discriminatory conditions and ensure the highest level of cybersecurity and data protection as well as the impartiality of the entities which handle data.
BM4 - Consumer reduces electricity bill	Self-Consumption	Barriers for self-consumption still exist but are being lifted (e.g. extinction of the "tax on the sun", in Spain).	Consumers are entitled to generate, store, consume and sell self-generated electricity in all organised markets either individually or through aggregators without being subject to disproportionately burdensome procedures and charges that are not cost reflective Consumers should be able to consume, store and/or sell self-generated electricity to the market

BM5 - Creating value through aggregation	Independent Aggregation	Independent aggregators are not recognized in some target countries, and not practical in others. Participation of aggregated demand in AS is still not open in all countries, but this is rapidly changing	Member States shall ensure that transmission system operators and distribution system operators when procuring ancillary services, treat demand response providers, including independent aggregators, in a non-discriminatory manner, on the basis of their technical capabilities.
	TSO-DSO Coordination	TSO-DSO coordination is still very limited. No cooperation exists for access to DER flexibility. Information exchange exists, but is limited (sometimes is done only under request)	Distribution system operators shall cooperate with transmission system operators in planning and operating their networks. In particular, transmission and distribution system operators shall exchange all necessary information and data regarding, the performance of generation assets and demand side response, the daily operation of their networks and the long-term planning of network investments, with the view to ensure the cost-efficient, secure and reliable development and operation of their networks. Transmission and distribution system operators shall cooperate in order to achieve coordinated access to resources such as distributed generation, energy storage or demand response that may support particular needs of both the distribution system and the transmission system.

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Annex A – Regulatory Questionnaire

Table of Contents

Abbreviations and Acronyms

AS	Ancillary Services
BRP	Balancing Responsible Party
CAPEX	Capital Expenditures
DER	Distributed Energy Resources
DG	Distributed Generation
DoA	Description of Action
DR	Demand Response
DSO	Distribution System Operator
ESCO	Energy Services Company
LV	Low Voltage
MV	Medium Voltage
OPEX	Operational Expenditures
RAB	Regulatory Asset Base
TOTEX	Total Expenditures
TSO	Transmission System Operator
UoS	Use of System (charges)
VPP	Virtual Power Plant
WACC	Weighted Average Cost of Capital

1. Scope, purpose and instructions for filling

The InteGrid concept and its demonstration can be hampered or required adaptations due to the existing (or foreseen) regulatory framework. In Task 1.3 we already carried out a general assessment of the regulation surrounding InteGrid's objectives. Now in WP7 we will review and extend the regulatory assessment, so recommendations can be provided.

The objective of this questionnaire is to update the information we have already gathered in Task 1.3. The question you will find below are mostly the same as you already answered. You will also find the answers you already gave to the questions, so you can easily verify if the information is still up to date.

This questionnaire consists on different sets of open questions in which you are encouraged, to the extent possible, to provide complete but concise answers. Feel free to add any reference or link you may deem relevant to provide further information. Exceptionally, some questions will contain multiple choice boxes. Please select one or multiple choices depending on the question.

In order to make the revision more efficient, all the questions carry a signal, showing their level of importance:

The green flag means that the question was already answered in the first questionnaire and the answer should be checked for possible modifications that recently happened in regulation. Please modify the answer in case of recent changes. Feel also free to add more information.

The target symbol means that the question was already in the first questionnaire as well, but we would appreciate a more detailed answer. The target questions were identified in the conclusions of D1.3 and comments from different reviewers. We expect to go deeper in their understanding of these topics in this deliverable. We would appreciate if you could review and complement the answer with additional information, to the extent possible.

The "new" symbol indicates a question that was not in the previous questionnaire, but was included due to its relevance. As these are very relevant questions, we would appreciate detailed information.

Please help us define the regulatory framework in your country by reviewing/answering this questionnaire. Considering both current regulation and any potential legislation change that you consider may take place in the near future. Please provide any references where this regulation may be found.

In case of comments or doubts, please contact leandro.lind@iit.comillas.edu

2. DSO Economic regulation

Power distribution is a regulated network monopoly within a given geographical area. Therefore, the revenues of DSOs are determined or supervised by NRAs and policy-makers. The economic regulation of electricity distribution companies defines how the allowed levels (i.e. those passed-through to the network tariffs) of network investments, other CAPEX, and OPEX are determined and recovered by DSOs. In addition to revenue regulation, distribution regulation has increasingly included additional incentive mechanisms related to the performance of DSOs in areas such as energy losses or quality of service.

This section includes questions related to all the topics mentioned above, with an emphasis on how expenditures related to DER and smart grid solutions are treated in the national regulation.

2.1. Revenue regulation and cost assessment

1. What is the general type of remuneration approach implemented in your country? What is the length of regulatory periods? Can you provide the remuneration formula?

   From of price control:

☐ Price Cap	☐ Revenue Cap

   Please comment below

   Length of regulatory period:

☐ 3 years	☐ 4 years	☐ 5 years	☐ 6 years	☐ 7 years	☐ 8 years

   Please comment below

2. Are CAPEX and OPEX calculated and regulated separately or jointly? Are there any mechanisms to provide DSOs with equal incentives to reduce OPEX and CAPEX equally?

☐ Separately	☐ Jointly

   Please comment below

3. How are new allowed investments determined and included in the RAB? Do DSOs need to submit investment plans? If yes, do regulators use any benchmarking or cost assessment tool to evaluate these investment plans and which one? If yes, how are deviations between approved investment plans and actual investments treated?

4. How are allowed OPEX determined? Do regulators use any benchmarking or cost assessment tool to evaluate OPEX efficiency? If yes, which type of approach is used and in what way?

5. If you have not already done so in the questions above, please describe whether and how the costs related to DER penetration and smart grid implementation are treated in the regulation of DSO revenues (investment plans, benchmarking, other).

6. Are there any relevant changes expected or planned for the next years?

2.2. Regulatory incentives for DSOs

2.2.1. Energy losses

1. Are there specific regulatory mechanisms to encourage DSOs to reduce energy losses? If yes, what kind of mechanism is used (symmetric bonus-malus, only penalties, only bonus)? Do DSOs buy energy losses directly at the market or are they simply subject to an economic bonus/penalty on top of their allowed revenues?

☐ Symmetric bonus-malus	☐ Only penalties	☐ Only bonus	☐ Others (please describe)	☐ No incentives

Please comment below

2. How are the parameters of the mechanisms to promote loss reduction determined? These parameters typically include the level of recognized losses (also referred to as reference or target losses) and the unit value of losses (usually associated to market prices). Do these parameters vary by DSO or region, time of the day or season of the year? Is the impact of DER on distribution losses considered somehow when calculating these parameters?

3. Are non-technical losses (fraud, meter tampering, etc.) addressed specifically in the regulation? Do DSOs see any incentive to reduce them?

4. Are there any relevant changes expected or planned for the next years?

2.2.2. Continuity of supply

1. What reliability indices are used to monitor continuity of supply? Are the faults occurring in the LV network included in these indicators, either jointly or separately? What network users are considered when calculating these indicators (only consumers or also DG units)?

2. Are there specific regulatory mechanisms to encourage DSOs to improve continuity of supply? If yes, what kind of mechanism is used (symmetric bonus-malus, only penalties, only bonus)?

☐ Symmetric bonus-malus	☐ Only penalties	☐ Only bonus	☐ Others (please describe)	☐ No incentives

Please comment below

3. How are the parameters of the mechanisms to improve continuity of supply determined? These parameters typically include the reference or target value and the unit incentive (usually related to the value of non-served energy). Do these parameters vary by DSO, region, or voltage level? Is the impact of DER on distribution losses considered somehow when calculating these parameters?

5. Are there any relevant changes expected or planned for the next years?

2.2.3. Innovation and smart grid deployment

1. Are there specific regulatory mechanisms funded through the electricity tariffs to encourage DSOs to test innovative solutions or fund pilot projects? If yes, what kind of mechanism is used (tendering schemes, additional WACC, accelerated depreciation, other)?

2. Are you aware of any plans to implement such schemes or to modify existing ones?

2.2.4. Other output indicators

1. Are DSOs subject to any regulatory mechanisms related to specific output indicators other than the ones mentioned above (continuity of supply, energy losses, fraud)[40]? If yes, what output indicators and kind of mechanisms are used?

2. Are you aware of any plans to implement such schemes or to modify existing ones?

[40] Regulators in Italy or the UK have stated the relevance of shifting towards and output-based regulation and have introduced specific new incentive mechanisms related to outputs such as DSO carbon footprint, vulnerable consumers, customer satisfaction, etc.

3. Grid connection and access of new DG

Regulation should ensure fair and non-discriminatory network access for DG units whilst allowing DSOs full recovery of efficient connection costs. In this regard, there is a trade-off between providing incentives for the optimal and cost-reflective siting of new generation capacity and facilitating entry for small-sized DG operators. For this purpose, connection charges and use-of-system (UoS) charges may be designed by the regulator for all agents connected to the distribution network, including DG. Likewise, grid access rules may affect the connection process of new DG units as well as its impact on the distribution grid. The following block of questions focuses on these issues.

3.1. Network charges for DG

1. What kind of connection charges (deep, shallow, shallowish) are applied to DG connections in your country?

☐ Deep	☐ Shallow	☐ Shallowish

Please comment below

2. Are they calculated and by whom, or they are set by simple and transparent rules? Who sets the rules? How are they approved?

3. Do DSOs publish openly information enabling new applicants to estimate in advance (before submitting the application for connection) their connection charges or identify areas of the grid with more available hosting capacity (e.g. on-line calculators, heat maps, etc.)?

4. Have DG to pay UoS charges in your country? What is the structure of current DG UoS charges? Are they applied to kWh, to kW, or both? Are there differentiated by network voltage levels, by DG sizes or technologies?

☐ No UoS for DG	☐ UoS for DG as Energy (€/kWh)	☐ UoS for DG as Capacity (€/kW)	☐ Both (€/kWh + €/kW)

Please comment below

5. Do centralized generators pay UoS charges? If yes, are these calculated using the same rules as DG?

6. How are network charges for DG designed? Flat-tariff, Time-of-use (ToU) tariff, dynamic tariff, other?

7. Are there any plans to modify in the near future the current situation regarding network charges applied to DG (plans or pilots for ToU or dynamic tariffs, for instance)?

3.2. Grid connection rules

1. Does regulation set limits in size/capacity for new distribution network users at each voltage level? Are these limits the same for generators and consumers?

2. Are new LV connections made as single-phase or three-phase connections? Are there specific rules in this regard for DG units (e.g. PV) or EV charging posts?

3. What are the operating voltage limits (voltage drop and voltage rise) allowed by the regulation? Are they different from standard IEC50160? Are they specific to the MV and LV systems? Are they monitored and enforced or simply used as ex-ante planning and connection criteria?

4. Is there any other relevant grid connection rule that may impact DER?

4. New roles of DSOs

In a highly distributed power system, the role of DSOs will not only be that of network planning and operation. They would increasingly need to interact more closely with the network users both as a means to support their own operations as well as to facilitate the access of DER to upstream markets and services. In fact, the evolving role of the DSO is a key component within the InteGrid vision. Thus, this section will explore the current situation regarding DSO interactions with DER as system optimized and market facilitator. Moreover, DSOs may also act, at least on a transitory stage, as owners and/or operators of some types of DER. This topic is also addressed hereafter.

4.1. DSO as system optimizer

1. Can DER participate in voltage control? Is there any specific requirement for voltage support (a fixed power factor, reactive consumption, constant voltage, etc.)?

2. How is the provision of this service regulated (mandatory requirements, incentive mechanisms, contractual agreements, non-firm connection, market mechanisms)? What types of DER are eligible (DG, DR, batteries)?

3. Can DER participate into local congestion management or other services to the DSO besides voltage control in your country? How is the provision of this service regulated? Can DSOs interact with aggregators or VPPs for these purposes? What types of DER are eligible?

4. Can DSOs own DER under specific circumstances (e.g. to compensate for the energy losses, under emergency conditions)?

5. Does the DSO have visibility of the DER generation/consumption profiles for grid operation purposes?

6. Are there any plans to modify in the near future the current situation regarding DER as a provider of network services?

4.2. DSO as market facilitator

1. Are there agents, such as aggregators, virtual power plants (VPPs), EV charging managers or other business arrangements that manage different DER connected to the distribution network?

2. When DER participate in upstream markets and services (energy markets, balancing, reserves, etc.), does the DSO intervene at any stage of the process (other than meter reading) to validate this service provision?

4.3. TSO-DSO coordination

1. Is there any coordination between TSOs and DSOs for **grid planning**? If yes, what is this coordination done for and how it is organized (data exchanged, hierarchy, etc.)?

2. Is there any coordination between TSOs and DSOs for **grid operation**? If yes, what is this coordination done for and how it is organized (data exchanged, hierarchy, etc.)?

3. Can the TSO procure/use resources connected to the distribution grid for ancillary service purposes? If so, do the TSO communicate to the DSO the activation of flexibility?

4. What is the current information exchange between TSO and DSO? What is the information shared and at what frequency?

5. Is there any TSO-DSO hierarchy in the operational procedures (e.g. TSO has the priority over DER)?

4.4. Ownership models for distributed storage

1. Is the connection of storage systems to the distribution grid regulated? Are there any specific connection requirements for distributed storage systems?

2. Are prosumers allowed to own storage behind their meters? If yes, under what conditions (size limitations, technical requirements, pricing options)?

3. Can *prosumers* provide services to the DSO using storage? If yes, under what conditions (size limitations, technical requirements, pricing options)?

4. Are DSOs allowed to own or operate directly storage systems? If yes, under what conditions (size limitations, constraints to prevent interference with competitive activities, time limitations, tendering mechanisms required)?

5. Smart metering

Smart metering is a key enabler for demand flexibility and well-functioning retail electricity markets. Accordingly, it is a central technology within many of the InteGrid functionalities. European directives place a strong emphasis in the need for deploying this infrastructure by 2020 and beyond. However, different countries may opt for different smart metering deployment and data management models. In this section, you will be asked to characterize the current situation in your country.

5.1. Roll-out model and responsibilities

1. Is the implementation of smart metering regulated (is it mandatory, or left to DSO or market initiative)? Are there any specific smart metering rollout programs? Who is responsible for its deployment? What is the current rate of deployment in the country?

2. What is the infrastructure considered by regulation (just the smart meters at consumers' location, does it also include data concentrators, communication networks, etc)?

3. What are the functionalities considered for smart meters (remote reading, load limitation, etc)?

4. Who is the owner of the required infrastructure (AMI) (the DSO, the supplier, an independent agent)? In case it is property of the DSO, how is it accounted for by regulation? Is it included in the asset base? How are these costs passed through to consumers (do consumers pay a fixed amount for meter rental)?

5.2. Metering data management

1. Who is in charge of meter reading and billing (the DSO, the supplier, an independent agent)?

2. How often can consumption be recorded (15min, 1h…)?

3. Do smart meters record data only on consumption? Or also on events (voltages, supply interruptions, etc.)? If yes, does the DSO have access to this data? How often?

4. What agent is responsible for third-party access to metering data for commercial purposes (DSO, supplier, independent data hub)?

5. How can data be accessed? Which third parties can access consumption data and under which conditions (anonymized, aggregated, etc)?

6. Retail tariffs and self-generation

The price signals seen by consumers are a key variable affecting demand behavior including their level of engagement, actual flexibility provision, or investment decision in grid-edge technologies (PV, storage, heat pumps). Oftentimes, market prices or network tariffs are seen in isolation from the rest of the cost components that are included in the retail tariff paid by end users. However, this is a myopic view. In order to properly assess the behavior of end users, it is necessary to consider the breakdown of costs in the retail tariffs as well as the structure of these tariffs.

Retail tariffs can be broken down into i) regulated charges needed to recover the costs of non-competitive activities and policy costs (transmission, distribution, system operation, capacity mechanisms, regulator costs, RES subsidies, other), ii) the cost of producing the electricity, and iii) taxes.

This section aims to characterize the composition of retail tariffs and their structure, as well as the regulation of self-generation in each target country.

6.1. Retail tariff design

1. What is the cost breakdown of the power system in your country? How are these costs passed-through to the different tariff categories? What is the level of taxation on the electricity bill?

2. What is the structure of the regulated charges paid by end users (energy, capacity, fixed, minimum bills)? Is this structure different for different consumer categories?

3. Are there still fully regulated tariffs for some groups of consumers? If yes, what is the structure of this tariff, who can offer it and what types of consumers are eligible to these tariffs?

6.2. Self-generation regulation

1. Is self-generation allowed in your country? If yes, are instantaneous energy surpluses remunerated in any way? How? Is net-metering permitted? At which timescale is net-metering applied (monthly, yearly)? What types of consumers are eligible to self-generation?

2. Are there any particular grid connection requirements or procedures for prosumers?

3. Are there any limitations in terms of installed capacity? Are there special requirements in terms of metering equipment? Are prosumers subject to any specific charge or levy?

7. DER, aggregation and BRPs

Granting DER access to markets and energy services provision requires in many cases a certain level of aggregation either to comply with market access rules or in order to benefit from portfolio effects. Therefore, intermediaries such as aggregators or VPPs can play a relevant role in a highly decentralized power system. Nonetheless, since this is a relatively new role in many cases, regulation may need to be adapted to remove potential barriers for aggregation whilst ensuring system security and preventing cross-subsidies among agents. The following questions analyze the existing rules for DER aggregation and the allocation of the balancing responsibility in these cases.

7.1. DER flexibility integration in markets

1. Is DER allowed to participate in any electricity or ancillary service market (aggregated or individually)?

☐ Yes, electricity markets (DA/ID)	☐ Yes, Ancillary Services (TSO)	☐ Yes, local services (DSO)	☐ No, DER cannot participate in markets or provide services

2. In case of any "Yes", which DER is allowed to participate (DG, DR, batteries)? is there other rules for DER participation (size, voltage level, others..)? Please describe.

3. Is there any form of "interruptibility contract" that DER can sign with the DSO? If so, is there a difference for DG and DR?

4. In which cases can the DSO curtail DG connected at the distribution level?

7.2. DER aggregation rules

5. Is aggregation of DER permitted for market participation? If yes, what types of services/markets are open for aggregators' participation? Under what conditions?

☐ Yes, electricity markets (DA/ID)	☐ Yes, Ancillary Services (TSO)	☐ Yes, local services (DSO)	☐ No, aggregation is forbidden	☐ There is still no regulation aggregation

Please comment below

6. Are there aggregators active in your country? What type of services are they providing? What type of resources are they managing?

7. Are VPPs active in your country? What type of services are they providing? What type of resources can be/are they managing?

7.3. Allocation of balancing responsibility

1. Are demand agents subject to balancing responsibility? If yes, are they subject to the same conditions than generators? How are storage units considered for balancing responsibility?

2. What are the rules to define a BRP? Is balancing responsibility defined for a specific unit, amount of capacity, company, other?

3. Are independent aggregators allowed in your country? Are independent aggregators BRPs? If not, how is the balancing responsibility between them and suppliers allocated when demand response actions are carried out?

8. Market design and access rules

Ideally, market design and its rules should create a level playing field so that all potential market participants may compete on equal conditions. However, this is not always the case in practice. Conventionally, market rules were designed for a centralized power system where large generators were the main market participants and demand was mostly inelastic and usually based on forecasts. However, future power systems should aim to integrate all flexibility providers regardless of their locations, size or technology. This may require revisiting existing market designs and access rules to enable such a vision.

8.1. Market design

1. What is the chronology for energy markets in your country? Are there intraday market sessions where market agents can change their position? If yes, how often? What are the gate closure times for such markets?

2. Are complex bids allowed in the markets? Are these complex bids also available for demand?

3. What is the level of liquidity or volume of energy traded in each one of these markets? What is the volume of energy traded in organized (auction-based) energy markets as compared to bilateral trading?

4. How is the provision of primary, secondary and tertiary reserves (frequency containment, frequency restoration and reserve restoration reserves respectively) organized in your country (mandatory/voluntary, auction-based, bilateral contracting, mandatory requirements)? How many different services/markets are defined? What is the trading period (day-ahead, year-ahead)?

5. How are prices determined in the different markets? Marginal pricing, pay as bid?

6. How are reserve requirements determined (defined in a network code, calculated by the TSO)?

8.2. Market rules affecting DER

1. How is the service or product traded in reserves markets defined (capacity-based, energy-based)? Are upwards and downwards reserves provided jointly? How fast and for how long does the service need to be provided?

2. How are imbalances settled financially (single pricing or dual pricing? How is the imbalance cost and penalties calculated? What are the imbalance payments used for?

3. When are system energy imbalance and imbalances prices published? (minutes/hours/days /months after real time?

4. What agents are subject to deviation imbalances? Are the rules the same for all BRPs or, on the contrary, some agents (e.g. RES) are given more favorable conditions?

5. What are the main market access requirements set in the regulation (size limitations, technical requirements, monitoring and control capabilities)?

6. Is demand-side bidding permitted? If yes, in what markets? Are there specific services that can only be provided by demand, DER and/or storage systems? Are these agents subject to any special conditions for market participation?