MOBILE ENERGY RESOURCES

IN GRIDS OF ELECTRICITY

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IDENTIFICATION OF REGULATORY ISSUES REGARDING MARKET DESIGN AND NETWORK REGULATION TO EFFICIENTLY INTEGRATE ELECTRIC VEHICLES IN ELECTRICITY GRIDS

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SUMMARY

Sub-Task in DoW	Description	Section	Responsible Partner
5.2 A	“Design of day-ahead and intra-day markets (Iberdrola, **PPC**, Comillas). The potential participation of EV loads and supply as a predictable and controllable load/generation profile in electricity markets, day-ahead and intraday markets, according to the current rules will be investigated in the different European regions. The role of aggregators of loads and generation EV portfolios to play in the market is also a relevant issue to be analyzed. Technical and regulatory barriers to the penetration of EV in these markets will be identified. Current practices and recommendations to improve market designs will be provided.”	**2**	**PPC**
5.2 B	“Design of balancing markets and reserve markets or procurement of operational reserves. Incentives for Transmission System Operators (Iberdrola, ICCS/NTUA, REE, **RAE**). According to results obtained in WP3, the impact of EV in the level of operational reserves will be analyzed. To achieve a practical implementation of the benefits derived from the participation of EV in the provision of operational reserves a set of regulatory actions should be recommended. The current designs of the mechanisms for provision of reserves in the different European regions will be analyzed. Restrictions or barriers that can be an obstacle for the participation of EV portfolios will be identified. Recommendations to improve the current situation will be given. In addition, incentives for Transmission System Operators to develop more decentralized control schemes to allow a massive participation in ancillary services provision coming from distributed energy resources, such as EV, will be investigated.”	**3**	**RAE**
5.2 C	“Incentives and revenues allowance for Distribution System Operators (RAE, INESC, **Comillas**) According to results obtained in WP3 and WP4, the connection of massive EV to distribution networks would impact the investment and operational costs of Distribution System Operators. In addition regulated revenues charged by DSOs through distribution network charges can be also affected. In this task, studies will be conducted to estimate the consequences from a regulatory and revenue point of view for distribution companies of largely increasing energy flows, namely in some specific periods. Improved regulatory schemes to deal with the associated investment and operation costs will be recommended according to the specific situations in the different European regions. In addition, incentives to be given to DSOs to introduce innovation in the way networks are operated and managed in line with the concept of Smart Grids will be proposed.”	**4**	**Comillas**
5.2 D	“Network tariffs design (**INESC**, Comillas, and RAE). The situation in the EU countries regarding the methods used to set network tariffs are very different ranging from simple postage stamp approaches discriminated per voltage level to the use of point connection tariffs based on marginal approaches. To achieve an efficient integration of EV regarding incremental costs and benefits, it is a key factor to design cost reflecting network tariffs. Those tariffs will provide economic signals about where and what time is more efficient from the point of view of the network to increase demand or generation by EV batteries. These network tariffs would be time and location dependant, including management of network congestions. They could eveICCS/NTUAlly suffer peaks in order to discourage charging in periods in which the capability of the system to accommodate the connection of more vehicles to plug in facilities is reduced. Advanced network tariff designs will be recommended starting from the current situation in the different European regions.”	**5**	**INESC Porto**

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LIST OF ACRONYMS - GRLOSSARY

Acronym	Meaning
AGC	Automatic Generation Control
AS	Ancillary Service
BRP	Balance Responsible Parties
BSP	Balancing Service Providers
CAPEX	Capital Expenditures
CCGT	Combined Cycle Gas Turbine
CI	Customer Interruptions
CML	Customer Minutes Lost
CNE	Comisión Nacional de Energia - Spanish Regulatory
CPM	Charging Point Manager
CUR	Last Resort Supplier/Retailer in Spanish for
CUSC	UK Connection and Use of System Code
DC	Direct Current
EDP Distribuição	Portuguese Distribution System Operator Energias de
DER	Distributed Energy Resources
DSM	Demand Side Management
DSO	Distribution System Operator
ENS	Energy Not Supplied
ENTSO-E	European National Transmission System Operators for
ERSE	Portuguese Regulatory Agency
EV	(Plug-in) Electric Vehicles
EVSA	Electric Vehicle Supplier Aggregator
EVSE	Electric Vehicle Service Equipment
FCDM	Frequency Control by Demand Management
FFR	Firm Frequency Response
HO	Home/Domestic
HTSO	the Hellenic TSO
HV	High Voltage
I&C	Instrumentation & Control
ICRP	Investment Cost Related Pricing
IFI	Innovation Funding Incentive
ILAS	Interruptible Load Ancillary Service
ISO	Independent System Operator
kW	Kilowatts
kWh	Kilowatt-hours
LAC	Loss Adjustment Coefficients
LCNF	Low Carbon Network Funds
LOLP	Loss of Load Probability
LV	Low Voltage
MAR	Maximum Allowed Revenue
MFR	Mandatory Frequency Response
MITYC	Spanish Ministry of Industry

MV	Medium Voltage
NIEPI	Número de interrupción Equivalente de la Potencia
NOIS	Nordic Operational Information System
NORDEL	Former Nordic TSO association representing Denmark,
OFGEM	British Regulatory Authority: Office for Gas and Electricity
OPEX	Operational Expenditures
PIQS	Plan to Improve Quality of Service
PR	Private Area with Public Access
PU	Public Area with Public Access
PYME	Spanish Small and Medium Size Companies
REN	Portuguese Transmission System Operator
RES	Renewable Energy Sources
RKOM	Norwegian Electricity Market Arrangement
RPI-X	Performance based regulation for Setting Network Operators' Allowed Revenues according to a Retail Price Index (RPI) as Inflation Rate and an Efficiency Factor X
RPM	Regulating Power Market
SA	Supplier/Aggregator or Retailer
SBP	System Buy Price
SoC	State of Charge
SSP	System Sell Price
Stattnet	Norwegian TSO
STOR	Short-Term Operating Reserve
TIEPI	Tiempo de interrupción Equivalente de la Potencia
TO	Transmission Owner
ToU	Time-of-Use
TSO	Transmission System Operator
TUoS	Time Dependent Use of System
TUR	Last Resort Tariff in Spanish “Tarifa de Ultimo Recurso”
UCO	Uncontrolled Charge
UCTE	Union for the Coordination of Transmission of Electricity
(D)UoS	(Distribution) Use of System
V2B	Vehicle to Building
V2G	Vehicle to Grid
V2H	Vehicle to Home
VPP	Virtual Power Plant

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IDENTIFICATION OF REGULATORY ISSUES REGARDING MARKET DESIGN AND NETWORK REGULATION TO EFFICIENTLY INTEGRATE EV IN ELECTRICITY GRIDS

1 INTRODUCTION

This report sums up the main insights from the research conducted in Tasks 2A through D of MERGE Work Package 5.

For facilitating the integration of electric vehicles in Europe, this report identifies the major regulatory hurdles that currently object a mass deployment of plug-in capable cars. It derives a high level overview of the way electricity markets are structured as well as network operation and ownership is at present regulated. Finally, this overview is used to gain recommendations for three development stages in the near, medium and long term.

1.1 Expert Survey for Regulatory Recommendations

In order to elaborate specific recommendations and guidelines for designing markets, tariffs and improving network regulation for the penetration of EV, which is the final objective of MERGE Work Package 5, in this second deliverable, an expert questionnaire has been developed to collect information regarding the project partner's national situation and the position of national regulators on the different issues.

1.1.1 Methodology

The guidelines and recommendations as a result of the research conducted in the MERGE project were organized around the following four main issues:

A. Design of day-ahead and intra-day wholesale energy markets as well as structure and agents in the retail energy markets, in particular, how EV loads and potential generation could be integrated, comparing current rules in different European regions.

B. Design of balancing and reserve markets considering the procurement of operational reserves, specifically regarding the efficient incentives for TSOs as well as EV aggregating entities.

C. Incentives and revenue allowances for DSOs, above all managing EV impact on investment and operational cost of DSOs and estimating consequences of largely increasing energy flows in specific periods. Furthermore, the roll-out for electric vehicle charging infrastructure including the different regulatory options for the ownership and operation of charging points in public locations with public access is broached.

D. Network tariff design, including the evaluation of different approaches from postage stamps per voltage to marginal use of connection points, with a comparison of the different current situation in EU countries.

The questionnaire was distributed among MERGE partners by the end of March 2011. For each regulatory issue, a general description of the problem and the current situation was provided. Main drawbacks and barriers in facilitating the progressive deployment of EV in Europe had been identified and were then rephrased into questions.

Finally, general recommendations to improve the current situation will be proposed identifying the entity responsible for their development and implementation.

Based on the answers, the aim of these recommendations has a twofold perspective: i) EU level, and ii) national level. To achieve this latter perspective the answers to the questionnaire presented in this document were collected from the corresponding information for the countries involved in the MERGE project including the opinion of national regulators. To sum up, the aim of this questionnaire was to find out for each regulatory topic:

- what the current situation or knowledge on the issue in the country was, and
- whether that can be of use for other member states.

The exact formulation of the survey questionnaire can be found in the Appendix of this report.

1.1.2 Sources of Data – Survey Response

The dissemination of the questionnaires to the MERGE partner consortium has led to a diverse feedback in terms of geographical as well as institutional background of the answering experts. Both academics from research institutes and universities as well as partners from industry and consulting have provided their insights and up-to-date knowledge about the specific matters and in the national regulation.

Countries	Expert	Role
Portugal	INESC	Research Institute
Greece	RAE, PPC, NTUA	Regulator, Utility, University
Norway	Inspire Invest	Industry / Consulting
Spain	UP Comillas, Iberdrola	University, Utility
(UK)	Cardiff	University
(Germany)	TU Berlin	University

Figure 1: Survey Responses and Expert Feedback

1.2 Development Stages of Electric Vehicles

Different levels of electric vehicle penetration have different requirements on design of electricity markets and network regulation. Therefore, three different phases have been identified in order to distinguish the policy recommendations given in this report. They are grouped in those that are immediate, rather mid-term and merely important in the long run. Immediately, the biggest challenge might be to foster the uptake and create trust in the new technology, further on, figures facilitating the integration of EV via aggregation and market participation should be addressed and then, in the long run, more complex and technically challenging services should be made possible.

The phases are denominated accordingly. Hence, Phase I for immediate recommendations is called *Catalyst*, Phase II is named *Consolidation*, and Phase III is titled *Advanced*. All of them are grouped in the chevron diagram depicted in Figure 2: Development Stages of Electric Vehicles

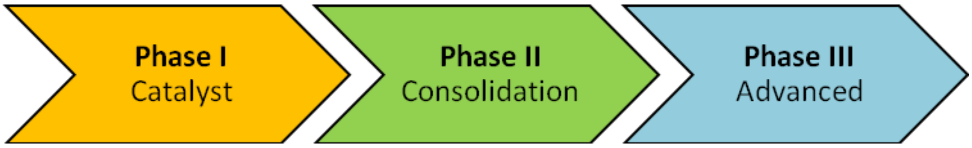

Figure 2: Development Stages of Electric Vehicles

1.2.1 Catalyst Phase

In the first phase, for immediate attention, absolute priority should be devoted to breaking important psychological barriers. In this phase of initial uptake, EVs can still be regarded as mere additional loads like any other domestic device.

Regarding public relations, all stake holders should be very cautious in for instance transmitting messages, related to favouring other non-EV related loads in case of network congestions. On the contrary, the network operators are in charge of assuring that all loads stemming from electric vehicles are not discriminated against compared to other domestic devices such as air conditioning etc. This hint can be generalized; communication to the public should always focus on the positive messages, such as recommending Time-of-Use (ToU) pricing instead requiring control or giving up priority to other devices.

Another principle should be noted: non-overcomplicating. Where possible, regulation should ease the life of early adopters striving towards new and challenging technology. Legislation should facilitate chance instead of creating complicated restrictions. The most ad-hoc and hands on solutions should be favoured with the least requirements for potential participants.

Obviously, the catalyst phase is the phase that is burdened with the least amount of uncertainty, as it is the closest to the near term. It actually starts as of right now and will only end when EV penetration ratios become very significant.

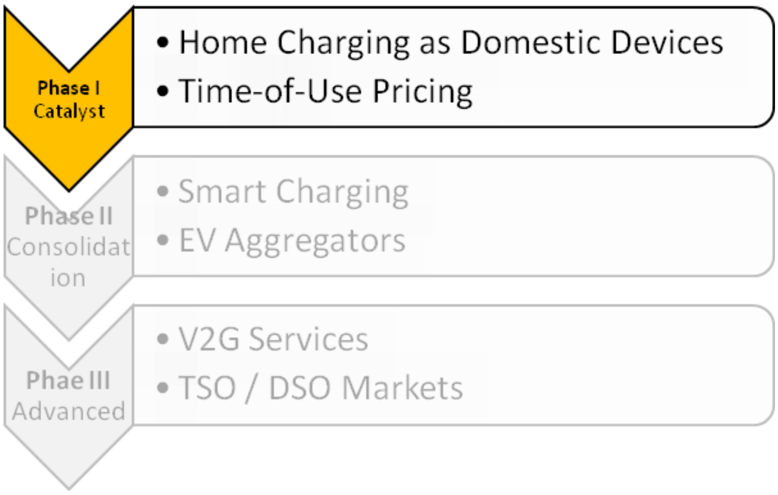

Figure 3: Phase I - Catalyst

1.2.2 Consolidation Phase

Depending on electric vehicle uptake, which is hard to foresee, the consolidation phase is considered to arise in the mid-term and hence is not of immediate concern. For this phase the electric power sector regulation should allow for the emergence of new business models of EV supplier-aggregators (EVSA) which are capable of managing the contracts of thousands of EV connecting simultaneously at different locations.

Their participation in energy markets, as well as in balancing and ancillary service markets should be facilitated. Risk hedging mechanisms will need to develop for assuring a stable functioning of systems. The potential relationship between charging points in public with the EVSA as well as with the final customer (EV) will need to be defined.

The development of expensive charging infrastructures in public sites, will become indispensable for the universal access of customers to this new technology.

The catalyst phase actually is the phase where smart charging and potentially control of fleets of EV for load management will become significant. Distribution system operators (DSOs) might have to validate control strategies and market results before they are determined to be feasible.

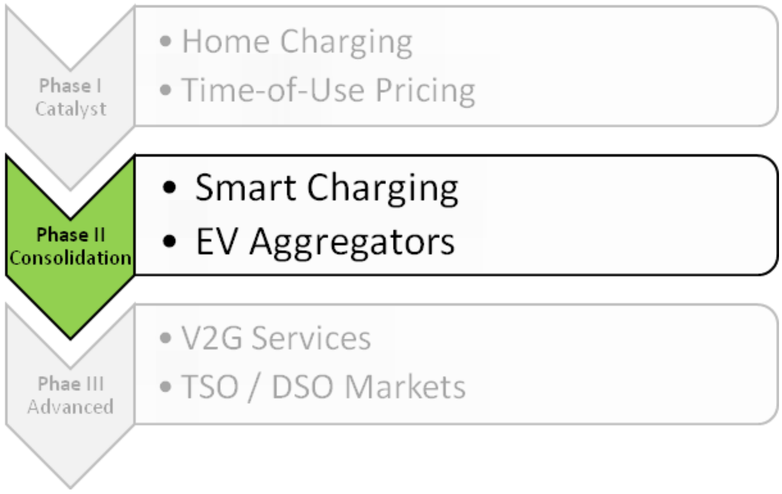

Figure 4: Phase II - Consolidation

1.2.3 Advanced Phase

The advance phase gathers the rather long term and somewhat futuristic scenarios. EVSA playing a substantial role in providing vehicle-2-grid (V2G) services and facilitating the aggregated participation of electric vehicles in balancing and ancillary service markets. Furthermore, they could be interacting with DSOs in setting up local markets for system services.

For such a scenario, more sophisticated control, measuring and billing infrastructures need to be put in place. There is a high need for cost/benefit studies to assess the profitability of these businesses before actual investment will take place. Other issues, such as warranty releases for battery performance of car manufacturers, need to be addressed as well.

It is to be noted that the concepts grouped in the advanced phase are not regarded as less important, especially as for instance frequency and voltage support might be highly important in integrating renewable energy resources in electric power system, however they are yet premature and not marketable and therefore need other attention than policies for the immediate deployment.

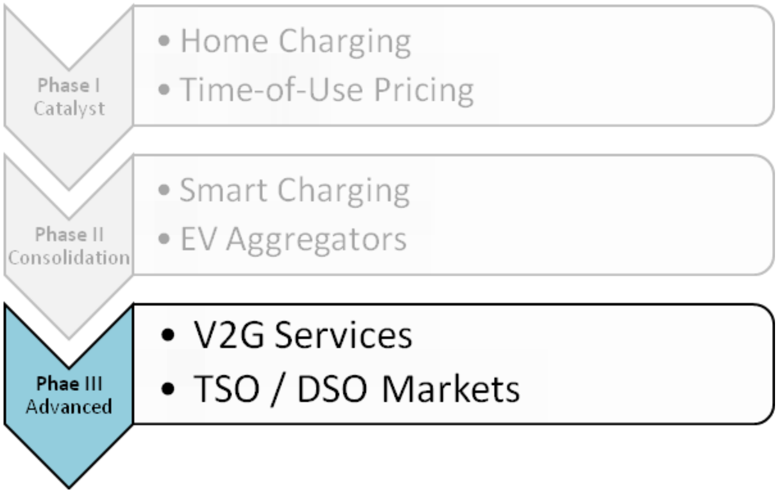

Figure 5: Phase III – Advanced

It has to be kept in mind, that the implementation of the proposed phases presented here, may bear not only advantages. Even though such a framework may help in providing decision makers the focus on the most important barriers, especially in the near term, that could impede the facilitation of a massive deployment of Electric Vehicles, there may be drawbacks. A potential disadvantage could be constituted by the fact, that early decisions may imply sunk costs and a commitment to hardly revocable results. This is just to say that even though they may not be obvious, the reader of this document should pay close attention to contradictions that the three phases may create in some parts.

1.3 Structure of this Report

In order to achieve these objectives, after a short introduction, this report indicates the main topics in sections 2 through 5, respectively section 2 discusses the *design of day-ahead and intra-day wholesale energy markets* (topic A), section 3 examines the *design of balancing and reserve markets* (topic B), section 4 analyzes *network regulation incentives and revenue allowances for DSOs* (topic C) and section 5 considers *network tariff design* (topic D). The last section, 6, summarizes the content and draws general conclusions notwithstanding topic specific conclusions within the respective sections.

It is to be noted, that each section may have its own list of references.

The appendix of this report contains not only the original questionnaire but also the national contributions by the partners.

2 DESIGN OF DAY-AHEAD AND INTRA-DAY WHOLESALE ENERGY MARKETS - WHOLESALE AND RETAIL ENERGY MARKETS

There exists a variety of challenges for efficient EV integration concerning the design of day-ahead and intra-day wholesale energy markets as well as retail markets.

Day-ahead and intra-day markets refer to the wholesale energy market, where generators sell electricity in large volumes to supplier aggregators (SA). SAs procure electricity to resell it to final customers on the so called retail market.

While the wholesale market is split up in different clearing sessions with varying trading windows ahead of the real time, i.e. day-ahead and intra-day sessions, the retail market has its own structures. The distinction should be made very clearly as can be seen in the following figure.

Figure 6: Wholesale and Retail Electricity Markets[1]

2.1 Retail Electricity Markets

2.1.1 Basic Characteristics

The activities of a retailer or supplier comprise so called technical and economic tasks. They include the billing of the energy consumed by the final customer according to energy and capacity prices set in the agreed contract. Therefore, a retailer has to store and use the information on the consumption of each final customer for load forecasting. Furthermore, the tasks embrace the acquisition of energy, e.g. in a power exchange, and managing the commercial relationships with the existing and potential new customers. This section focuses on the interactions of market agents such as SAs and the regulation they have to follow in order to perform their tasks when supplying EV users.

The SAs are market players that bridge the trading gap between generation and demand, fulfilling various functions from the wholesale to the retail market. In capital market theory, these functions mainly include transforming lot sizes, i.e. trading volumes and quantities of goods, risk transformation, i.e. hedging against undesirable events, and term transformation, i.e. monthly payments for domestic customers.

The profits of the SA result from the difference in prices, quantities, terms and risks at wholesale compared to final customer level. In order to assure a viable business model, the aggregated demand for the final customers has to be as accurately

[1] Big final customers sometimes may choose to participate in wholesale markets directly.

forecasted as possible, and then accordingly procured. If positions do not close as expected, that is, if the forecasting errors are causing a need for balancing of supply and the aggregated SA's demand, more costly ancillary service products have to be procured on the balancing markets.

In countries where electricity distribution and supply have been unbundled to favour competition among agents, all final customers should have access to competing generators through their choice of SAs and fully regulated tariffs, if they exist, are intended to only present a back-up option. In these cases, final customers remunerate the electricity supplier for the service, who in return procures the energy and pays the distributors regulated charges for grid services and other system costs.

Due to the uncertainty, stand-alone retailing is regarded a high-risk and low-return business. In theory, it is of high interest to the SA to obtain a very flexible demand, which is able to respond to varying market prices, in order to reflect the actual opportunity cost of the customers more appropriately and pass on part of the risk exposure to the final customers. In this sense, including a percentage of flexible demand procured by smart charging of EVs in their portfolio can be of interest for SAs in the future.

2.1.1.1 Tariff Choice: Last Resort vs. Retail Market

With the liberalization process of electric power systems in Europe, unbundling of regulated natural monopolies such as networks and commercial activity such as retailing electricity was established. Therefore, the promotion of electricity customers to participate in these retail markets is a basic principle but in reality is hard to realize as the final product turns out to be hardly distinguishable. Different regulatory setups within the common EU directives are possible. The following paragraphs introduce the situation in Spain and Germany.

<u>Spain</u>[2]

Therefore some of the member countries, such as Spain[3] have established so called two supply agent models for LV customer choice: Last resort[4] and "free market".

Any consumer is "eligible" i.e. free to go to the retail market, however only those with a contracted power above 10kW are obliged to go to the retail market. Those customers connected to LV and with a contracted power lower than 10kW may stay if they wish under a regulated tariff, the so called Last Resort Tariff (TUR in Spanish for "Tarifa de Ultimo Recurso"). The qualification criteria for LV customers may vary and include thresholds for maximum contracted power. In the future, the kW threshold is expected to diminish. These consumers are supplied by the so called Last Resort Supplier/Retailer (CUR in Spanish for "Comercializador de Ultimo Recurso") which effectively is assigned to suppliers associated to the incumbent distribution companies.

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[2] Greece and Portugal are quite similar.

[3] as of 2009, Royal Decree No. 485/2009

[4] This option is sometimes also referred to as: "last resource"

Last Resort suppliers are a continuation of the previous retail model, in which customers connected to LV and with a power contracted lower than 10kW purchase electricity from the retailer at a regulated tariff (use-of-system charge). This sort of agent is responsible for all commercial and technical related activities, including quality-of-supply. The unitary costs for both the fixed component (contracted-power related) and the energy consumption are regulated by the Ministry of Industry (MITYC). The list of authorized last resort suppliers is published by the MITYC. However, the last resort suppliers have to procure their energy through a tender called CESUR, organized by the market operator OMEL. Therefore, all energy supplied to the final customers choosing not to turn to the free market alternative, is auctioned every three months.

In case of the free market alternative, the customer's bill consists of a fixed component access tariff (set by the MITYC), in order to primarily recover the so called system costs (network costs among others), while energy purchase prices are established under a bilateral agreement between both two wholesale market participants, i.e. a generator and a retailer. The list of free market retailers is published by the MITYC. These may subcontract metering activity. The retailer also settles the charges for using the network with the according distribution system operators.

The following graphic depicts the Spanish day-ahead wholesale market prices and energy volumes happened on Wednesday, March 2nd 2011[5] [2.1]. This date is chosen to be representative in its characteristics of total energy traded 584.99 GWh, high maximum price of 53.50 €/MWh occurring during the midday, low minimum price of 32.15 €/MWh occurring during night hours, intermediate arithmetic mean price of 45.52 €/MWh and average trading volume weighted price of 46.41 €/MWh.

[5] not including intra-day components, capacity payments or other cost constraints.

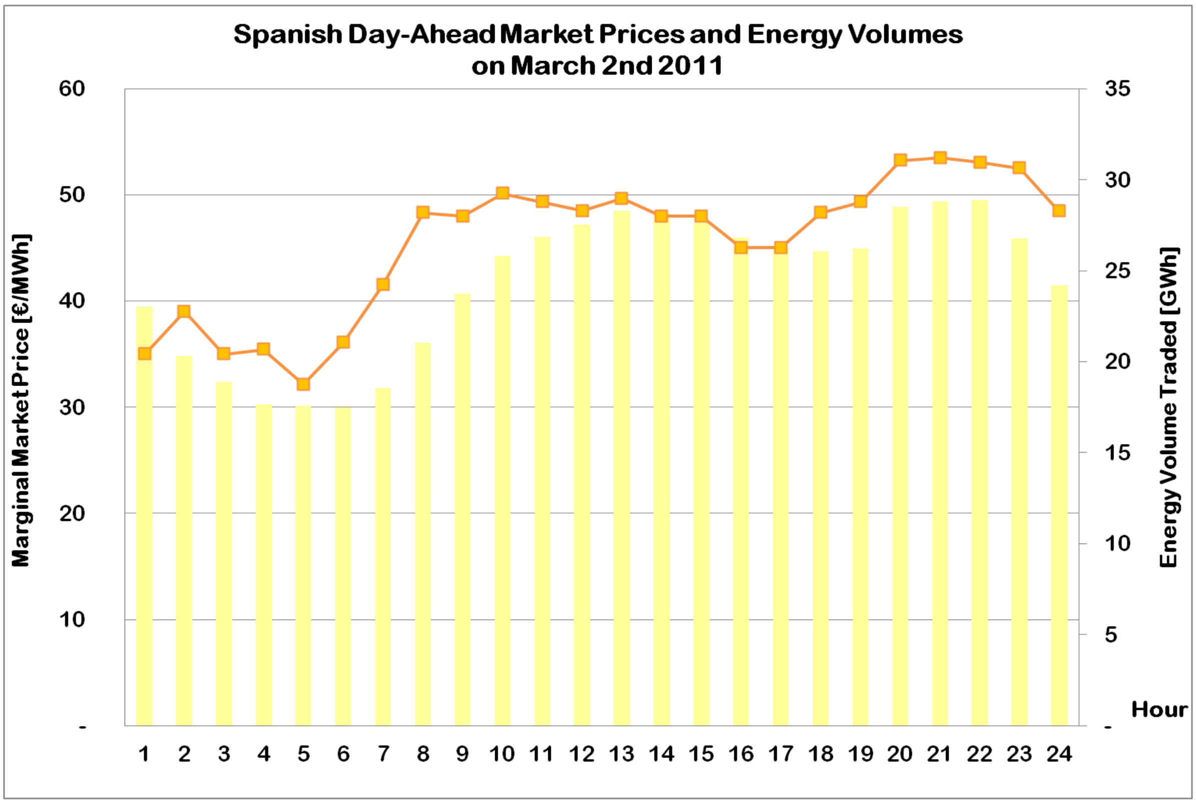

Figure 7: Spanish Day-Ahead Market Prices and Energy Volumes on March 2nd 2011

As depicted in the following graphic, the wholesale electricity price only makes up about 49.2% of the total electricity price to final customers. In September 2010, the components of electricity prices of to final customers with hourly varying prices in Spain made up: Fixed Access Tariff 1.9 €c/kWh (16.8%), Variable Access Tariff 3.43 €c/kWh (30.3%), Commercialization Margin 0.41 €c/kWh (3.6%) and Wholesale Energy Cost 5.57 €c/kWh (49.2%), [2.2].

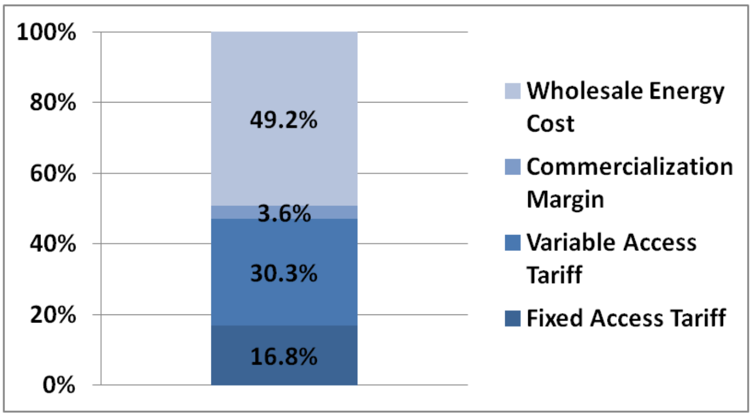

Figure 8: Components of Electricity Prices of Final Customers with Hourly Varying Prices in Spain September 2010

Germany

On the other hand, there exists regulation in some member states such as Germany, and Norway in which all final customers regardless of their contracted power level are obliged to "go to the retail market". Effectively, that means that a German customer has to choose his energy provider[6]. Usually these providers offer "all-inclusive" packages for "load profile customers"[7], connected in low voltage. They include all three cost components:

- Regulated tariffs for grid usage (access fees)
- Energy procurement and delivery
- Taxes and pubic charges for renewable support schemes etc.

A detailed composition of these prices can be explained taking the year 2009 as an example. On top of the so called wholesale prices traded at the European Energy Exchange (EEX) in Leipzig there are additional components to arrive to the final tariff that end users were paying (ca. 0.16 €/kWh). On average, net access fees, concession levies, and apportionments from the German Renewable Energy Law (EEG) and the German Act on Combined Heat and Power Generation (KWKG) made up 26.1% of the consumer price before sales taxes of supplementary 19%. See Figure 9.

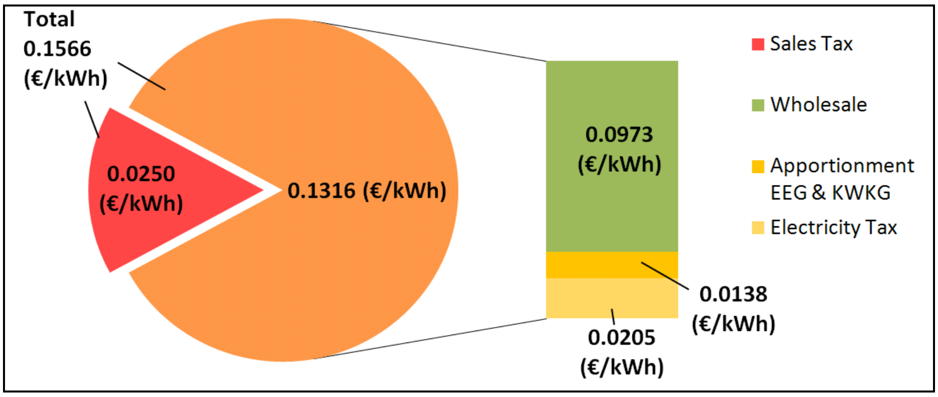

Figure 9: Composition of End User Electricity Prices in Germany 2009 [2.3][8]

[6] No withstanding the fact, that customers not opting for a „new retailer" are staying with incumbents, if switching costs are perceived to outweigh the advantage of a new contract, willingness is not provided or simply the final customers lack knowledge of the procedures to follow.

This may well be the motivation to establish free switching between retailers as it has happened in Portugal. There, the final customer has the right to do a cost free switching of retailers up to four times per year.

[7] Load Profile Customers are those final customers with a yearly consumption less than 100.000 kWh. The settlements for these can be made according to what is called „standard load profiles".

[8] (Dürr 2010): Average Residential Rate for a Household with an annual consumption of 3500 kWh for the year 2009, including wholesale prices with variable generation cost for fuels, transport and CO_2, sales taxes of 19 %, as well as net access fees, concession levies, apportionments from EEG and KWKG. Own illustration.

To complete the indication of governing legislation in the German retail market, the possibility to switch to default tariffs still exists, yet should be treated as abnormal. In the highest level electricity Act, the ENWG 2005 in response to the Directive 2003/54/EC, Art 36 treats the so called “Grundversorgungspflicht” of energy utilities for certain assigned territories in their area of operation, a duty to offer a basic tariff with common conditions and common prices for every household customer. These prices and conditions must be made publicly available, i.e. on the internet, and offered to any private customer who requests the “default tariff”. The designation of default suppliers is made according to the highest share of household customers in a given territory, every three years determined by the distribution company. In case of a change in default supplier during the three year evaluation period, all common conditions and prices are handed over to the subsequent default supplier according to the contracts in place [2.4].

Settlements for Energy Charges to the Final customer

In most of the countries, such as in Spain, the residential customers may choose the electricity supplier. The distribution company may or may not own the meter and provide the metering results to the supplier. The supplier bills the customer monthly, based on capacity and energy charges plus some extra payments related with specific system costs or with some specific taxes. The supplier settles his energy purchases in the market, i.e. long term contracts, day-ahead markets, etc., according to standardized profiles, wherever hourly differentiated meters are not available that translate the monthly or bi-monthly energy measures of its consumer portfolio into an hour by hour purchase. Besides, the retailer will pay the access tariff to the distribution company.

By definition, the default supplier is selected if the customer cannot find a supplier on the market, the customer is moving in without choosing a supplier or if the customer does not choose a supplier for instance when the market opens. The term “supplier of last resort” is defined in primary law as well as in secondary legislation and it is applicable in case the supplier goes bankrupt or the contract expires [2.9].

2.1.1.2 Agents of the Retail Market

The following paragraphs give rise to the different situations of the member states concerning the advancement of creating functioning retail markets after the processes of unbundling and liberalization. The various possible arrangements are introduced via Spain, Portugal and Germany.

Spain

As of 2009, the royal decree RD 485/2009 establishes two supply agent models for LV customers: Last Resort and free market. The former consists of 5 firms while the recently implemented free market retailing accounts for 33 companies. The main firms perform activities under both retailing models.

Market information is provided by the Comisión Nacional de Energía (CNE). According to this regulatory agency, in 2009, the free market represented 10,6% of the LV energy sales.

Retail market share for 2009 is:

- Endesa: 52,4%
- Iberdrola: 25,7%
- Unión Fenosa: 8,7%
- H. Cantábrico: 5,9%
- Gas Natural: 4,7%
- Other: 2,6%

The following graphic visualizes the given information of the Spanish retail market structure in a pie of a pie diagram.

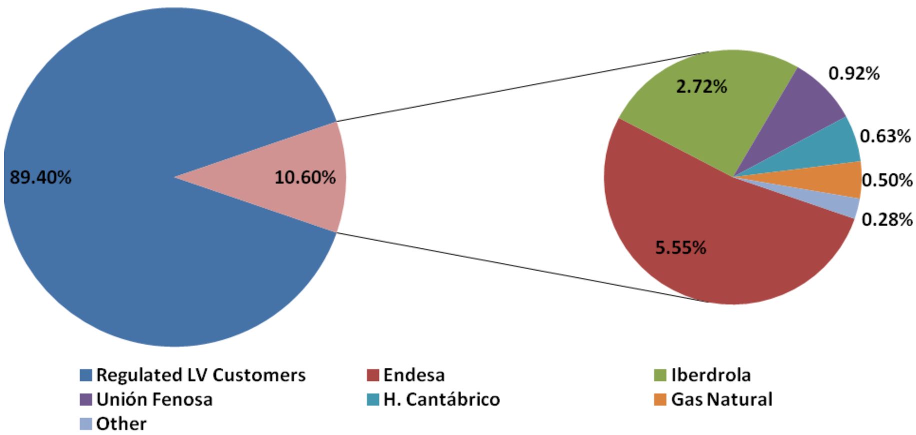

Figure 10: Retail Market Share in Energy Sales as in 2009 (CNE)

It is sometimes argued, that in Spain, retailers offer their services usually at rather similar conditions (with regulated prices). In practice, low demand customers are not highly incentivized to change supplier. In addition, the presence of free market still represents low activity, with some of the new retailers having financial difficulties.

However, by definition, the default supplier is selected if the customer cannot find a supplier on the market, the customer is moving in without choosing a supplier or if the customer does not choose a supplier for instance when the market opens. The term “supplier of last resort” is defined in primary law as well as in secondary legislation and it is applicable in case the supplier goes bankrupt or the contract expires (European Regulators’ Group for Electricity and Gas 2009).

Portugal

In Portugal the situation is rather differentiated. The free retail market comprises 6 retailers that supplied 360,463 out of 6,000,000 clients by the end of March 2011. The share of the free market in terms of connection voltage varies a lot and it is very large in higher voltage clients and drops as one goes towards LV., Almost 90% of the clients connected in EHV, HV and MV are already supplied by retailers in the free market. Regarding LV clients it is important to distinguish between Special LV (contracted power larger than 41,4 kW) and Normal LV (contracted power below 41,4 kW). On SLV, about 51% of the clients are already on the free market while on NLV (including domestic clients) almost 90% of them remain in the regulated market [2.5].

Furthermore, the average demand of the free clients on the 12 months finished in March 2011 corresponded to 22.367 GWh. This represents an increase of about 6% regarding the value obtained in February 2011 and it corresponds to 46,5% of the total de-mand in the country.

In March 2011, 4544 clients migrated from the regulated market to the free market, corresponding to 1418 GWh of new demand in the free market. On the other hand, 3305 clients went out of the free market (LV clients that returned back to the regulated market) representing about 23 GWh of demand on an annual basis. In March 2011, 770 clients changed of retailer inside the free market. These clients represented an annual demand of 64 GWh.

Taking into account the changes reported in the previous bullet, the total number of clients in the free market increased by 1239 and the demand increased 1395 GWh.

Germany

Traditionally the German retail market used to be highly concentrated, with four big suppliers RWE, E.On, Vattenfall Europe and ENBW. But even though most of the generation remains in the hands of a few, the retail market draws a different picture, as during the last decade more and more new agents entered the game.

Aside the big legally unbundled utility companies there exist over 900 different suppliers offering as many as 9000 tariffs. Out of these, approximately 5% of the electricity supply companies are regional suppliers, 80 percent are municipalities owning both distribution and small generation assets (with partially strong ownership shares of the "big four") and maybe 15% pure retail companies [2.6].

In total, the German electricity suppliers are employing more than 170.000 people. Altogether, more than 25% of the German end users have switched their electricity supplier while around 53% are thinking about switching, which manifests an increase in switching potential by more than 20% compared to spring 2009. Especially the young people between 18 and 33 years of age seem to be well trained with mobile phone and internet service providers, and therefore represent the most switching affine group of customers. Concerning non private final customers, around 50% of all commercial customers have switched the supplier while 100% of the industry customers opted for a different supplier since the liberalization of the German electricity retail market [2.7].

2.2 New Agents and Wholesale Market Characteristics

A massive deployment of plug-in Electric Vehicles will to cause the necessary emergence of new agents in the electric power system. Depending on the charging mode, i.e. the scenario in which the charging process is taking place, defined by determinants such as charging point location and the level of control over the charge, the interacting new and old agents and their relations for delivering the final product might change. The following sections treat these new agents and their prospective functions in future regulation for Electric Vehicles.

2.2.1 Charging Point Managers

Charging Point Managers (CPMs), owning the charging infrastructure assets, are believed to be acting as final customers on private property with public access. They are understood to buy the required electricity to resell it to other EV owners connected to the local charging station under a commercial agreement with specific terms and conditions. To the distribution system however, a CPM is regarded as a single final customer. The supplier would have to pay the regulated access tariff according to the contracted capacity and consumption measured on the interface to the network. The CPM in general would have a supply contract with a supplier. A regulatory option would be to oblige these contracts to be at least time or load variable, including TOU components.

As with any other final customer the measuring and metering at the final customer point is related with network activity and therefore only the measuring, on the interface with the EV user is the business of CPMs.

Private set ups of multi-dwelling homes can make up a significant share of the population in urban areas. There, competing objectives when installing the wiring in the parking lot with multiple charging points for EVs may exist. It is not obvious to require the entire community to install charging installations with EV markets virtually non-existing, as there are higher initial costs involved. However, the goal may be to have EV charging for a maximum number of people at some point in the future with lowest cost per connection for the charging installation. Therefore, the recommendation for CPMs in multi-family dwellings is to install charging infrastructure one by one as individuals opt for EVs. Furthermore, it might make sense to, starting early on, keep future uptake of EV markets and therefore a need for charging infrastructure in mind, when building new homes.

Several options have been proposed and may exist:

1) Install a common wire (and the corresponding sized Transformation Center). Each particular site will be fed by a short branch connecting the common wire to the exact site place.

Advantages: If a majority of car holders switch to EVs, it could be more efficient (in economic terms) to meet the necessary garage infrastructure investments.

Disadvantages: for the beginning (phase I) a small number of EVs are expected. It woul constitute a barrier to force a common wire installation since the neighbour community would have to agree to bear this investment cost. A rejection should be expected from those neighbours that still don't have in mind to switch to an electric vehicle. Moreover, it is surely not economically efficient to adopt such an investment cost when it will be fully used only several years ahead.

Two modalities for metering purposes have been proposed under this scheme

a) A single fiscal meter for the common wire (with or without non-fiscal individual meters to allocate the charges according to actual use of each neighbour or not)

The idea is that either the charging consumption cost is assumed by the whole neighbour community (as it happens in some place with heating or water services), in which case only one meter device is needed with the corresponding savings in measurements devices, or at least a single connection point is declared with the corresponding savings in access charges.

Disadvantages: EV owners do not have the freedom to choose retail/aggregator supplier except if complex roaming process are available. In case of a common non-individual-consumption based charge, it leads to perverse inefficient use of the charging.

b) A fiscal meter for each garage site (with or without non-fiscal individual meters to allocate the charges according to actual use of each neighbour or not)

This solution (common wire plus individual fiscal meter) requires that the common wire and the dispersed metering will be under the distributor charge. Distribution companies will be against this solution (it could be a barrier) since they do not have means of control as they do now their wires (nobody has access to them) and the metering devices all gathered together in a close room. There would be an extra cost associated.

2) Install a particular wire for each EV site in the garage

This can be arranged, without requiring the agreement of neighbours, avoiding a strong barrier. Furthermore it could be less costly if the EV deployment is progressive (in terms of wires and CTs).

Two modalities for metering purposes have also been proposed under this scheme

a) A single fiscal meter for the house and EV consumption

This solution would be cheaper for the consumer as he has to contract only one single access point.

This would provide a natural incentive, even without ToUs tariffs, a clever management of the EV charging, at night presumably, since the consumer knows that if they want to feed at the same time the car and the house, they need to contract more capacity (KW) which would imply additional cost for them. This would help to avoid problems in the distribution system feeding the house. (Note that this discussion is valid also for individual houses).

b) Two fiscal meters, one for the house and the other for the EV consumption

An advantage would be consumption based taxation of electricity for mobility use[9].

CPMs should be free to define their objective function that is most beneficial to them. This could include an installation of Electric Vehicle Service Equipment (EVSE) that meters the connection points of each and every car and design according rates for the usage of this infrastructure. On the other hand, it could be favourable for the CPM to simply charge for parking time and space without measuring user specific consumptions by internalizing energy procurement and infrastructure investment costs on an aggregated level in the parking time rates. Hence, the CPM could be offering the charging of the electric vehicle as an additional service to customers with whom there already is some other type of

[9] See recommendations section 2.4.1

commercial agreement. The second arrangement alludes to the main challenge of a regulatory framework forming the basis of legislation that fixes the rules for such operation of the charging service. Any set of requirements concerning metering layouts, financial liability and technical capability should be designed according to the principle of non-over-complication, applying restrictions only where absolutely necessary.

2.3 Wholesale Electricity Markets and Supplier Aggregators

However, if the penetration of EV gets very large and the bids sent by the aggregators to the market become very relevant, new specialized EV aggregators should arise and additionally in close interactions with DSOs the operation of distribution networks will also have to be considered. In such a case, the DSO should be called to validate the flows resulting from normal demand from a technical point of view and be informed about the amounts to be bought by the aggregators.

The following table summarizes the day-Ahead and intra-day wholesale electricity market structures in the different member states at a glance. As a simple introduction to and advanced regulation of wholesale electricity markets only the Spanish and Portuguese case is elaborated in more detail via the joint Iberian peninsula framework. In general, the differences in the setups are not regarded to hinder EV integration whatsoever and therefore if further knowledge about the particular cases of other countries wants to acquired, the reader may well refer to the sources indicated in the answers to the expert questionnaires.

Country	Day-Ahead	Intra-Day	Pool or Bi-lateral Contracts	Computation Mechanism	Demand Side Bidding?	Forecasting Procedure?
Greece	x	no	mandatory pool	10 step bids - co-optimization of unit comitment and AS, water and RES are set and enter at zero price. Gate Closure at 12:30	Yes	Conducted by the TSO
Norway	x	x	Both, but Pool represents 70%	Hourly Bids, Block Bid, Linked Block bid and Flexible Hour Bid. Marginal Pricing. Gate Closure at 12 (noon). 12-36 hours ahead for 24 hour periods.	Yes	Estimated consumption for market bids - post settlement of accounts - deviations paid via prefixed price
Spain/ Portugal in joint market for Iberiangene peninsula	x	x	Pool	Marginal Price. Gate Closure at 11 am. 6 consecutive 4 hour intraday market sessions.	Yes	Conducted by the TSO
Germany	x	x	Both, but moving towards spot market	Merit order marginal pricing. 12 noon. From 3pm to 75 min before real time intraday trading is possible		

Figure 11: Day-ahead and intra-day wholesale electricity market characteristics at a glance

Spain

The wholesale electricity market is common for Portugal and Spain under the so called MIBEL market. The specific rules are detailed in OMEL, "Operation Rules of the Electricity Market", (in Spanish), available in www.omel.es. Normal Regime Generation (renewable and small hydro units are known as Special Regime Generation and have specific rules) should communicate their selling bids to the market operator or establish bilateral contracts with the demand. The demand can also bid on the market. The electricity market has a daily basis and it works in the scope of the Common Iberian Electricity Market established between Portugal and Spain and in operation since July 2007. It is a symmetrical pool market to which all agents should communicate their bids till 11am each day. After establishing the operation programs, this information is sent to the two system operators for technical validation and at about 4pm the feasible operation program for the next day is obtained. Then, the two TSO's contract the required levels of ancillary services and at about 8pm starts the first session of the intraday market for the whole period of the next day. There are currently 6 sessions of the intraday market with time intervals of 4 hours typically to contract small amounts of electricity for periods that start 4 hours afterwards. Finally, transmission and distribution wiring activities are regulated and retailing is developed in competition although a regulated retailer still exists namely to supply LV consumers that didn't migrate yet to the free market.

2.4 Recommendations

2.4.1 Recommendations Concerning Retail Markets

Summarizing the recommendations concerning retail markets for the first, i.e. the catalyst phase the following is stated:

- The first best solution is a combination of measurements with a single smart meter per customer with an implementation of ToUs tariffs.
- Secondly, if standard load profiling is kept for the domestic loads, at least for load associated with electric mobility, ToUs tariffs and smart metering should be implemented for EVs
- Thirdly and least preferable but also imaginable the implementation of separate metering of load associated to electric mobility is implemented.

The use of standardized load profiles for qualified customers with a sufficiently small consumption and little contracted power is a suitable approach to deal with load from domestic customers as long as EV penetration levels remain unchanged. If they change, however, it would be a lost opportunity to make better use of such an hitherto idle potential of very flexible and schedulable load.

For standardized load profiling, the illustrative example is the German approach, in which Load Profile Customers are those final customers with a yearly consumption less than 100.000 kWh. The settlements for these can be made according to what is called „standard load profiles". Their energy consumption is measured by basic electricity meters, which count only electric energy in kWh.[10]

As opposed to that customers with an energy consumption ≥ 100.000 kWh/a are called "load curve customers". Their measurement category is not energy but electrical power (kW), measured with a special device, the power meter. Power meters register the average electrical power in each 15-minute measuring period. This data results in the load curve, which gives the amount of electrical power over the course of time.

With EVs however these approaches become less and less suitable. The thresholds maybe debatable, however due to the fact that EVs present a significant additional load to a normal domestic household load and consumption, regulation needs to

[10] Smart metering in this context refers to the first intuitive step to any metering system that is able to distinguish different time periods. This does not impede that this metering system could also comprise sophisticated communications systems.

adapt. Therefore, tariff, metering, settlement and billing structures should comply with appropriate incentives to the final user.

As soon as EV penetration becomes significant, which may certainly vary from case to case, depending on the DSOs assets, the structure of the network and renewable intermittent generation to be integrated, then, smart metering should be implemented.

It is important to understand that with smart metering there is no need for the application of standard load profiling. But, without smart meters that are capable of distinguishing measurements over time, TOU tariffs are ineffective. They are crucial in providing the appropriate charging incentives to the final customers. However, TOU tariffs can be dangerous, causing additional peaks in the system if local charging optimization is not taking into account the equality of the incentives to all EVs. One solution to these “avalanche effects” could be to introduce different TOUs periods for different customer groups. The more sophisticated solution, with EV penetration reaching significant thresholds, would be to use direct control over the charge by an aggregating entity. No matter who owns the meter, which can be varying in the different countries, where there are smart metering roll out programs in the next 7-10 years, a clear recommendation to oblige the DSO to change the meter of EV owners is given. EV owners should not only be given the priority for receiving the meter, rather assured that they receive it.

The separation of electricity measurements for different types of uses remains a controversially discussed topic. The arguments against discriminating load measurements include reasoning that efficient management of electric power systems should be addressing all types of loads, not just EVs. Furthermore these arguments are concerning fraud prevention and avoiding of additional costs of administration. If an electricity for EVs would be priced (i.e. because of additional taxes or reducing subsidies) differently than other loads, the potential of final customers circumventing such a regulation rises. The additional costs of administration are difficult to quantify ex ante but may arise because of parallel databases, processing and storing large amounts of information etc.

Smart metering does not automatically refer to having different meters, except if some type of tax is intended to be put in place. However, in order to not create additional barriers, taxing would be more appropriate in Phase II, when EV penetration rates become significant.

Or, the second solution could be including the obligation of separate smart metering for EV. That way, the consumption of the vehicles would be clearly distinguished between the standard load profiles for unchanged final customers, i.e. with low consumption and little contracted power, and those final customers having purchased EVs.

For the separately metered EV load as well as for any other loads, time of use tariffs should be either incentivized and or required. Nowadays, to promote efficiency, suppliers, regardless whether they provide electricity to EVs or to other domestic customers, should be required to provide every final customer with at least one time variable or load variable tariff option as permitted by EU directive 2006/32/EG [2.8].

In a consecutive step, legislation should require all customers to be exposed to time and load variable tariffs to incentivize the creation of a price sensitive demand side of the electricity sector.

The roll-out of meters with advanced bi-directional communication infrastructures based on mandate M/441 is recommended.

Phase II
Consolidation

For many countries, retail markets are not functioning in low voltage final customers, which are going to be the EV users. Legislation needs to promote switching for customer specific tariffs on free retail markets to ensure efficient energy procurement.

In the longer run, decision makers should improve the image of electricity retail markets and push the development of functioning markets for the customers. Policy makers of all parties and countries should agree on the recommendation to private customers to change the electricity supplier whenever economically attractive, to create the right signals to the incumbents. It is the duty of all regulators as advocates of an efficient system to take away the fear of final customers that the new retailers would have financial difficulties.

It is not necessary to separate metering, however the advantage of having distinguished measurements for EVs from the other domestic consumption lies in applying different tariffs to EVs than to other uses. This could be an interesting lever for taxes. With electric mobility becoming massively propagated, it may be fair to tax EV for their use of public goods, such as roads etc. These taxes could be applied at the time of car registration, locally dependant on traffic or directly at the electricity consumption. In the last case, the only way of assuring that the taxing of mobility at electricity consumption level remains controllable is to have a meter inside the car. Otherwise, with moving EVs from one final point to another, the EV user could bypass fixed metering installations

2.4.1 Recommendations Concerning Charging Point Managers

Phase I
Catalyst

As it has been undertaken in some of the surveyed member countries, legislation needs to define the figure of charging point managers in detail. At EU level an umbrella directive that normalizes the conditions in the member states would be helpful. The need for such a figure should be recognized and the most important pillars concerning obligations and degrees of freedom for the licensing of electricity resale, technical specifications and financial viability need to be drafted to fit the country specific solutions.

The CPM entity should be left with a certain degree of freedom concerning his business model, i.e. to define contracts with EV customers including price components, to guarantee a maximum confidence in such business. This would mean that there would be no regulation to install metering devices if this is not desired. But if meters are installed they should comply with regulation existent.

Financial liabilities should not be as strict as for retailers that deal with larger volumes and assume high risk positions in wholesale markets. The main argument to be made here, lies in the fact, that CPMs should be able, as any other final customer, to either be supplied by an SA, or participate in the wholesale market himself. The decision should lie with him. If the CPM then decides not to participate in wholesale markets, he certainly should not be obliged to meet all the requirements that resellers have to meet up to now.[11]

In the particular case of CPMs acting on joint private property such as, parking spaces of multi-dwelling units, in Spain there are many discussions concerning the allocations of costs among the different community members. Once again, consistent with the definition of Catalyst Phase recommendations, a solution that is devoted to minimize initial barriers for EV deployment should be favoured. Therefore, usually an agreement is needed between a single final customer, willing to acquire an EV including the charging equipment, and the entire neighbourhood community. A requirement like that could be a big barrier, because if the installation devices are not present for home charging, most likely the individual would withdraw his purchasing intention. Therefore, legislation should ensure, that community authorization for new installations for example in common private property of community housing is not always strictly needed.

Another point is that electricity meters should comply with general requirements and they need to be checked upon every now and then. Similar practices are currently already undertaken in industries like in gas stations etc. An authority of assuring justice in that context is advisable.

Most pressingly, a level playing field for new and incumbent players in electricity retail should be designed. No imposition should be made on how CPMs are to resell energy. So decisions can be made on the local level: prices, charging installation, as all these points are business model characteristics. Legislation could leave the details open and let the market develop itself such that details concerning types of measurements, time intervals, storage capabilities, switches and communication (Bi-/Uni-Directional) and bandwidth for communication are left out in the beginning.

2.4.2 Recommendations Concerning Wholesale Markets and Supplier Aggregators

In general wholesale electricity markets in Europe seem apt to integrate the new highly flexible loads from electric vehicles as they are structured today. The general framework in its current design allows for the integration of EV fleets that are aggregated by a certain new entity as well as being dispersed as regular dispersed domestic loads. The presence of both day-ahead as well as intraday and close to real time trading schemes is regarded suitable for EV integration in all the cases. No major barriers have been detected in that respect. However, in the following paragraphs, a couple of minor thoughts and recommendations are passed on specific to the phase dependency of EV penetration.

[11] Reselling in this context refers to the activity of electricity resale to EV only, i.e. strictly for the purpose of charging electric vehicles. Hence, reselling does not mean that any final customer can now resell energy for his own purposes.

Phase I
Catalyst

Electricity supplier or electricity retailer is the agent who sells energy to final customers, the electricity end consumers. The supplier therefore aggregates contracts with final customers and procures the energy in the wholesale markets, and possibly agrees on demand side reductions measures of the final customers to be offering other services to the market. Hence, these agents already exist and are denominated supplier aggregators (SAs).

In the near term uncontrolled and home charging modes are very likely to dominate the scene, in which most of the functions and objectives of the SA stay the same. In the scenarios where EVs are charged at home, the EVs will merely present and additional net load to the SAs of domestic electricity customers. In short, this load is more volatile because it is a flexibly schedulable charge and hence presents the opportunity for more business, but also the threat of adding uncertainty to the forecasting. As during this phase there is no control over the charging process from the SA, the main means of influencing the charge of the electric vehicles will be the offer of EV user customized electricity prices with at least time-of-use (ToU) differentiation. The main objective remains, to get the demand side involved in the market game by passing on the volatility of prices and thereby reducing its own risk. The proposition by electric vehicles could be theoretically a valuable one, as they present schedulable loads, which if reacting to the price signals may contribute to reduce uncertainty and risk exposure of the SAs, while increasing turnover significantly.

Phase II
Consolidation

With the electric vehicle penetration reaching an advanced stadium, surpassing significant shares in the vehicle fleets, appropriate demand forecasting techniques will become crucial to an efficient integration of EVs in wholesale electricity markets. The time frame plays an important factor. Forecasting EV charging with merely several hours in advance is going to be critical for managing energy in the day-ahead or intra-day markets. The optimal gate closure for each market may be very different concerning ancillary services, in particular balancing markets. But for wholesale energy markets the current set up shall be sufficient.

The discussion about the controllability remains unresolved. With significantly big size fleets and sufficient historical data, the statistical approach might allow forecasting with enough accuracy so that the lack of control as well as the uncertainty could be managed. However for that, very advanced prediction algorithms will be required.

In the same regard the functions of supplier aggregators are expected to remain very much unchanged or at least will not undergo drastic revolutions. The specialization on EV demand may create a certain advantage and profit opportunities, due to the flexible nature of the load. The suppliers are hence expected to design customer specific services and market them accordingly to attain those potential benefits. However on the regulatory side no changes are necessary for that.

Phase III
Advanced

As the design of wholesale energy markets is yet at an advanced and very sophisticated level, the required changes currently seem rather minor and therefore seem possible to be implemented within the catalyst and consolidation phases. Other long term recommendations for the advanced phase hence are not given.

Refer to the next chapter on ancillary service.

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3 DESIGN OF BALANCING AND RESERVES MARKETS

In this section, the impact of the participation of Electric Vehicles (EVs) in the balancing and reserves markets is investigated. Since there does not exist a uniform electricity market design across Europe, the current designs for the provision of reserves in different European regions are briefly described. Furthermore, restrictions and barriers that can be an obstacle for the participation of EV portfolios are identified, and specific recommendations to improve the current situation are given. In addition, incentives for Transmission System Operators to develop more decentralized control schemes to allow a massive participation in ancillary services provision coming from distributed energy resources, such as EVs, are discussed.

3.1 Introduction

With an increasing amount of Electric Vehicles (EVs) connecting to electricity networks, the electric power system might undergo a significant change as the base of potential Ancillary Service (AS) providers is broadened. The EVs could use their batteries and inherent storage capability to provide such services, which are currently under the control of Transmission System Operators (TSOs) that determine the required amounts, contract and manage their use. Grid operational issues may however much more arise at the medium to low voltage distribution level than in transmission assets. Therefore, in parallel to ancillary system services procured by the TSO, authority and competencies may have to be extended to DSOs in parallel.

Even more so, in the future, when distribution networks might operate in an isolated mode (for instance due to a failure of the HV/MV or MV/LV substation), some responsibility regarding the management of an AS could also be assigned to Distribution System Operators (DSOs). However it is possible that DSOs would rather be interested in local ancillary services that are most likely not frequency but load flow related[12], and in this case the scope of new reserve products or requirements at Distribution System level would need to be investigated. In this section we focus on EV participation in existing TSO-procured reserves, particularly through Demand Side Management.

In Central Europe, the European Network of Transmission System Operators for Electricity (ENTSO-E) is the responsible institution for frequency control, which is carried out in 3 different control phases differentiated mainly by the timeframe of calling upon them: primary (a few seconds, decentralised turbine speed governors), secondary (seconds up to 15min, centralised automatic) and tertiary (within 15min for large incidents, manual), as shown in Figure 12 [3.1].

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[12] Section 4 on network regulation incentives and revenue allowances for DSOs reports on this issue in more detail.

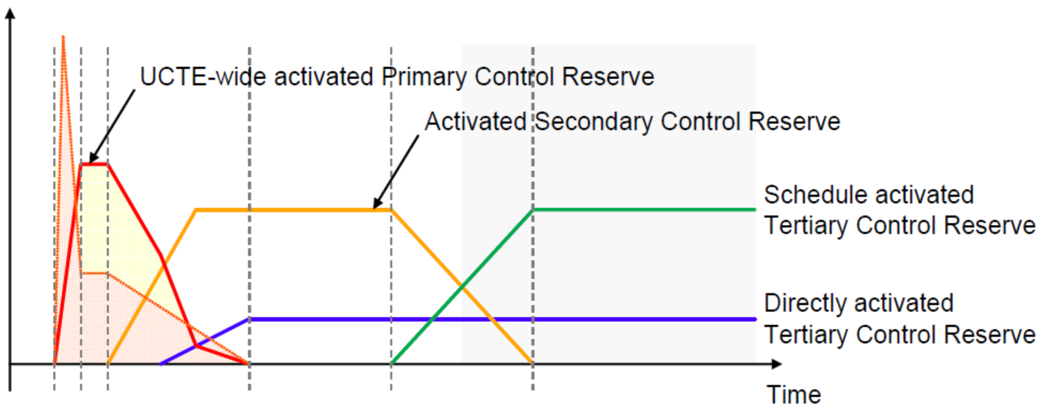

Figure 12: Principle frequency deviation and subsequent activation of reserves [3.1]

This report will mostly focus on the frequency-related reserves, and omit issues of voltage control and congestion management.

Up until now, the agent that could provide frequency-regulation services usually had to be a generator, i.e. the agent had to own physical equipment. However, the growth of Distributed Energy Resources (DERs), such as the EVs, which do not have the capacity of generation units and are not visible by the TSOs, requires adequate aggregation and representation. In the case of EVs, the principal agent that is going to emerge is the EV Supplier Aggregator (EVSA), as described in Deliverable D5.1 of MERGE project, Work Package 5, Task 5.1 [3.2]. EVSA can consider the concept of the Virtual Power Plant (VPP) to address the need for the effective integration of EVs in the electricity grid regarding both technical and economic aspects. The integration of EVs in a structure such as the VPP, which can properly operate and present them to the system and market operators, has been addressed in Deliverable D1.3 of MERGE project, Work Package 1, Task 1.4 [3.3].

The remainder of this section is organized as follows. In Sub-Section 3.2, a brief description of intraday and balancing/reserves markets is listed. In Sub-Section 3.3, certain European markets are reviewed, and the current market designs of the mechanisms for the provision of ASs are described. In Sub-Section 3.4, the barriers and restrictions that can be an obstacle for the participation of EVs in the provision of ASs are identified, and in Sub-Section 3.5, general as well as country-specific recommendations are made to improve the current situation and facilitate the participation of EVs. Lastly, in Sub-Section 3.6, the regulatory framework and the incentives for the TSOs, in order to develop more decentralized control schemes to allow a massive participation in ASs provision from DERs, such as EVs, is investigated.

3.2 Intraday and Balancing/Reserves Markets

This sub-section focuses mainly on the balancing and reserves markets. However, since the electricity trading market usually consists of a sequence of markets realized in different timeframes, as shown in the following Figure 13 [3.4], a short link with the intraday market, -i.e. the market that precedes balancing, is provided in this sub-section.

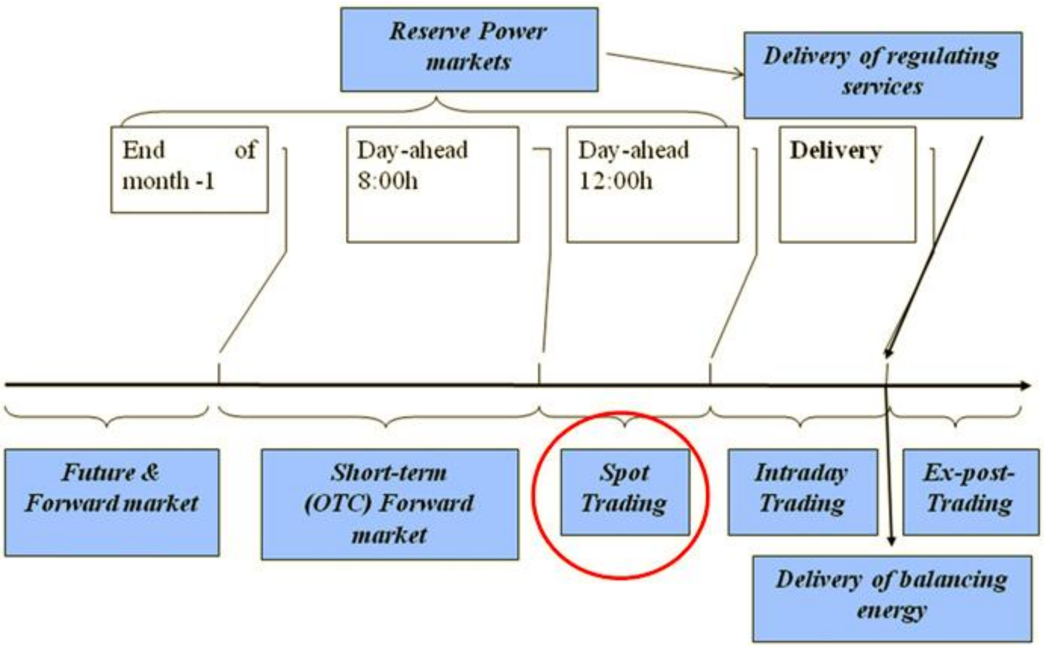

Figure 13: Typical sequence of electricity trading markets [3.4]

Intraday markets operate between the spot markets (day-ahead) and the physical gate closure, i.e. the time after which the schedules submitted to the TSO cannot be changed. These markets are needed to adjust/update the day-ahead scheduling taking into account the new information as the system moves closer to the real time, when unforeseen events can occur, such as unit outages, updated load forecasts, etc. In addition, these markets are needed to allow for adjustment of infeasible schedules resulting from spot markets with simplified design, as the one in a typical power exchange. The design of intraday markets vary significantly across countries.

EVSA can participate in intraday markets to reduce uncertainties; submitting bids close to the physical delivery reduces the uncertainties, since the aggregator may have a more accurate estimate of the load profile. The issue of restructuring electricity markets by moving the market gate closure near the physical delivery is widely discussed among market designers, as the integration of intermittent sources has changed the traditional concepts in designing electricity markets.

Balancing markets are used by TSOs to acquire the resources needed for the balance between generation and demand on a real-time basis. This is done by acquiring reserves. The so-called balancing mechanism includes the market-based procurement of required reserves, the activation in real-time to achieve the balancing, and the settlement of the imbalances.

EVSA can participate in balancing markets offering all three types of ASs, related with primary, secondary and tertiary control [3.1]. The issue of definition and procurement of ASs varies worldwide and there is a vast growing literature on this topic. These differences are the source of some confusion, because they extend not only to the precise definition of the services but also to the terms used to describe them. Such ambiguities appear even for terms that should be obvious and unambiguous, e.g. “spinning reserve” [3.5]. Recent surveys of some markets may help reduce this confusion by outlining a framework that can accommodate many definitions of ancillary services [3.6-17].

The EVSA may participate as a provider of demand response services, in the case of smart charging, or a provider of both ancillary services and balancing energy, in the case of Vehicle-to-Grid (V2G). The main advantage of an EVSA participating in the balancing and ancillary services markets, especially in the V2G case, is its ability to operate as a group of extremely flexible hydro pump units, being able to (even simultaneously) provide primary, secondary and tertiary reserves, participate in the balancing market by balancing its injections and withdrawals, as well as store energy. Moreover, due to smart-charging availability, the EVSA may enjoy an increasing flexibility to self-balance within the balancing period, as the number of EVs increase their share in the EVSA’s portfolio of customers, thus reducing the imbalance charges for all its customers.

The level of participation of the EVSA in the balancing and reserves markets depends on the specific design characteristics of each market. Since the balancing and reserves markets vary significantly across European markets, a review of the current market designs in certain, indicative and representative countries is listed in the next sub-section.

3.3 Provision of Reserves in the Different European Regions.

In this sub-section, a brief description of the balancing and reserves markets in the following European electricity markets is listed:

- Greece
- Germany
- Spain and Portugal
- Norway
- UK

The above countries are indicative of the approaches that are employed across Europe with respect to the provision of balancing and ASs, in particular the frequency-related ones. A summary of the market characteristics with particular interest to EVs is presented in Appendix 3.A.

3.3.1 Greece

The Greek wholesale electricity market is a mandatory pool, which comprises a day-ahead market (gate closure at 12:30 pm of the previous day), with co-optimization of energy and reserves for the entire 24h-period, and a marginal pricing rule for energy [3.18]. Currently, the demand participates only with pumping and exports; there is no participation/bidding on the consumer side.

In the Greek market, ASs are procured by the Hellenic TSO (HTSO) [3.19] and their provision is characterized as mandatory, since the generators must offer to the day-ahead market their maximum technical capacity in providing each respective AS, based on the declared (to the HTSO) technical characteristics of each respective unit.

The HTSO publishes daily, for the next day, ASs requirements (08:00), ASs prices (14:00), and ASs day-ahead schedule (14:00). As the ASs market begun its operation in October 2010, not adequate data are available regarding its traded value/average price. There exist penalties for not submitting “acceptable” ASs offers, based on the requirements of the market rules, and for not following the HTSO’s dispatch instructions; penalties increase for units that have not met their settlement for additional days in the past month and according to the extent of deviation. The HTSO has also the capability to contract units for the provision of ASs following a tender (the so-called contributor units for ASs); as this option has not been implemented in practice yet, it won’t be discussed further.

3.3.1.1 Types of Reserves

The frequency-related ASs (reserves) include primary, secondary, and tertiary reserve, in accordance with the Operations Handbook of the Union for the Coordination of Transmission of Electricity (UCTE) [3.1] – which in 2009 was integrated into ENTSO-E along with other TSOs – regarding primary, secondary, and tertiary load-frequency control, respectively.

An overview of Greece's wholesale market with emphasis on ASs (reserves) is presented in [3.13]. In what follows, we mention the basic features of each reserve type.

Primary Reserve

Primary reserve is provided by generation units, within 30sec from the frequency distortion, and for at least 15min. The primary reserve requirements are set by the HTSO at 80MW for the whole system; there does not exist any particular zonal requirement within the Greek interconnected system. The generators submit offers for the provision of primary reserve to the day-ahead market, daily (until gate closure), together with their energy offers. The offers are submitted by each generation unit and for each trading period (1h) and comprise of only the price requested for the provision of each ancillary service as €/MW (due to mandatory provision). The implied minimum bid size is 1MW. There is also a price cap set to 10€/MW. The offers submitted from about 55 units are approximately 650MW. Primary reserve is paid based on the highest bid accepted by the day-ahead co-optimization of energy and reserves (availability payment); energy related with the provision of primary reserve is settled at the imbalances settlement.

Secondary Reserve

Secondary reserve is provided by generation units capable of operating under Automatic Generation Control (AGC) within 15min from the activation of the system secondary control. In the Greek market, two types of secondary reserve are established: secondary reserve up, and secondary reserve down. A sub-category of the secondary reserve up (down), defined as a fast secondary reserve up (down) which can be provided within a period of 1min, is currently implemented by the HTSO. This type of reserve has been recently formulated in order to commit at least one hydro unit for provision of secondary reserve, since hydro units have the greatest AGC ramp-rate limits. The secondary reserve requirement ranges between 100-450MW for secondary reserve up and between 100-150MW for secondary reserve down, depending on the hour of the day, for the whole system; there does not exist any particular zonal requirement within the Greek interconnected system. The generators submit offers for the provision of secondary reserve to the day-ahead market, daily (until gate closure), for each trading period (1h), which comprise of only the price requested for the provision of secondary reserve both up and down (uniform bid with implied minimum size 1MW) as €/MW. Nevertheless, the co-optimization has a requirement (and thus solves) both for upwards and downwards secondary reserve. The offers submitted from about 13 units (hydros and CCGTs) account for around 3000MW. There is also a price cap set to 10€/MW. Secondary reserve is paid based on the highest bid accepted by the day-ahead co-optimization of energy and reserves (availability payment); energy related with the provision of primary reserve is settled at the imbalances settlement.

Tertiary Reserve

Tertiary reserve is provided by generation units, within 15min following a related dispatch instruction by the HTSO. It is called “spinning” if the unit is synchronized, and “non-spinning” if the unit is not synchronized. Currently, in Greece, the provision of this service is not remunerated (there is no availability payment as such for the primary and secondary reserve); nevertheless, energy related with the provision (activation) of tertiary reserve is settled at the imbalances settlement. The tertiary reserve requirement is set by HTSO at about 5-6% of the system load (usually 300-600MW). However, the increasing penetration of RES in the system is expected to increase the need for tertiary reserve in the near future. The co-optimization takes into account the tertiary reserve requirement constraint (in the upwards direction, on an hourly basis) for the whole system; no particular zonal tertiary reserve requirement is applied.

Ancillary Services under Consideration

Demand response is not recognized as an AS. However, there is an additional AS under consideration by the HTSO: the Interruptible Load Ancillary Service (ILAS): it is the possibility to automatically interrupt load supply for a given customer in order to contribute to frequency regulation. The provision of ILAS requires that such a load may be automatically interrupted either by the HTSO through tele-operation or through under-frequency switches installed by the customer in accordance with HTSO instructions.

3.3.1.2 Imbalances Settlement

Balancing is performed solely by the HTSO and every market participant has a balancing obligation (mandatory); there is no explicit balancing market. For the energy balancing, the HTSO considers the offers and bids submitted to the day-ahead market (period of 1h). The imbalances are calculated for each bid submitted to the day-ahead market, i.e. for each load representative and each generating unit.

The (imbalance) price is determined by the marginal price, calculated by solving the day-ahead schedule for the metered consumption (instead of load declarations) and renewable unit production (instead of forecasts), as well as the actual availabilities of generation units. In the cases where a generation unit has received dispatch instructions to deviate from its day-ahead schedule, additional payments are considered.

Positive instructed deviations are paid at the imbalance price, and negative instructed deviations are charged as bid. In case of uninstructed deviations, the positive ones are not paid, and the negative ones are charged at the imbalance price. Load deviations are settled at the imbalance price. The HTSO does not calculate any imbalance prices for ASs; the ASs cleared quantities are paid at the day-ahead ASs prices.

The price cap for energy is equal to the day-ahead price cap; last value set to 150 €/MWh. Price floors for the generators are equal to the minimum variable cost of each generation unit. For hydros, there is a regulated price; last value set to 53 €/MWh. There are penalties for generation if the deviation of metered energy from dispatch instruction is larger than a certain tolerance level (currently set at 2%).

3.3.2 Germany

In the past, the electricity market in Germany was more based on bilateral contracts but it is now moving towards a spot market. The day-ahead market auctions take place at 12:00 noon every day for the next day. For the intraday market, it is possible to trade for every hour of the next day from 15:00 of the current day until 75min before every hour [3.20].

3.3.2.1 Types of Reserves

The German ASs consist of 3 types of reserves: primary, secondary (which is the most used), and tertiary, and are procured by the TSOs.

Primary Reserve

Primary reserve is defined and dimensioned according to UCTE rules. The reserve bids are submitted on a monthly basis, with minimum bid size 5MW, minimum duration 15min, and are symmetric. The remuneration consists of a pay-as-bid capacity payment. This service is mainly provided by large thermal power plants. For primary reserve, beginning from 27 December 2010, the tender has been taking place weekly.

Secondary Reserve

Secondary reserve is dimensioned according to the Graf/Haubrich method, with non-mandatory participation (but subject to pre-qualification),and is mostly provided by large thermal power plants. The reserve bids are submitted monthly, separately for upwards and downwards reserve, and the minimum bid size is 10MW, with minimum duration 15min; there are high tariff and low tariff time periods. Capacity and energy are remunerated on a pay-as-bid basis; activation is done on a merit-order principle. For secondary reserve, beginning from 27 December 2010, the tender has been taking place weekly.

Tertiary Reserve

Tertiary reserve is also dimensioned according to the Graf/Haubrich method, and participation is not mandatory (but subject to pre-qualification). Power plants that provide tertiary reserve should be able to increase/decrease 30MW within 15min (right after the demand) for at least 4 consecutive hours. Tertiary reserve is procured by a daily auction. The power plants submit bids, separate for upwards and downwards reserve, with minimum bid size 15MW, split into 6 periods, and each of them covering 4h of the following day. Capacity and energy are remunerated on a pay-as-bid basis. For the tertiary reserve, beginning from 27 December 2010, the tender takes place daily on working days (Mondays - Fridays) for the next working day. For weekends and public holidays, the tender takes place on the last working day before them.

3.3.2.2 Imbalances Settlements

BRPs must be in balance when energy is aggregated in 15min windows and single pricing is used to charge for imbalances. In general, if the price of balance energy is positive, BRPs that are short -on energy- have to pay, and those who have a long position receive money. On the other hand, if the price of balance energy is negative, those BRPs who are short will receive money, and those who have a long position have to pay. The overall sum of the payments is proportional to the whole system's imbalance: the spans of imbalances are just payments between BRPs and therefore costs are indifferent to the TSOs, yet incentivizing the BRPs to keep their account balanced.

3.3.3 Spain/Portugal

Since July 2007, the wholesale electricity market is common for Spain and Portugal under the so-called MIBEL market; this is a pool-based market, which comprises both day-ahead and intraday markets, operated by OMEL [3.21]. Even though bilateral trading is allowed the majority of transactions is performed in the spot market. Each country maintained its control area and each of them is further divided in several balancing areas in order to monitor generation outputs regarding scheduled values. ASs are managed by the two TSO's: REE in Spain [3.22], and REN in Portugal [3.23].

All agents, including demand-side ones, should communicate their bids in the day-ahead market which is cleared at 11:00 each day, when the base daily operating schedule is obtained. This information is sent to the two TSOs for obtaining the viable daily schedule and contracting the required levels of ASs. The market participants are allowed to adjust their daily schedules through 6 intra-day markets which cover 4h time intervals; the first interval covers hours 21-24 of D-1 (previous day).

3.3.3.1 Types of Reserves

The frequency-related ASs include primary, secondary, and tertiary reserve, defined according to the UCTE requirements [3.1]. An additional AS also exists, called deviation management to manage for large deviations between supply and demand. An overview of ASs in the Spanish system is presented in [3.14]. In addition, reference [3.15] contains information on the provision and procurement of ancillary services in Portugal, as well as the possible future developments in the common electricity market between Portugal and Spain.

Primary Reserve

Primary reserve is a mandatory, non-remunerated AS provided by online generators that should provide at least 5% of their output power. The amount of primary reserve to be in place in 2009 was 318MW in Spain and 51MW in Portugal.

Secondary Reserve

Secondary reserve is defined according to UCTE recommendations. Given the peak load in 2008, the recommended secondary reserve was 522MW in Spain, and 185MW in Portugal; however, in Spain, the secondary reserve will be fixed close to the failure of the bigger generation unit of the system (1000MW). The generators submit bids including the up/down available reserves (MW) and the price of the secondary reserve band (€/MW). The TSOs contract secondary capacity on a least cost basis, and the reserve capacity price corresponds to the price of the last accepted bid. The energy used inside this reserve band, in the event of a disturbance, is termed as secondary energy and it is paid according to the price of the up or down tertiary reserve for the corresponding trading hour. The secondary control can be supplemented by fast tertiary reserves, in case the up secondary reserve is unable to cover the maximum lost generation.

Tertiary Reserve

Tertiary reserve is a manually activated service that supplements and replaces secondary reserve and is contracted on national markets. It is provided by generation units and refers to power available within 15min, which can be maintained for at least 2h. Each TSO determines the minimum required amount of tertiary reserve corresponding to the maximum power that can be lost due to a single generator outage increased by 2% of the demand forecasted for that period, on an hourly basis for the next day. The generators are obliged to submit bids, comprising of the volume in MW and the corresponding energy price in €/MWh, by 23:00 D-1; the bids can be updated until 25min before the delivery period or even during the delivery period if necessary. The used energy is valued at the marginal price and is remunerated only if it is activated.

Slow Reserve

Slow reserve (activation time greater than 15min) is an optional AS provided by generation units and pumped storage through the Deviation Management mechanism. This service is foreseen to balance differences between scheduled generation and forecasted demand, larger than 300MWh, and to restore tertiary regulation reserve. The requirements are set by the TSO in the period between the intraday sessions, with minimum duration 1h. The bids comprise energy blocks (MWh) and price (€/MWh) and are selected by economic merit order; remuneration is made at marginal price only in case of activation.

Currently, demand does not participate in the provision of ASs, except for specific industrial customers that are contracted as interruptible loads and can provide some sort of balancing service.

3.3.3.2 Imbalances Settlements

The imbalances are settled according to whether they are made in favour of the system or in opposition to the system. Upwards/downwards imbalances in favour of the system receive/pay the daily marginal price. Upwards/downwards imbalances in opposition to the system receive/pay the minimum/maximum of the daily marginal price and the average price of downwards/upwards energy used for secondary reserve, tertiary reserve, and deviation management.

3.3.4 Norway

The wholesale electricity market in Norway is pool-based (Nord Pool) and allows for bilateral contracts; the pool represents 70% of the volume in day-ahead and intraday markets. The price computation mechanism for energy is based on marginal pricing.

A systematic overview of ancillary services in the Nordic countries, namely Norway, Sweden, Finland and Denmark (East and West) is provided in [3.16]. Only West Denmark is a member of UCTE, and therefore follows the UCTE definitions of ancillary services; in the remaining Nordic countries the ASs are defined by NORDEL [3.24].

3.3.4.1 Types of Reserves

The frequency-related ASs mainly comprise primary control and balancing services; secondary reserves do not apply in the Nordic region (except for West Denmark due to the UCTE requirements).

Primary Control

Primary control comprises frequency-controlled normal operation reserve and frequency-controlled disturbance reserve.

1) Frequency-controlled normal operation reserve

The Nordic System Operation Agreement stipulates that the frequency controlled reserve for normal operation shall totally amount to 600MW at 50Hz for the Nordic countries. It shall be activated with a regulation capacity of 6000MW/Hz to keep the frequency between 49.9 and 50.1Hz. This means that the frequency regulating reserve is fully activated at a frequency of 49.9Hz [3.25].

2) Frequency-controlled disturbance reserve

For larger frequency deviations down to 49.5Hz, caused by disturbances in the system, the frequency controlled disturbance reserve is activated. This is dimensioned based on the current "dimensioning disturbance", for example the loss of a large generating station. The amount of the frequency controlled disturbance reserves varies depending on the operational situation, but is often around 1000 MW [3.25].

The primary reserves are to a certain extent exchanged between the Nordic TSOs (except for West Denmark which exchanges the reserve with UCTE), but each subsystem must have 2/3 of the frequency regulating reserves within its own system. In Norway, hydropower mainly provides primary reserves. The Norwegian TSO, Statnett, has 1-year contracts with about 40 Norwegian generators for maintaining primary reserves. The basic principle is that the generators set the droop in their turbine governors at 6%. If more reserves are needed, the TSO may ask Norwegian generators to set the droop at a higher level. Compensation to the providers is determined as a share of the total regulating power that the TSO requires for the Norwegian power system. To compute each provider's share, aggregates larger than 10MW and power plants larger than 20MW are included. When there is local, national or Nordic demand for increased primary reserves, the TSO can ask for a reduction in static. When the TSO enters into a contract with one or more providers to reduce the static below 6%, the providers receive an additional compensation based on the time and the amount provided. The TSO also facilitates a voluntary weekly market for the delivery of additional primary reserves. The providers submit price bids for delivery in predefined periods and are compensated ex post with the marginal price. The additional primary reserve sold to neighboring countries is compensated based on the bid price [3.16].

Balancing Services

A general distinction of balancing services (equivalent to tertiary reserve) is between fast and slow reserves. The fast reserves are activated manually, and must be able to restore the automatic reserve within 15min, whereas slow reserves are available in a period longer than 15min to recover the fast reserve. The fast reserve is further distinguished into regulating bids and fast disturbance reserve.

1) Regulating bids

The Nordic TSOs receive bids for upward or downward regulation from players who are willing to raise or lower their production or consumption. A bid for upward regulation indicates how much the player asks to be paid to sell a certain volume of regulating power corresponding to increased production or reduced consumption. A bid for downward regulation indicates how much the player is prepared to pay to buy a certain quantity of regulating power corresponding to reduced production or increased consumption. The TSOs submit all their national bids to a common Nordic regulation list sorted according to rising or falling prices. The list is available to all Nordic TSOs in a common information system named NOIS (Nordic Operational

Information System). These resources are thus traded on a sort of "single-buyer" market, where the TSOs act jointly as a buyer in procuring resources for the balance regulation [3.25]. This market is called the regulating power market (RPM) in the Nordic region, and balancing services in Norway are generally procured through this market. Market participants may submit bids for physical power regulation on an hourly basis for the following day. These bids must specify the size (MW), the location and the price of the individual regulating objects. Uninterruptible activation of the power reserve must be possible for at least 1h. If the reserve is offered for several hours, bidders may also specify a minimum activation time as a multiple of full hours. Suppliers of reserves from consumption may also stipulate a minimum waiting time (max. 8h) until the unit can be called up again. Bids in other Nordic regions may be similarly utilized. The RPM price is generally determined by the most expensive/inexpensive bid utilized in upward/downward regulation [3.16]. The minimum bid size in the Nordic region is 10MWh/h except in Norway, where 25MWh/h is normally used, and exceptions can be made by the TSO. From January 2009 there has been a general exception in Norway that allows bids down to 10MWh/h for smaller players. The argument for a higher limit in Norway was that many small bids can lead to an inefficient regulation. However the limit has successively been reduced in order to encourage for smaller players (generation but above all flexible demand) to participate in balance regulation and increase the volume of the available resources in balance regulation [3.26]. In Norway, bids should be submitted at 19:30 D-1; in the other countries the bids should be submitted at the latest 30min before the hour of operation. From 2009, this is harmonized by introducing a gate closure for bids at 45min before the hour of operation in all countries. If technical problems occur, the TSO (Statnett) can utilize more expensive bids ''out of merit.'' The bidders are compensated according to a ''pay-as-bid'' scheme, and the regulation is noted as special regulation. This is also the case when upward and downward regulation occurs simultaneously and with small regulation volumes (less than 25MWh). When the RPM does not give socio-economic efficient pricing within a geographical area, the TSO can suspend bids and compensate with the prevailing area spot price. Market players failing to supply regulating power must pay the additional costs incurred [3.16].

2) Fast disturbance reserve

To be able to deal with disturbances and restore the frequency controlled disturbance reserve there exist fast disturbance reserves, which must be available in addition to the normal regulating bids [3.25]. In Norway, there is a market arrangement, RKOM, to secure sufficient operational reserves in the system. In RKOM, Statnett organizes tenders with weekly contract periods, which resemble European call options, but differ in that their valuation is determined by the bidders; thus, there is no connection between the exercise price and the activation price. The bidders specify only the type of reserve (generation or consumption) and the grid area (for RPM specific plants are nominated only on a daily basis). In addition, power reserves are only made available from 5 to 23h, from Monday to Sunday. Any bids must have a minimum volume of 25MW, and the primary criterion for their selection is the offered price per MW [3.16]. Generally the fast disturbance reserves are made available to the common regulation list; however, they are not normally intended to be used as normal bids but to be kept until all commercial bids have been used, and this is usually automatic as the reserves have a higher price than normal bids [3.25].

3.3.4.2 Imbalances Settlement

The Nordic region presently uses two pricing systems to manage imbalances:

One-price system: The regulating power market (RPM) price is used to settle imbalances depending whether a market player's imbalance contributes to or counteracts the total system imbalance.

Two-price system: In this system, two prices are used for the settlement of imbalances. The RPM price is used if a market player's imbalance counteracts the total system imbalance, but the area price is used if a market player's imbalance contributes to the total imbalance.

Norway is the only country in the Nordic region that uses a one-price system.

3.3.5 UK

The UK market design is based on bilateral trading between generators and suppliers across a series of markets, namely the Forwards and Futures Contract Market intended to reflect electricity trading over extended periods, the Short-term Bilateral Markets, to enable participants to fine-tune on a half-hourly basis their trade contract positions as demand and supply forecasts become more accurate as real time is approached, and the balancing mechanism, meant to ensure that security of supply is maintained effectively and efficiently.

3.3.5.1 Types of Reserves

National Grid [3.27] controls system frequency through three separate balancing services:

- Mandatory Frequency Response (MFR)
- Firm Frequency Response (FFR)
- Frequency Control by Demand Management (FCDM)

In addition, there exist the following reserve services:

- Short-Term Operating Reserve (STOR)
- Fast Reserve

Mandatory Frequency Response (MFR)

The MFR is provided by all generating units, which must:

- have a 3-5% governor droop characteristic;

- be capable to provide continuous modulation power responses to counter the frequency changes via synchronized generation through their automatic governing systems.

Following a successful assessment by the National Grid that the generating unit meets the minimum requirements, a mandatory service agreement is put in place (or amended), which allows National Grid to instruct the service when it is needed. Service providers delivering the service as instructed receive two types of payments: a Holding Payment (£/h), based on the bids submitted on a monthly basis, and a Response Energy Payment (£/MWh).

Firm Frequency Response (FFR)

FFR is provided by both generating units and load entities, which must:

- have suitable operational metering;
- pass the FFR pre-qualification assessment;
- deliver minimum 10MW response energy;
- operate at the tendered level of demand/generation when instructed (in order to achieve the tendered frequency response capability);
- have the capability to operate (when instructed) in a frequency sensitive mode for dynamic response or change the MW level via automatic relay for non-dynamic response;
- communicate via an automatic logging device;
- be able to instruct and receive via a single point of contact and control where a single FFR unit comprises of two or more sites located at the same premises.

FFR is procured through a monthly tender. Having considered the quality, quantity and the nature of the services, National Grid will accept the most economical tender. Payment of FFR provision is composed of a fixed payment per nominated window that National Grid instructs, a capacity payment composed of two parts (Availability Fee (£/h) plus Nomination Fee (£/h)), and an energy payment (£/MWh) – based upon the actual response energy provided in the nominated window.

Frequency Control Demand Management (FCDM)

FCDM is provided by the demand. An FCDM provider must:

- provide the service within 2sec of instruction;
- deliver for minimum 30min;
- deliver minimum 3MW, which may be achieved by aggregating a number of small loads at same site, at the discretion of National Grid;
- have suitable operational metering;
- provide output signal into National Grid's monitoring equipment.

National Grid procures this service through bilateral negotiations with providers. Once the test has been completed, a site can join the scheme subject to signing the FCDM AS agreement. The provider declares availability for each settlement period on a weekly basis, and is paid with an Availability Fee (£/MW/h).

Short-Term Operating Reserve (STOR)

STOR is provided by both generators and demand. An STOR provider must be able to:

- offer a minimum of 3MW or more of generation or steady demand reduction (this can be from more than one site);
- deliver full MW within 240min or less from receiving instructions from National Grid;
- provide full MW for at least 2h when instructed;
- have a recovery period after provision of reserve of not more than 1200min (20h);
- be able to provide STOR at least three times a week.

STOR is procured via competitive tender with three tender rounds per year. There are two forms of payment that National Grid will make as part of the service: Availability Payments (£/MW/h) -service providers are paid to make their unit/site available for the STOR service within an Availability Window, and Utilisation Payments (£/MWh) -service providers are paid for the energy delivered as instructed by the National Grid; the latter includes the energy delivered in ramping up to and down from the contracted MW level.

Fast Reserve

Fast reserve is provided by both generators and demand. A Fast Reserve provider must:

- have the capability to delivery within 2min of instruction;
- have the delivery rate greater than or equal to 25MW/min;
- be able to sustain output for minimum 15min;
- halt or start to unwind Fast Reserve delivery within 2min of instruction;
- have the unwind rate greater than or equal to 25MW/min;
- deliver minimum 50MW for a single instructable unit or aggregation of more than one unit;
- deliver against either constant MW value or known MW profile.

Procurement of this service is made with a monthly tender, and payment through an Availability Fee (£/h) for each hour in a tendered service period where the service is available, and a Fee (£/MWh) payable for the energy delivered.

3.3.5.2 Imbalances Settlement

Any imbalances between participants' contractual positions (as notified at the gate closure) including accepted offers and bids, and the actual physical flow are settled at one of the dual imbalance prices:; System Buy Price (SBP) and System Sell Price (SSP). SBP is the price at which deficits are charged when the system is short, and approximates the marginal price at which the system had to buy in order to make good the deficit on behalf of the party (i.e. an approximation of the marginal price of accepted offers). SSP is the price at which surpluses are charged when the system is long, and approximates the marginal price at which the system had to sell in order to dispense with the surplus spill energy (i.e. an approximation of the marginal price of accepted bids). Imbalance prices are derived by taking the average cost of the marginal 100MWh of actions that the National Grid has taken to resolve the energy imbalance - excluding those "tagged" actions taken for system balancing reasons. Under these arrangements the “reverse price” i.e. SBP when the system is long and SSP when the system is short, continues to be based upon a forward market price derived from Power Exchange trades.

3.4 Identification of Restrictions & Barriers

In the previous sub-section, we examined the designs and particular characteristics of balancing and reserves markets in several European countries. Since EVs are potential contributors to the provision of demand-side reserves, the primary restriction to be lifted is regarding the provision of reserves from the demand side. All countries, the UK being a notable exception, focus on reserve provision from generators.

Despite the differences, it is possible to distinguish the different types of reserves in two categories:

- reserves that are **automatically activated** from local signals (primary or mandatory frequency response in the UK).
- reserves that are **activated following a TSO instruction** (secondary, tertiary according to the UCTE definition or balancing services).

Reserves are designed as a critical component through which system reliability and security of service is ensured by the TSO. It will be therefore very important to demonstrate that EVs can reliably participate in this critical service. The yet untested technology and the need to develop new procedures will probably be the biggest obstacle to overcome in the path towards EV participation in reserves provision. Fortunately, the gradual penetration of EVs in the following years will provide TSOs and DSOs with sufficient time to test solutions and arrive at specifications and best practices.

3.4.1 Automatically Activated Reserves

The provision of automatically activated reserves from EVs, namely primary frequency control, requires equipment that enables charging in a frequency sensitive mode. There are yet no specifications that would allow manufacturers to provide this equipment. Furthermore, since this equipment would be the interface between the car and the grid, harmonization of technical requirements among different regions, which would enable EU-wide specifications, would be very positive.

Depending on how the provision of locally activated frequency control from plugged-in EVs when charging, is arranged (i.e. on a mandatory basis), it could be implemented without the intermediary role of the aggregator (EVSA). However, remuneration of this service, either directly or bundled in a special tariff scheme, would be required to compensate for battery degradation and equipment cost.

The remuneration of primary control varies. In some countries (e.g. Greece, Germany, Norway, UK) there is an availability payment, whereas in other countries (e.g. Spain and Portugal) the service is mandatory and non-remunerated. Energy related with the provision of this service is remunerated either through an energy payment (e.g. UK) or cleared through the imbalances settlement. As a result of these differences, if a remunerated primary control scheme was to be implemented for EVs, it would certainly have to be extended and adapted to other generators in the countries where currently primary control in non-remunerated. This means that ultimately AS provision and procurement schemes will most likely have to be reshaped in most countries in order to have non discriminatory designs.

3.4.2 Reserves Activated Following TSO Instruction

These types of reserves are typically procured on a competitive basis following bid submission by qualified generators or load entities. EV loads would need to be aggregated by an EVSA in order to compete with existing market participants for these services.

The requirements that could potentially impede the participation of EVs through a load aggregator into these markets are the following:

- *Minimum bid size*: Depending on the reserve product minimum bid size ranges from 1 to 50MW. This level of minimum bid could be considered a barrier due to the large number of EVs required to aggregate this capacity.
- *Minimum Duration*: The minimum duration of each service can also impose a barrier to the participation of EVs in the reserves provision, through the resulting energy constraint, due to the limited storage capability of EVs.
- *Procurement/Contracts*: The procurement of reserves through monthly or weekly markets is also another barrier due to the high uncertainty regarding the availability of each service provided by EVs. Although advanced forecasting techniques could help an EVSA estimate the reserve availability, participation of EVSAs in weekly or monthly procurement process could entail unwarranted risks. Participation in daily markets with early gate closures could be considered less challenging.
- *Symmetric bids and prices*: Such a format can also be considered as a barrier to the participation of EVs. If the upwards and downwards commodities are not priced separately. Quantitative analysis [3.28] has shown that participation of EVSA entities in secondary reserves market can be profitable. However, the extra cycling imposed in the case of V2G would reduce profitability of upwards reserve provision (battery discharging) due to the increased battery degradation. In the case of EVs being controllable loads, the provision of reserves in both directions, e.g. by setting the charging level at a lower than maximum level, would place an extra limitation on the EVSA's ability to optimize the EV charging profile according to market signals, while assuring a minimum battery State of Charge (SoC) at the end of the charging period. Therefore, the provision of downwards reserves would be more attractive for EVSAs, especially at the introductory phase.
- *Geographical locations*: Considering the mobility of EVs, the establishment of site-specific constraints on the reserve provision constitutes a constraint in the

participation of EVs in reserves provision. This problem can be aggravated in the borders of control areas, which EVs may cross even on a daily basis.

- *Information and I&C requirements*: In this case EVs – DSO – EVSA – TSO real-time communication and real-time measurement should be established. An alternative to real-time measurement for very small units could be that units below a certain size need to produce documentation afterwards to verify that regulation has taken place. On the other hand, with the development of new communication solutions to measure and control even small loads and production units, it could be reasonable to specify real-time measurement for at least all new units (in this case EVs) that can be considered for balance regulation [3.26].
- *V2G infrastructure*: Based on the currently available technology, it is estimated that the cost of additional equipment required to enable bi-directional energy transfer, would involve a significant cost to the consumer, which would offset the income from participating in the reserves and balancing markets [3.29] This fact is a significant barrier to the development of V2G. Furthermore, the saturation of the balancing and reserves markets, due to their limited size and following a massive EVs participation, is likely to drive prices down and reduce the income from the provision of reserves and balancing services. Nevertheless, controllable charging is still an attractive option; although it constrains the potential of the EVSA with respect to the participation in the reserves and balancing markets, it requires substantially lower investment costs.

3.5 Recommendations to Improve the Current Situation.

3.5.1 General Recommendations

Having identified the barriers and restrictions for the participation of EVs in balancing and reserves markets, the following general recommendations are proposed. The recommendations are put in a timeline, grouped in the following three phases:

- *Catalyst Phase*: In this phase, the actions should be devoted to breaking important psychological barriers of stakeholders (TSOs, fleet operators, car manufacturers). In this phase of initial uptake, EVs are regarded as mere additional loads like any other domestic device.

- *Consolidation Phase*: In this phase, the recommendations refer to mid-term actions, so that the EVs can participate as controllable load in balancing and reserves markets.

- *Advanced Phase*: In this phase, the actions represent long-term and challenging goals with respect to V2G services.

3.5.1.1 Catalyst Phase

The Catalyst phase should include short-term actions aimed at creating the framework and the necessary infrastructure that will allow EVs to provide balancing and reserves services in the mid-term. To this end, the barriers that constrain the EVs penetration, and particularly barriers that limit the EVs' possibility in the provision of balancing and reserves services should be removed. The preparation of common requirements and standards across EU countries, as well as the removal of any legal barriers for the provision of ASs by EVs should be the first priorities in this initial phase. In this context, the following actions are recommended:

- Time of Use (ToU) tariffs are expected to be the only immediate means of shifting load from peak to valley hours. Demand-Side Management (DSM) could be implemented from early on, and interruptible contracts specially designed for EVs could be offered to EVs' owners.
- TSOs, in close cooperation with DSOs, should be encouraged to foster pilot projects that will prove concepts and test solutions for enabling centrally controlled charging. This process, aside of the immediate gains in the technical know-how, will be a driver towards breaking important psychological barriers. Based on the so-far gained experience, functional specifications and best practices can be proposed.
- The preparation, preferably at EU level of specifications for equipment that enables EV charging in a frequency-sensitive mode should be encouraged. This is not a requirement for the Catalyst phase, however it can be expected to be a time-consuming process that will require strong support from the industry side. Initiatives within the context of the Smart Grids Task Force or the Smart Grids European Technology Platform could help kick-start this process at this early stage. The equipment can be either integrated with the car or located at the charging point. This action is expected to create a friendly environment for the future participation of EVs in the provision of frequency-related ASs in the Consolidation and Advanced phases.

3.5.1.2 Consolidation Phase

In the Consolidation phase, the recommendations should address potential measures to facilitate the EVs participation in the balancing and reserves markets as a controllable load (smart charging). These recommendations refer to the mid-term, assuming a critical level of EVs penetration. Furthermore, we assume that, by this stage, specifications for controlled charging in a frequency-sensitive mode have been adopted and that car or charging point manufacturers are in the position to supply this equipment. In addition, we assume that the entity of the EVSA is defined and that suppliers or fleet operators are in the position to assume this role. The proposed actions follow below:

- The clarification of the EVSA role is essential for the participation of EVs in the balancing and reserves markets. This role can be filled by existing market participants or newcomers. In order for the market participants to have a clear picture of liabilities and obligations of the EVSA, this entity should be clearly defined; licensing should be based on transparent and non-discriminatory criteria that allow new entrants on an equal basis with existing market players.
- Tight access rules for the demand-side participation in balancing and reserves markets should be reviewed. These rules include minimum load and specific site restrictions that constitute constraints, considering the mobile nature of

EVs. This action will remove potential discriminatory rules and will allow the provision of ASs by EVs.

- EVs are expected to be primarily controllable loads (smart charging), and even in the case of V2G, an EVSA's net position is expected to be that of a load. Therefore, EVs participation in reserves markets can be enabled through the participation of the demand-side either through a separate service or in direct competition with reserves offered by conventional generation. According to simulations for the participation of EVs in the provision of balancing and reserves as controllable loads, in the typical sense of DSM, the financial benefit may not be substantial, but it is obtained at practically zero cost. On the contrary, the provision of V2G reserves and balancing services may opt for more attractive returns, but requires high investment costs [3.29]. Therefore, encouraging typical DSM participation seems to be the first step to be taken by EVs regarding balancing services.
- Participation of EVs in balancing and reserves markets should be possible. Within this context, the establishment of an "evaluation" period to assess "capacity" and reserve availability of the aggregator (or VPP) similar to that of the "commissioning period" of a new power plant could be examined. The issue of specific site restrictions could be overcome by defining minimum reserve requirements for each control/balancing area/zone alongside overall requirements set for a cluster of control/balancing areas/zones. In this way, the same level of system security can be maintained while solving the issue of cross-border mobility of EVs.
- EVs will be inherently compromised by the fact that their purpose is to serve mobility and by their storage limitations. Therefore, it is expected that often the available capacity for upwards reserve (i.e. reducing the load, e.g. by decreasing the charging rate) may often be quite different from the available capacity for downwards reserve (i.e. increasing the load, e.g. by increasing the charging rate). Further studies [3.28] suggest wide differences in profit margins between up and down reserves in some markets. Distinguishing and allowing separate bids for up/down reserves will provide EVSAs with adequate flexibility to place bids that are in line with the restrictions placed from charging patterns and battery SoC.
- Reserve procurement in some countries is realized on a monthly or weekly basis. EVSA bids for reserves will be based on forecasts regarding battery SoC, as well as the users' set charging constraints. Reserve procurement lead times closer to real time, preferably not earlier than D-1, would allow more accurate forecasts by EVSAs.
- The establishment of markets that clear closer to physical delivery (intraday/balancing) can be beneficial to all market players. With uncertainty decreasing as we move closer to real time, market players are able to better adjust their positions, hence reducing their imbalance charges.

Some of the above recommendations can be considered applicable to the Advanced phase, since they are meant to facilitate EVs participation in reserves markets through the EVSA. Nevertheless, assuming that a suitable regulatory framework is in place, most services could be provided as demand-side reserves through controlled charging.

3.5.1.3 Advanced Phase

In the Advanced phase, long-term objectives are addressed assuming a full deployment of EVs and V2G services. This scenario requires substantially high investment costs and seems to be quite optimistic at the moment; nevertheless, in the event that this scenario is realized, the potential for the participation of EVs in balancing and reserves markets will be increased, due to the possibility for "reverse charging". Apart from the technical issues that need to be arranged and clarified in the V2G case, the following actions should also be encouraged.

- The adoption preferably at EU level of Information and I&C requirements that will enable secure EV – DSO – EVSA – TSO real-time communication and real-time measurement is required before the implementation of this scenario. This action will create the necessary framework that will enable the EV-SAs to participate in reserves and balancing markets.
- An issue that should be taken into consideration, particularly under the V2G case, is the event of saturation of the reserves and balancing markets, following an increased number of EVs that will be able to provide balancing and reserves services. This effect should be considered, because if a large proportion of the vehicle fleet were to participate in the provision of V2G balancing (reserves) services, the resulting increase in supply in this market could be expected to drive down the prices of balancing (reserves) services making an overall return on the investment in charging equipment still harder to achieve [3.29]. Therefore, quantitative studies on the potential saturation levels for each particular service, along with their financial implications on the respective prices and consequently on the expected revenues of EVs, should be recommended.
- Last but not least, further steps on the harmonization, at EU level, of the provision and procurement schemes for ASs, and redesign of the current rules - whenever required, in order to have non-discriminatory schemes (involving payment rules) between existing generators and other future providers of ASs, such as EVs, are also strongly recommended actions.

3.5.2 Country-Specific Recommendations

Having described general recommendations, classified in three phases: catalyst, consolidation, and advanced, we proceed to a brief country-specific description of the most important aspects of the balancing/reserves market design that each country (among the ones examined in this report) should reconsider.

3.5.2.1 Greece

Following the general recommendations, the Greek market should firstly allow the load participation in reserves markets. The establishment of a real-time market, similar to the example of the US markets, where ASs will be traded, is also desirable. In addition, the distinction between up and down reserve, especially for the tertiary reserve, and a remuneration scheme for this type of reserve, which is currently not remunerated, is expected to benefit EVs and allow for higher wind penetration in the future.

3.5.2.2 Germany

The German market, apart from allowing the load participation in providing reserves, could reduce the minimum bid sizes for all the types of reserves (preferably down to 1MW) and move the trading closer to real time (instead of monthly or weekly contracts). The minimum duration of tertiary reserve should also be reduced (currently it is 4h). It is worth mentioning that a recent study [3.28], provides quantitative results for the revenues of EVs in Germany through their participation in the reserves provision, and concludes with specific recommendations.

3.5.2.3 Spain/Portugal

Spain and Portugal should also allow the participation of the load in the reserves provision. In addition, the establishment of tertiary reserve down, as a remunerated commodity, and the reduction of the minimum duration of 2h for tertiary reserve up would facilitate the EVs participation.

3.5.2.4 Norway

Norway should also allow the participation of the load in the reserves provision. The minimum bid size has been reduced to 10MWh/h for balancing, following the harmonization of the Nordic countries markets, however, a further decrease down to even 1MWh/h would facilitate the participation of EVs. The gate closure for the regulating bids has been moved very close to real time (45min before delivery), however, weekly markets and yearly contracts for primary reserve still exist; it would be preferable to move the latter closer to real time.

3.5.2.5 UK

Based on the generic recommendations, and given the fact that in the UK the provisions for reserve procurement allow the participation of the demand side, some further recommendations for the UK market would be to allow the aggregated EVs participation in FCDM, possibly by reviewing requirements (e.g. reducing the 3MW-limit down to 1MW, and relaxing the specific location requirement), as well as to examine the possibility of procuring reserves at a time closer to physical delivery.

3.6 Incentives and Regulatory Framework for Transmission System Operators

Intermittent power sources are expected to play a key role towards achieving EU targets for 2020 and beyond, regarding RES participation in the total energy demand. Nevertheless, the increasing share of RES – mainly wind – requires additional operating reserves to mitigate this impact without compromising operational reliability. The proposed options include improved wind forecasting, flexible generation units and storage.

The large scale wind penetration in European electricity markets has been well studied, and the well-functioning intraday and balancing markets are considered as prerequisites [3.4], [3.31-33]. In parallel, the expected growth of EVs is considered to increase the flexibility of the power system due to their inherent storage capability, and contribute in the large scale integration of wind power through their participation in balancing and reserves provision [3.33].

In the previous sub-sections, we identified possible barriers to EV participation in reserve procurement by TSOs, and proposed specific recommendations for the improvement of the current framework. In this sub-section, we proceed one step further and present a logic of how TSOs could be incentivized to develop schemes that would allow massive participation of EVs, and DERs in general, in reserve procurement.

3.6.1 Defining Reserve Requirements

In general, TSOs rely heavily on reserve procurement for maintaining system integrity, in most cases almost at any cost. The safety concerns, along with the fact that reserves costs are typically socialized to consumers, provide TSOs with a natural incentive to overestimate the reserve requirements.

One approach to counter this indifference of the TSO is to use incentive schemes, which expose the TSO to some of the costs for system balancing (or sharing profits from savings on balancing costs). Thus, the TSO would be motivated to reduce costs that would otherwise be fully passed on to consumers [3.30]. This approach is used in the UK effectively. Another approach is to precisely define rules for as many decisions of the TSOs as possible. A combination of the two approaches is also possible.

From a technical viewpoint, the operational reserves that must be maintained in order to attain the required reliability standards for a traditional power system, which has to cope with generation outages and load forecasting error, are very well documented (see e.g. UCTE recommendations). With increasing penetration of intermittent energy, basically wind, probabilistic reserve assessments have been explored (see e.g. [3.34] for a literature review on probabilistic methods for setting reserve requirements). It’s expected that both frequency regulation reserve and fast reserve requirements will increase considerably. It’s also safe to assume that downwards reserve requirements are those that will be most affected since upwards reserves are already required to counter a generating unit production loss. In a system with large RES penetration, downwards reserves will have to be maintained to counter any unforecasted RES production increase, if RES production is not to be curtailed. This requirement can be addressed effectively with storage technologies including batteries, compressed air storage, flywheels, hydrogen, superconducting magnetic energy storage, thermal energy storage, ultracapacitors, and last but not least EVs.

In this context, TSOs should be encouraged to develop control schemes that allow for the massive integration of these technologies in power systems along with the possibility for participating in reserves provision. As a first step, the TSO needs to define the requirements and the market size for these technologies, according to transparent rules.

With regard to the probabilistic reserve assessment, it is vital that the trade-off between achieving a certain level of system security and the cost associated with this level is identified. As discussed in the previous sub-section, apart from system security, a new requirement is set by Directive 2010/28/EC, namely that “*Member*

States shall ensure that appropriate grid and market-related operational measures are taken in order to minimise the curtailment of electricity produced from renewable energy sources". In order for this to take place in a transparent and cost-effective way, practical rules should be established by the Regulator and followed by the TSO, coupled with possible incentives to attain targets in the most cost-effective way.

3.6.2 Setting the Rules

The aforementioned rules would derive from a risk assessment process which would involve setting minimum reliability and maximum allowed wind curtailment criteria, and assessing the upwards and downwards reserves required in order to meet these criteria. The two requirements can be combined in a multi-criteria approach that would consider the cost for reserves provision, the level of the system security and the RES penetration. A recent study on setting the operating reserve in this new environment can be found in [3.34]. The outcome of this assessment may well be that current systems would either not be able to achieve the set criteria or would do so at a high financial and/or environmental cost, thereby reducing the environmental benefit from RES power generation.

The use of EVs and DERs alongside other storage technologies may help to maintain a very low risk, at a lower cost compared to a traditional power system with conventional power plants. Moreover, since EVs can operate as a controllable load, it is possible to increase the load during valley hours to accommodate high wind power penetration levels, at a cost lower than the respective cost from decreasing the generation output of conventional units or using storage units (e.g. pumping storage).

Considering the integration of EVs in power systems [3.35-37] and the modifications required in order to facilitate their participation in the reserves provision, a decentralized control scheme should also be implemented. The decentralized control scheme means that between the DSO/TSO and EVs there are aggregation agents that control the EVs charging rates according to market signals. In the specific case of secondary reserves, the TSO continues to have a centralized control scheme (i.e. AGC), but the reserve suppliers are distributed and controlled by aggregation agents. This is a hierarchical control scheme, and more details can be found in [3.37]. It is believed that no additional costs in communication equipment are necessary for the TSO, since all the necessary communications are likely to be supported by the smart metering infrastructures that are expected to be deployed in the near future.

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Appendix 3.A - Summary of Reserves Markets Characteristics

	Demand participation	Symmetric bids	Minimum bid size	Minimum duration	Procurement/Contract	Remuneration
Greece	No	Primary: symmetric Secondary: symmetric bids, separate up/down requirements Tertiary: up only	Primary, secondary and tertiary: 1MW	Primary: 15min Secondary/tertiary: 1h	Primary, secondary, and tertiary: Day-ahead market (12:30 D-1), with hourly periods	Primary and secondary: highest bid accepted for capacity (availability payment) Tertiary: not remunerated (no availability payment)
Germany	No	Primary: symmetric Secondary, and tertiary: asymmetric	Primary: 5MW Secondary: 10MW Tertiary: 15MW	Primary: 1 month (week) Secondary: 1month Tertiary: 4h	Primary and secondary: monthly (currently weekly) market Tertiary: daily market	Primary: pay-as-bid for capacity Secondary and tertiary: pay-as-bid for capacity and energy
Spain/ Portugal	No (Except for pump hydro in tertiary)	Primary: symmetric Secondary: symmetric bids (band) Tertiary: Up	Primary: all generators have to participate and are dispatched proportionally Secondary: 10MW (plus additional requirement for integration in regulation zone with 300 MW of installed power) Tertiary: 10MW Slow: All available capacity that was not placed in preceding markets	Primary: 15min Secondary: 1h Tertiary: 2h	Primary: mandatory Secondary: daily Tertiary: daily (23:00 D-1, updated until 25min before delivery) Slow: optional, between intra-day sessions	Primary: Not remunerated Secondary: highest bid accepted for capacity with up/down substitution pricing of tertiary reserve price for energy Tertiary and slow: marginal price for energy if activated
Norway	No	Primary: symmetric Balancing: asymmetric	Primary: 1 MW Balancing services: 10MWh/h	Primary: 15 min Balancing: 1h Tertiary: 10h	Primary: 1-year contract; weekly market for additional reserves Balancing: Regulating Power Market with gate closure 45min before hour of operation for regulating bids; RKOM weekly market for fast disturbance reserve	Primary: share on total capacity required in 1-year contract; marginal price in weekly market for additional reserves; pay-as-bid for reserve sold to neighbouring countries Balancing: highest regulating bid for energy if activated; pay-as-bid for special regulation;
UK	Yes	MFR: symmetric FFR: symmetric FCDM: Assumed Down STOR: Up Fast Reserve: Up	MFR: N/A FFR: 10MW FCDM: 3MW STOR: 3MW Fast Reserve: 50MW	MFR: N/A FFR: N/A FCDM: 30min STOR: 2h Fast Reserve: 15min	MFR: Mandatory service agreement FFR: Monthly tender FCDM: Bilateral negotiations STOR: Year-Quarter tender Fast Reserve: Monthly tender	MFR: Holding (£/h) + Energy (£/MWh) payment. FFR: fixed payment + capacity payment (£/h) + energy payment (£/MWh) FCDM: Availability Fee (£/MW/h). STOR: Availability Payment (£/MW/h) + Utilisation Payment (£/MWh): Fast Reserve: Availability Fee (£/MW/h) + Utilization Fee (£/MWh)

4 NETWORK REGULATION INCENTIVES AND REVENUE ALLOWANCES FOR DSOS

An appropriate EV charging management could allow DSOs to defer or avoid certain network reinforcements. However, charging management is not likely to be in place during the early stages of EV development. Therefore, EVs could cause an increase in peak load in certain distribution areas, leading to an increment in distribution network costs. Additionally, EVS will constitute an extra demand to be supplied by the distribution network. Consequently, power flows through the grid will be affected and this, in turn, will impact different aspects of distribution network operation such as protections schemes, voltage control, energy losses, etc.

DSOs are regulated companies due to the fact that electricity distribution is deemed to be a natural monopoly. Hence, regulatory bodies are in charge or determining the revenues that DSOs are allowed to collect through the distribution network charges. Furthermore, some additional regulatory incentives are frequently set, such as incentives to reduce energy losses or to improve quality of service. Therefore, the regulation of DSOs should be adapted to account for the potential impact of larger shares of EVs on distribution network planning and operation. More specifically, regulation should ensure that DSOs are not jeopardized by the connection of EVs by adequately accounting for the potential impacts of EVs on distribution network costs. Moreover, DSOs should be encouraged to incorporate EVs into distribution network planning and, as technology and commercial structures allow for it, implement operational strategies that allow them to defer network investments thanks to the coordination of EV charging.

According to Article 26 of the EU Directive 2009/72/EC, DSOs must be legally and functionally unbundled from other activities in the electricity sector such as generation and retailing. However, DSOs serving less than 100000 consumers are not required to observe these provisions. Thus, the situation in different Member States can vary greatly and the impact of small DSO unbundling requirements on EV deployment can also differ in each country. The development of EVs and aggregators could be hampered by lack of unbundling as DSOs have privileged access to sensitive information, such as metering data or network connection costs. This could cause cross-subsidies between the liberalised activities, i.e. generation and retailing, and distribution to arise. Additionally, DSOs could use this information to discriminate among different retailers or aggregators. Consequently, current unbundling provisions may need to be revisited.

Last but not least, the responsibilities of DSOs in developing the infrastructure needed to perform EV charging in public areas with public access, i.e. street charging, are not clear yet. Several alternatives are possible, each one of them possessing different pros and cons. However, unless regulation clearly allocates responsibilities for public charging infrastructure development, this could be stagnated thus hampering the adoption of EVs.

This section presents the current situation in participating countries concerning the aforementioned issues: DSOs economic regulation, energy losses, DSO performance on quality of service, DSO unbundling and DSO responsibility in public charging infrastructure development. Furthermore, some recommendations will be provided considering the three EV implementation stages: catalyst, consolidation and advanced. The section concludes with some conclusions drawn from the analysis of the responses.

4.1 DSO revenues and incentives to integrate EVs

4.1.1 Distribution network planning

DSOs can generally plan their networks and make their investment decisions without a direct intervention of the regulator. These investment decisions are made by forecasting the future growth in demand and DG connections and dimensioning network components according to the expected power flow requirements. Some kind of incentive regulation is in place in most participating countries (all but Greece). Therefore, DSOs will try to minimise these investments while ensuring that adequate levels of security and quality of supply are maintained. In Greece, where incentive regulation has not been implemented yet, the distribution company has to perform a three-year investment plan which must be submitted to the regulator.

Moreover, some of these costs are incurred specifically to reduce energy losses or improve quality of service. Since, some regulatory incentives for these purposes are frequently in place, which will be dealt with in more detail later in this document, DSOs perform cost-benefit analyses to make these investment decisions. For example, the Portuguese DSO has carried out an investment plan devoted to the improvement of continuity of supply in certain areas with a particularly low quality. This is called the Plan to Improve Quality of Service (PIQS) and it was started in 2004. The PIQS includes investments in new lines or interconnections as well as expenditures in improved maintenance actions and protection and control equipment such as auto-reclosers. The areas where certain actions are to be performed are identified in terms of the expected benefits in terms of quality improvement and, to a lower extent, reduction in energy losses. These benefits are measured through the initial rate of return expected (return on investment in the first year after the action).

Respondents were asked about what mechanisms exist nowadays to encourage DSOs to make efficient investment decisions. The responses show that these are generally limited to the incentives to reduce costs inherent to incentive regulation or the aforementioned incentives to reduce losses and improve quality or service. In Germany, DSOs have asked for a special amortisation ratio for investments in new technology. In Norway, some mechanisms are being introduced, albeit few details have been provided. The most notable example of specific incentives to innovate when deciding network investments is that of the UK. In 2005 the innovation funding incentive (IFI) through which DSOs could spend up to 0.5% in innovative projects was introduced. More recently, in 2010 the low carbon network funds (LCNF) allocates £500m during the period 2010-2015 to be spent in smart grids projects [4.2].

The large-scale penetration of EVs will cause is bound to affect the way distribution networks are planned nowadays. Since EVs will bring about an increment in demand, incremental investments might be expected to ensure there is enough grid capacity to supply conventional loads as well as EV charging requirements. Nonetheless, this impact will presumably depend to a great extent on the charging profiles of EVs as well as the load profiles of conventional consumers. A controlled EV charging or even the implementation of V2G capabilities will reduce the amount of investments needed to accommodate EVs. However, including the potential impact of EVs in network planning still does not seem to be in the agenda of DSOs as this is not seen as a major problem in the short-term. This suggests that in the future, DSOs will need to pay more attention to this issue.

4.1.2 Incremental distribution costs driven by EVs

Although it is very important for the further deployment of EV that its effect on network investments is accounted for in regulatory arrangements, there is no concept yet as to how this can be implemented. DSOs revenues should be calculated taking into account the incremental effect on CAPEX & OPEX of different EV penetration levels in order to neutralise the negative impacts of high EV penetration levels on DSO incremental costs. These costs comprise incremental network reinforcement costs, energy losses, active network management costs, and other operational costs.

At the moment, DSOs in all participating countries, except for Greece where cost of service regulation is still applied, are regulated under RPI-X regulation; more specifically a revenue cap formula. As mentioned previously, new regulation is being elaborated for Greece and the final provisions are yet unknown. Under revenue cap, the regulator broadly determines the level of allowed revenues at the beginning of the regulatory period (typically from 3 to 5 years) and sets a path for its evolution (X factor) during this period. Regulators use different methods to appropriately define these parameters promoting cost reductions while ensuring the financial viability of DSOs. Generally, past information and forecasts made by the DSOs are considered by the regulators. This data are used either in econometric benchmarking analyses, as in Germany, Norway, Portugal and UK, or to feed engineering models that as in Spain. The main difference lies in the fact that the former approach develops a benchmark according to the observed best-practices between the regulated firms, whereas the second approach builds a separate benchmark or reference network for each individual DSO.

Allowed revenues of DSOs currently do not include the potential effect of EVs of distribution OPEX and CAPEX. Nonetheless, it seems reasonable that regulators consider this in the future. This could be done by including these costs directly in the regulated asset base of DSOs. This would be straightforward in the case of Spain, as RNM allegedly can directly take into account the impact of EVs without any major changes. For the remaining countries using econometric benchmarking, this would require regulators to consider the number or the demand of EVs as an explanatory variable in the benchmarking analyses. Alternatively, regulators could complement current remuneration formulas with one or more added terms accounting for the impact of EVs. According to this term, the DSO revenues would be increased proportionally to the number of EVs that are connected to their grids. An example of this kind of revenue driver can be found in the distributed generation incentive framework applied in the UK (OFGEM, 2009). However, contrary to DG, EVs are in essence mobile loads which may not have a specific point of connection to the grid as they can be charged through the premises of a conventional consumer. This may hamper the application of such a revenue driver based on the number of the energy consumed by EVs.

4.1.3 Operational mechanisms to defer investments driven by EVs

Previous sections have assessed current distribution planning and regulatory practices. The importance of acknowledging of the impact of EVs on distribution costs by regulation has been pointed out as a major issue. Furthermore, an appropriate management of EV charging is deemed essential to minimise these incremental costs. However, little has been said about the means through which DSOs could ensure an efficient network development that would lead to lower distribution network costs and consequently lower network tariffs for consumers.

So far the planning of the networks was done with very high security margins concerning load and voltage capacities. But in general a DSO investing in networks has two different options to allocate money, either by reinforcing the grid structures with additional distribution capacity or by spending on control mechanisms and contracting other agents that could be beneficial to the efficient operation. In this regard, EVs could present new opportunities for DSOs to solve operational problems due to congestion or low voltages in the grid by reducing the charging rates and displacing the charging times. This would additionally avoid or defer certain network investments. In order to attain this, DSOs will require operational procedures and economic arrangements. This could be done through contracts between DSOs and other agents such as EVSA, for instance to ask for charging reductions to EVSA in exchange for an economic compensation.

These mechanisms would be very similar to the existing demand response mechanisms such as interruptible contracts. This type of contracts can be signed by consumers in Germany, Spain and Portugal. Notwithstanding, these contracts are generally limited to large industrial consumers that are larger than a certain power threshold. This limit is set to 5 MW in Spain and to 0.25 MW in Portugal. Furthermore, the decision to interrupt these loads is made by the TSO alone. Consequently, DSOs presently have no means of managing loads to solve operational problems in any of the participating countries.

The responses to the survey show that respondents envision that some of these concepts currently applied in transmission networks could migrate to distribution networks as well. However, the conditions of these agreements and the agents involved must be clarified. In the case of interruptible contracts at transmission levels, the TSO signs the contracts directly with end-consumers. However, since the number of EV owners will be much higher and their size much smaller, some kind of EVSA agent seems to be the appropriate contractor. In Spain, the figure of load manager that has been recently created could perform this task. In Portugal, it seems that the manager of the operations in the electric mobility network should be the agent in charge of these issues. In the remaining countries, such an agent would be necessary to allow for these agreements.

4.1.4 Incentives to reduce energy losses

Distribution energy losses can be categorised into two groups, depending on their underlying causes. On the one hand, non-technical or commercial losses are due to incorrect billing or electricity thefts. On the other hand, technical losses occur for different physical phenomena such as the heat that is produced in electrical equipment when an electrical current flows through them. Technical losses tend to be the most relevant in countries with a mature electrical system. Notwithstanding, commercial losses can be significant in developing countries. Hereinafter, the focus will be placed on technical losses, as it will be assumed that these are the most relevant in the participating countries.

Energy losses in distribution networks can be reduced by DSOs through specific investments or some operational strategies. However, unbundled DSOs do not purchase energy to supply end consumers. Therefore, they are not naturally encouraged to incur additional costs to reduce losses unless specific economic incentives are put in place, let alone if incentive regulation is applied. Consequently, it is frequent to provide DSOs with this type of incentives.

In most countries surveyed, DSOs face different types of incentives to reduce energy losses. The only exception would be that of Greece. However, this is directly explained by the fact that, as it will be explained in more detail in a later subsection, the distribution activity is not unbundled yet. Therefore, a DSO as such does not exist in this country.

Two main approaches can be found to encourage DSOs to reduce the energy losses in their networks. In some countries, DSOs have to purchase energy to compensate for the energy losses. In these cases, a limited amount of losses in included in their allowed revenues. However, if the cost of purchasing energy exceeds this amount, DSOs would suffer an economic loss. If, on the contrary, DSOs are able to reduce the cost of purchasing losses below this value, they would get an additional benefit. This is the scheme followed in Germany and Norway. Alternatively, some regulators set specific incentives to promote loss reductions. These basically consist in a term added to the distribution revenue formula that is computed as the product of a certain value of losses (in €/kWh) that multiplies the difference between some reference losses and the actual losses. Consequently, if actual losses exceed the reference ones, DSOs would perceive a penalty and vice versa. This mechanism is the one implemented in Spain, Portugal and the UK.

In essence, both approaches are very similar. The main difference would lie in the strength of the incentive, i.e. how energy losses are valued. In the first case, the market price would be the valuation of losses. Nonetheless, the second alternative seems more flexible to provide stronger or weaker incentives. However, in most cases, the valuation of losses is generally made according to spot or average market prices. In the case of Spain, a correction parameter of 0.2 multiplies the spot market price in the computation of the incentive. This may seriously dilute the incentive to reduce energy losses. In both cases the reference values for losses or the amount of energy purchases included in the allowed revenues are set according to historical values. Only in the Spanish case, a methodology to specifically account for future increments in demand or DG has been reported. In this case, a technical model called reference network model is used to compute some losses factors specific for each DSO.

The penetration of EVs can significantly affect the level of (technical) losses as power flows through the distribution network are modified. EVs will constitute an increment in the amount of load that has to be supplied through the distribution networks. Hence, losses are bound to increase since a large share of these is proportional to the square of the power flows through the distribution grid.

Nonetheless, the negative impact of EVs on losses can be mitigated by managing the vehicle charging. Moreover, in areas with large penetrations on DG, EV charging, if appropriately managed, can allow DSOs to reduce energy losses. The implementation of V2G strategies could contribute to reducing energy losses, but it seems unlikely that V2G were primarily driven by energy losses reductions.

Nowadays, the reference values for the incentive schemes or the amount of losses that is included in the allowed revenues do not take into account the impact of EVs. This seems reasonable as the current penetration of this new technology can be considered negligible. However, as the EVs become widespread, regulatory methodologies should be adopted to consider the impact of EVs on energy losses. Note that this impact may not be reflected in past values, especially in the EV adoption is very fast. Consequently, if reference values are determined only according to past information, DSOs would be prejudiced by the connection of EVs. Nonetheless, there are not clear provisions as to how this can be done in the future.

4.1.5 Incentives to improve quality of service

Incentive regulation of DSOs has been generally accompanied by incentives to improve quality of service. Within all the possible aspects related with quality of service, the main focus of regulation is generally placed on continuity of supply due to its direct relation with network investments and operational costs. Continuity of supply measures the frequency and duration of interruptions suffered by distribution network users. These interruptions are generally caused by failures in the network components.

The survey has shown that in all the participating countries incentives of this kind have been implemented (Portugal, Norway, Spain and UK) or there are plans to implement them in the short term (Greece and Germany). Similarly to energy losses, these incentives are generally set through a bonus-malus mechanism. In this case, different indices that measure the number and duration of interruptions are used for these purposes. The survey has revealed that the indices sued differ on a country basis. In Portugal, a value of energy not-supplied (ENS), computed as the product of the energy distributed over one year times the measured TIEPI (Tempo de Interrupção Equivalente da Potência Instalada), is used. In Spain, the indices TIEPI and NIEPI (Tiempo/Número de interrupción Equivalente de la Potencia Instalada) are used. On the other hand, the customer minutes lost (CML) and the customer interruptions (CI) indices are used [4.3]. The main difference between these indices is that the ones used in Spain and Portugal measure the average number of duration of the interruptions per each kW of demand and installed transformation capacity, whereas the indices used in the UK measure the average number and duration of the interruptions experienced by each individual consumer regardless of its size.

It is still unclear how EV might affect the quality of service provided by DSOs. In principle, quality of service targets for DSOs should not be changed due to network integration of electric vehicles. DSO CAPEX and OPEX to meet current quality of service targets should be recognized through adequate DSO revenues. DSO incentives to look for new ways to improve quality of service by using EV could be implemented. The capacity of EV to supply loads in islanding mode is a possibility that would improve continuity of supply, however this is nowadays far from real DSO practices. How EV could be used to increase quality of service is a subject that needs further research and innovation efforts.

The responses to the survey denote that there is not a clear view as to what the impact of EVs on quality of service will be. Nevertheless, respondents tend to agree that smart metering and the coordinated charging of EVs is a precondition to benefit from any potential advantage of EVs in this regard. Despite the fact that the contribution of EVs to improve quality of service is unlikely to be attained in the early stages, this should be analysed since now to gather more insights that would guide the development of future regulatory arrangements.

Moreover, the accommodation and controlled operation of EV can cause some quality of service problems that should be solved by DSOs. The clearest example is that of under-voltages produced by the voltage drop caused by EV charging. In this case, network reinforcements and control actions can be required to maintain the quality of service targets. However, the results of the survey show that these issues are still being analysed by DSOs and regulators. However, it is mentioned that regulation should consider provisions on this issue because they are likely to occur.

4.2 DSO compliance with EU unbundling provisions

A lack of unbundling at the distribution level may negatively impact the deployment of electric vehicles. Since networks are still operated as natural monopolies, fair and non-discriminatory network access is an essential condition for the development of competition in the generation segment and for mitigating market power for the benefit of the final EV customer. There is an asymmetry of information if DSOs have access to market sensitive information, e.g., through the collection of metering data and the managing of exchange of information. Furthermore, a lack of unbundling coupled with a lack of transparency bears the risk of cross-subsidies between the competitive generation segment and the regulated network activity. All these factors can cause problems for integrating the new market agents (EV supplier aggregators) in the electric power system with EVs, when DSOs display anticompetitive behaviour.

Art. 26, Directive 2009/72/EC, lays down the possibility for an exemption: Member States may decide to exempt integrated electricity undertakings serving less than 100,000 customers, or serving small isolated systems, from the unbundling provisions. Since the situation is very different from country to country, the impact of small DSO unbundling requirements on EV deployment can also differ in each country. Therefore, before making a general recommendation at EU level on this issue, it would be important to collect information of the particular situation in each country involved in MERGE.

The responses to the survey reveal that in all the countries, but Greece, DSOs are legally and functionally unbundled. In Greece, the vertically integrated electricity undertaking (Public Power Corporation, PPC) still performs the distribution activity. Nonetheless, a legal unbundling is expected to be implemented from 2012 by creating a subsidiary 100% owned by PPC. Moreover, Germany will finalize transposing some aspects of the EU Directive during the last quarter of 2011. After these changes, all participating countries would comply with the Directive unbundling provisions.

Notwithstanding, in some countries such as Spain, Portugal or Greece, DSOs would still belong to the same corporation as major generation and retailing companies in spite of being unbundled. This could create some problems as DSOs could try to hamper the activities of other generation or retailing companies that want to access their networks in order to benefit the generation or retailing firm belonging to the same corporation. However, this type of problems has not been reported to be happening for any country.

DSOs serving less than 100000 consumers are not generally unbundled in any participating country, as permitted by the EU Directive. This may not be significant in countries where these small DSOs do not account for a significant share of the overall connections. This is the case in Greece (just one small DSO located in the area of Athens airport), UK, Portugal and Spain. Even in the case of Spain, where there are over 300 of these DSOs, their relevance is minor as they account for less than 3% of connections. On the contrary, small DSOs are predominant in Norway and Germany where small DSOs supply the majority of consumers. In these cases, it should be examined whether cross-subsidies could arise between regulated and non-regulated activities.

According to the respondents, there are no plans to implement further ways of unbundling besides to aforementioned ones in Greece and Germany. These additional measures could be either to require ownership unbundling or require unbundling of small DSOs. It should be analyzed whether the adoption of EVs could introduce the need to implement any of these changes, particularly the lack of unbundling between distribution and retailing in those countries where the share of small DSOs is significant.

4.3 DSO responsibility in the roll-out of public charging infrastructure

The role of DSOs in developing the charging infrastructure on street, the so-called charging in public areas with public access, is to be determined. From the DSO perspective there are two main options: i) charging assets are built by DSOs as part of their concession, thus being these added to the regulated asset base and their cost recovered through the distribution network charges, or ii) the infrastructure is developed and operated by an agent independent from the DSO that may or may not act as a retailer as well. Considering these alternatives, Eurelectric has identified four potential market models for the development of this infrastructure [4.1]. The four different market models are represented in Figure 14.

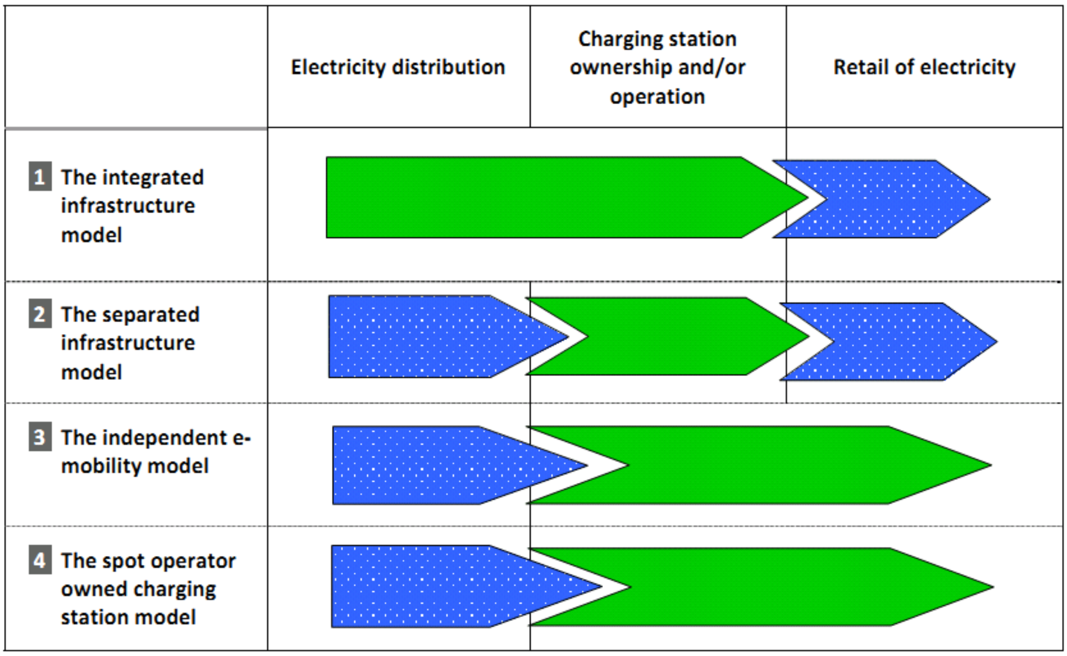


Figure 14: Market models for the development of public charging infrastructure. Source [4.1]

Respondents were asked about their views on this topic and whether some actions had already been taken in their respective countries. All of them seem to agree that EV charging in public areas with public access is necessary either to prevent drivers from purchasing an EV due to concerns about the driving range (Germany) or to allow EV users without a private parking space to charge their vehicles (Spain and Greece).

Moreover, there is a general consensus that the first two options would be preferable to the “independent e-mobility” and the “spot operator owned charging station” models. The main reasons for this are that DSOs already have the knowledge in building and operating the grids and that options 3 and 4 could represent a step back in the unbundling of distribution and retailing. Furthermore, an independent e-mobility agent or a spot operator may find that the volume of sales in a certain geographical area may be insufficient to recover the cost of the infrastructure at least in the initial stages of the EV uptake. Additionally, a small volume of sales could prevent these agents from becoming a full market agent (either due to size limitations or to high transactions costs) thus having to purchase energy from retailers and re-sell, which is not always permitted by regulation.

Norwegian respondents have shown their preference for option 1 specifically, either because they consider that it would be the easier to implement as no major changes are required in current arrangements. However, recent regulation passed in Portugal has specifically advocated and implemented option 2. This is deemed to allow the clear identification of the activities and the corresponding assets and the creation of access tariffs while running retailing under competition.

4.4 Recommendation related with distribution network regulation to enhance EV integration in each one of the development stages

During the catalyst phase, EV owners may receive time of use energy prices, although coordinated charging will presumably not be in place. Therefore, the DSO cannot ensure that EVs are charged during valley hours. This may create high uncertainties when planning distribution networks. Nonetheless, this impact will be partially mitigated by the moderate penetration levels that will be present during this phase and it should be attended as any other incremental demand (in terms of capacity and energy). Regulation at this stage should focus on compensating DSOs for the incremental costs driven by EVs. This could be done by directly including these costs in the regulated asset base or through revenue drivers added to current remuneration formulas. Nonetheless, the latter alternative is deemed more complicated due to the mobility of EVs and the fact that they will not have a specific point of connection as they will be charged at a consumer's premises.

Innovative solutions that may facilitate the integration of EVs in future stages should be tested from now. However, specific regulatory mechanisms seem to be required to promote the active participation of DSOs. The UK has recently implemented regulatory incentives of this kind, thus being a reference for the remaining countries.

Additionally, the unbundling processes and implementation of incentive regulation should be finalised at this stage. This is expected to happen in Germany before the end of 2011. Among the participating countries, Greece is the one that needs to undertake more profound changes. Nonetheless, it is expected that an unbundled DSO regulated under some form of incentive regulation will exist by the end of 2012.

At this stage, EVs are expected to be mainly charged at home plugged as any other domestic device. Nonetheless, the lack of a public charging infrastructure may constitute an important barrier in those countries where people in urban areas generally live in apartment blocks or without a private parking such as Spain or Greece. Consequently, the agent responsible for the development of this infrastructure should be determined as soon as possible. Respondents showed preference for two potential alternatives. Either the DSO is made responsible of its development, or an independent (from distribution and retailing) agent does this. Portugal and Spain are the only countries where regulation has already been passed, effectively implementing the second alternative.

When the number of EVs reaches a significant amount, the consolidation phase should start. At this moment, EVSA agents have been created and can control, at least to a certain extent, EV charging. DSOs have gained sufficient knowledge about the behaviour of EV so as to include them properly in network planning processes. Consequently, regulation should shift its focus from compensating DSOs for incremental costs to the promotion of an efficient network development. Moreover, EVs should by now have a relevant effect on grid losses. Thus, regulatory incentives should be prepared to account for this impact when setting reference values.

Regarding unbundling between distribution and retailing, the main problems could arise in those countries with larger shares of small DSOs, i.e. Norway and Germany. If relevant conflicts are identified, further ways of unbundling should be explored. These could include the legal unbundling requirement of all DSOs with less than

100000 connections, reducing the number of minimum connections for DSOs to be exempt from unbundling or forcing some mergers between distribution companies. It is not envisioned now that ownership unbundling should be required as no major problems have been reported.

The infrastructure to charge EVs in public areas with public access would be very relevant when EVs become widespread at this stage. Therefore, DSOs or other entity should start developing it. Presumably, corrections to the initial regulatory arrangements will be needed as more experience is gained. However, these difficulties cannot be envisioned now.

Finally, the advanced phase will be reached provided that the EV has been finally adopted at a relevant scale and the technical and commercial solutions have been developed. At this stage, EVSA can provide certain services to DSOs under conditions established through grid codes. These grid codes would define the services to be provided and contain the conditions under which this is done (minimum requirements, local markets for ancillary services, pricing arrangements, etc.). Many of these services will have a strong local component, e.g. congestion management or voltage control, which should be carefully taken into account when developing these grid codes. This will allow DSOs to include these potential services in their planning and operational practices. The implementation of V2G capabilities will additionally bring about the possibility of improving continuity of service through islanded operation with the contribution of EVs.

The recommendations provided for each one of the three phases defined within the MERGE project have been summarised in Figure 15.

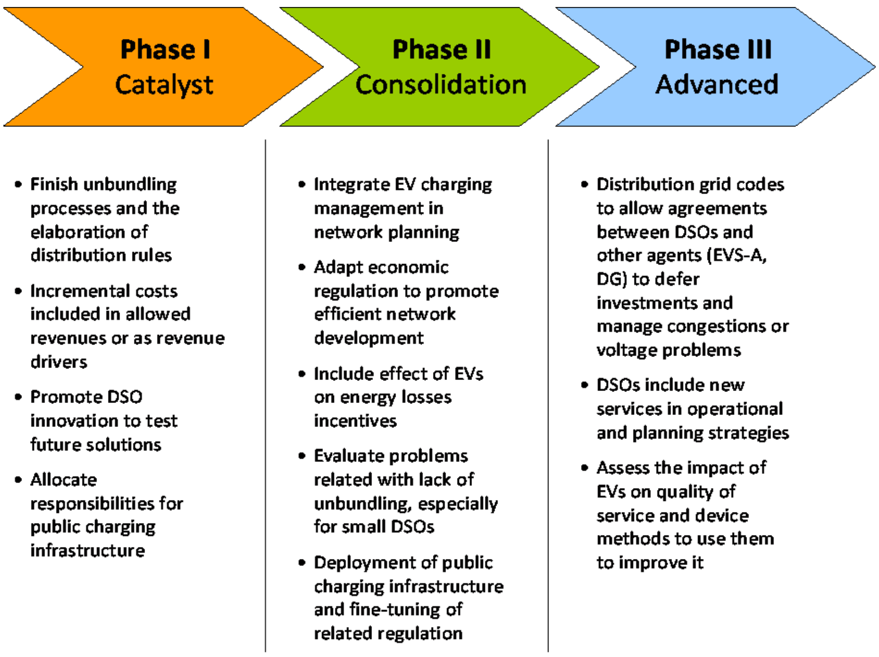


Figure 15: Summary of recommendations regarding distribution network regulation

4.5 Conclusions on distribution network regulation

This section has reviewed the current arrangements for distribution network regulation in participating countries. The existing barriers to the development of EVs have been identified and several regulatory recommendations have been provided. As a result of this review, the focus of regulation in the three stages defined for the progressive adoption of the EV could be summarised as follows:

- **Phase I – Catalyst:** Regulation should focus on compensating DSOs for negative effects on costs of EV charging and promoting innovation to find solutions needed in future stages. Unbundling processes should be finalised in those countries where some reforms are still pending. Finally, the responsibilities in the development of public charging infrastructure should be clarified to facilitate the transition to the next phase.

- **Phase II – Consolidation:** The deeper changes in regulation will be required at this stage. It is no longer enough to merely compensate DSOs for the potential negative impact of EVs. Sufficient knowledge has been gathered so as to require an efficient network development, for which appropriate regulatory incentives and planning procedures are required. The problems arising from lack of unbundling, if any, will be likely to arise during this stage. Being this the case, these should be analysed and solved. Finally public charging infrastructure must be developed, for which DSOs may play a central role.[13]

- **Phase III – Advanced:** this last phase would be devoted to the implementation of more sophisticated operational tools for DSOs. EVs have to become active agents, through the control of EVSA, and can now be used to solve congestions or voltage problems and reduce interruptions.

4.6 References regarding DSO regulation and incentives

[4.1] Eurelectric, 2010. “Market Models for the Roll-out of Electric Vehicle Public Charging Infrastructure. A Eurelectric Concept Paper”. September 2010

[4.2] Eurelectric, 2011. “Regulation for Smart Grids”. February, 2011.

[4.3] OFGEM, 2009. “Electricity Distribution Price Control Review 5. Final Proposals – Incentives and Obligations”. Ref. 145/09. 7 December 2009.

[13] However, whe operation and ownership of public charging infrastructure remains to be decided.

5 NETWORK TARIFF DESIGN WITH EV DEPLOYMENT IN THE PARTICIPATING COUNTRIES

5.1 Structure of this section

In order to achieve the objectives mentioned in the introduction of this document, this section is structured as follows. Apart from this Introduction, subsection 5.2 details the information that was possible to obtain regarding the Use of System Tariffs, UoS tariffs or charges, in Germany, Greece, Norway, Portugal, Spain and the UK.

Subsection 5.3 enumerates the most relevant regulatory principles that typically frame the design of tariff systems in general and in particular of Use of System charges and then it raises and discusses that advantages and drawbacks of some issues as the adoption of flat or time variant tariffs, the dependency on the location and the consideration of the impact of network losses.

Finally, subsection 5.4 draws the main conclusions that were identified.

5.2 Network Tariffs in the Participating Countries

5.2.1 Germany

Tariffs for grid usage are calculated by every local grid company. They depend on customer groups. Load profile customers, who are connected only in low voltage, are charged with a simple tariff only for the energy they have consumed. Additionally they pay for meter operation, meter reading and invoicing. There are no flat rates in German grid charges. Load curve customers pay two-stage tariffs: They are charged for the received yearly maximum power and the sum of energy. Their grid usage tariffs depend on the level of connection point – low, middle or high voltage. And of course they pay higher tariffs for automatic metering, reading and monthly invoicing.

The Federal Network Agency has specified detailed conditions for allocating costs and calculating grid charges for about 900 grid companies by-law (StromNEV). Based on those rules every DSO yearly computes its own charges. Before being published on its internet site, they have to be checked and approved by the regulator.

5.2.2 Greece

For the purpose of Distribution Use of System (DUoS) charges, consumers are categorised based on their connection voltage and metering capabilities. More specifically, consumers are categorised into five categories: MV consumers, domestic consumers, LV consumers with maximum demand meters (with and without reactive power metering) and other, non-domestic LV consumers.

For MV customers, 50% of allocated costs are recovered through a capacity charge and 50% through an energy charge. The energy charge is a flat rate with no time differentiation. The capacity charge is charged on maximum demand recorded during peak hours (daily between 11 am-2 pm).

The percentages for LV customers are 20% capacity charge and 80% energy charge. For domestic consumers, only 10% is charged through a capacity payment. For all LV customers, the capacity charge is charged on the connection capacity (kVA) and therefore it is a fixed charge per customer. For LV customers with zonal meters which can record demand during off-peak hours, the energy charge is not charged during the off-peak demand.

All prices are uniform across the country. The Minister for Environment, Energy and Climate Change sets the allowed revenue and use of system charges following an opinion by RAE based on the data submitted by the Distribution Company.

5.2.3 Norway

In Norway the total amount paid by consumers is split in two components. The first one corresponds to the amount to pay for the electricity that is bought from a power supplier. This amount is associated to a market price that results from the competition between different market agents. The second term corresponds to the electricity distribution tariff to be paid to the local network company that is responsible for conveying the electricity till the installations of the consumers. This electricity distribution tariff covers the network power transmission and distribution costs.

Transmission and distribution functions are provided in a monopoly basis by network companies and so it is reasonable that these businesses are regulated, as a way to compensate the absence of competition. In this case, in Norway the Norwegian Water Resources and Energy Directorate, NVE, acts as regulatory agency for the sector and does not determine the specific values of these tariffs, but it sets an upper limit for the yearly income that each of these companies can get from consumers. Acting in this way, NVE aims at preventing consumers from paying excessive prices for power transmission and distribution, or conversely it aims at preventing that network companies obtain excessive money not justified according to operation and investment costs plus a reasonable revenue rate.

On the other hand, and although not setting the tariffs themselves, NVE determined the structure that each company should adopt for these tariffs. In brief, the transmission and distribution tariffs paid by households should include a fixed component in NOK/year and an energy component in NOK/kWh.

The regulation of the transmission and distribution network activities made by NVE comprises setting the regulated revenue of network companies, associated to the maximum amount these companies can obtain each year from consumers. This regulated revenue reflects as far as possible the network costs and these include fixed and variable costs. Fixed costs include capital and maintenance costs in the sense they are not dependent on the amount of transmitted power. On the other hand, variable costs correspond to network operation costs and basically they reflect the cost that network companies incur in buying power to balance network active losses, which can amount to 8 to 10% of the total transmitted power.

As mentioned above, the transmission and distribution tariffs include a fixed and an energy component. The fixed component corresponds to an annual fixed amount that, in the minimum, should cover the customer specific costs including metering, settlement and invoicing. On the other hand, the energy component depends on the consumption and in the minimum should cover the costs of marginal losses, that is the amount of losses in the network that would occur if there was an extra kWh of demand, for a given amount of load. In addition, the adopted regulatory rules indicate that that the total amount paid by the consumers shall cover the total fixed network costs. After setting the regulated revenue, each specific distribution company shall then set the two tariff components so that these rules are accomplished. For household consumers, the common rule is that:

- the fixed tariff component covers the consumer specific costs plus a part of the fixed network costs;

- the energy component covers the cost of losses plus the remaining of the fixed network costs.

As a result of these rules, the electricity distribution tariffs are not the same through the country and vary from company to company. In the first place, the costs incurred by each company may be different, both in terms of fix and energy related costs. This has a direct impact on the regulated revenue set by NVE and so on the total amount to be obtained from the consumers. Secondly, even if the total regulated revenue is the same, different companies can adopt different scaling for the fixed and the energy terms thus resulting in different amounts to be paid by consumers having similar demand. Usually, large differences in network tariffs are due to differences in operation costs reflecting different topographic, climatic conditions as well as differences in the density of the demand or the consumers. These factors are considered by NVE when setting the yearly regulated revenue and cannot be changed by a company in order to increase its tariffs.

Finally, the same network company can have different network tariffs for different sets of consumers. For instance, it is not unusual that the fixed component of the network tariff is larger for isolated cottage customers rather than for urban households. This would only reflect the typical lower utilization of isolated cottage consumers. Due to its lower demand, these consumers would then have a lower contribution to cover network fixed costs. In order to ensure that these consumers cover their share of fixed costs, the fixed component of their network tariff would be higher in these cases. In any case, the total amount obtained by the company from all its customers shall not exceed the regulated revenue set by NVE.

This information was obtained in [5.4].

5.2.4 Portugal

Independent regulation has a history of about 15 years in Portugal, given that the Regulatory Agency was created by the legislation passed in 1995. Then, it started operating in an installation regime until its status and internal operation rules were approved in 1996. Afterwards, the Portuguese Electricity Regulatory Agency, ERSE, started the preparation of the codes it had to issue according to the legislation passed in 1995. One of them was the Tariff Code whose first version was approved in 1997. Using the approaches and mechanisms established in that code, *ERSE* set the tariffs in the electricity sector in December 1998 to be in force during 1999.

The Tariff Code [5.1] defines regulatory periods of three years so that 1999-2001 corresponded to the first regulatory period, 2002-2004 was the second, 2005 corresponded to a transitory year that was finally considered as an extension of the second regulatory period, 2006-2008 corresponds to the third complete regulatory period and we are currently completing the fourth regulatory period. ERSE has the responsibility of setting a number of parameters to be used all along a regulatory period as well as fixing the tariffs for every year using those parameters and other information submitted by regulated companies. This means that in the year before the beginning of a new regulatory period (that is in 1998, in 2001, in 2005 and in 2008) ERSE conducts extensive studies and analysis on the behavior and on the performance of the regulated companies in order to fully characterize them so that the parameters to be used all along the next regulatory period are fixed in a more sounded and robust way.

It is still important to mention that the legislation passed in 1995, confirmed in this particular point by the new Electricity Law passed in February 2006 [5.2], established that ERSE is fully independent from the government and it is the sole responsible for setting the tariffs on the regulated activities. *ERSE* has fully administrative and budgetary autonomy (its budget is directly financed by one tariff paid by all electricity consumers) and its board cannot be dismissed by the government.

The first version of the Tariff Code identified a set of activities in the electricity sector designed to cover the entire value chain from generation to the final relation with consumers. These activities were selected so that they allow allocating all costs in the industry into one of these activities in a clear and transparent way, in order to eliminate cross subsidies. The Tariff Code was revised twice from 1997 to 2008 but the general organization of regulated activities and of the corresponding tariffs remained unchanged. Regarding the regulated activities, they currently include [5.1]:

- Energy Acquisition – namely to supply the consumers that didn't move from the regulated tariffs to the free market;
- Global Use of the System – including the operation of the control center, the provision of ancillary services, the operation of the Regulatory Agency and of the Market Operator managing the pool market;

- Transmission of Electricity – including the operation, expansion and maintenance of the National Transmission Network, established at 400, 220 and 150 kV;
- Distribution of Electricity - including the operation, expansion and maintenance of the National Distribution Network, organized in HV, MV and LV networks;
- Retailing – including the commercial structure of the Regulated Retailer and the relation with regulated consumers (namely measurements and billing).

Each of these activities is associated with a regulated tariff that, according to the Tariff Code, is fixed so that it is possible to recover the Regulated Remuneration of that activity in each year. Accordingly:

- Energy Acquisition – Energy Tariff set so that it is possible to pay along each year the energy bought by the Regulated Retailer in electricity markets;
- Global Use of the System – Global Use of the System Tariff so that it is possible to pay the ancillary services, to remunerate the operation of the National Control Center, of the Regulatory Agency and of the Market Operator. This tariff also internalizes the subsidies included in the feed-in tariffs paid to Special Regime Units, the costs of efficiency energy programs and the subsidies assigned to the power companies in Azores and Madeira archipelagos;
- Transmission of Electricity – Transmission Network Tariff designed to pay the operation, expansion and maintenance costs of REN, the national transmission provider, having the concession of the National Public Transmission Network;
- Distribution of Electricity - Distribution Network Tariff designed to pay the operation, expansion and maintenance costs of EDP Distribuição, the national distribution provider, having the concession of the National Public Distribution Network, in HV, MV and LV;
- Retailing – Retailing Tariff designed to pay the retailing costs of the Regulated Retailer.

The Tariff Code also includes a number of variables that can be subjected to measurements in order to evaluate the degree of use of each activity. The tariff variables are as follows:

- contracted power, €/kW/month;
- average power in peak hours, €/kW/month;
- active energy in peak hours, €/kWh;
- active energy in full hours, €/kWh;
- active energy in valley hours, €/kWh;
- active energy in super valley hours, €/kWh;
- injected reactive energy , €/kVArh;

- absorbed reactive energy, €/kVArh;
- fix term, €/month.

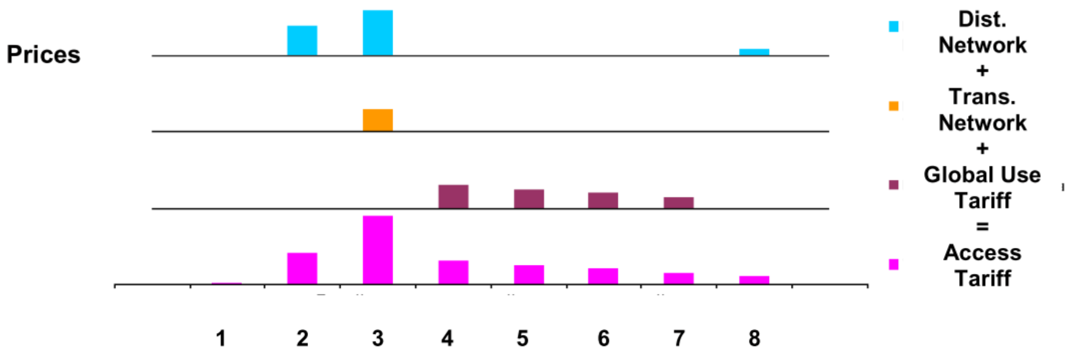
As it will be detailed later, ERSE sets prices for some of these variables in order to establish the values of each regulated tariff.

The tariffs mentioned above can be considered as elementary ones in the sense that each of them is directly related with one of the regulated activities established in the Tariff Code. Using these elementary tariffs and the prices set for the tariff variables in each of them, it is possible to create second level tariffs, or composed tariffs, by simply adding the prices in different tariffs for the same tariff variables. Using this additive concept, it is possible to understand that the Access Tariff paid by all clients (free and regulated clients) to use the infrastructure of the system independently of the generation company that is actually supplying them, results from the addition of the following elementary tariffs:

- Global Use of the System Tariff;
- Transmission Network Tariff. The transmission tariff has two terms corresponding to the use of interconnection and 400 kV lines on one side and to the use of the remaining transmission system established at 220 and 150 kV;
- Distribution Network Tariff. This tariff is decomposed in three terms: Distribution Tariff in HV, in MH and in LV.

Figure 16 illustrates the formation of the Access Tariff as the addition of these four elementary tariffs. For each of them, the bars indicate the tariff variables for which ERSE set non zero prices so that adding the bars in each vertical line (that is, for the same tariff variable) will result in the price set for each tariff variable in the Access Tariff. As an example, the Transmission Network Tariff only has a price for the peak power. On the other hand, the peak power price in the Access Tariffs results from the addition of the peak power prices set in the Transmission and in the Distribution Network Tariffs. This additive principle is also applied considering the connection level of the consumers. As a result:

- a consumer connected at HV distribution level pays an access tariff that results from the addition of the Transmission Network Tariff, plus the Distribution Network Tariff for HV networks and the Global Use of the System Tariff;
- on the other hand, a consumer connected at LV distribution level pays an access tariff that results from the addition of the Transmission Network Tariff, plus the Distribution Network Tariffs for HV, for MV and for LV networks and the Global Use of the System Tariff.



Tariff variables

1 – Fix term (€/month)

2 – Contracted power (€/kW/month)

3 – Average power in peak hours(€/kW/month)

4 – Energy in peak hours (€/kWh)

5 – Energy in full hours (€/kWh)

6 – Energy in normal valley hours (€/kWh)

7 – Energy in super valley hours (€/kWh)

8 – Reactive energy (€/kvarh)

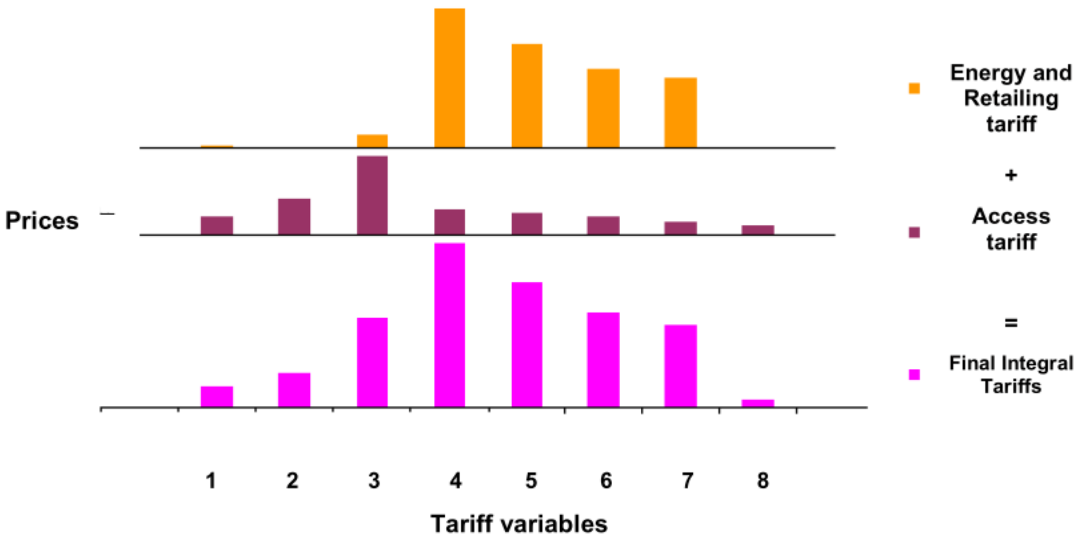
Figure 16: Structure of the Access Tariffs in terms of elementary tariffs and tariff variables (source ERSE web site).

Using a similar reasoning, the integral tariffs paid by regulated consumers are the addition of the access tariff as described in Figure 16 with the Energy Acquisition and the Retailing Tariffs. Accordingly, Figure 17 illustrates the additive principle applied to the final integral tariffs. According to these two figures, energy prices (on peak, full, valley and supper valley hours) are very reduced in terms of the access tariffs but are quite large and in fact determine the Energy Tariff and so their presence in the final tariff is also very significant. On the other hand, power prices (on contracted power and on peak power) are largely used in network transmission and distribution tariffs. In particular, the Transmission Network Tariff is established only in terms of a peak power price while the Distribution Network Tariff comprises prices both for contracted power and for peak power.

The selection of the tariff variables and the price setting is under complete responsibility of the Portuguese Regulatory Agency for the Energy Services, ERSE. In particular for the transmission and distribution UoS tariffs, the Regulatory Agency selected the Average Power in Peak Hours for the transmission UoS and the Average Power in Peak Hours and the Contracted Power for the distribution UoS. The reasoning for this selection is as follows:

- the Average Power in Peak Hours reflects more closely the use of branches more centrally located in the power system and so this variable is used in the Transmission UoS and in the Distribution UoS for HV networks. The price set for this variable is more reduced for the Distribution UoS for MV networks and it is simply not used in the Distribution UoS for LV networks;

- as one goes to more peripheral branches, namely to radial areas with lower voltage levels, the use of the system and the required capacity is more determined by the contracted power. As a result, the Distribution UoS for MV and LV networks use prices set for the contracted power.



1 – Fix term (€/month)	5 – Energy in full hours (€/kWh)
2 – Contracted power (€/kW/month)	6 – Energy in normal valley hours (€/kWh)
3 – Average power in peak hours(€/kW/month)	7 – Energy in super valley hours (€/kWh)
4 – Energy in peak hours (€/kWh)	8 – Reactive energy (€/kvarh)

Figure 17: Structure of the Final Integral Tariff in terms of elementary tariffs and tariff variables (source ERSE web site)

5.2.5 Spain

In Spain, the access tariff are set by the Regulatory Commission and they include several components, in order to ensure the full recovery of transmission and distribution costs (investments and maintenance), the renewables feed-in tariff costs, the support to securitize some level of autonomous national coal as fuel), the System Operator, Market Operator and Energy Regulatory Commission costs, the overcosts of the power systems in the islands, …). These costs correspond to fixed amounts established by the Ministry of Industry.

The access tariffs have both a capacity (€/kW) and an energy (€/kWh) term. A two (and up to six depending on the size of the consumption) time period access tariff (TUoS tariff) is available. The prices are uniform and without any regional differentiation for the same kind of consumer all over Spain. This means that for the same voltage connection level and contracted capacity, the TUoS is the same.

Distribution MV network voltage is between 132 kV and 11 kV, while LV is usually below 1 kV. Most residential and office related buildings are connected to the LV grid. MV is used primarily for industrial supply.

The system's regulator, Comisión Nacional de Energía (CNE), classifies energy demand as domestic (LV), small and medium size companies (PYME) (LV), MV (<36kV) and HV (>36kV). Thorough market information is periodically published by the CNE.

For LV the rank of contracted power stands from 0.3 kW to 15 kW for one phase installations and from 1 kW to 44 kW for three phase installations (minor values can be found in old installations with 127V instead of 220-230V phase-neutral installations).

For MV (<36 kV) the contracted power may rise to 2 MW.

For tariff purposes (access tariff) the categories of consumers are set as follows

- Low voltage consumer with contracted power below 10 kW;
- Low voltage consumer with contracted power in between 10 kW and 15 kW;
- Low voltage consumer with contracted power above 15 kW;
- Medium or high voltage consumer with contracted power below 250 kW;
- Medium or high voltage consumer with 6 different tariff periods.

In terms of energy consumption by categories of consumers, in June 2010, the total number of supply points of electricity in Spain reached 27.3 million. From them, 26.5 million supplies (97%) that represent 36% of the energy consumption, correspond to the domestic segment, 0.8 million (3%) that represent 22% of the energy consumption, correspond to the small and medium size companies segment, and 20,155 (0.1%) that represent 42% of the energy consumption to the industrial segment.

5.2.6 UK

After looking at different documents, it was possible to conclude that in the UK the regulations define Connection Charges and TUoS tariffs that are briefly characterized below.

5.2.7 Connection Charges

According to what it is established in Part 1 of Section 14 of the Connection and Use of System Code, CUSC, [5.3] the connection charges are established to recover with a reasonable rate of return the costs involved in providing the assets that establish the connection with the National Electricity Transmission System. The procedure involves the following steps:

- definition of the boundary between connection assets and transmission system infrastructure assets, in order to clearly identify the assets that will be subjected to remuneration;

- identification of the users of these connection assets in order to allocate the cost by the users;
- computation of the Gross Asset Value, GAV. As indicated in paragraph 14.3.3 of the CUSC, the GAV represents the initial total cost of an asset to the transmission licensee. For a new asset it will be the costs incurred by the transmission licensee in the provision of that asset. Typically, the GAV is made up of the following components:
    - Construction Costs - Costs of bought in services;
    - Engineering - Allocated equipment and direct engineering cost;
    - Interest During Construction – Financing cost;
    - Liquidated Damages Premiums - Premium required to cover Liquidated Damages if applicable.
- the GAV of an asset is re-valued each year normally using for instance an RPI approach or the Modern Equivalent Approach in which it is identified the cost of an equipment that can replace the one under analysis. For ease of calculation, April is used as the base month;
- computation of the Net Asset Value, NAV, of the equipment. The Net Asset Value of each asset for year n, used for charge calculation, is the average (mid year) depreciated GAV of the asset. The NAV of an asset in year n is computed using the following equation, where A_n is the age of the asset (number of completed charging years old) in year n and DP is the depreciation period;

$$NAV_n = GAV_n . \frac{DP - (An + 0{,}5)}{DP} \tag{5.2.1}$$

- As an example, at constant price terms an asset with an initial GAV of £1m and a depreciation period of 40 years will normally have a NAV in the year of its commissioning of £0.9875m (i.e. a reduction of 1.25%) and in its second year of £0.9625m (i.e. a further reduction of 2.5% or one fortieth of the initial GAV). This process will continue with an annual reduction of 2.5% for each year of the asset's life.

5.2.8 Use of System Charges

According to what it is established in paragraph 14.14.1 of Part 2 of Section 14 of the Connection and Use of System Code, CUSC, [5.3] the Transmission Network Use of System charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) Activity function of the Transmission Businesses of each Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licences, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security. Prior to a new price control exercise, the Regulatory Agency defines the Maximum Allowed

Revenue, MAR, for each TO and this MAR amount is then recovered by the TUoS charges.

The TUoS charges are set according to a methodology termed as Investment Cost Related Pricing, ICRP, that aims at reflecting the operation and investment costs of transmission providers as well as transmitting a signal to the users or future users of the systems, both in terms of generators and loads. This model was introduced in 1992 initially in England and Wales and then it spread to Scotland under BETA. The ICRP model basically corresponds to a transportation model formulated using the DC model of transmission systems and it aims at moving electricity from generators to the load points under peak demand and according to specified security criteria. As a result one derives incremental investment costs at different locations both from the point of view of the impact of connect new generation to the system and new loads. Paragraph 14.14.5 of Part 2 of Section 14 of the Connection and Use of System Code, CUSC, specifies that these charges shall be computed for 21 generation zones and for 14 demand zones and it determines that generation charges should cover 27% of the regulated revenue while the demand charges cover the remaining 73%.

Using this transportation model, the model calculates for a given injection of 1 MW of generation at each node, with a corresponding 1MW offtake (demand) at the reference node, the increase or decrease in total MW-km of the whole network. Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The marginal km cost for demand at each node equal and opposite to this nodal marginal km for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1 MW of generation has on the total circuit km. Typically, the amount of money recovered with the payment of these generation and demand TUoS charges does not cover the MAR amount. This justifies the adoption of a reconciliation step

As a result, the TUoS charges in &/kW display a geographic differentiation along Great Britain and as a result end consumers will also pay tariffs geographically differentiated depending on the demand zone they are ultimately connected to. Regarding DUoS charges, the distribution service is provided by several regulated companies each one operating on a specific geographic area and subjected to particular RPI-X regulations. This ultimately means that the DUoS charges will also have different values in each of these regions.

5.3 Discussion Issues

5.3.1 General regulatory principles

The electricity codes in force in different countries and the corresponding Tariff Codes typically enumerate a number of principles that should be followed by Regulatory or State Agencies when preparing the tariff systems. These general principles will now be addressed because they define the framework and they characterize the practice followed by Regulatory or State Agencies.

Taking as an example the Portuguese Electricity Law [5.2], these general principles are as follows:

- equality of treatment and opportunities that shall be ensured to all participants;
- tariff uniformity, so that the tariff system is universally applied to all clients, namely ensuring that all clients under the same conditions are subjected to the same regulated or access tariffs;
- transparency in the formulation and setting of the tariffs;
- elimination of cross subsidization mechanisms, namely by:
    - the adequate identification of a set of activities that cover the entire value chain from generation to the end consumers;
    - the complete identification of the involved costs together with their correct assignment to the identified activities;
    - the adoption of the additivity principle through the establishment of a tariff system that involves a number of elementary tariffs that cover the identified activities. Subsequently, Access Tariffs or Final End User Tariffs will be formulated as additions of elementary tariffs;
- transmission of economic signals to the users of the networks, in order to use these networks and other installations of the power system in a more efficient way, both from an economic and from a technical point of view;
- protection of the clients regarding the evolution of the tariffs along time, while ensuring the economic and financial balance of the regulated activities assuming that they are managed in an efficient way;
- establishment of incentives to induce the efficient management of the regulated activities;
- contribution to the promotion of energy efficiency and environmental conditions.

According to these principles, clients should pay access tariffs reflecting the costs they are bringing to the system both in terms of investment in expansions and reinforcements and in terms of operation, for instance related with the required levels of ancillary services and network losses. However, the tariff uniformity principle is usually understood in a much broader way, in terms of requiring that regulated tariffs apply universally to all clients. In practice, this typically corresponds to the definition of access tariffs that do not contain any geographical differentiation, although the case of UK corresponds to an exception. This means that access tariffs are typically discriminated by voltage connection levels, they can accommodate some type of time differentiation but, in general, they should not contain any differentiation regarding the type of electricity use and the location so that no consumer classes or geographical areas are privileged.

If a large deployment of EVs occurs, this is likely to represent a discontinuity in the natural evolution of the demand and of the regulated investment and operation costs. If that is the case, some of these principles should be discussed and questioned in order to continue to provide a fair treatment to all network users and to allocate the costs to the users without cross subsidies. In the next paragraphs these issues will be discussed in more detail.

These discussion points are organized in three groups according to the urgency in adequately addressing them to achieve a reasonable and fair integration of EVs in the electricity networks. Group 1 integrates issues that should be addressed in the first place, Group 2 corresponds to medium term issues that, in any case should deserve attention in order to prepare their implementation in due time, and Group 3 corresponds to less pressing issues.

5.3.2 Group 1: Catalyst Phase

5.3.2.1 Tariff variables – power and/or energy

The situation in different countries varies regarding the tariff variables adopted to set UoS charges. In some countries, they include both power and energy terms while in others they are typically set using power terms (using peak power and/or contracted power). In some other countries, as in Portugal, the access tariffs have an important energy component that is not associated with the transmission nor with the distribution UoS charges but in fact with the Tariff for the Global Use of the System that, among other items, recovers the costs associated with the renewables feed in tariffs. This means that as the penetration of renewables, namely wind parks, increases the share of the energy term in the Portuguese Access Tariffs becomes more important.

From the point of view of transmission and distribution UoS charges, several regulatory agencies consider that regulated transmission and distribution costs are very much dependent on investment and maintenance costs and that these costs are strongly correlated with power either in terms of peak power or in terms of contracted power. In this case, the costs of network losses are included in the tariff system using multiplicative loss coefficients established in terms of power, as detailed in Section 5.6.5.

However, if losses become more relevant, a specific energy term can be included in the transmission and distribution UoS charges to take into account this issue. This term can be set per voltage level and it can eventually be discriminated by different classes of distribution networks with the same voltage level depending, for instance, on a measure to be selected of the penetration of EVs in a given area.

5.3.2.2 Flat or time variant tariffs

Regarding the time dependency, the situation of the analyzed countries is also different. In several cases, the access tariffs are established in terms of a flat charge all through the country and without any time differentiation. In other cases, as for instance in Spain, there is a time differentiation that can go till 6 time steps.

The consideration of a time differentiation in the integral tariffs to be paid by EVs is an important issue as a tool to induce charging patterns that are more adequate as a way to avoid or at least to postpone expansions or reinforcements. Since the integral tariffs are composed of two terms – energy and access tariffs – this time differentiation can be incorporated in one of them or in both.

In general, TUoS and DUoS charges are largely related with investment and maintenance costs in many cases are set according to power terms (either using the peak power or the contracted power). This ultimately means that introducing some time differentiation at this level is not so easily justified. On the other hand, since the tariffs should have a universal nature, if some time differentiation was introduced in the power terms, that would also have to be applied to all other LV clients connected to the same network.

As a result, it seems more reasonable and easier to implement a time differentiation on the energy terms of the integral tariffs. Energy terms can correspond to a tariff term of the integral tariffs to pay the energy required to the charging and also to a tariff term of the access tariffs designed to cover network losses. In both cases, a time differentiation is easily incorporated and in fact is already present in most tariff systems in which there are different regulated prices for the energy in peak, full and valley hours. This means that the existent more reduced energy prices in valley hours would naturally be also used to induce battery charging in off-peak hours.

As a result of this reasoning, it seems more natural not to include any time differentiation on the access tariffs (except on energy terms eventually present to cover network losses) and, on the contrary, clearly differentiate the price of the energy required to charge the batteries. The time differentiation of the energy term and the design of the most adequate set of time periods should result of a study to be conducted on the operation of typical distribution networks in order to get conclusions regarding the maximum admissible levels or battery charging along the day that do not imply significant investments on reinforcements or expansions.

5.3.3 Group 2: Consolidation Phase

5.3.3.1 Dependency on the location

The emergence of a new class of users, as EVs, places a number of challenges because the large deployment of EVs can correspond to a discontinuity in the natural evolution of the demand. This ultimately means that some of the well-accepted principles enumerated in Section 5.6.1 should be discussed and eventually some adaptations should be incorporated in tariff codes.

As an example, the tariff uniformity principle as it is currently understood indicates that all clients connected at LV pay the same access tariff. This means that some kind of average approach is widely used in order to set the amount of this tariff to recover the global management costs (namely the control center and ancillary service costs), transmission regulated costs, and distribution in HV, in MV and in LV regulated costs.

However, if a deployment of a large number of EVs occurs in a specific geographic area this will most likely require extra investments in expansions and reinforcements (that is, investments beyond what it was expected as a result of the natural increase of the remaining loads) together with extra operation costs (for instance, related with network losses).

The current flat rates by voltage connection levels would simply socialize these extra costs by all clients, even though extra costs are due to a particular class of consumers. Is this fair? Is this is line with the principle that states that cross subsidies should be eliminated? If such a discontinuity on the demand evolution occurs, it seems there is a contradiction between the tariff uniformity principle on one side and the elimination of cross subsidies on the other, meaning that some decision at the regulatory level should be taken for instance involving the adoption of a tariff scheme that gradates the application of these two principles.

In the limit, if some dependency of the UoS tariffs regarding the location existed, EV owners could be induced to select the locations to charge the batteries according to the available tariffs. In the long run, this would transmit a signal to the users in order to adopt more efficient behaviors. For instance, this would mean charging the batteries in areas where the networks were less demanding in terms of new investments so that the UoS tariffs were more reduced.

However locationally dependent UoS tariffs may transmit economic signals that may have implications on investment decisions. Under the assumption of price elastic final consumers, electric vehicles are more likely to be adopted in areas of lower electricity prices. Therefore in the long run, networks with lower “locational” UoS components in the price perceived by the final customer, may be more likely attractive for EV charging and hence for EV uptake. The same implication would be true for localization and siting of industry and production plants, therefore this is a controversially discussed topic.

5.3.4 Group 3: Advanced Phase

5.3.4.1 The impact of network losses

Current regulations incorporate the cost of network losses in different ways in the tariffs to be paid by the end consumers. One of the procedures corresponds to set the values of the different tariffs for a given voltage level and then adopt coefficients that multiply these values if one wants to translate them to another voltage level.

As an example, consider a consumer connected at LV. According to the additivity principle stated above, this consumer pays an access tariff that should remunerate the costs of system management and ancillary services plus the costs of using transmission, distribution in HV, distribution in MV and distribution in LV networks. The problem is that this consumer is connected at LV where all his measurements are performed. So, in order to supply 1 MW of power to this consumer it is necessary to inject a value P_T MW in the transmission system, a value $P_{D,HV}$ in the HV distribution network, a value $P_{D,MV}$ in the MV distribution network and finally a value $P_{D,LV}$ in the LV distribution network and all these values typically follow (5.6.1).

$$P_T > P_{D.HV} > P_{D,MV} > P_{D,LV} > 1\,MW \tag{5.3.1}$$

These values can be related by the mentioned multiplicative coefficients, usually termed as Loss Adjustment Coefficients, LAC, so that we obtain expressions (5.6.2) to (5.6.4).

$$P_{D,MV} = (1 + LAC_{MV/LV}).P_{D,LV} \tag{5.3.2}$$

$$P_{D,HV} = (1 + LAC_{HV/MV}).P_{D,MV} \tag{5.3.3}$$

$$P_T = (1 + LAC_{T/HV}).P_{D,HV} \tag{5.3.4}$$

Accordingly, this consumer will pay a transmission UoS charge that is set at the transmission boundary of the system and that then has to be translated to LV using (5.6.5). He will also pay the distribution at HV UoS charge set at the distribution HV boundary and translated to LV using (5.6.6). He also pays the distribution at MV UoS charge set at the distribution MV boundary and translated to LV using (5.6.7) and he finally pays the distribution LV UoS charge, at the voltage level he is connected to. So, this consumer pays UoS charges given by (5.6.8).

$$CUoS_{T \to LV} = (1 + LAC_{TV/HV}).(1 + LAC_{HV/MV}).(1 + LAC_{MV/LV}).CUoS_T \tag{5.3.5}$$

$$CUoS_{HV \to LV} = (1 + LAC_{HV/MV}).(1 + LAC_{MV/LV}).CUoS_{HV} \tag{5.3.6}$$

$$CUoS_{MV \to LV} = (1 + LAC_{MV/LV}).CUoS_{MV} \tag{5.3.7}$$

$$TCUoS_{LV} = CUoS_{T \to LV} + CUoS_{HV \to LV} + CUoS_{MV \to LV} + CUoS_{LV} \tag{5.3.8}$$

In these expressions:

- $CUoS_T$ - UoS charge set for the transmission system;

- $CUoS_{T \to LV}$ - UoS charge set for the transmission system and translated to LV;

- $CUoS_{HV}$ - UoS charge set for the distribution HV system;

- $CUoS_{HV \to LV}$ - UoS charge set for the distribution HV system translated to LV;

- $CUoS_{MV}$ - UoS charge set for the distribution MV system;

- $CUoS_{MV \rightarrow LV}$ - UoS charge set for the distribution MV system and translated to LV;

- $CUoS_{LV}$ - UoS charge set for the distribution LV system;

- $TCUoS_{LV}$ - total UoS charge to be paid by an LV consumer.

Typically, these LAC coefficients are computed in average terms for each of these voltage levels. This approach is certainly adequate for the current use of the networks at different voltage levels. However, if a large deployment of EVs occurs in some networks, network losses will assume different patterns in different geographic areas for the same voltage level. This ultimately suggests that these LAC coefficients should not be set regardless of the networks themselves but some differentiation should be incorporated in this scheme. In the limit, each distribution network at each voltage level should be studied and a specific LAC should then be computed. In order to avoid this level of complexity, we can suggest selecting the values of the LAC coefficients for each network according to some measure of the penetration of EVs in that geographical area.

This approach would contribute to reduce the cross subsidies associated to network losses that a pure average approach would introduce. However, it would not solve all the problems because in the same networks other consumers than EVs would start paying larger UoS charges due to the increased penetration of EVs in that particular network.

5.4 Conclusions on Network Tariff Design with EVs

This section gathers the information obtained in the answers to the questionnaire entitled “NATIONAL QUESTIONNAIRE - Identification of Regulatory issues about Market Design and Network Regulation for Efficient Integration of EV in Electricity Grids”. It covers the answers obtained from participants from Germany, Greece, Norway, Portugal, Spain and the UK in what concerns the tariffs for Use of the System.

It also enumerates the most widely used regulatory principles typically followed by Regulatory Agencies when designing tariff systems and when setting UoS charges. These principles are important because they have been framing the activity of Regulatory Agencies and will most likely continue to guide their activity. This means that any tariff design of UoS charges that can be designed in the scope of MERGE will have to consider these generic principles.

In any case, the deployment of a large number of EVs will represent a change of paradigm in many well established routines for distribution network operation, planning and regulation and so these issues have to be addressed in due time. The rapid increase of EVs in some geographical areas can be understood as a discontinuity in what could be seen as the natural evolution of the demand regarding which DSOs will naturally be prepared to answer. If such discontinuities occur, then some of these principles can be contradictory between themselves suggesting that at least a new look and some discussion should be conducted on this area. This is the reason to include a number of points that were raised as a contribution to this discussion in subsection 5.3.

5.5 References for Section 5 on Network Tariffs

[5.1] ERSE, "Tariff Code", (in Portuguese), December 2009, available in www.erse.pt.

[5.2] Ministry of Economy and Innovation, "Law of the Electricity Sector", Law 29/2006 of 15th February, February 2006.

[5.3] Connection and Use of System Code, CUSC, UK, available in http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/

[5.4] Norwegian Water Resources and Energy Directorate web page: http://www.nve.no/en/Electricity-market/Transmission-Tariffs/Transmission-tariffs-to-households-/

6 CONCLUSIONS

This report was composed with the goal to analyze and overcome regulatory barriers for the massive penetration of electric vehicles in different European member states. The recommendations contained herein are elaborated under the principle of leading toward a consistent framework with a clear timely scope. All undertakings to foster EV penetration in Europe should contain the long term perspective such that the risk of ending efforts before success is established is minimized. Therefore, the report has aimed, where possible, at incentives to enable early decisions for building sufficient confidence and trust in the technological opportunities that are at hand today. Furthermore, the authors are convinced that it should be at the heart of every recommendation to reduce policy and hence final customer and tax payer cost.

With the intention to give stakeholders a clear picture of the steps that lie ahead early commitments decisions on the most pressing issues are favoured as they create regulatory stability and reduce investment risks. Collaboration, coordination and harmonisation of activities for a successful advancement into a future of massive EV deployment is regarded as crucial. In addition to that, there is a need for explicit definition of the roles of different agents of the electric power industry and stakeholders for future EV deployed societies as a whole [6.1].

In the United States, Smart Grid Interoperability Panel (SGIP) of the National Institute of Standards and Technology (NIST), a special working group addresses a variety of regulatory issues arising in the context of electric vehicles. Market relevant issues similar to those discussed in this report, including final customer prices of vehicle to grid services and appropriate taxation of the energy provision and the definition of reselling agents are mentioned. Metering specification and requirements for communication and control are pointed out. Also, very practical, hands-on points are raised. The question of how to define fire safety-laws for charging equipment is one of them. Furthermore, crash safety and protection against risk of electrocution, harmful vapours etc. are of concern. Battery recycling requirements are an important issue once the market has grown significantly [6.2]. The US Department of Energy's Quadrennial report assigns future charging infrastructure, battery technology electric motors and power electronics as the main points of interest for government funded research [6.3].

This section gives a joint conclusion, summarizing the preceding sections, which provide topic specific recommendations in detail. This report has indicated the main topics in sections 2 through 5, respectively section 2 discussing the *design of day-ahead and intra-day wholesale energy markets* (topic A), section 3 analyzing the *design of balancing and reserve markets* (topic B), section 4 *network regulation incentives and revenue allowances for DSOs* (topic C) and section 5 considering *network tariff design* (topic D).

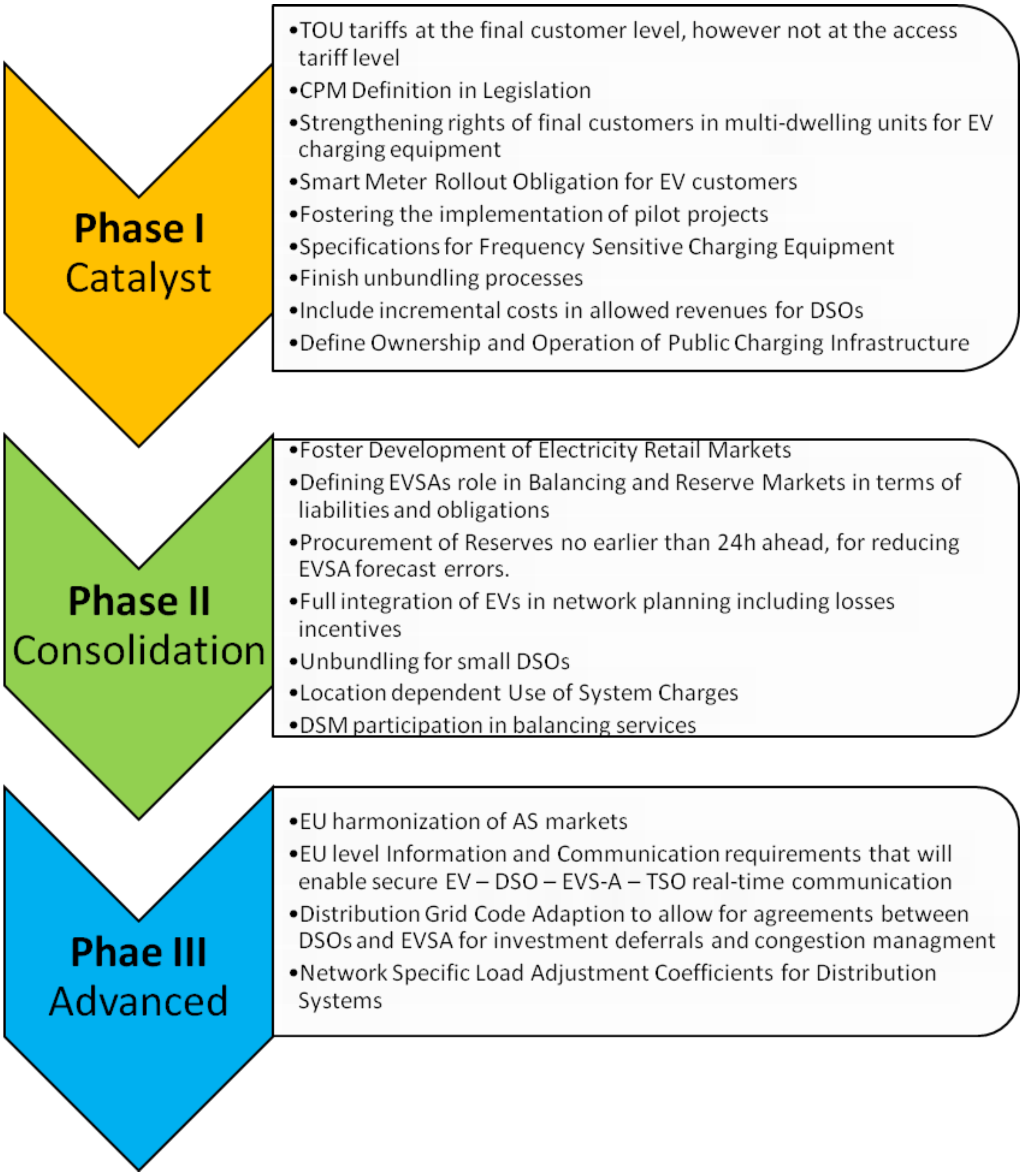


Figure 18: Joint Conclusions by Development Phase

One of the key umbrella recommendations remains to promote research & development. Additional efforts to design appropriate codes and standards, as well as, coordinating the development of adequate infrastructure, charging and vehicle systems are needed, such that technology is spread and research outcomes are disseminated extensively.

6.1 Conclusion Specific References

[6.1] International Energy Agency. 2011. *Technology Roadmap: Electric and Plug-in Hybrid Electric Vehicles*. June. Accessible at http://www.iea.org/papers/2011/EV_PHEV_Roadmap.pdf.

[6.2] NIST SGIP 2011. *Plug-In Electric Vehicle (PEV) Regulatory Issues Table* Accessible at: http://collaborate.nist.gov/twiki-sggrid/pub/SmartGrid/V2GRegulatoryIssues/PEV_Regulatory_Issues_list_v4.doc

[6.3] DOE, US. 2011. *Quadrennial technology review*. Accessible at http://www.doe.gov/sites/prod/files/ReportOnTheFirstQTR.pdf

APPENDIX 1 - QUESTIONNAIRE

APPENDIX 2 – ANSWERS TO QUESTIONNAIRE PORTUGAL

APPENDIX 3 – ANSWERS TO QUESTIONNAIRE GREECE

APPENDIX 4 – ANSWERS TO QUESTIONNAIRE SPAIN

APPENDIX 5 – ANSWERS TO QUESTIONNAIRE GERMANY

APPENDIX 6 – ANSWERS TO QUESTIONNAIRE NORWAY