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Topic 12

From Distribution Networks to Smart Distribution Systems: Rethinking the Regulation of European Electricity DSOs

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Executive summary

Technological advances are reshaping today's electricity markets. More mature technologies for local renewable generation and decreased investment costs thereof, joint with national support schemes, led to a significant market penetration of distributed generation in many EU countries. Not only distributed generation but a newly emerging broad range of distributed energy resources (DER), including local storage, electric vehicles and demand response, are driving or at least allowing for potentially significant changes in the planning and operation of power systems. These changes also pose challenges for the regulation of power systems. Today, some challenges are only a possibility, and might arise once technologies mature and be more widely deployed, as for instance with electric vehicles. Other challenges, foremost related to distributed generation, are already established facts and observable in many EU distribution systems. However, the same technologies that are causing substantial challenges can – with the right regulation and market design – be exploited to establish a more efficient and also cleaner electricity system than our current one.

In the light of these changes, this THINK report discusses regulatory implications of changing local electricity markets and to this end sets the focal point on electricity distribution system operators (DSOs) as regulated local entities and local market facilitators. First, we shed light on where the current regulation of DSOs needs updates to allow for welfare-enhancing DER technologies to be adapted efficiently and in a timely fashion. We find that a major challenge is to update regulation such that distribution companies are not negatively affected by the development of DER and are incentivized to foster the integration of viable new technologies into the market. Moreover, we find that updates are needed to provide the right regulatory tools to DSOs such that they can also benefit from the services DER can offer for system operation and planning. Ultimately, the priority task of regulation is not to try to predict what the future will be, but to design DSO incentives that make possible all welfare-enhancing business models under any future market development.

Section 2 demonstrates the need to review existing regulation. We illustrate the impact of distributed energy resources on electricity markets at the distribution level. The broad range of new technologies offers plenty of possibilities for new business models, whose performance and even viability may critically depend on the regulatory regime of DSOs. These new business models may potentially even lead to a paradigm shift that might shake up the traditional value chain and cause a radical change of the power market architecture as we know it today. For this reason, DSO regulation has to be examined in its full spectrum. We identify four major areas of regulation that need to be reviewed: allowed DSO remuneration; distribution grid tarification; potential new infrastructure tasks of DSOs vis-à-vis energy market actors (such as ICT infrastructure for advanced meter data or EV charging stations); and the potential new roles and functions of DSOs in system management vis-à-vis transmission system operators.

Section 3 sets the scene and discusses the present state of electricity distribution in the EU. Today's DSO landscape resembles a huge patchwork with diverse national implementations of relevant pieces of EU legislation and resulting heterogeneous end-user market structures in different Member States. Substantial differences arise regarding operated voltage levels, the scope of activities, the size and number of DSOs in a country, the level of unbundling, applied regulation, et cetera. Even though full eligibility of customers is mandatory, and the choice of suppliers and tariffs increased in many EU retail markets, the degree of retail market liberalization and competition still varies significantly across the EU. Insufficient unbundling poses one of the most serious obstacles to retail competition in many distribution markets. This heterogeneity in regulation and market structures aggravates the problem of finding a unanimous approach to appropriate DSO regulation.

Section 4 assesses the four identified areas of regulation that may have a significant impact on the performance of the potential new business models and the DSOs themselves. First, *remuneration schemes for DSOs* need to be reviewed. Increasing amounts of DER require substantial investments to connect all new resources and to enable the system to deal with increased volatility of net demand and peak demand fluctuations. With massive DER penetration, an active management of DER has the potential to decrease the total costs of DSOs compared to a business-as-usual handling of these resources, and hence DSOs also need to invest in ICT infrastructure that empowers them to employ DER for their daily grid operations. While overall remuneration has to increase, a sound regulation that efficiently incentivizes DSOs to engage in active system management has to take account of i) changing OPEX and CAPEX structures, ii) the optimal choice among both, and of iii) how to incentivize DSOs to deploy innovative solutions.

Second, the present *design of network charges* does not provide a level-playing field among all agents that use the distribution network. With an increasing penetration of DER, ill-designed distribution network charges will become even more problematic. Business models exploiting, for instance, inefficient arbitrage possibilities caused by differentiated treatments of different DER technologies, or of certain types of producers and consumers, might flourish in the absence of sound tarification procedures. Moreover, grid users are becoming complex, sophisticated agents, which can have very diverse consumption and/or production patterns, and being able (and willing) to react to price signals. Tariffs, therefore, should reflect the true costs (or benefits) of different types of load and generation for the distribution system, which will depend on the agent's geographic location in the system as well as on the profile of injection/withdrawal from the connection point. Any hidden subsidies should be removed and replaced by sufficient but direct subsidies that do not turn into inefficient signals. A reference framework to design the new network tariffs is proposed in this report.

Third, regarding new infrastructure tasks and hence new *DSO activities vis-à-vis markets*, there are a number of areas in the newly emerging market environment where there is no consensus about whether the respective tasks should be under the responsibility of the DSO or not. The regulatory challenge here is to clearly define the roles, boundaries and responsibilities of DSOs. Different proposed (regulated as well as liberalized) models for (1) the ownership and management of metering equipment, (2) data handling and (3) EV charging infrastructure all have their advantages and disadvantages. These tasks may or may not be offered at lowest cost (due to sufficient synergies with grid operation) and/or in a more qualitative way by the DSOs as compared to other third regulated agents or commercial actors. The suitability of a certain model will depend on system-specific conditions, such as scale and scope economy potentials, degree of uncertainty regarding best technological solutions, or concerns with respect to possible market entry barriers. Though, if a full rollout of advanced meters (including data management), and also EV charging infrastructure must be provided in a timely fashion, advantages lie in the domain of the DSO. Regulators, however, have to take care not to foreclose market structures through DSOs becoming incumbents once new technologies are deployed at scale and commercial actors want to enter the market.

If general exemptions from unbundling for small DSOs prevail, additional regulatory means gain in importance. As for ICT and EV infrastructure, standardized access for third parties is crucial to counteract non-existing unbundling. Likewise, also small DSOs need to provide for sufficient data availability such that entry costs for third parties (especially competing retailers) are further reduced. Incentivizing joint ventures of several small DSOs may reduce costs for new infrastructure and also reduce problems related to limited unbundling.

Last, regarding *DSO activities vis-à-vis the TSO*, the general responsibilities of network operators with respect to grid management do not change, but the set of tools available to perform their tasks is enriched by DER. The increasing amount of DER establishes the need for a clearly defined differentiation and cooperation of tasks between distribution and transmission system operators. National regulatory authorities should aim at establishing a hierarchy between the DSOs and TSOs with respect to their actions that have an impact on final system balancing. Furthermore, products that DSOs and TSOs use to ensure reliable grids (and often procure for this sake) should be clearly defined in terms of geography and timing. Coordination needs will differ among systems. It makes a difference whether a distribution system contains only an insignificant amount of DER, or whether it contains a whole portfolio of DER including also non-negligible volumes of local storage and DR potential. Moreover, regulation or coordination efforts have to take account of which voltage levels are part of the distribution activity, with coordination needs probably increasing when DSOs also operate MV (or even HV) grids.

In the **European context**, regulation has to be kept at minimum level, respecting the principle of subsidiarity. Accordingly, we see neither the need nor a solid justification for an EU-wide comprehensive harmonization of the regulation of DSOs, although we recommend setting clear minimum requirements in a few key regulatory aspects, as well as the publication of EU guidelines to spread, encourage and monitor good regulatory practices in some of the critical areas that have been identified in this report:

First, EU guidelines for a sound regulation and adequate remuneration of DSOs as well as for distribution grid tarification should be formulated, followed by regular monitoring and benchmarking to reveal shortcomings of national regulatory approaches. Urgent research is needed to develop adequate procedures for remuneration of DSOs and distribution network tariff design. Second, the EU should mandate that consumer data are made available to registered agents (provided that individual consumers give their authorization for the use of their personal profiles). The definition of the specific format of data provision (i.e. one of the three data models proposed, or a combination thereof) can then be left to the Member States. Third, depending on system complexity and the number of tasks to be accomplished by DSOs, stricter unbundling requirements should be mandated. As the complexity of the system increases, an insufficiently unbundled DSO could either stay with a restricted set of tasks, or the DSO could expand its portfolio of activities, but accompanied with "higher Chinese walls" between the DSO and its subsidiary retailers that engage in trading of distributed sources. Finally, procedures and principles of coordination between DSOs and TSOs also should be defined at a European level in order to avoid distortions in competition and barriers for market entry due to different rules and market designs in different Member States. It needs to be ensured that the interactions between these different types of system operators are well defined and that they are in compliance with the network codes.

Section 5 concludes.

1. Motivation

Recent technological advances are reshaping today's electricity markets. While changes of electricity market architecture in the past generally related to wholesale markets, today, new advancing technologies are expected to radically change local electricity markets at the distribution level. More mature technologies for local renewable generation, decreased investment costs thereof and ambitious national support schemes for low-carbon generation led to a significant market penetration of distributed generation in many EU Member States. At the same time, innovation in metering and appliances allows consumers to react to local and upstream generation patterns and prices. Consequently, traditional top-down power flows from centralized generation sources connected to the transmission grid to consumers are challenged by local distributed generation and local means of electricity trade. Moreover, existing decades-old distribution infrastructure may need significant renewals soon in many systems. In order to allow for further market penetration of advanced local generation and consumption technologies and an efficient operation of distribution grids, the renewal and expansion of existing networks should go hand in hand with a modernization of distribution systems.

In a bigger perspective, even though patterns of electricity generation, transportation, distribution and consumption are revolutionized (along with increasing consumption per se, e.g. due to the electrification of other sectors such as transportation), the traditional triangle of EU energy market policy – competition ("2014"), sustainability ("2020", "2050") and security of supply – remains valid. Although these three high-level EU energy policy objectives traditionally were discussed on the transmission and wholesale level, they have large implications for the distribution level as well. Competition implies competitive retail markets including adequate consumer response to economic signals; sustainability implies the facilitation of low-carbon generation or the implementation of energy efficiency enhancing measures, et cetera; and supply security relates to the reliability and quality of electricity supply, which also requires an adequate level of distribution grid investments.

Changes driven by the newly emerging broad range of distributed energy resources – be it distributed generation, local storage, electric vehicles or demand response – hence also might impact the balance between the three EU policy pillars. As a consequence, the existing regulatory compact has to be examined within a broad range of energy policy fields. Distributed generation may enhance sustainability, but poses challenges for distribution system operators (DSOs) because all distributed generation wants to be consumed and major grid investments, especially in rural areas, are required. Without a sound regulation, however, grid investments might not be optimal. Distributed generation competes with traditional upstream power sources and the idea of well-functioning and competitive markets mandates that cheapest sources, whether from upstream or local, find demand first. But for effective competition, also network tariffs have to provide a level-playing field for all types of generation. Furthermore, distributed energy resources add many new coordination tasks to local energy markets. It has to be identified whether the responsibilities for those tasks will be with regulated authorities such as the DSOs or with commercial market actors.

In the light of these changes, this THINK report discusses the regulatory compact related to electricity DSOs. First, we shed light on the missing blocks in the current regulation to allow for the welfare-enhancing technologies to be adapted efficiently and in a timely fashion. A major challenge is to design regulation such that distribution companies are not negatively affected by the development of distributed energy resources, and, thus do not have an incentive to hamper their deployment. We develop proposals on how to adjust to a new regulatory compact that provides a level-playing field for current and new energy services and that properly treats regulated actors that provide this level-playing field. Moreover, we also ask how to design the right regulatory tools so that DSOs can also benefit from the services DER provide for system operation and planning. It is argued that the priority task of regulation is not to try to predict what the future will be, but to make possible all welfare-enhancing business models under any future market development.

Welfare enhancements and cost savings that can be achieved in future distribution markets are substantial. The share of distribution costs in the final customer's electricity bill lies in the range of 15% (in the UK) and 30% (in the Czech Republic), see ECME (2010), indicating that the regulatory framework of DSOs has a substantial impact on electricity prices in the EU. In the future, distribution costs are likely to increase as massive grid investments have to be undertaken. The IEA Energy Outlook estimates that investments in distribution networks will amount for about two thirds of all transmission and distribution investments by 2020, with this share growing to almost three quarters by 2035. Hence, a cost-effective regulation of DSOs will have a positive effect in reducing the total cost of electricity, with a beneficial impact on consumers and the competitiveness of European firms alike. Well-regulated DSOs also contribute to a better functioning of (local) electricity markets.

The report is organized as follows. In Section 2 we identify the areas of DSO regulation that are challenged by the new technologies. In Section 3 the shortcomings in the respective regulatory areas are identified before regulatory changes are proposed in Section 4. Section 5 concludes. This report primarily focuses on the impact that the new technologies mentioned above have on the DSO business and touches upon other classical issues in regulation such as consumer protection only whenever needed.

2. Why and where the existing regulation needs to be reviewed

In what follows, we first illustrate the impact of recently matured technologies on electricity markets at the distribution level. Having this impact in mind, the existing regulation is examined. Four major areas of regulation are challenged: DSO remuneration, distribution grid tarification, but also regulation considering the DSO as a key player along the full value chain (i.e. DSO activities vis-à-vis markets as well as vis-à-vis the TSO). These areas have to be reviewed, because the broad range of new technologies offers plenty of possibilities for new business models, and potentially may even lead to a paradigm shift that might shake up the traditional value chain and cause a radical change of the power market architecture as we know it today.

2.1 New technologies challenge existing regulation

Distributed generation (DG) and resulting increasing system imbalances, congestions and need for connections in distribution grids are no new phenomenon. There already is a massive deployment of DG technologies in distribution networks at low-, medium- and high-voltage levels. For example, Eurelectric (2013) reports that "in many places [in Germany], the DG output of distribution networks already exceeds local load – sometimes by multiple times." Such

DG sources include rooftop solar PV, wind, biomass, micro-cogeneration and a multitude of back-up generators that are installed in the premises of hospitals, banks, hotels and firms. While these technologies are not always entirely new, significant cost reductions, that can make them competitive with conventional centralized generation soon, will lead to ever higher degrees of DG penetration and many consumers becoming active "prosumers".

Another field of current technological advances is **distributed storage** (DS), which might become viable soon at all voltage levels and also in larger amounts. While several forms of electricity storage have been installed and different battery types are currently showing high market growth rates, bulk pumped hydro is still the by far most widely used technology with more than 127 GW of operating capacity worldwide (EPRI, 2010). However, a lot of R&D is ongoing to improve technologies and reduce costs (Ruester et al., 2012), and many experts consider that small-scale, local energy storage connected to the distribution grid or to end-consumers will complement centralized large-scale storage and become a critical component of "the grid of the future" (Kaplan, 2009; Eyer and Corey, 2010; He et al., 2011).

Third, the use of **electric vehicles** (EVs, both purely electric and hybrid) which have to charge from the grid and may also inject power back to it in order to provide valuable services to ensure system stability and avoid congestion ("vehicle-to-grid", V2G), is expected to grow. Kampman et al. (2011) present three scenarios for the penetration of electric vehicles. In the 'most realistic' scenario, a market penetration of about 3.3 million EVs in the EU is achieved in 2020, increasing to 50 million EVs in 2030 (with a share of about 60% of these electric vehicles being PHEVs). Smart charging is assumed to become standard after 2020.

While the above technologies all relate to physical consumption and production, recent technological advances in metering and communication enable active **demand response** (DR)[1] and enhanced distribution automation, thereby also facilitating and allowing for a wider deployment of DG, DS and EVs. Whereas at the beginning of the liberalization process, DR has been considered only interesting for large customers, technological advances (e.g. cost reductions of intelligent metering systems; advanced energy boxes that can optimize consumption subject to individual constraints reducing risks and efforts of reacting to price signals) make this concept interesting also for small-scale and residential consumers. Given a positive cost-benefit analysis, by 2020, at least 80% of all European consumers shall be equipped with intelligent metering systems (EC, 2009), and consequently, time-varying pricing will be technically possible.

In the remainder, we denominate the above technologies collectively as **distributed energy resources** (DER). Today, some challenges arising with DER technologies are only a possibility, as for instance it is currently not known how successful EVs or storage will be. Other challenges, foremost related to DG technologies, are already established facts.

Accordingly, these new technologies entering the grid at low-voltage levels change power system architecture and functioning. The integration of operation technology and IT is key. Traditional systems had been designed to distribute electricity top-down from generation connected to the transmission level to end consumers, and the distribution system had been designed accordingly such that there were

1. DR means that consumers are able to change their load (into both directions) in response to signals, be it price-based (time-of-use, real-time pricing, critical peak pricing) or volume-based (e.g. direct load control based upon a previous agreement with the customer).

	Downward adjustment*		Upward adjustment*	
Flexible operation of DG	Temporary production decrease (e.g. wind curtailment)	- P	Temporary production increase (e.g. from backup generators)	+ P
Electric energy storage	Charging	+ C	Discharging	+ P
Electric vehicles	Charging (smart charging)	+ C	Discharging (vehicle-to-grid services)	+ P
Demand response	Temporarily consuming more	+ C	Temporarily consuming less	- C

* Limited potential in all cases, to be discussed

- P ... producing less // + P ... producing more
- C ... consuming less // + C ... consuming more

Figure 1: DER's ability to provide downward and/or upward adjustment to the system

Source: Own depiction

no bottlenecks or congestion ("fit-and-forget approach"). In contrast, today's distribution systems are challenged by new features such as increased volatility of net demand and peak demand fluctuations, reverse flows from the distribution to the transmission level in times of local generation exceeding local demand, and increasing possibilities of energy and power trades at the local level. Many related markets, such as ICT applications, are expanding. Hence, even though the DSOs' objective remains to "ensure the long-term ability of the system to meet reasonable demands for the distribution of electricity […] [and to operate] under economic conditions a secure, reliable and efficient electricity distribution system" (EC, 2009), the set of available tools to ensure this core task is expanding.

The same technologies that are bringing these challenges today can – with the right regulation and market design – be exploited in order to arrive at a more efficient and also cleaner electricity system than our current one. As Figure 1 describes, all DER technologies can be employed for downward and upward adjustments. Of course, there is a limited potential for all these types of devices (e.g. availability of storage to 'consume' electricity is restricted by the size of the reservoir; no possibility to increase production from solar PV panels if the sun is not shining; no V2G service provision if EV users are driving, et cetera). Moreover, available potentials will depend on the system characteristics, see also Olmos et al. (2011). Consequently, the value of these devices in providing certain services will differ by service, by location in a specific system, by agent, and over time. Nonetheless, employing and aggregating DER services offers a powerful and flexible tool for power trade and system balancing, and can help to decrease the total cost of DSOs (with respect to a more traditional approach of merely connecting the new devices to the network) by allowing for an active distribution system management (Box 1).

2.2 New business models arise from DER technologies

The massive introduction of DER technologies will be made possible and also reinforced by new business models that might evolve (and actually are already evolving). Some of them, if successful, can change the structure and organization of power systems substantially and also offer opportunities for DSOs to make efficient use of the operation services with economic value that DER technologies may offer. Many poten-

Box 1: Three-step evolution of distribution systems (Eurelectric, 2013)

The development towards 'smart' distribution systems can be described in three steps. First, the traditional ***passive distribution networks*** have been developed based on a "fit-and-forget" approach. With an increasing penetration of DER, also system 'smartness' should increase. An approach used already today in some countries with a high share of DG, therefore, is a reactive network integration, or "operation only" approach. Congestion and other grid problems are solved at the operation stage by restricting load and generation, i.e. DSOs solve problems once they occur.

An ***active system management*** would allow DSOs to become "real system operators". The existing hosting capacity of the distribution network can be used more efficiently if an optimal use of DER is considered. Eurelectric (2013) proposes that DSOs should have the possibility to buy flexibility on so-called "flexibility platforms" to optimize network availability in the most economic manner and to solve grid constraints. Network reinforcement then could be deferred until it becomes more cost-effective than procuring services from DER. However, in-depth analyses going beyond the current more conceptual discussion are required to propose suitable concrete architectures and responsibilities, including an answer to the question on who should set-up and coordinate such a flexibility platform.

tial and existing business models associated to DER at the distribution network level typically involve some sort of aggregation, such as the aggregation of "smart" grid users to participate in energy markets and to provide ancillary services or the offering of energy services to customers. A group of aggregated DER in the following will be referred to as a **distributed local system** or DLS.

Hence, in general terms we can define a distributed local system as a grid-connected ensemble of demand, energy storage and generation resources, i.e. DER, with advanced control and communication capabilities, which provide energy services to their members and offer energy services to their DSO and/or TSO.[2] At the individual residential level, some local "energy control box" would be in charge of managing all the energy appliances, as well as the generation and storage resources, and deciding the best joint utilization given the energy needs of the customer and the existing economic and reliability conditions in the power system. The same approach can be valid for a group of residential units or a larger aggregation of residential and commercial entities, up to the level of a neighborhood or a small town. The key point is that local management and control could make better use of the existing local synergies and use resources closer to the existing constraints. The magnitude of these potential advantages still remains to be proven.

All business models on local level can boost their competitive advantages vis-à-vis upstream sources by relying on aggregation. There are several reasons to consider that aggregation and hierarchical control might have sizeable advantages over centralization:

- Aggregation of DER can reduce the risk for each individual DER to not meet its market commitments. When aggregating individual DER within one market portfolio, the risk of not meeting market commitments is hedged among units. *For instance*, in case tariffs for end-consumers include a capacity component linked to a maximum instantaneous consumption limit, it might make sense to aggregate a group of end-consumers to take advantage of the fact that not all consumers demand their maximum at the same time.

2. The DLS is a broader and more flexible concept than the micro-grid, which is ubiquitously used in the technical literature and appears to refer to a subsystem that is connected to the rest of the system by a single point and that is meant to operate mostly autonomously. DLSs do not require the capability of being autonomous or of requiring all its members to be connected (in exclusivity) to a single point in the network.

Box 2: Examples of different distributed local systems

A DLS could be located within just one physical site, say at the household level: as a combination of active demand response, plus electricity generation (rooftop solar PV, for instance), micro-cogeneration, heat and/or electricity storage and the family EV.

A DLS could also include several agents at one location: a fleet of EVs whose charge is managed from a single control entity in collaboration with the users of the vehicles, who receive an economic compensation for the ancillary services that all together provide to the local DSO and/or the corresponding TSO, plus other benefits in terms of maintenance of the vehicles, parking priorities or car renting could be a DLS.

A DLS could also include several agents at several locations: a company might form a DLS by owning solar PV panels that are installed at the rooftops or the premises of their clients, selling them full electricity services, where the energy may come from the PV panels or from the main grid, but the customers only interact with this company as their only electricity retailer.

A DLS could also include several agents, locations and resources: a DLS may combine some wind or solar PV farms, plus a portfolio of loads of several types and a fleet of EVs and some local storage, all of them sited in the same geographical area under the same DSO, but not all necessarily connected to the same point in the grid, and offer energy services to its consumers and deals to its producers that better the conditions offered by any centralized incumbent utility, the default tariff or the electricity spot market.

- Aggregating otherwise relatively inflexible DER products to one DER product bundle furthermore increases the possibility for DER units to take part in the markets for system services. Moreover, individual DER might not be interested in overcoming by themselves the complexities of market participation just to make a small sum of money. Aggregated DER solve this problem and can offer more complete and flexible products to DSOs and/or TSOs, who often demand system services with particular technological features. *For instance*, TSOs often ask for minimum bidding capacities to be accepted as offer in their markets.

- Aggregating DER can exploit arbitrage potentials if existing network charges preferentially treat larger devices from the same type, or aggregations of devices of different types. Hence, aggregation might reduce grid charges for each aggregated DER unit. *For instance*, a TSO might require unlimited interruptibility in the month of August. Gathering together a portfolio of different consumers allows intermediaries to enter into more limited agreements with their customers (e.g. instead of asking one consumer the possibility to reduce her load three days per month, they can contract with three consumers to reduce load once).

- Aggregating DER can decrease potential costs from not meeting market commitments, especially when balancing markets are lacking liquidity. If markets would be "perfect", it would always be possible to buy or sell the commodity at the competitive market price. But in case of lack of liquidity, this is not the case. With low market liquidity, individual DER units risk having to buy costly services from dominant actors in the balancing market in order to correct for imbalances. *For instance*, in such a setting, holding a portfolio of a storage facility and a wind turbine could decrease imbalance costs.

If DER technologies might – or might not – cause a paradigm shift from the traditional centralized top-down system towards decentralized local sub-systems depends on the total costs of energy provision from DER compared to upstream sources, including the network costs. Even if DER will not become a real

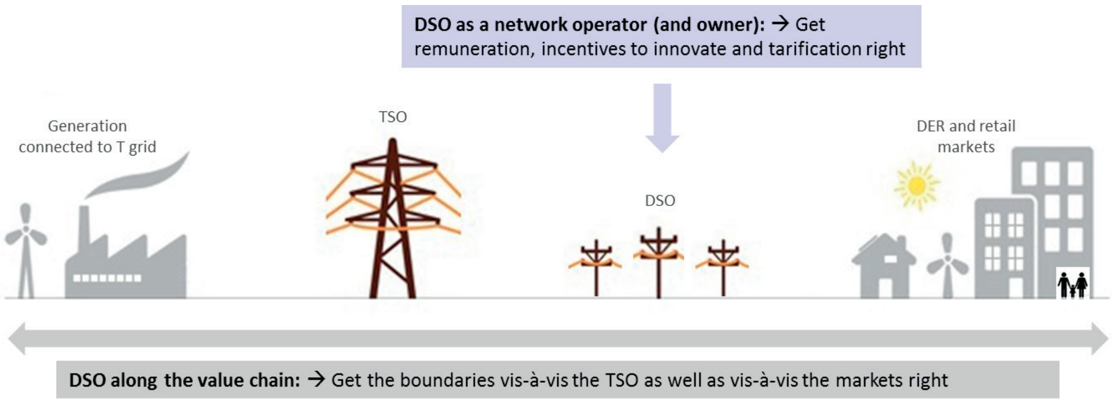

Figure 2: Relevant areas of regulation

Source: Own depiction using pictures from http://www.westernpower.com.au

game changer, the power system has already changed and will continue to do so. In any case, DER have to be *able* to participate in the market, even more so once national support schemes are running out and there is also a need to rethink regulation if no full paradigm shift occurs. The critical importance of a clear regulatory roadmap that provides sufficient certainty to the regulated companies and the market agents cannot be overemphasized.

2.3 Four areas of existing regulation need to be reviewed

As discussed above, the market penetration of decentralized energy resources opens possibilities for decentralized trade of energy. These trade opportunities allow for new business models, mainly related to aggregation and marketing of DER. Also DSOs can use DER resources for their daily tasks of ensuring system functioning and planning grid investments. However, to exploit the full range of potentials that DER offer, DSOs have to undertake significant upfront investments in grid (and related) infrastructures (EC, 2010). At the same time, for DER to flourish and to enable DER to compete with resources connected to the transmission grid, DSOs also have to provide adequate conditions for network access and usage. The latter also includes adequate conditions for new business models related to the aggregation of DER.

As a consequence, existing regulation needs to be reviewed with respect to both, the incentives for DSOs as a network operator (and owner), and the incentives for DSOs as a key player along the value chain. Reviewing incentives for DSOs as a network operator implies revisiting regulatory schemes for allowed remuneration and resulting incentives to innovate, as well as revisiting network tariff design. First, DSOs are a natural monopoly for which allowed remuneration has to be regulated. Second, this allowed revenue will be collected via distribution grid charges. The structure and format of these charges will have an important impact on grid users' behavior. Finally, reviewing the existing regulation considering DSOs as key players along the value chain, including their role in the market when becoming active system managers, implies revisiting the regulatory base of DSOs both vis-à-vis the TSO and vis-à-vis energy and power markets. Figure 2 illustrates all areas of regulation covered in the remainder of this report.

With the above overview of critical points in current regulation, we can add precision to our initial questions addressed in this report. Do we need to rethink regulation at distribution level? In particular, we have to examine if there is a need to rethink

- the methods of determining the regulated remuneration of distribution companies,
- the design of distribution network charges,
- the functions and the level of unbundling of DSOs, and
- the relationship between distribution and transmission system operators.

When providing the overall regulatory compact, the above issues are interdependent. Allowed remuneration heavily influences the design and foremost the level of tariffs. The design of tariffs, in turn, has a major impact on the energy market. And the DSO can become a more active player and in this light its remuneration and tariff setting vis-à-vis other active market players becomes even more delicate. Before deriving in-depth recommendations on each of the above issues, we first discuss the shortcomings of the existing regulation in the following section.

3. The present state of electricity distribution in the EU

Electricity distribution in the EU is characterized by very diverse national implementations of relevant pieces of EU legislation and resulting heterogeneous end-user market structures in different Member States. This section gives a brief overview on the present regulation of electricity distribution activities and the current organization of distribution sectors throughout the EU. We also point out two major shortcomings in EU retail markets – ill-designed regulated prices and insufficient unbundling, and infer what these mean for the regulation of DSOs as market facilitators.

3.1 The present regulation of electricity distribution in the EU

Common understanding: European legislation (Directive 2009/72/EC) defines **distribution** as "the transport of electricity on high-voltage, medium-voltage and low-voltage distribution systems with a view to its delivery to customers". **DSOs** are understood as "natural or legal persons responsible for operating, ensuring the maintenance of and, if necessary, developing the distribution system." Article 29 does explicitly also allow for 'combined transmission and distribution system operators'. However, in most Member States, TSOs and DSOs are separate entities.[3] Furthermore, regulators agreed on a definition of **smart grids** which is technology-neutral and focuses on what they can deliver, with smart grids being "electricity networks that can cost-efficiently integrate the behavior and actions of all users connected to it – generators, consumers and those that do both – in order to ensure economically efficient, sustainable

3. In Ireland, for instance, the situation is different in that electricity transmission and distribution networks are owned by ESB, a state-owned, vertically integrated company also active in production and supply. A legally separate company, ESB Networks, has been established to carry functions relating to the operation of networks (Source: IEA (2012) Energy Policies of IEA Countries, Ireland 2012 Review). Note, however, that the remuneration scheme and the tariff design differ and are separately applied to transmission and distribution.

power systems with low losses and high levels of quality and security of supply and safety" (CEER, 2011).

Tasks of DSOs: According to Article 25 of the Electricity Directive, DSOs are responsible for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity, for operating, maintaining and developing a secure, reliable and efficient electricity distribution system. When planning the network development, energy efficiency and demand side management measures or distributed energy resources that might supplant the need to upgrade or replace capacity shall be considered. DSOs shall facilitate market functioning by providing non-discriminatory access to the grid and by providing system users with the information they need for efficient access to, including use of, the system. Moreover, Member States may require the DSO to give priority access to RES generators or CHP units.

Unbundling requirements: There are different requirements for DSO and TSO unbundling.[4] For DSOs, legal unbundling is required, demanding legal, functional and operational (staff) separation of the DSO from other actors in the supply chain, but not creating "an obligation to separate ownership of assets of the DSO from the vertically integrated undertaking." Where the DSO is part of a vertically integrated undertaking, it shall be independent in terms of its organization and decision-making from the other activities not related to distribution. Member States also shall ensure that the activities of vertically integrated undertakings are monitored so that they cannot take advantage of their vertical integration to distort competition. In particular, vertically integrated DSOs "shall not, in their communication and branding, create confusion in respect of the separate identity of the supply branch of the vertically integrated undertaking." Member States may, however, decide not to apply this rule to integrated electricity undertakings serving less than 100,000 connected customers.

Regulation of DSO revenues and distribution grid tariffs: The Electricity Directive specifies a number of very general provisions related to the regulation of DSO revenues and distribution grid tariffs. Accordingly, it is under the responsibility of national regulatory authorities (NRAs) to adequately regulate the DSO(s) in their territory. NRAs shall also fix or approve conditions for connection and access to the network, including the grid charges themselves or the methodologies used to calculate them. Those tariffs or methodologies shall allow the necessary investments to be carried out in a manner allowing those investments to ensure the viability of the networks. Tariffs shall further be transparent and non-discriminatory. Any cross-subsidies between transmission, distribution and supply activities are to be avoided.

The Energy Efficiency Directive (Directive 2012/27/EC) specifies some further criteria for energy network regulation and grid tariffs. First, tariffs shall be cost-reflective of cost-savings achieved from DSM and DR measures as well as from DG, including savings from lowering the cost of delivery or of network investment and a more optimal operation of the net-

4. TSOs have a basic choice between three models: (1) ownership unbundling, (2) an independent system operator (i.e. transmission system remains with vertically integrated company, but system operation is performed by ISO), or (3) an independent transmission operator (i.e. asset ownership and system operation stay within vertically integrated company, but ITO supposed to be independent from the integrated company. The transmission system operator "shall not, in its corporate identity, communication, branding and premises, create confusion in respect of the separate identity of the vertically integrated undertaking or any part thereof" nor "share IT systems or equipment, physical premises and security access systems with any part of the vertically integrated undertaking nor use the same consultants or external contractors for IT systems or equipment, and security access systems." For further rules see Annex 1 of this report).

work. Second, national network regulation and tariffs shall "take into account the cost and benefits of each measure, provide incentives for grid operators to make available system services to network users permitting them to implement energy efficiency improvement measures in the context of the continuing deployment of smart grids."[5]

Retail market competition: By 2007 at the latest, electricity markets in all EU Member States had to be opened up to competition. Full eligibility for customers is mandatory. DSOs are supposed to carry out the switch of suppliers without any delay or discrimination and it should be guaranteed that the incumbent supplier does not have any advantage. Moreover, where roll-out of advanced meters is assessed positively, at least 80 % of the consumers shall be equipped with intelligent metering systems by 2020. The need to accelerate the deployment of smart grids, to establish a sound regulatory framework supporting further improvements in competition and responding to new challenges, and to facilitate the participation of new flexibility sources in energy/power markets is also recognized in recent EC Communications on smart grids (COM(2011) 202) and on the internal energy market (COM(2012) 663).

Summarizing, the broad architecture for the internal electricity market in general and for distribution systems in particular is laid out in the Third Package and complementary legislation. However, existing EU regulation leaves room for differing national implementation and for country-specific approaches to DSO regulation. The four areas identified in Chapter 2 are not adequately addressed yet.

5. In particular, this concerns (a) shifting load from peak to off-peak periods; (b) energy savings from DR by energy aggregators; (c) demand reductions from energy efficiency measures undertaken by energy service providers, including ESCOs; (d) the connection and dispatch of generation sources at lower voltage levels; (e) the connection of generation sources from closer location to the consumption; and (f) energy storage.

3.2 The present organization of electricity distribution in the EU

In what follows we illustrate that the EU legislation and according national implementations also resulted in different organizations of electricity distribution in the EU. We first outline the diversity of European DSOs along several parameters, such as size or scope. Subsequently, we briefly discuss how retail markets differ throughout Europe in terms of competition, regulated prices and unbundling, and infer what these differences imply for the regulation of DSOs as market facilitators.

3.2.1 The present organization of European electricity DSOs

First, there is already huge diversity among Member States regarding what is understood as "distribution". The boundary between transmission and distribution in terms of operated **voltage levels** covers a wide range (Figure 3). For instance, in the UK, distribution companies operate networks up to 132 kV and only very high voltage lines fall under the responsibility of the TSO. In contrast, in Belgium, the TSO – besides the high voltage grid – is also responsible for the 70- and 36 kV lines.

There also is **diversity regarding how DSOs are designated.** Based on Article 24 of the Electricity Directive, it is the Member States who "shall designate or shall require undertakings that own or are responsible for distribution systems to designate […] one or more distribution system operators." Between the two poles of purely public – and often also vertically inte-

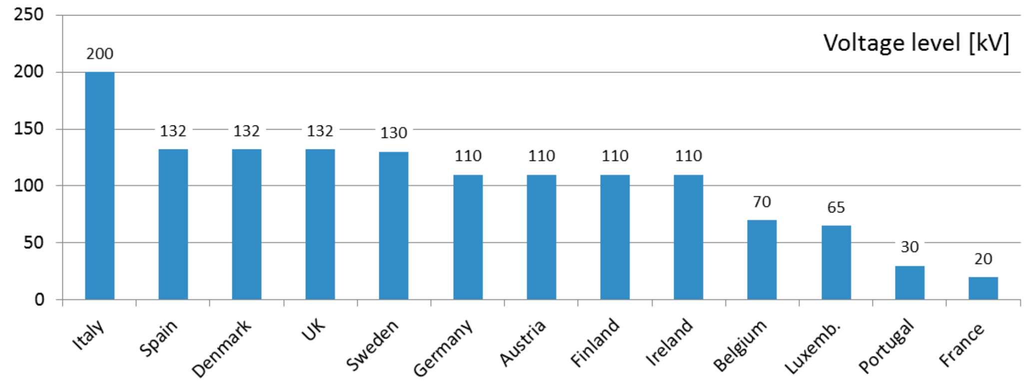

Figure 3: Voltage level operated by DSOs in selected Member States

Source: Own depiction based on DG-GRID (2007)

grated – distribution companies (e.g. Malta) and full privatization (e.g. several German and British DSOs such as EVB Netze GmbH or UK Power Networks), various forms of public-private-partnerships have been implemented. The French ERDF, for instance, holds more than 700 concession contracts with the network belonging to local authorities. In Slovenia, a limited liability company has been licensed by the government and was granted a concession for a period of 50 years. This company then signed leasing contracts for the grid with the regional distribution companies.

Different arguments speak in favor of appointment procedures that involve certain competitive elements. Contracting out public services might allow public authorities to take advantages of scale and scope economies of their private partners. Using tendering procedures also should increase the incentives for a more efficient service provision by generating competition *for* the market where competition *in* the market is absent (Williamson, 1985; Saussier and Yvrande-Billon, 2007). However, such contracts can involve high transaction costs, and there is mixed evidence on the efficiency of public-private agreements in different network industries (Saussier et al., 2009, Ruester

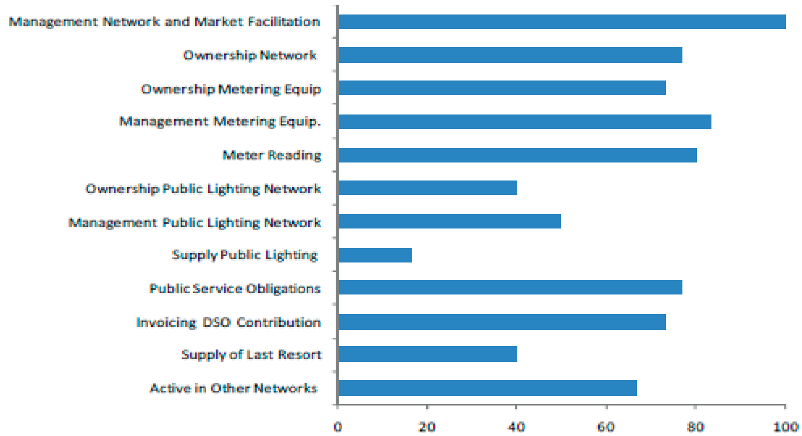

Figure 4: Scope of DSOs (survey data)

Source: Eurelectric (2010)

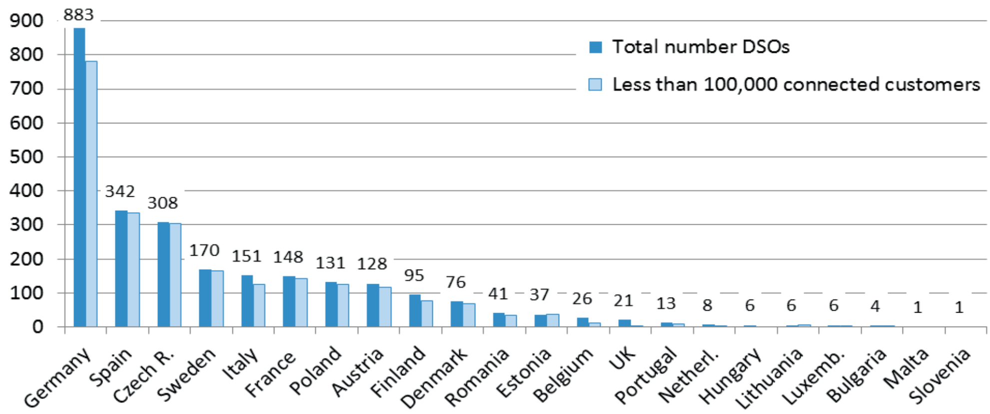

Figure 5: Number of DSOs in selected Member States (2012 data)

Source: Own depiction based on CEER (2013)

and Zschille, 2010, and references therein). Moreover, after a period of privatization, a recent trend evolved back to municipal utilities ("re-municipalization", see Bauer, 2012; Menges et al., 2012).[6]

Regarding the **scope of activities**, all European DSOs have some responsibilities in common, whereas other tasks are part of the DSO business model in certain countries but not in others. Obviously, all DSOs operate the grid, even though it has to be recognized that concrete grid operation activities and complexities will also depend on operated voltage levels. In most Member States, the meter is owned and managed by the distribution network operator, albeit this 'traditional distribution network operator task' has been opened for competition in a limited number of countries. Moreover, DSOs might have certain public service obligations (e.g. 'supply of last resort'), might be responsible for public lighting, et cetera.

There is huge diversity regarding the **number of DSOs and their size**. Whereas some countries have only one (e.g. Slovenia) or a few (e.g. Hungary, Netherlands) DSOs, countries like Sweden, Spain or Germany with more than 150, 300 and 800 distribution companies, respectively, have a sector structure being shaped by the presence of many small-scale DSOs supplying a relatively small area with a limited number of connected customers.

The first (1996) Electricity Market Directive required DSOs to hold separate accounts from their parent companies, that is, generation, transmission and distribution accounts had to be separated. Directive 2003/54/EC in addition mandated "functional unbundling" (organizational and decisional independence), "informational unbundling" (confidentiality of information) and "legal unbundling". Finally, in 2009, Directive 2009/72/EC introduced rules for a more separated branding and customer-communication. For electricity *transmission* system operators, ownership **unbundling** is implemented in about half of the Member States. For DSOs, legal unbundling is much more common than (voluntary) ownership unbundling. In the majority of countries, exemptions from DSO unbundling rules provided for in Art. 26 of Directive 2009/72/EC are applied in the cases that DSOs fall below the 100,000 customer threshold (see Table 1).

6. In Germany, for instance, between 2007 and 2012, more than 170 expired concessions (for electricity, water and other sectors) have not been tendered again by local authorities and more than 60 new "Stadtwerke" have been founded (VKU, 2012).

Country	Total number TSOs	Ownership unbundled	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100,000 cust.	Exemption
Austria	3	-	128	-	11	117	yes
Belgium	1	1	27	11	27	12	no
Bulgaria	1	-	4	4	4	1	no
Czech R.	1	1	3	-	3	NA	yes
Denmark	1	1	77	-	77	71	no
Estonia	1	1	37	NA	1	36	yes
Finland	1	1	85	-	51	82	no
France	1	-	148	-	5	143	yes
Germany	4	2	869	-	146	794	yes
Hungary	1	-	6	-	6	-	no
Italy	11	1	144	119	10	134	yes
Lithuania	1	-	2	-	2	4	yes
Luxembourg	1	-	6	-	1	5	yes
Malta	-	-	1	-	-	-	no
Poland	1	1	22	-	7	15	yes
Portugal	3	1	13	10	11	10	yes
Romania	1	1	37	5	8	29	yes
Slovak R.	1	1	3	-	3	162	yes
Slovenia	1	1	1	-	1	-	no
Spain	1	1	351	-	351	345	yes
Sweden	1	1	173	-	173	167	yes
The Netherl.	1	1	8	5	8	3	no
UK	3	1	19	13	6	5	no

Table 1: Unbundling of electricity TSOs and DSOs of selected Member States (2010 data)

Source: EC (2012c)

Regarding the **regulation of DSO revenues**, the decentralized decision making and development of national regulatory regimes (dependent on individual sector characteristics, the historical evolution of the regulatory design, national policy priorities, or regulatory capabilities) have resulted in a wide heterogeneity in current regulatory practices. In general, a revenue allowance is determined taking into account operating and capital expenditures, as well as depreciation together with the rate-of-return set by the regulator. Methods for determining the regulated asset base and the weighted average cost of capital differ widely. There is cross-country variation regarding the numerous parameters applied, such as risk-free interest rates, debt- and market premiums, the assumed capital gearing share, beta factors, et cetera. The calculation of the allowed rate-of-return might be based on nominal or real values. Moreover, in some countries an extra return can be made from incentive schemes for specific performance related to for instance losses or quality of service. Regulators today put strong emphasis on OPEX reduction (Eurelectric, 2010). Benchmarking DSOs is a common concept.

There is a huge diversity also regarding **distribution grid tarification** (see also Table 5 to 7 in Annex 1). Eurelectric (2013c) offers an extensive overview on the legal basis and responsibilities of different actors in setting network tariffs in different EU Member States. Grid fees typically involve connection charges and charges for system usage. Connection charges for new grid users cover the whole spectrum from shallow to deep charges. While shallow charges only account for the costs of connecting new resources, deep charges include all externalities that newly connected sources impose on the system. Tariffs for system use may contain fixed-, energy-related as well as capacity-related elements. Many countries, such as Germany for instance, also introduced exemptions from network charges for certain types of grid users, such as low-carbon generation connected to distribution networks. In addition, use-of-system charges often include also various regulatory charges (e.g. RES fees, taxes paid to local authorities or other energy policy costs; Table 6 in Annex 1). According to ECME (2010), taxes and levies account for relatively large parts of the final bill, with their share ranging from 11% in the UK to about 62% in Denmark.

3.2.2 Competition in European retail markets and implications for DSOs

DSOs shall act as market facilitators in retail markets. However, retail market structures differ widely across and within countries, especially with respect to competition, price regulation and implemented unbundling. Hence, also DSO approaches to market facilitation should differ, as argued in the concluding paragraphs of this section.

First, there are significant differences in terms of the structure of electricity generation and national **retail markets**. Markets still are highly concentrated – in eight Member States, more than 80% of power generation is controlled by former incumbents and energy markets in general are perceived as not being sufficiently transparent and open for new entrants such as aggregators and ESCOs (EC, 2012b). Although prices on wholesale markets have converged to some extent, significant differences in retail prices can be observed (Figures 8 and 9 in Annex 1), which of course to a certain extent can be explained by differences in network cost and taxation. Consumer prices were among the highest in Germany and Denmark, including a higher tax burden due to national energy policies subsidizing the use of RES. Net retail prices excluding taxes where the highest in Cyprus and Malta (both being energy islands and relying on expensive electricity generation based on oil-fired plants) as well as Ireland (having only one interconnection).

Customers in two thirds of the Member States can now choose from several suppliers. However, switching rates are still quite low; in 2010 fewer than 10% of the households changed their supplier in most countries (Table 8 in Annex 1). Estimates indicate that these small-scale consumers EU-wide could save up to €13bn per year if they switched to the cheapest electricity tariff available (EC, 2012b). Though, low levels of supplier switching do not necessarily have to be an indicator for ineffective competition. In a mature market, prices would probably have converged already. And a lack of switching can also be explained by other than price-related factors, such as customers' satisfaction, trust to the supplier, or a lack of information. In addition, even though the Third Package states that changing the supplier should not take longer than three weeks, switching might require up to two months.

In summary, even though full eligibility of customers is mandatory, and a positive outcome of the liberalization process appears to be the general increase in choice of suppliers and tariffs, the degree of retail market liberalization and competition still varies significantly across the EU. There is a consensus about "room for more competition in retail power markets" (Lowe, 2011). Two major drawbacks persist:

First, national governments have typically been reluctant to eliminate **regulated end-user tariffs**. As reported in ERGEG (2010), in 17 countries regulated electricity retail prices exist; and also for business customers this is still a common practice (see Figure 10 in Annex 1). However, regulated tariffs discourage consumers from searching for alternative suppliers and, even more consequential, might prevent their exposure to more elaborate price signals. Unfair competition arises if these tariffs are ill-designed and calculated, establishing values deliberately *below* the minimum levels needed to cover the cost of energy (plus the regulated charges, which include the network tariffs and other charges such as subsidies to renewables, cogeneration, local fuels, institutions or taxes). Such too low regulated end-user tariffs do not only hamper the functioning of retail markets, but also the wholesale liberalization process as they might foster market foreclosure to the benefit of incumbent suppliers (de Suzzoni, 2009). It should be noted, though, that measures implemented to protect vulnerable consumers do not equate to maintaining regulated energy prices for certain categories of consumers. Customer protection and the protection of vulnerable customers, instead, are *social* issues rather than energy policy issues, and it should be the national governments' responsibility to define according tools.

Second, **insufficient unbundling** can be one of the most serious obstacles to retail competition given that DSOs shall act as "'entry gates' to retail markets […] making them an important influence on the level of competition as well" (CEER, 2013). As recently reported in CEER (2013), not all Member States have fully implemented the Third Package. Moreover, not all countries have transposed the formulated requirements in EU Directives to the same extent into national laws. For instance, rebranding[7] is not required to comply with the Third Package in all countries. The report also shows that in those countries where unbundling has taken place, the rebranding of DSOs is sometimes not fully satisfactory and could still leave room for confusion among customers.

Negative effects of insufficient unbundling are also widely recognized in the literature (see e.g. Nikogosian and Veith, 2011, and references therein). Davies and Waddams Price (2007) find "clear evidence that those UK incumbent electricity suppliers which remained vertically integrated […] have retained a higher market share than those where these functions have been undertaken by separately owned companies." Harmful practices that can prevent the retail market from successfully developing are manifold. Such practices might include an asymmetry in access to commercial information, giving the retailer belonging to the same group as the distributor an advantage; the (illegal) use of references to the distributor's services (e.g. advantages in technical service or QoS) in the retailer's commercial advertising; a lack of adequate procedures to switch supplier and undue delays; or discriminatory practices, including excessive rates, in relation with renting, installation and maintenance of metering equipment if this is the responsibility of the distribution company.

Finally, it will make a difference for regulatory consequences whether the adequate DSO regulation and distribution tariff design, or the right vertical boundaries of DSO tasks vis-à-vis the TSO and/or the market are discussed within a more simple system architecture as we had it in the past, or whether in contrast, one considers increasing complexities coming along with the increasing penetration of DER (Cossent et al., 2009; Frias et al., 2010; EDSO, 2012; Eurelectric, 2013). At one extreme, there are areas without a noteworthy penetration of DER and where investments in distribution grids are solely motivated by a renewal of aging infrastructure and the connection of new consumers. The distribution grid is expanded radially and designed such that grid user needs are satisfied.

7. Rebranding: DSOs are required to change their communication and branding in such a way that they can clearly be distinguished from supply branch and, thus, create a clearly separate image.

In contrast, there are systems with a substantial penetration of DER and small-scale consumers behaving as prosumers already today.

It also will make a difference whether the respective DSO is subject to (voluntary) ownership unbundling as is the case in the Netherlands, or whether in contrast it is a small integrated operator being exempted from any unbundling provisions. This for instance often is the case for small German ("Stadtwerke") or Spanish ("Cooperativas") utilities, which also engage in other-than-energy social activities within their territory and might actually be able to act as a kind of 'large DLSs'.[8] With increasing complexity in the system architecture, the need for DSOs to *actively* manage the distribution network increases. However, as shown in Figure 6, more than half of the European DSOs are not unbundled (most of these are very small and supply a reduced percentage of customers), either because of a lacking implementation of the provisions set out in the Third Package, or because of a national decision to apply the exemption rule for small DSOs. As discussed above, also implemented, but still insufficient, unbundling can be one of the most serious obstacles to retail competition.

8. Selected cases of exemplary types of European DSOs, illustrating persisting heterogeneity:

Alliander: Dutch DSO with about 3 million connected customers, legally unbundled, owned 100% by Dutch municipalities, manages gas and electricity networks in five different Dutch provinces/areas.

Stadtwerke Emden: Small German DSO "Stadtwerk" in Northern Germany, ca. 50,000 connected customers, exempted from unbundling, 95% owned by local firms and 5% owned by the City of Emden, manages gas, electricity, district heating, water and city transport for the City of Emden, more than 80% DER (mostly wind).

ERDF: French DSO with about 35 million connected customers, legally unbundled, owned by EDF (with EDF being traded on the Paris Stock exchange and 85% shares belonging to French state).

4. Assessment of the four regulatory areas

High levels of DER penetration in local electricity markets affect all areas of DSO regulation. In the following, we assess these areas within the previously identified four categories: DSO remuneration, distribution network tarification, the boundary of DSOs vis-à-vis the market, and the boundary of DSOs vis-à-vis the TSOs.

4.1 Adequate regulated remuneration of distribution network activities

This section discusses the need to revisit current regulatory practice in terms of regulating DSO expenditures as well as stimulating DSO innovation.

4.1.1 Regulating expenditures for active distribution system management

For high amounts of DER connected to distribution systems, the total costs of business-as-usual management of distribution networks (that is, a continued "fit-and-forget" grid management) will likely increase in most systems. Yet, increasing amounts of DER have a twofold impact on DSOs' cost structures: First, substantial future investments are required to properly connect all DER to the distribution networks, to enable the system to deal with increased volatility of flows and net demand and peak demand fluctuations, and to set up ICT infrastructure that empowers DSOs to employ DER for their daily grid operations. Second, DER at the same time offer a new set of instruments for grid operation and thereby a tool for DSOs to better perform their tasks of ensuring a reliable, secure and efficient electricity distribution. DER allow for an active distribution system management and

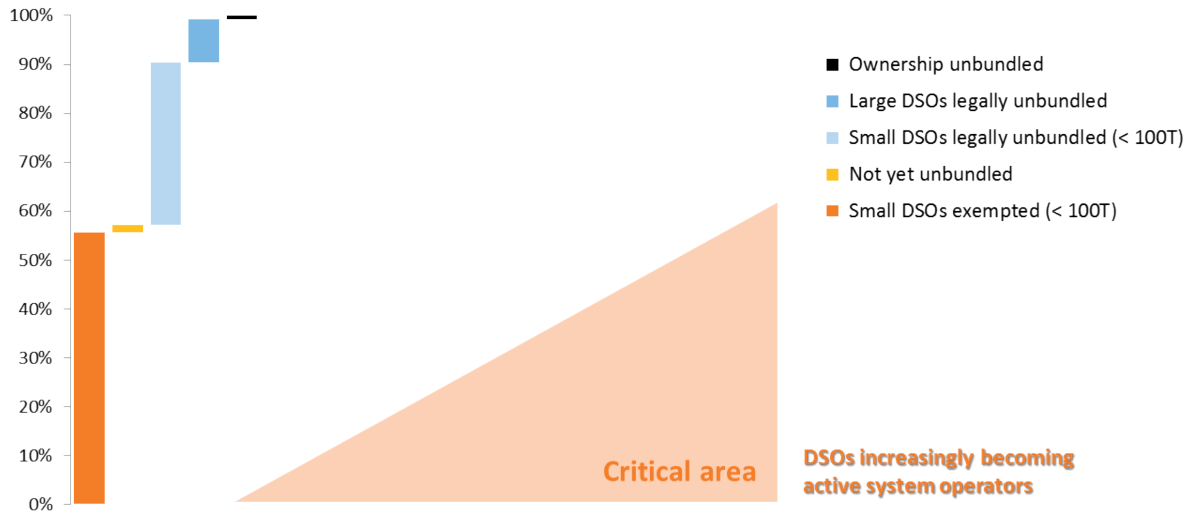

Figure 6: Insufficient unbundling

Source: Own depiction using data from EC (2012c)

Disclaimer: This figure does not represent shares of customers connected to the respective types of DSOs. Such a figure ideally should also be shown in terms of kWh distributed and in terms of number of supplied consumers. However, unfortunately these data are not available.

have the potential to decrease the total costs of DSOs compared to not relying on DER in local system management. For instance, relying on DER to solve local congestion can postpone investments in new lines.

In terms of operating and capital expenditures (OPEX and CAPEX), the use of DER in distribution grid management can decrease OPEX compared to business-as-usual, for instance related to contracting system services from competing DER instead of relying on more expensive in-house solutions for voltage control and loss compensation. In contrast, how the use of DER will impact CAPEX is not obvious. Using DER for grid operation can decrease CAPEX in the longer-run if grid investments can be deferred (CAPEX hence being substituted for OPEX). On the other hand, in the short-run significant expenditures for investments into grids and ICT infrastructures supporting grid monitoring and automation are needed upfront.

That employing DER can lead to overall cost savings for DSOs compared to business-as-usual is also confirmed by Yap (2012) or Cossent (2010), as shown in Figure 7.[9] Cossent estimates non-negligible cost savings from using an active system management approach for rural, sub-urban and urban areas in the Netherlands, Germany and Spain, especially so for increasing DG shares on the way to 2020. In a similar vein, Mateo and Frias (2011) and Pieltan-Fernandez et al. (2011) argue that unless the DSO controls electric vehicle charging within an active system management approach, the DSO would have to heavily invest into low- and medium-voltage lines to compensate for local peak demand resulting from EVs. This example from EVs clearly demonstrates the trade-off between CAPEX and OPEX and resulting potentials to avoid unnecessary costs for DSOs.

9. Even though the cost reductions from active system management compared to BAU scenarios might not for all systems be significant (especially in those where peak demand remains unchanged or even increases with a higher penetration of EVs, and the DSO hence cannot avoid building new lines), in systems with high degrees of active demand and storage, the volatility of distribution flows can be decreased, grid planning is eased, and potentially also less new lines have to be built.

Box 3: Evidence for the cost of integrating distributed generation

A lot of evidence for system cost changes resulting from the integration of distributed generation exists already. Power injection from DG changes flows, modifying **energy losses**. This effect can be both, positive or negative, depending on a number of parameters, namely the penetration level, the concentration and location of DG units within the system, as well as the technologies themselves, see e.g. Ackermann and Knyazkin (2002), González-Longatt (2007), de Joode et al. (2009), Cossent et al. (2010), Yap (2012). A low penetration of DG tends to reduce losses as local generation is absorbed by local load. As the penetration of DG increases, generation starts to exceed local demand (particularly for lines of low load and/or at time of low demand), leading to reverse flows and increasing losses. In DG GRID (2006), minimum losses for the UK system, for instance, have been calculated for a DG penetration of 5GW. Quezada et al. (2006) also find that wind power shows the worst behavior with respect to losses reduction, and that DG units with reactive power control provide a better network voltage profile and lower losses.

The need for **grid reinforcements** will strongly depend on the system management approach. In DG GRID (2006), the authors illustrate substantial benefits from active network management for different levels of DG penetration and concentration. Again for the UK distribution system, up to 50% (15-40%) of the cost of upgrading the system could be saved for an installed capacity of 5GW (10GW). Moreover, a reconfigurable network, i.e. a network that can change its topology by opening and closing switches on power lines and thus dynamically changing its topology in response to load and supply, can allow grid operators to reduce losses and to accept more intermittent renewable generation (see Lueken et al. (2012) for simulation exercises thereon).

National regulators establish national approaches to DSO remuneration for a specified regulatory period and for a range of services DSOs are supposed to deliver. Delivering these services requires the DSO to undertake CAPEX and OPEX. The regulation therefore usually specifies how CAPEX and OPEX are treated, if they are treated differently, and what form of regulation (e.g. cost- or revenue-based) is applied for either type of expenditures. Specifying services is usually referred to as output-based regulation. In contrast, regulators could in principle also specify the inputs and clearly define the investments a DSO is allowed to undertake. Output-based regulation may be preferred by the regulatory authorities, who do not possess sufficient information on what optimal inputs would be. However, regulating outputs is difficult, too, due to challenges related to their measurement and verification. Furthermore, investments might be undertaken in one regulatory period, while the outputs are realized only during the following period(s).

These difficulties directly point to the question of how to incentivize DSOs to engage in active distribution system management. Active system management aggravates the measurability of delivered services. At the same time, CAPEX will temporarily increase in order to undertake needed upfront investments and regulators have to find a way to incentivize DSOs to engage in efficient CAPEX. Furthermore, as OPEX are expected to increase, regulators have to implement smart ways to benchmark new types of operational expenditures. If negotiation and benchmarking CAPEX and OPEX becomes too complex due to new types of costs (ICT infrastructure, new platforms to procure system services, et cetera), regulatory authorities have to increasingly rely on engineering estimates of expected costs of engaging in more active system management.

Traditional models are not suited anymore and new types of engineering models are needed, although they take significant effort to build so that they can incorporate the essential technical features of distribution networks and DER connection. Such refer-

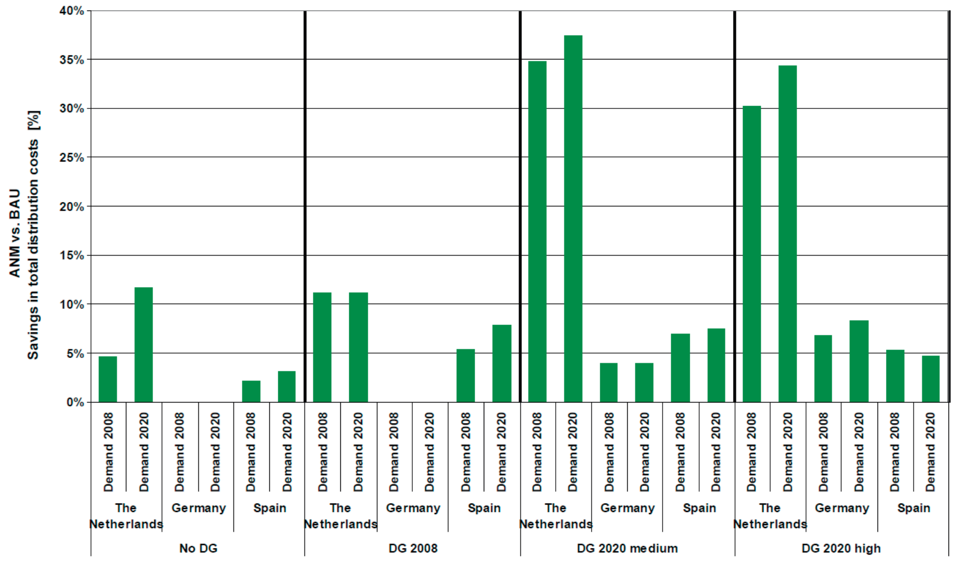

Figure 7: Savings in total distribution costs from active system management for selected countries

Source: Cossent et al. (2010)

ence network models (RNMs) are for example applied in Spain, as discussed by Gómez et al. (2013) and Mateo Domingo et al. (2011) and have been also used in Sweden and Chile, at least. Being large-scale distribution network planning tools, RNMs can be used to estimate efficient distribution cost and to plan distribution networks – both green-field or incrementally from existing grids. In contrast to traditional planning tools where it is the modeller who provides network expansion candidates, such RNMs generate network reinforcements automatically. See also Gómez et al. (2012) for different case studies that illustrate the applicability of these models to the assessment of the impact of massive DER deployment. In the absence of sufficient information on multiple actual cases of distribution network costs in the presence of diverse levels of DER penetration, which would render benchmarking possible, RNMs are the only tool presently available to regulators to make a reasonable assessment of efficient distribution costs. Admittedly, RNMs are complex to develop and to use, and are still a subject of research.

A promising alternative approach is currently taken in the UK, with the "RIIO" model.[10] This new regulatory framework aims at incorporating investment incentives by relying on an output-based, total expenditures approach, hence bypassing the problem of estimating, negotiating or benchmarking CAPEX and OPEX. The regulatory period was extended from 5 to 8 years with a possibility of a partial review after 4 years. Thus, investments and services produced with investments are more aligned to one regulatory period. Ofgem defines six output categories (consumer satisfaction, reliability and availability, safety, conditions for connection, environmental impact and social obligations). Each DSO then has to come up with

10. "RIIO" stands for *"setting **R**evenue using **I**ncentives to deliver **I**nnovation and **O**utputs"* (Ofgem, 2010), and incorporates three basic elements: (1) an ex-ante price control that sets the outputs that network companies are required to deliver and the revenue they are able to earn for delivering these outputs efficiently, (2) the option to leave the realization of infrastructure projects to third parties, and (3) a time-limited innovation stimulus. For a more detailed discussion see Benedettini and Pontoni (2012).

an eight year business plan that specifies TOTEX and services to be delivered.

Whether such an output-based TOTEX approach outperforms updated current CAPEX and OPEX mechanisms also depends on the amounts of investment needed (differing among Member States and distribution systems), and also on the information and precision of cost estimates available to different national regulators. Potentially, for Member States with many DSOs, for which estimating the needed expenditures for each distribution system becomes complex, RIIO-like total expenditures might be well suited. Whenever national regulators suffer less from information asymmetries and hold more information and better estimates on distribution cost structures (also because less investments might be needed due to a limited penetration of DER), an updated regulation with negotiating on CAPEX and benchmarking OPEX could be the preferred solution.

The problem of not being able to properly estimate DSO expenditures gains even more importance because DSO revenues at the same time might decrease as DER penetration increases (Bauknecht, 2012). This might be a source of perverse incentives for DSOs, since the most common approaches to distribution network remuneration are based on the volume of distributed energy (see also Section 4.2 for further discussions thereon). With the integration of distributed generation, probably even connected to local storage, as well as demand response and energy conservation measures at the consumer side, revenues for DSOs might decline as demand can be (partly) satisfied locally and less energy needs to be distributed (Pérez-Arriaga, 2010).

4.1.2 Stimulating DSO innovation

Besides mere compensation of DSO expenditure, the regulation of DSOs also has to stimulate innovative solutions to distribute electricity. While the form of remuneration itself results in different incentives to be cost-efficient (e.g. within a revenue-based system DSOs get to keep all the savings from cost reductions), and also in the choices among CAPEX and OPEX, the regulatory framework can also include additional elements that stimulate DSOs to deploy innovative technologies and operating procedures. These elements can range from tendering funds for which DSOs can compete with innovative investment models to increased remuneration for certain innovative investments compared to their standard investment counterparts.

Italy, for instance, in 2011 introduced a WACC extra-remuneration for modernizing distribution networks in a 'smart way', i.e. deploying solutions such as control, regulation and management of load and generating units, including also EV charging systems. Moreover, demonstration projects can receive an extra remuneration on CAPEX.[11] In the UK, innovation – which might include not only technological developments but also the implementation of new operational processes or commercial arrangements – will be supported through two mechanisms. First, the longer-term, output-led, incentive-based, ex-ante defined revenue streams for distribution companies do not penalize unsuccessful innovation. Second, partial financing for innovation projects will be provided, awarded based on competitive processes. Required funds are planned to be raised from use-of-system

11. Extra WACC of 2% is allowed for 12 years on the part of the RAB associated to investments needed for demonstration project (ordinary WACC is 7% pre-tax; so total WACC for smart grid demonstration projects is 9%, and after 12 years it then falls back to 7% for rest of life span of the investment), see CEER (2011).

charges which in turn are recouped from consumers. They will be treated as a pass-through cost in the price controls of the regulated companies (see Ofgem, 2010; 2011). The £500 million Low Carbon Network Fund was introduced in 2010. For a detailed comparison between the Italian and the UK innovation schemes see Benedettini (2012).

4.1.3 Policy implications and EU involvement

An adequate incentive regulation is not easy to design and may in addition be prone to trade-offs among, for instance and in line with the above, low allowed revenues for DSOs and their ability to finance innovation. Indeed, in a survey conducted by CEER (2011), two major barriers to the deployment of smart and active distribution systems were identified, namely first, to encourage network operators to choose the most *cost-efficient* investment solutions, and second, to encourage network operators to choose *innovative* solutions. In many EU Member States, the current regulation of DSOs does not always provide the right incentives to efficiently develop and operate the grid, and to consider new flexible resources in network planning made possible by DER.[12] DSOs need to know that they will properly be compensated for eventual cost increases coming with DG integration, which is not guaranteed under today's regulatory schemes. That DSO regulation has to be reviewed is widely recognized, see de Joode et al. (2009), Bauknecht (2012), Benedettini and Pontoni (2012), and Agrell et al. (2013).

Increasing levels of DER lead to increasing costs for DSOs. New models and approaches to help regulators estimating the remuneration of distribution networks with strong DER penetration are acutely needed. Cost increases can be cushioned by investing in active system management tools. Therefore, incentive regulation for DSOs has to allow for overall higher compensation of DSOs, but at the same time set sufficient incentives to invest in ICT and grid infrastructure in order to exploit the full potentials that DER offer. Summing up, regulation that efficiently incentivizes DSOs to engage in active system management has to take account of i) changing OPEX and CAPEX structures, ii) the optimal choice among both, that is how DSOs can be incentivized to find the optimal trade-off between using DER or building new lines, and iii) how to incentivize DSOs to be innovative and find solutions (e.g. for ICT, data handling but also system services) in-house or by outsourcing.

Regardless of what regulatory mechanism precisely is chosen, there are general improvements that within each regulatory framework can incentivize needed future investments. Such improvements could include a prolongation of regulatory periods, a higher focus on measurable output definitions and according DSO performance indicators, through which DSOs are compensated for a higher DER penetration in their grids and the implementation of innovative projects.[13] In the UK, for instance, a revenue increment per kW of connected DG has been included into DSO remuneration (Frias et al., 2010).

12. Niesten (2010), for instance, discussing the Dutch electricity sector, argues that existing regulation delays grid expansions and is insufficient to coordinate DG and network investments.

13. CEER (2011) discusses a number of (technology-neutral) indicators that can help to quantify the effects/benefits of grid 'smartness'. Indicators of adequate grid capacity include for instance the hosting capacity for DER in distribution grids (used in Italy as a revenue driver; minimum requirements in the UK and Norway), or the energy not withdrawn from RES due to congestion or security risks (used for monitoring in different Member States). Indicators of enhanced efficiency and better service include for instance grid user satisfaction, the level of losses, the actual availability of network capacity with respect to its standard value, or the time to connect a new user.

Alternative approaches will not always work for all existing distribution systems, and the appropriateness of certain regulatory instruments may depend on the existing regulatory framework, the penetration of DER, et cetera. We see neither the need nor a solid justification for an EU-wide harmonization of the regulation of DSOs. Nevertheless, national regulators probably can benefit from sharing bad and good practices. EU guidelines for a sound regulation and adequate remuneration should be formulated and regular monitoring and benchmarking can help to reveal shortcomings of national regulatory approaches.

4.2 Adequate distribution network tariff structure and format

The allowed remuneration discussed above materializes in the form and level of distribution network tariffs. Rodríguez-Ortega et al. (2008) already pointed out that "a higher degree of efficiency will be reached not only by introducing competition in generation and retailing activities, but also by designing [ ] distribution tariffs that send sound economic signals." Distribution network tariffs typically include connection charges and use-of-system charges.

Connection charges differ substantially in different Member States, as also demonstrated in Section 3. *Shallow charges* only cover the direct cost of connection to the nearest point of the distribution grid and result in subsidization of new grid users whenever the full costs on the system exceed the connection charge to be paid. In contrast, *deep charges* additionally include an estimate of the costs of necessary upstream network reinforcements and, thus, carry a strong locational signal for new grid users (including DER).[14] Likewise, a mix between shallow and deep charges (e.g. deep charges for units above 10 MW as in the Netherlands, see Cossent et al., 2009), that only subsidizes small units, but deeply charges large (commercial) ones have their drawbacks. Such charges are not technology-neutral and might result in a sub-optimal choice of DER scales. An adequate design of connection charges has to take account of these trade-offs.

In contrast to connection charges that require a one-time payment only, **use-of-system (UoS) charges** have a relatively larger impact on grid-users. However, a sound methodology to design UoS charges for the different agents with very diverse consumption or generation patterns (including DG, or aggregations of consumers, producers, local storage, fleets of EVs, micro-grids, et cetera) does not exist. Elements that bias a level-playing field for grid users may come in various forms, generally occurring whenever agents can reduce network charges by combining different DER at one metering point. Such cases establish hidden subsidies, might lead to business models arbitraging the network charges, can contribute to inefficient allocation of DG units, and, likewise, have the potential to erode the financing of distribution systems. Given that DSOs have to raise a fixed amount of income, such arbitrage leaves other agents that do not or cannot combine sources contributing relatively more to finance the distribution system. Moreover, in many countries, UoS network charges are to a large part recovered via energy-related tariffs. Capacity-related or fixed charges usually represent only a fairly minor share of the network tariff for (especially residential) customers, although a large share of system costs is eventually determined by the maximum re-

14. Also deep connection charges might lead to biased investments. If deep charges increase with the amount of DER connected, but fall again once grid investments have been undertaken, investment in DER may halt as costs increase. DER investors will likely wait for others to invest first, expecting new grid investment and lower deep charges afterwards.

Box 4: Examples for ill-designed network charges

Certain network charging schemes are particularly biasing, as for instance *volumetric network charges together with net-metering*, particularly if old meters (still predominant in most EU countries; these meters only provide the accumulated net consumption over a long period of time until the value is recorded, typically one or two months) are used. Volumetric charges imply that grid users pay according to the amount of energy taken or fed into the system (€/kWh). Net-metering implies that, if at one agent's meter point both load and generation exist, the agent only pays for the net energy fed into or taken from the system during a specified period of time. If, say, the metering interval is 24 hours, then netting energy fed into or taken from the grid neglects that, for instance, during the morning and evening peak hours much load was taken from the system, and during mid-day hours much energy was fed into the system (e.g. from rooftop solar PV). This way, the distribution system is used during most of the time interval. However, the netted amount of energy could be close to zero and thereby reduce the network charge substantially.

This problematic issue also is recognized elsewhere. Different forms of net-metering also exist in many US States, see Yap (2012). EEI (2013) express concerns about US distribution tariff structures typically resulting in non-DER customers absorbing the lost revenues occurring due to net-metering. The authors call for a revision of tariff structures, particularly in states with potential for high DER adoption to mitigate cross-subsidies and to provide proper customer price signals that finally will support an economic implementation of DER.

Yet another example of ill-designed network charges relates to volumetric use-of-system charges that increase in brackets over the energy consumed. Again, if net-metering is applied, by combining load and distributed generation at one meter point, the agent can fall in a lower bracket and significantly reduce his network charges, while the impact of the agent on the network costs probably remains the same. Consequently, high-consumption grid users then fall into the group of low-consumption users and benefit from more favorable tariffs.

quired capacity of the grid user at a specific location and time.

Very little progress has been made by regulation in this respect, despite of the fact that DG has been present in many distribution networks for a long time already. How network costs are allocated among grid users, however, will become particularly important in future times when local entities like DER may compete with centralized resources for the provision of electricity to end consumers.

In some countries, use-of-system charges also include an assortment of policy costs (from subsidies to renewables or domestic fuels, to stranded generation costs or the cost of institutions, see Table 6 in Annex 1), which are added to the purely network charges to become an "access tariff" that all consumers have to pay. For the sake of transparency these costs should be treated separately, so that the reference framework to be presented does not apply to them.

4.2.1 Regulatory principles for the pricing of electricity networks

A satisfactory tariff design is essential both to promote optimal short-term system usage and to guide efficient long-term grid development. When setting grid tariffs, a number of regulatory principles, therefore, should be considered (see also Lévêque, 2003; Pérez-Arriaga and Smeers, 2003; Sakhrani and Parsons, 2010). These principles include: *economic sustainability* (or revenue sufficiency – tariffs shall fully recover the infrastructure cost), *allocative efficiency* (tariffs should send economic signals that encourage efficient operation and investment) and *cost-causality* (costs should be allocated to those agents who make the network to incur in these costs), as well as *non-discrimination* (or *equity* – not implying that the same amount of costs should be allocated to all grid users, but instead that the same use of the network must result in the same network tariff under the same circumstances). Moreover, tariffs should be *transparent* (the method of computing the tariffs must be known to the public), *stable* in order to minimize regulatory uncertainty, *simple* in the methods proposed to facilitate comprehension and acceptance, and obviously also *consistent* with the legislation in place.

These multiple objectives are not always compatible with one another, and often are in outright conflict. It is impossible to simultaneously meet all of them, at least in their full dimensions. A higher allocative precision and time resolution of pricing will conflict with simplicity, and also perhaps with the stability requirements. The principle of economic efficiency may clash with sustainability since network charges that are based on marginal costs are not expected to provide full cost recovery (due to the lumpiness of grid investments, economies of scale, reliability constraints), et cetera. The efficient allocation of costs for which cost-causality cannot be determined (e.g. subsidies to renewables) should follow the Ramsey-pricing principle, which is clearly discriminatory.

Tariffs ideally should be allocated as far as possible based on the principle of *cost-causality*. Cost-causality forms a paramount principle that is important not only for the reason of non-discrimination and also economic sustainability, but in a context of liberalized markets also for economic efficiency. In fact, assuming the absence of any market power and perfect information, the maximization of global surplus can be achieved by a tariff system where the costs for network infrastructure are allocated to those who cause them or benefit from the assets (Pérez-Arriaga and Smeers, 2003). In what follows, we present a reference framework for the design of distribution grid tariffs that is based on the overarching principle of cost-causality.

4.2.2 Reference framework for the design of distribution grid tariffs

Today, individual grid users no longer can be considered "simple consumers". In contrast, they are agents connected to the distribution grid, which can have very diverse consumption and/or generation patterns, being able (and willing) to react to price signals. Increasingly, grid users should be seen as complex, sophisticated agents, able to actively participate in the electricity market, and with net profiles of consumption and production (the only information available about what happens behind the meter for tariff design purposes) that will be totally disparate. In other words, they can be understood as the simplest version of a distributed local system, representing a combination of demand (conventional demand but also new consumption from electric vehicles), local generation and potential for energy storage and/or demand response.

This fact demands the immediate overhaul of the current paradigm of network tariff design, to be replaced by another one following the guidelines to be cautiously proposed here. The current paradigm, exclusively designed for pure consuming agents and where distributed generation was considered a minor exception, does not hold anymore. The power system of the future (of the present already in many countries) will be much more complex and the tariff design paradigm has to be changed immediately, before much efficiency distortion is created and many agents will acquire rights to ill-designed subsidies. A continuation of traditional tariff design methodologies applying widely uniform charges over the whole distribution system and, thus, socializing network cost among all "consumers", would imply an increasing cross-subsidization. Such practice clearly is against the principles of cost-causality and economic efficiency and will create all sorts of perverse incentives to game the tariff system.

Instead, grid tariffs, on top of guaranteeing full cost recovery, should be able to convey efficient economic signals to the entire diversity of agents that may connect to the distribution grid. We shall assume availability of detailed on-line information about the net demand minus generation profile of the agents, as provided by an advanced meter (if this is not the case, reasonable assumptions and simplifications will have to be made, until universal hourly meters in the EU will be a reality). Three **cost drivers**[15], depending on the *geographic location* in the distribution system as well as on the *profile of injection/withdrawal* from the connection point, can be identified, following Rodríguez-Ortega et al. (2008):

- First, the existence of the agent (as well as of all other agents, which jointly require a minimum basic network to be connected to the grid) in a specific geographical location; and the grid user's *subscribed capacity*;[16]

- Second, the grid user's *contribution to the local distribution peaks that have an impact on the design of the distribution network at all voltage levels.* (Two kinds of peaks have to be considered, since a feeder can either be in import or export mode. A grid user can then either help the system at the coincidental peak times – e.g. by injecting power when there is excess demand – or, in contrast, may worsen the situation – e.g. by injecting power when there is excess supply or having net consumption when there is excess demand. Hence, the respective tariff component can be either positive or negative. This cost driver is expected to have the most impact on cost allocation and it is the one that will vary drastically with the nature and behavior of the agents connected to the grid.); and

- Third, the grid user's aggregated *contribution to losses* based on her (yearly) profile. Optimal reduction of total network losses with appropriate network reinforcements also has an impact on network design.

A network reference model (as briefly described in Section 4.1 and presented in-depth in Gómez et al., 2013) can be very useful to evaluate these three components of distribution network charges and how the costs to be allocated to the agents depend on the characteristics of the driving factors: location and profile.

Signals need to be efficient and predictable. This implies that a sound methodology respecting as far as possible the principle of cost-causality should be implemented.[17] Since agents connected to the distribution grid can change their usage pattern in the mid-

15. As summarized in Rodríguez-Ortega et al. (2008), cost drivers should be derived from the cost-causality function and should (i) have a great impact on network cost, (ii) be easy to measure, and (iii) be useful when charging grid users, that is, they should be related to their decisions on where when and how to consume.

Transmission network charges might be subject to a similar (probably less detailed) treatment. This report only deals with distribution network regulation.

16. This concept does not exist in many countries, and the availability of hourly meters renders it mostly irrelevant. A shallow connection charge and the voltage level of the connection may take care of any major differences among the sizes of the agents.

17. The other two basic principles of network cost allocation at transmission level as in Olmos and Pérez-Arriaga (2009) ("network charges should not depend on commercial transactions" and "network charges should be computed ex-ante") become less relevant here. Commercial transactions by default are already ignored in tariff design at distribution level. And network charges cannot be computed ex-ante for agents that may change their profiles drastically in a short time (e.g. by installing some local storage).

term (imagine, for instance, a prosumer, consuming most electricity during morning and evening peak hours and injecting power from rooftop solar PV during off-peak mid-day hours, who decides to invest into energy storage capacity), the charges associated to the grid users' contribution to the peaks need to be adapted closer to real-time (e.g. monthly; with a zero charge in most months). Charges reflecting a grid user's aggregated contribution to losses, in contrast, could be computed and charged over a longer-term (e.g. annual) horizon since it is the aggregated value of losses for a long time that has an impact on network design; therefore this charge can be made to depend on the yearly net-consumption profile.

Admittedly, the proposed reference framework for the design of electricity distribution grid tariffs involves many complexities and the calculation of individual tariffs for each grid user would not only involve extremely high computation efforts and transaction costs, but would also result in tariffs perceived as difficult to understand and to implement. Applied to real-world settings, therefore, a transparent, sufficiently simple and implementable methodology could consider a number of "zones within the distribution system" (those predominantly importing power, exporting power or neutral), and a number of "types of agents" connected to it, perhaps corresponding to some sort of classification of types of profiles. When distribution costs are allocated to those who cause them – admittedly not a simple task – distribution tariffs will induce a more efficient behavior of grid users.

Note that, with very few exceptions (such as big industrial consumers) distribution tariffs will not be a key determinant of siting decisions. On the other hand, distribution tariffs can be used to send signals adapted to the location and the utilization patterns of different kinds of users, with the purpose of reducing the local peak demands and thus the overall capacity needs and distribution costs.

Some intriguing issues will have to be contemplated in a detailed design of distribution network charges. One is how to make compatible the generalized policy of a "single socialized tariff" for residential consumers in many European countries with the multiplicity of tariffs that will be needed to deal with the diversity of profiles of the agents. Another one is the treatment to apply to any agent or grouping of agents that decide to function in partial or total independence from the grid (e.g. autonomous micro-grids), but who are responsible for the network development to supply them in the past.

The proposed reference framework has not addressed the resolution of network constraints that may require the curtailment of generation or demand at distribution level. This is a short-term issue that must be dealt with separately from the design of tariffs to recover the costs of the distribution network. Situations of critical network congestions should be addressed by demand and local generation response programs (offering remuneration for a certain demand reduction or extra production in a certain period of time and location) or by emergency curtailments.

4.2.3 Policy implications and EU involvement

Insufficiently differentiated grid tariffs that do not reflect the impact of grid users with different consumption and/or production patterns on system costs increase cross-subsidization between grid users and counteract the principles of cost-causality and economic efficiency. An overhaul of current tariff design methods and the development of a sound methodology for the design of electricity distribution tariffs, therefore, are urgently needed.

Implicit subsidies inherent in existing tariff structures have to be identified and made transparent. The

	Allowed DSO revenue		
Cost drivers according to which total cost are allocated	Minimum required assets to just connect the agent (and all others)	Grid user's contribution to peaks	Grid user's aggregated contribution to losses
Format of respective tariff components	Calculated once for each agent, or all agents of a kind in a zone, on top of the strict shallow connection cost Charged in €/year	Calculated for "zones within the D system" and "types of agents"; updated regularly (e.g. monthly) Charged in €/kW	Depending on actual grid usage Charged in €/kWh
Example 1: Household with a typical consumption profile	Subscribes a contract for 4 kW withdrawal	Consumes most during peak hours Relatively high positive charge	Total consumption of 300 kWh per month
Example 2: Household with an advanced hourly meter, an EV, solar PV on the roof, energy storage and "smart" behavior	Subscribes contracts for 10 kW withdrawal and 75 kW injection	Consumes most during night (off-peak) and injects during morning and evening peak hours Negative charge	Total consumption of 600 kWh per month Total generation of 500 kWh per month (yearly average)

Figure 8: Reference framework for the design of electricity distribution grid tariffs

combination of net-metering, traditional electricity meters and volumetric network charges, for instance, results in non-DER users typically cross-subsidizing "prosumers". Moreover, distributed generation in numerous Member States is exempted from distribution network UoS charges, which in some cases should be positive and negative in other cases. Such hidden subsidies or penalties should be removed as soon as possible and replaced (if this is the case) by sufficient but direct subsidies that do not turn into inefficient signals. This in turn does not only avoid distortions in competition, but also allows for sending efficient economic signals to renewable generators in order to better reflect the actual costs (or benefits) they cause to the system. The scale of investments needed in the coming decades and their correlation with generators' siting decisions is such that, even if there is no consensus on what is the best methodology to apply, the effort is justified.

We see neither the justification nor even the convenience for an EU-wide harmonization of distribution tariff design. However, national regulators will certainly benefit from sharing good practices and a set of EU guidelines on how to improve tarification. Tariffs should be allocated as far as possible based on the principle of cost-causality, and as system architecture and functioning get more complex, it has become clear that the absence of economic signals to certain groups of grid users and the hidden subsidies to other groups cannot be justified. At least policy makers have to start by replacing exclusively volumetric tariffs, by adding a capacity charge that properly reflects the impact of the agents in the cost of the network. Distribution network charges must depend on a grid user's geographic location in the distribution system as well as on the profile of injection/withdrawal from the connection point.

It is out of the scope of this report to offer a detailed proposal for robust tariff designs. Research is immediately needed to come up with detailed proposals for distribution network tariff design that provide a level-playing field for all types of grid users, and that do not distort (or minimize the distortion of) economic efficiency. It should be noted, though, that policymakers might have a preference for cost socialization instead of introducing economic signals that deteriorate the situation for certain users, as well as for keeping grid tariffs simple and easy to understand.[18]

4.3 DSO activities vis-à-vis the energy and power markets

DSOs are supposed to be neutral market facilitators with 'markets' being not only retail markets, but also energy and power markets for balancing purposes and ancillary services. A range of different agents are conducting businesses within the distribution system, such as retailers, metering companies or ICT companies. In the future, the number of agents will increase, as retailers but also new specialized agents can engage in offering, and possibly also aggregating, energy services from different sources. As the number of agents and the complexity of the system tasks increase, the question arises what tasks exactly lie in the domain of the DSO, and what tasks can be well performed by market players.

On the one hand, there are basic DSO tasks (such as planning, operating and maintaining the distribution grid) which due to its cost structure are monopolistic activities and have to be regulated. These tasks can be disaggregated into a set of DSO services (Hermans, 2013). When drawing from past experience in the telecom industry, the business approach of network operators might move from 'managing assets' to 'managing a portfolio of services'.[19] Accordingly, one could think of *energy transport services* (with clear and different product specifications, including the transportation of electricity to consumers, but also e.g. feed-in of electricity from DG, or the charging of EVs), *access services*, *market facilitation services* (e.g. facilitating supplier switch), and finally *system operator services.*

On the other hand, there are clearly commercial activities for which the DSO ought to provide a level-playing field (such as buying/selling electricity) and regulatory intervention here should be restricted to support an efficient market functioning. The transition towards a system with large amounts of DER implies the advent of new business models, as discussed above. Also margins related to the implementation of IT hard- and software arise, which will technically enable market participants to take part in local energy markets as close to real-time as possible. In smart distribution systems, data volumes and the value of data will increase drastically.

Several tasks within this new market environment in theory may be fulfilled by regulated agents (which could be the DSO or also a third regulated party) or by non-regulated ones. Hence, the regulatory challenge here is to clearly define the roles, boundaries and responsibilities. The following examines the boundary between the DSO and the markets and presents different arguments for tasks to be regulated as DSO responsibility or to be delivered by commercial actors. We concentrate on those areas where there

18. In this vein, BDEW (2013) found that the introduction of very sophisticated grid tariffs (in this case including also locational signals) would likely suffer from high implementation efforts and difficulties related to political enforcement.

19. Initially, a phone call could only be made over a copper wire to which also a telephone number was directly connected. Infrastructure and services were integrated. Later, service and infrastructure were decoupled when customers could move and keep their telephone number. Today, with the emergence of the internet, the service was split into a telecom transport service (DSL-, VPN-service, etc.) and many end-user application services (e.g. a voice-over-IP service). New end-user services and new business models emerged on top of well-defined telecom transport services.

is no consensus about whether the respective tasks should be under the responsibility of the DSO or in contrast be managed by a third regulated agent or by the market. Concretely, we discuss (1) the ownership and management of metering equipment, (2) data handling and (3) EV charging infrastructure. Other activities that in some countries are part of the DSO activities but not in others, including public service obligations, supply of last resort, public lighting, billing, or the compensation for losses are not in the focus of our analysis.

4.3.1 Ownership and management of metering equipment

One of the main policy drivers in Europe for considering intelligent metering and more informative billing has been the Energy Services Directive (Directive 2006/32/EC). With the Energy Efficiency Directive (Directive 2012/27/EC), the requirements for accurate billing information based on actual and historical consumption have been reinforced. Moreover, given a positive cost-benefit analysis, at least 80% of all consumers shall be equipped with advanced metering systems by 2020.[20] Metering services consist of several activities that do not necessarily all have to be carried out by a single party. These services include the meter manufacturing and provision (a clearly competitive activity), meter installation and ownership, meter operation, and data handling. In what follows, we concentrate on the ownership and management of metering equipment. For an in-depth discussion of the institutional organization of data handling see Section 4.3.2.

Deciding on who should control metering equipment is important for several reasons. Advanced meters are strategic assets that can provide significant value to suppliers and customers alike (Haney et al., 2009; Olmos et al., 2011). Benefits of advanced metering include benefits for suppliers and network operation (e.g. reducing technical and non-technical losses, reducing the cost of meter reading) as well as direct customer benefits (e.g. cost savings from increased operational efficiency of metering passed to customers, easier supplier switching due to remote meter reading). Ownership structures and management responsibilities will have an impact on the rollout of advanced meters in individual countries. Moreover, advanced meters might become an object used to create barriers to competition by raising market entry and switching costs, especially in case the retailer is the owner of the meter.

Ownership and management of electricity meters have traditionally been the domain of network operators, bundled as a component of network management and electricity distribution services. In recent years, however, several countries have pursued competition in metering, and consequently, today, two main models can be observed in EU Member States:

1) First, a **regulated model** (applied in most countries, e.g. Italy, Sweden) where metering activities are treated as a regulated monopoly and in which the regulator sets the rules according to which advanced meters can or have to be installed, together with the methodology to remunerate the corresponding costs;

2) Second, a **liberalized model** (e.g. Germany, UK)[21] where some or all metering activities are

20. See Haney et al. (2009) for a summary of various cost-benefits analyses related to the rollout of advanced meters that have been conducted internationally. As also highlighted in Joskow (2012), costs and benefits vary across customers, distribution systems and regions, depending amongst others on the penetration of DER.

21. The **UK** is the only country where meter reading is the responsibility of the supplier. Large customers can buy and manage their own meters, and it is also possible to out-

open to competition and in which the installation of advanced meters is left to the free initiative of market agents.

Hence, depending on the arrangements in place, the (advanced) electricity meter may be the property of the DSO, an independent meter operator, the retailer or even the customer himself. The organization of the metering market has an impact on how costs and benefits are distributed across the supply chain, which in turn can have a significant effect on the decision on whether and how to deploy advanced meters. Under a regulated model costs can be recovered through regulated charges which are directly passed on to customers. In contrast, in a liberalized model, the costs will also be passed on to customers, but in a competitive setting.

Batlle and Rodilla (2009) and Schächtele and Uhlenbrock (2011) discuss these alternative approaches. The major advantage of the *liberalized model* is that technology choice is left to the market. In case of complete market liberalization, as introduced in Germany, any party who wants to enter the market – be it a retailer, DSO or any third party – is allowed to do so and can compete for consumers. Competitive pressure should foster operating efficiency and incentivizes agents to innovate and to seek new technological solutions. However, when the retailer owns the meter, there is a certain risk that it might turn into a barrier for the consumers to switch providers, since changing the equipment might not be straightforward or cheap. There is a need for certain clauses allowing the retailer to hedge against the risk of incurring stranded cost if the consumer decides to switch soon after the new equipment is installed. Meter operators could reduce their investment risks by offering longer-term service contracts to consumers taking on the investment cost and recouping them over the contract period. In contrast, the *regulated model* can simplify a mass-rollout of the new technology. Investment risks are low and costs can be socialized.

Member States can choose among a mandatory or a market-driven approach regarding the rollout of advanced meter infrastructure. A mandatory rollout forcing every consumer to install an advanced meter, however, might not be cost-effective since for some consumer groups costs might exceed potential benefits. On the other hand, a mandated, comprehensive and coordinated introduction of advanced meters could allow for a lower-cost rollout benefiting from economies of scale (Schächtele and Uhlenbrock, 2011; Frontier Economics, 2007a). Moreover, Wissner and Growitsch (2010) argue that if consumers underestimate the savings potential from using an advanced meter, they would have an inadequately low willingness to pay.

A general way to guarantee the installation of advanced metering infrastructure is to introduce certain compulsory requirements related to the functionalities of electricity meters. The Standardization Mandate M/490 to European standardization organizations to support the deployment of smart grids, formulated by the EC in 2011, in this vein calls for the development of a "set of consistent standards within a common European framework […] integrating a variety of digital computing and communication technologies and electrical architectures, and associated processes and services." Standards for meters, communication procedures and data formats become even more cru-

source meter provision to a meter operator and meter asset manager (i.e. meter package tailored to large customers' needs, as for instance is interesting for a chain with many stores). In Germany, the metering market is liberalized but the DSO is assigned the default metering operator in case the consumer does not make an active choice. However, it remains to be verified how successful or unsuccessful (in terms of proven positive effects for the customers) the application of a certain model has been so far.

cial in a competitive environment, where investment risks without any standards in place may be very high in case the competitive meter owner/operator cannot be sure that the investment will not become stranded if, for instance, the customer switches to a supplier who does not agree to use the same technology.

In summary, under a liberalized model, advanced meter implementation likely will occur more slowly and in a more fragmented manner, as the customer has the choice to pay for an advanced meter or not. However, once barriers to a wide-spread rollout have been removed (e.g. via some form of standardization), competitive forces will likely reflect in more efficient outcomes in the long-run. Competition shall be conducive for innovation and cost reductions and may support the development of a broader range of metering technologies and solutions in contrast to a situation in which a single regulated market actor (or policy maker) attempts to choose a 'winning' technology early in its innovation chain.

The decision on how to organize the metering market is influenced by a number of parameters. First, a higher magnitude of potential *scale economies* in the rollout will speak in favor of metering activities being treated as a regulated monopoly. A single meter operator here would cause lower cost, at least in the short-run. Second, if there are *economies of scope* with other DSO activities, there are arguments for giving the responsibility of meter ownership and management to the system operator. Third, *uncertainty about best suited technological solutions* calls for a setting where market agents compete with each other. Further arguments relate to *possible market entry barriers*. If metering is unbundled from DSO activities, there are some doubts whether small retailers will have the capital necessary to invest in metering and related ICT infrastructures. Larger players might use metering services to build entry barriers. Last, one might argue that the regulated model seems to be the most appropriate to *achieve a fast mass rollout of advanced meters* that is required in order to facilitate the development and optimal system integration of DER.

Ultimately, the choice also depends on the number and size of DSOs in different countries. With many small DSOs that do not allow for significant scale or scope economies, commercial agents might well undertake meter reading. Similarly, in Member States with high DER penetration and strong benefits from a timely rollout of advanced meters, supporting DSOs as meter owners and innovators might be the most promising solution, not at least because the most successful rollouts all benefited from political and regulatory support.

4.3.2 Data handling

Data is an information good and stands in contrast to classical private goods, which are excludable and for which rivalry occurs. Data, as an information good, is **non-rivalrous**, because consuming data does not diminish the amount available to others. For instance, data on consumption patterns of end-users might be used by more than just one retailer to construct tailor-made contracts. Depending on the technology and the legal regime, data can be **to a certain extent non-excludable** (meaning it cannot be used and consumed by just one agent who can exclude others from using it). Technologically, data is often consumed by several parties at a time (e.g. by retailers, who observe data of power flows and prices for end-users, and by end-users who observe such data to possibly adjust). Hence, situations can occur in which certain actors cannot be excluded, especially those signing a mutual contract and having to verify its fulfillment ex-post.[22]

22. For a more detailed illustration of these characteristics of information goods see Varian (1999).

In smart distribution systems, data volumes and the value of data will increase drastically and data supports three categories of activities within the distribution system, being a key input for (i) commercial operations, but also for (ii) ensuring a stable system functioning and quality of supply, and (iii) efficient grid planning. The Smart Grids Task Force Expert Group (EG) 2 distinguishes between "*personal* and *non-personal* data; personal data is considered as specific data and can be traced back to the individual consumer whereas non-personal data could be aggregated data and does not contain references to natural persons." This definition will be important for both ownership and data security implications, which EG2 is currently examining. In this section, we discuss whether all data should be managed and provided for by a single regulated entity and if yes, whether this entity should be the DSO.

Three data models have been developed within the Smart Grids Task Force EG3. In a first model, it would be the DSO acting as a market facilitator and being responsible for all sub-processes related to metering and data processing. In an alternative model, these tasks would be undertaken by an independent third party, also regulated as a natural monopoly. In contrast, a third model proposes the creation of a "trusted data access point manager", a commercial role played by certified companies. Hence, whereas in the first two models data handling would be organized by regulated entities and on data hub(s), this is not the case for the third one. See Table 1 in Annex 2 for further details. Models might co-exist and even be combined. For data security and privacy reasons customers will always be the owners of their 'personal' data and have to approve if data should be sent to third parties.

A major decision national regulatory agencies have to make is if data is best handled with one regulated entity (as in the first two models) or within a commercial market setting (as with the third model). In theory, *if data is non-excludable and a public good*, it is best treated at a regulated monopolist, because otherwise, under-provision of data would occur. Alternatively, DAMs would have to be obliged to provide all critical data to the DSO, but also make certain non-personal and aggregated data visible on platforms to increase market transparency and ease the entry for new business models. Similarly, *if data is partly excludable*, the market is no solution either. Commercial market actors focusing on data trade only, will not be able to recover their investments in data aggregation or generation. Only one market actor that holds total exclusivity rights for data can offer data as a monopolist. Finally, *if data is excludable*, market actors can, however, bundle data generation and trade with operations on the infrastructure or energy and capacity markets. In this way those actors will be able to subsidize data processing, and are thus able to offer costly services related to data aggregation or generation as part of a bigger product package.

While aggregated data is enabling the market, personal data is in fact driving it. There is a commercial use for personal data where retailers, traders or aggregators can take margins from and the market might be able to take care of personal data efficiently. Actors engage into contracts with these data, and owning data and having sufficient knowledge guarantees profit margins. Hence, the performance of new business models, as well as the functioning of retail market competition, will rely on comprehensive consumer data. Any interested party should be able to get access to such data – provided that individual consumers give their authorization for the use of their personal profiles – and data should be provided as cheaply as possible. The definition of the specific for-

Box 5: Proposed data models

***DSO*:** All personal and aggregated data is with the DSO, who stores the data in one or several data hubs. One data hub can also be jointly operated by several DSOs. Metering and all sub-processes stay with the DSO. Supplier switching takes place via the DSO and the hub. Also TSOs can ask for relevant information from such data hubs.

***Central data hub*:** All personal and aggregated data is with a newly introduced regulated third party. This entity is independent from the DSO and all other market players, and stores all relevant market information in one or several data hubs. Metering and sub-processes might then be undertaken by the DSO or commercial market players. This new central data hub agent will also be responsible for organizing supplier switching.

***Data access-point manager*:** Personal and aggregated data is not centrally stored and no official market data hubs exist. Data is directly extracted from meters for all necessary processes. The entity responsible for guaranteeing data access at each meter point is the data access-point manager (DAM), which can be any certified commercial actor. Hence, several DAMs might co-exist and compete for delivering their services to grid users. However, the metered agents (households, distributed storage, EVs or distributed generation) do not per se choose their respective data manager, but the entity that invests in the installment of advanced meters.

mat of data provision and related cost recovery and possible cost socialization (i.e. one of the three data models introduced above, or a combination thereof) can then be left to the Member States. Data required by system operators for security of supply and system integrity as well as for optimal planning of the network (which is customers' configuration data but also behavior data, i.e. consumption and feed-in volumes and capacities), should *always* be provided to the relevant party.

As summarized in Table 2 and discussed in-depth within the Smart Grid Task Force EG3 and elsewhere (EC, 2013a), all models have their pros and cons considering (a) the efficiency in supporting the rollout of advanced meters and related infrastructures at lowest possible costs, and (b) the implementability of each solution. Therefore, a minimum set of requirements regarding how the data are obtained, stored, made available and privacy is preserved – as far as possible independently of the respective data model – should be defined at EU level. Minimum requirements should follow at least three high-level principles that take account of consumer, DSO and market actor needs. First, the data interface should be designed according to clear and transparent rules respecting customer privacy and customer access to their own data. Second, network operators must have access to data needed for ensuring the network performance. Third, (cross-border) trade among market actors should be enabled by simple and cost-efficient interfaces to existing (interregional or international) data hubs. These minimum requirements then shall be met anywhere in Europe, regardless of the model(s) that is (are) chosen by each Member State.

One regulatory option to support a level-playing field could also be to oblige DSOs to ensure access compatibility to its ICT infrastructure for all market players. Market players then could find the most efficient technology standards for their own ICT devices, while the DSO then has to ensure that this standard is compatible to its central network ICT. This principle of market leadership in ICT deployment and standards and DSO guaranteed applicability of such standards avoids technological lock-in, compared to a situation in which DSOs are first movers in implementing ICT. Furthermore, this principle aggravates potential market abuse of insufficiently unbundled

DSOs that possibly could use ICT standards to the disadvantage of competing retail firms.

A key question to be addressed here is also how to achieve cooperation and synergy between DSOs and ICT companies while maintaining a level-playing field in the market. Hermans (2012) proposes a joint venture model where communication infrastructure for smart grids becomes part of smart grid infrastructure, i.e. falling into the regulated domain, but at the same time ICT companies provide their expertise in building and operating this new infrastructure, thus generating revenue outside the regulated domain. Merging distribution and data infrastructure business models, however, opens new regulatory concerns that should be addressed in future research.

4.3.3 Electric vehicle charging infrastructure

Recent debates show that there also is a need to discuss which types of agents should be authorized to provide EV charging infrastructure, which theoretically could be considered a fully regulated monopoly or a commercial activity. One could imagine **three general possible ownership structures**, namely (i) DSOs or similarly regulated entities, (ii) commercial actors and private investors (including retailers or aggregators), or (iii) public entities, maybe even offering free access. Today, all forms of ownership can be observed: In Germany, more than 50 DSOs operate charging stations (VKU, 2012). In Florence, Italy, SILFI SPA, the public lighting company, operates more than 100 charging stations. But also private investors are entering the market, often backed-up by pilot-project initiatives and corresponding public funding (PikeResearch, 2012).

Recognizing that "a question of great importance concerns the degree of regulation needed for an effective and efficiently functioning market for charging infrastructure", Eurelectric (2010c) describes **four possible market models** for public charging infrastructure[23]:

1. <u>Integrated infrastructure market model</u>: The charging infrastructure is fully integrated into the DSO's assets and the commercial relationship stays between customers and retailers using this infrastructure. The main difference to a conventional electricity contract is that customers are allowed to charge at any location within the charging network managed by the DSO while still receiving one bill from the retailer. Charging infrastructure would be collectively financed with costs being reflected in tariffs for grid usage.

2. <u>Separated infrastructure market model</u>: EV charging infrastructure is conceived as a new, separate and independent step in the value chain, and therefore a new agent, the "charging infrastructure operator" would be created. This new operator still is a special distributor that is independent of retailing activities, and infrastructure falls under rules concerning unbundling. Retailers have access to all EV charging sockets of all charging infrastructure operators. Charging infrastructure would be financed based on the "user-pays" principle.

23. It is typically distinguished between three types of EV charging (Gómez et al., 2011; Eurelectric, 2010c), namely (a) private areas with private access (e.g. charging your car in your own garage); (b) private areas with public access (e.g. supermarket); and (c) public areas with public access (e.g. public parking lot; charging here typically by EV customers who live in apartments without private charging facilities, or by customers parking their car for a shorter stay – whereas the first require long-term charging, the latter might need "fast charging", which is a special technical concept).

	Option 1 – **DSO as a market facilitator**	Option 2 – **Central data hub**	Option 3 – **Data access point manager**
Efficiency criteria			
Non-discriminatory, neutral market facilitation?	Problems if Insufficient **unbundling** (possible inefficiencies on retail market, strategic actions might increase switching cost, et cetera) Difficult to properly monitor DSOs (e.g. for countries with very large number of DSOs)	Third party = regulated, neutral actor providing non-discriminatory access to information	DAM = commercial role DAM shall "provide and prioritize rights" of any market actor → possibly critical situation since data responsible party should act in a non-discriminatory manner
DSO able to ensure system stability?	Yes (+ possible benefits from synergies)	Yes (given that DSO gets all necessary data in a timely and efficient manner)	
Incentives to innovate and to improve data infrastructure?	Lower (depending also on whether an 'intelligent' incentive regulation can be introduced)		Higher
Economies of scale and/or scope?	Economies of scale and scope	Economies of scale	Lower
Regulatory efforts	Regulation has to properly incentivize traditional DSO task plus data management (→ multi-dimensional incentive regulation)	Possible high installment costs for new regulated agent Two monopolies in a row (DSO & CDH) have to be regulated // might imply redundancies	Many market actors need to be "certified"
Implementability			
Simplicity and clarity for consumers?			Higher consumer efforts to (a) deal with many interfaces and to (b) take many decisions
Trust from consumer side // privacy concerns	All data goes to central hub (but fact that DSO is well-known, already regulated entity may add consumer confidence) Regulator can control security and privacy issues	All data goes to central hub Regulator can control security and privacy issues	Consumers individually decide themselves to whom to give data (or not)
Possibility to socialize costs among grid users?	Yes	No	No

Table 2: Comparison of the proposed data models

3. Independent e-mobility market model: An "independent e-mobility provider" would install a proprietary network of EV charging sockets and provide electricity *bundled* with other services (incl. the charging). Charging infrastructure would be financed based on the "user-pays" principle.

4. Spot operator owned charging stations market model: Charging stations and selling of electricity are conducted by parking spot owner or operator who does not directly own the spot but rather has the right or license to operate it. Multiple market players together with existing players like retailers and DSOs (outside their regulated activity) would compete. Charging infrastructure would be financed based on the "user-pays" principle.

EV charging infrastructure does not inherit cost structures that would lead to a natural monopoly (that is, sub-additivity of costs is not given), nor can under-provision due to a notion of public goods be expected, given that there is a sufficient amount of EV users and demand for charging stations. Taken together, this speaks clearly in favor of a market-based approach.[24] However, in practice, business models suffer from at least two major challenges that justify policy intervention:

First, there will be no demand for electric vehicles without charging stations, but also no incentives to invest in charging stations without the penetration of a sufficiently large number of vehicles. Policy intervention might be justified to address this **"chicken-and-egg problem"**, to stimulate the demand for EVs and charging stations and thus to kick-start the deployment of this technology. This is also confirmed in various empirical studies. Schroeder and Traber (2012), for instance, show that a market-driven rollout of public fast charging stations in the German market is unlikely to be profitable and that such investments are fairly risky (e.g. due to uncertain EV adoption rates, local use rates, competition between public and private charging facilities). If private investments take place at this premature stage, it appears to be driven by other motivations (charging stations may be used to attract consumers with main revenues generated from non-electricity sales).

Similarly, Tran et al. (2012) argue that - on individual consumer level - the adoption of EVs mostly is motivated by financial incentives (e.g. tax deductions), environmental concerns or affinity towards new technologies. However, because consumers tend to be risk-averse, they also conclude that policy intervention is required to accelerate EV adoption. Using a simulation approach, they find that for battery electric vehicles to be competitive on the market for cars, a) EVs would have to lose 20% of their price premium compared to internal combustion engine cars, and b) this has to be combined with a 60% increase in EV refueling possibilities. Ito et al. (2013) argue with *positive externalities of charging stations*. Investment in infrastructure has a direct and an indirect gain. First, there are direct gains from the charging stations itself, and second and indirect, one charging station increases the vehicles cruising range. This is another argument in favor of policy intervention supporting EV infrastructure, at least initially.

Note, however, that the "chicken-and-egg problem" which speaks in favor of actions to jump-start adequate infrastructure investment and customer adoption must not necessarily result in public or DSO ownership of charging stations. Alternatively, also competitive tenders for infrastructure roll-out or sub-

24. Furthermore, charging stations do not necessarily have to have access to the grid, as the electricity can also be provided for with local generation. Such non-grid competition further argues in favor of a market-based solution.

sidizing pre-qualified private entities can kick-start EV adoption.

Besides problems related to externalities, there are also different charging systems in place or under development, which might diminish incentives to change from traditional to electric transportation. **Standardization**, in contrast, ensures interoperability and also can support competition in manufacturing. Problems with competing networks and standardization have already been studied by Katz and Shapiro (1985). In such situations, policy intervention can decrease the adaptation costs that come with changing the infrastructure (in this case from conventional to electric vehicles) and increase overall welfare. In principle, such standardization, however, can also arise out of industry self-interest. In the EU, the European Parliament in 2010 recognized that it is important to achieve a single European EV market and called for international or at least European standardization of "interfaces between vehicles and recharging infrastructure". After more than two years of debate, the EC announced in early 2013 that the three-phase coupler developed by the German Mennekes would be accepted as EU standard.[25]

In the "Mobile Energy Resources in Grids of Electricity" (MERGE, 2011) project, stakeholders from different Member States have been asked about their opinion regarding the four models described by Eurelectric. Respondents to the questionnaire first agree that EV charging in public areas with public access is necessary (instead of fully relying on charging stations on private property) in order to build a sufficiently dense network of charging stations. There furthermore is a general consensus that the first two options are preferable because of a number of reasons: DSOs already have knowledge in building and operating grids; Options 3 and 4 could represent a step back in unbundling of distribution and retailing; and independent e-mobility agent or spot operator also may find that volume of sales in a certain geographic area may be insufficient to recover cost at least in initial stages of EV uptake.

The above arguments are in line with Gómez et al. (2011). The authors argue that for EV charging points in private areas with private access, the EV owner should take care of the charging point. For charging points on private property but with public access, this would be the tasks of a charging point manager. In contrast, for the charging infrastructure in public areas, installation cost would be substantially higher and the business model would involve higher risks. Therefore, in order to ensure a large rollout, this business should be regulated and charging stations should be developed by the corresponding DSO. Obviously the regulation should include the mechanisms for the recovery of the costs of deploying and operating these facilities.

Hence, to conclude, the key point seems to be that 'if we want EV deployment to happen, a non-market based solution is required – at least in the initial phase of market uptake.' However, such intervention has to be done with care. If regulated models are used to push the adoption of EVs, the future market structure will be heavily influenced. Once EVs are adopted and demand for charging stations is high enough, market solutions can outperform the regulated solution. However, by that time the market will be dominated by formerly regulated incumbent companies running the charging stations. Furthermore, EV technology is changing and regulating the market today might hamper the adoption of even better technologies (vehicle technology and charging technology) tomorrow.

25. Official press release: http://europa.eu/rapid/press-release_IP-13-40_en.htm

Ultimately, the decision on which model to implement should be left to Member States. The deployment of EV charging stations by DSOs requires massive amounts of investment, but it cannot be assumed that the financial situation of all DSOs is the same throughout Europe. Moreover, the EV penetration differs among systems, as does the interest to build these infrastructures and use them to develop business models for V2G service provision. The "chicken-and-egg problem" will thus also be more or less severe in different Member States. Hence, the market integration of EVs should be tailored to the different specific characteristics of DSOs and distribution systems. Nonetheless, for all policies it holds that EV integration should proceed gradually, as technologies are still evolving and technological lock-in, especially a publicly supported one, should be avoided.

4.3.4 DSOs' operating procedures to procure DER services

Today, DSOs mainly ensure system reliability along three major lines of tasks: network investments, maintenance and reinforcement, voltage control, and load/generation curtailment. While the first implies providing grid infrastructure, both latter tasks concern the operation of the grid. Voltage control helps to keep adequate levels of quality of supply. With load curtailment in case of local congestion, DSOs can handle emergency situations.[26] Hence, DSO network management has been until now mainly based on acting directly on the networks, e.g. changing the load flows, trying to deviate the potential surcharges through alternative circuits, but not managing certain loads unless in cases of emergency events, in which DSOs guide their operation decisions by security protocols that in principle are agreed with the regulator or at least are subject to ex-post supervision.

Increasing amounts of DER offer new means for system operators in executing their tasks. Primarily, DER offer solutions for grid operation. But short-run grid operation measures also have positive effects on the longer-term planning and grid investments, since using DER to manage congestion in the short-run at the same time can postpone or even avoid future grid investments. Therefore, the potentials of DER can be used to perform short- and long-term DSO duties. In particular, DER offer network operators additional instruments to (i) manage short-term problems in the grid, (ii) to optimize the cost of maintaining the desired quality of service, (iii) to reduce grid losses and (iv) to reduce or postpone future investments. In this vein, the Electricity Directive (Art. 25(7)) already mandates that "when planning the development of the distribution network, energy efficiency/demand-side management measures or distributed generation that might supplant the need to upgrade or replace electricity capacity shall be considered."

Eventually, to engage in an efficient use of DER, more active DSOs will have to contract energy- and capacity-related products, and therefore likely employ market-based mechanisms such as procurement auctions, similar to the ones TSOs are currently using to procure reserves. The involvement of DSOs in such commercial activities leads to the overarching question whether, and if yes, how, DSOs should be allowed to purchase services with economic value from DER, such as network congestion management, volt-

26. In some countries (e.g. Italy, Spain, Ireland), curtailment management is with the TSO and the respective DSOs have to ask the TSO to constrain DG (mostly only possible for generation units above a certain capacity threshold), see Eurelectric (2012). There are different approaches in different Member States regarding a potential curtailment of DG (Eurelectric, 2013). In Belgium, curtailment by the DSO is allowed for security issues. In case of congestion at the TSO level, the TSO has to send an order to the DSO. In Germany, generation units above a certain size can be curtailed also in normal operation.

age control, or support to system recovery after a local blackout. This question is of special relevance given that many DER technologies in principle can also provide services with economic value to other market agents, as it could be for instance the case of retailers, who could either resort to them for their own needs (to minimize the cost of their imbalances) or eventually to resell them in the ancillary services markets and services run and acquired by the TSO.

Thus, the DSO would compete directly with commercial local aggregators in distributed local systems. This competition could result in incentives for the DSO to abuse its role as a market facilitator. New regulation, hence, should encourage DSOs to start new market places to procure system services. Since DSOs are regulated firms, they should be subject to specific operating procedures to regulate the ways in which they conduct and channel their DER acquisitions. Essentially, as discussed by Batlle and Rivier (2012), these procedures should ensure that DER resources purchased by distributors are acquired transparently and impartially (i.e. in public auctions supervised by the regulator) and that products purchased by distributors in such auctions are clearly defined and at the avail of the system operator at all times (see the discussion on TSO and DSO coordination later in Section 4.4). Regulator supervision has to guarantee that DSOs purchase DER services from retailers under conditions in which all are treated equally (e.g. guaranteeing that the group's own retailer is not favored).

4.3.5 Policy implications and EU involvement

The newly emerging market environment not only requires infrastructure for energy distribution. In addition, also infrastructure for metering, data handling, and EV charging is needed. Currently, there is no consensus about whether the respective tasks to provide such infrastructures should be under the responsibility of the DSO or not. The regulatory challenge is to clearly define the roles, boundaries and responsibilities, so that there is a level-playing field for all potential and valuable business models. When moving from "passive distribution networks" towards "active distribution system management", DSOs become real system operators and the existing hosting capacity of the distribution network can be used more efficiently if an optimal use of DER is considered. Thus, DSOs become agents that manage local markets for network services or directly purchase services with commercial value from other agents, and their role and organization will have an important impact on (retail) market functioning.

The regulatory principle in this transition should be such that whenever new responsibilities are best performed by competitive market actors, the DSO's role remains to facilitate local markets and to act as an enabler and smart integrator of competitive services that make use of the distribution network in their business processes. In turn, whenever new responsibilities show sufficient synergies with the traditional tasks of regulated monopolies that operate the network, the DSO should be made responsible for these new services. In this case, therefore, regulators also have to provide appropriate regulation and incentives that properly embed all new responsibilities into the existing incentive regulation schemes.

Different proposed (regulated as well as liberalized) models for (1) the ownership and management of metering equipment, (2) data handling and (3) EV charging infrastructure all have their advantages and disadvantages. These tasks may or may not be offered at lowest cost (due to sufficient synergies with grid operation) or in a more qualitative way by the DSOs as compared to other third regulated agents or commercial actors. The suitability of a certain model will depend on system-specific conditions and the decision about whether to include such tasks into the DSOs' portfolio should, therefore, be left to national authorities. Though, if a full rollout of advanced meters (including data management), and also EV charging infrastructure shall be provided in a timely fashion, advantages lie in the domain of the DSO. Regulators, however, have to take care not to foreclose market structures through DSOs becoming incumbents, because once new technologies are deployed at scale, commercial actors could enter the market and enrich competition and the quality of respective services.

For all new infrastructure services it holds that when regulators opt for implementing these new tasks via DSOs, possible repercussions on energy and power markets have to be ruled out. As discussed in Section 3, retail market competition and, in particular, the current levels of unbundling are not fully satisfactory. With an increasing penetration of DER and the accompanying advent of new market actors and business relations, the negative effects of limited unbundling might become aggravated. Ownership unbundling would effectively eliminate any incentive for inappropriate practices. When mandatory ownership unbundling, however, is politically not enforceable, or is economically counterproductive for the customers' choice (through a drastic reduction of suppliers on the market) or for the customers' bill (through duplication of costs in separated entities or loss of synergy with other local utility functions) stricter implementation of unbundling requirements and market transparency measures should be mandated as more responsibilities are given to DSOs. Accordingly, as the complexity of the system increases, an insufficiently unbundled DSO could then either stay with a restricted set of tasks, or the DSO could expand its portfolio of activities, but accompanied with an increasing level of unbundling, i.e. towards "higher Chinese walls" between DSOs and their subsidiary retailers that engage in trading of distributed sources.[27]

At the same time it has to be noted that before investigating new forms of "Chinese walls", the implementation of, and the compliance with, existing unbundling requirements have to be reinforced. In the past, unbundling frameworks have gradually been implemented, becoming stricter over time. CEER (2013) sees still limited progress on DSO unbundling in countries that do not fully transpose the 2009 Directives and corresponding requirements. Moreover, throughout the EU unbundling efforts are still on-going and, thus, a final evaluation is not possible at this stage. In this light, for DSOs that expand their portfolio of regulated tasks, the timely compliance to existing unbundling requirements gains in importance.

Hence, the existing unbundling rules place minimum requirements on DSOs, on top of which additional requirements can gradually be added as the role of a DSO changes with an increasing penetration of DER. These additional requirements could mostly center around the use of customer data and transparency in procurement of services for DSO system operation. For instance, switching procedures should include clear mechanisms for accessing commercial information. An appropriate data management procedure should guarantee the availability of information for all interested retailers, to the extent allowed under data protection legislation. With regard to procurement of DSO services, market transparency could be facilitated by obliging DSOs to ex-post publishing procurement-related data. In this way, all units, also

27. Of course, individual Member States always can decide to apply stricter rules. As suggested by Batlle (2013), additional procedures might include preventing users from choosing the supplier pertaining to the same group as their distribution company, or not allowing regulated retailers to operate in areas supplied by their group distribution company.

those not controlled by the DSO's integrated retailer, can control if their bid was treated according to official procurement rules. Also, public auction mechanisms could be imposed to DSOs to transparency and non-discrimination. Another more severe measure might include limiting the maximum duration of contracts or providing for cancellation. Strict supervision by regulatory agencies is necessary to prevent potential irregular practices and furnish advice on the appropriate package of measures to be finally adopted.

It has to be discussed if **small DSOs** that want to engage in additional tasks as introduced above, but which currently might be exempted from strict unbundling requirements, should also be exempted from additional "Chinese walls" that come with these new tasks. On this level, EU and national regulation will have a very high impact on local governance and municipal structures, in which often a part of the profits from distribution activities are also used for municipal social activities. Nonetheless, all problems arising from unbundling that are extensively discussed above likewise apply to small DSOs. If general exemptions from unbundling for small DSOs prevail, other regulatory means gain in importance. Therefore, especially for small exempted DSOs, new ICT or EV infrastructure needs to be sufficiently standardized such that third party market entry is facilitated. Furthermore, it should also hold for small DSOs that market data relevant to accessing this ICT infrastructure and finally relevant for trading and retailing has to be made available such that barriers to market entry are further reduced. Hence, also the minimum requirements for data handling introduced above apply to small DSOs.

A further interesting regulatory option is to incentivize groups of small DSOs to jointly invest in ICT or EV infrastructure. Joint ventures among DSOs solve two problems. First, joint investments exploit synergies and reduce each DSO's contribution to the costs of setting up such new (and costly) infrastructure. Second, given that each DSO belongs to different companies with different respective affiliated retailing incumbents, negative effects from limited unbundling can be mitigated.

4.4 DSO activities vis-à-vis the TSO

As stated in Art. 12 and 25 of the Electricity Directive (Directive 2009/72/EC), both the TSO and the DSO are deemed responsible for "ensuring the long-term ability of the system to meet reasonable demands for the transmission [distribution] of electricity, for operating, maintaining and developing [...] [their] system." With regard to short-term reliability and system stability, though, it is currently foremost the TSO who is responsible for "ensuring a secure, reliable and efficient electricity system and, in that context, for ensuring the availability of all necessary ancillary services". More active DSOs will, however, play an increasing role here, too, and as a consequence, an increased cooperation among DSOs and TSOs – not only with regards to long-term planning as done so far in many EU Member States – becomes crucial. From a regulatory perspective, the tasks of the different network operators have to be clearly defined to allow for an efficient system operation and cooperation.

As discussed above, the potentials of DER can be used to perform short- and long-term TSO and DSO duties. Therefore, the functions of DSOs will likely become more similar to the functions TSOs have. While DSO network management has been until now not based on managing certain loads unless in cases of emergency events, TSOs have pursued tasks that, besides long-term grid planning, are more directly related to balancing the network and, hence, relate to short-run supply security. These tasks typically in-

DSO	TSO
Long-term distribution grid planning and grid development (including the connection of load and DG and guaranteeing efficient access and use of the grid)	Long-term transmission grid planning and grid development (including the connection of bulk generation (and load) and guaranteeing efficient access and use of the grid)
Grid operation, in particular: • Voltage control • Load/DG curtailment in case of emergencies	Grid operation, in particular • Frequency containment • Frequency restoration • Replacement of generation

Table 3: A taxonomy of system operators' tasks directly related to grid management

clude frequency containment, frequency restoration and replacement of generation units. Representative products that deliver the respective services are referred to as primary, secondary and tertiary reserves (ENTSO-E, 2012).

Because the business of TSOs and DSOs are heavily interlinked, the regulatory border between these two types of system operators has to be reviewed. To this end, the following distinguishes between differentiation and coordination among DSOs and TSOs.

4.4.1 Differentiation among DSOs and TSOs

There is a wide range of products that DER could offer to network operators. Table 4 lists major services and identifies the type of DER that theoretically could be able to offer those. By their technical nature, there are various factors limiting the potential (or also suitability) of certain resources to provide certain services. Moreover, not all DER can be treated equally. Larger DG for instance could be monitored and remote-controlled while other, especially small-scale, DER may not be dispatchable and should be forecasted and monitored by the DSO on an aggregated basis at substation level.

In general, DER can be used by both the DSO and the TSO and for both congestion management and balancing purposes. Assuming that the DSO is responsible for local congestion and the TSO for the overall system balance, four cases can arise: the distribution system is balanced and there is no congestion (normal operations); the system is balanced, but there is congestion (DSO should act); the system is unbalanced, and there is no congestion (market parties should act, as also the TSO); the system is unbalanced, and there is congestion (DSO should act on congestion, market parties and TSO on the unbalance). While the reason for TSO or DSO operations might differ, the sources they use for their tasks may come from DER and clear rules for TSO-DSO responsibilities and coordination are hence needed.

For some of the above products in Table 4, it is straightforward if it is either the DSO or the TSO who can demand them. However, for others, in principle all network operators can have an interest. Even though technically possible, it today is an open question to what degree DSOs would use DER on a very short-term basis (hourly or daily as TSOs do with traditional balancing and ancillary services), as mechanisms to contract products on an hourly or daily basis might be very costly for DSOs. Certainly, it should be expected that DSOs will use DER for mid- or long-term contracts in order to optimize grid operation and grid expansion.[28] Such procedures help avoiding or postponing investments, especially in regions with heavy seasonal peaks such as holiday areas, or where there are local concentrations of loads – such as electric vehicles – which can be easily shifted in time.

In fact, the DSO is well-positioned to purchase and aggregate diverse system operator services of use to the TSO. In addition, whenever DER sources in principle can be used for different services and by both TSO and DSO, the products have to be clearly defined and rules have to be set out on who can use these products. Besides technical differentiations, products with economic value to system operators can be differentiated by region and over time:

- *Products first can be attributed to be location-specific or system-wide.* For instance, a DSO procuring voltage control services will have to rely on local resources within its distribution area, while system-wide services can be delivered by resources spread across different distribution systems. Moreover, in order to use DER for congestion management, available resources need to be assigned to certain zones in the electricity system. Differentiated areas have to be defined.

- Second, *products can be characterized by their time of delivery*. Wherever DSOs and TSOs in principle can procure the same service, a more clear coordination among DSO and TSO is needed the more this product relates to real-time trading. The closer products become used in real-time, the more they have system security character, and have to be procured and used by the entity that is eventually responsible for maintaining short-run supply security.

Generally, there is no need to modify the TSO balancing market, because they by definition clear at system level. However, an efficient market functioning is key and any barriers (for certain groups of agents such as DER or aggregators) to participate in these markets should be removed as far as possible. As for the use of DER for local feed-in and curtailment management for example, rules are missing (e.g. in Austria) or only determined at the TSO level (e.g. in Spain or Italy), or defined at both the TSO and DSO level (e.g. in Germany), see Eurelectric (2012). The regulatory aim should be to allow DER competing on equal terms with the agents that currently provide system operators with valuable services. In this vein, the Energy Efficiency Directive, demanding that system operators, in meeting requirements for balancing and ancillary services, shall "treat demand response providers, including aggregators in a non-discriminatory manner, on the basis of their technical capabilities," goes into the right direction. Moreover, as discussed in-depth elsewhere, it is necessary to improve market price signals and adjust regulatory incentives to better reflect – i.e. recognize and remunerate – the value that flexibility resources can provide to the system.[29]

28. Thereby, the product definition should take account of the fact that system balancing remains a TSO task, while services DSOs demand in general relate to "local *congestion management*" rather than what could misleadingly be referred to as "local *system balancing*". Balancing implies placing imbalance costs on parties that create the imbalance. In contrast, congestion management implies costs for either the DSO (in case of shortage of agreed transport capacity) or for grid users (in case of excessive volumes being offered and having to be refused in the day ahead plan by the DSO).

29. Ruester et al. (2012b) conclude that balancing market rules should be modified such that they relax minimum bidding requirements and rules requiring symmetric up- and downward bids in order not to impede market access for small, decentralized market players. This will allow DER to value services they technically can provide, and thus probably also will have a positive impact on market liquidity. For the provision of ancillary services, replacing bilateral contracts by competitive tendering wherever possible could help revealing and quantifying the value of alternative flexibility means. In the conception of tender-

Service	Type of DER able to offer the service	System operator procuring such services
System balancing services	All types of DER	TSO
Frequency control	All types of DER	TSO
Voltage control	All types of DER	DSO
Blackstart	Larger-scale DS and DG	TSO and DSO
Short-term security congestion management	DG, DS, DR, (EV)	TSO and DSO

Table 4: Major services which DER can provide to TSO and/or DSO

Nonetheless, even if products for system services are well defined, as discussed above, some technologies could offer their services to both DSO and TSO. Batlle and Rivier (2012). discuss examples for such operations. The DSO could either procure services to satisfy its own needs only, or procure services also on behalf of the TSO, or both system operators engage in simultaneous procurement. Note that especially for the first two options, the procurement procedures differ. If, as discussed in Batlle and Rivier (2012), the DSO only procures according to its own need, say capacity to limit demand in one of its several distribution areas, the procurement procedure would only invite bids from that distribution area. If the DSO, however, would also procure additional resources for the TSO, the DSO could accept bids from several or all of its distribution areas. The DSO in this way can find the cheapest sources within a larger geographical area and, if sources are not needed, pass on to the TSO (without acting commercially, that is, not changing the terms of the initial bid submitted by the DER or aggregator). This example already suggests that even with efficient designs of services coordination among DSOs and TSOs will be needed.

ing, it is also recommended to adopt performance-based, source-neutral remuneration schemes.

4.4.2 Coordination among DSOs and TSOs

Coordination among DSOs and TSOs and information exchange will play a particular role as the amount of DER increases and as DSOs become more active and 'real system operators'. Today, at the transmission level, generators send schedules to the TSO for system balance purposes. On the distribution level, DSOs have no systems installed for acquiring data from DG (especially of smaller size). Only in some cases TSOs receive information from DG in real-time. There usually is no short-run operational exchange between TSOs and DSOs. In future systems with even higher DER penetration, however, a well-structured and organized information exchange between relevant actors is necessary: the DSO will need information about DG forecast, schedules and active dispatch to improve their visibility and to assist with close to real-time management of the distribution network including local network constraints. On the one hand, the participation of flexibility resources in balancing markets run by the TSO could lead to constraints in the distribution grid. On the other hand, DSO congestion management to solve constraints could have repercussive effects on transmission grids and TSO operation.

Given the complexity of the tasks and the large number of agents involved, a hierarchical decomposition of the supervision and control actions is adequate. A clear hierarchy of functions between TSO and DSOs has to be established. The TSO is the party that is responsible for system balancing. DSOs, after having undertaken their DER-related activities should submit their protocols to the TSO, who is the final responsible system operator. Such protocols are especially important for those DER that can provide services to both TSO and DSO. In this sense, all DER have to be monitored with respect to what product they are offering and at which time. In turn, then the data on dispatch should be given to DSOs as soon as possible, so that the DSO can react accordingly in emergency situations and curtail the most appropriate DER. Moreover, any action on distribution network users requested by the TSO should be agreed with the respective DSO. A TSO should not act on any individual DER connected to distribution grid, but an order from a TSO towards DER embedded in distribution systems should be executed by the DSO.

In line with the integration of the internal energy market in Europe, also the EU network codes have to take account of the new tasks and need for coordination for system operators. These network codes have to account for the possibilities for cost recovery of European DSOs and TSO, as otherwise the respective system operators do not have sufficient incentives to engage in their tasks. For first basic principles on network codes for system operation see Eurelectric (2012b).

4.4.3 Policy implications and EU involvement

The general responsibilities of network operators with respect to grid management do not change, but the *set of tools available* to perform their tasks is enriched by DER. DER can offer a range of products to (i) manage short-term problems in the grid, (ii) to optimize the cost of maintaining the desired quality of service, (iii) to reduce grid losses and (iv) to reduce or postpone future grid investment needs. Some of these products are clearly relevant for either the TSO or the DSO, whereas other types of services might be of interest for both types of network operators. The aim should be to allow DER to compete on equal terms with the agents that currently provide TSOs with ancillary services and to offer valuable products also to distribution system operators.

Note that, in line with the above, to enable DSOs to engage in active system management they need to have a clearly defined legal basis for doing so. With DSOs applying new short-term tools made possible by DER, also clearly defined rules have to be established. As DSOs, when procuring system services, interact with the energy market in a more direct way than before, these processes must be in line with strict rules under coherent supervision. These rules imply that DSOs only buy flexibility offered from DER or aggregators thereof, and do not act like commercial players (i.e. using these resources for arbitrage possibilities instead of system services), only acting "beyond the grid user's meter" in absolute emergency situations in order to ensure grid integrity.

A clear product definition for the use of DER in DSO and TSO operations is needed. Tasks of the different network operators have to be clearly defined to allow for an efficient system operation. In principle it is not problematic when DER can provide services to both the DSO and the TSO. However, clear protocols have to be established regarding which resource has sold products already, to whom, and for what time-frame. Clear product definitions have to be established due to the current absence of any regulation addressing how DSOs can engage in the use of DER. The product definition shall comprise technical features (capacities, et cetera), local features (e.g. whether it is possible to deliver system-wide services), and time dimensions. Wherever DSOs and TSOs in principle can procure the same service, more coordination among DSO and TSO is needed the more this product relates to real-time trading. A clear hierarchy of functions between TSO and DSOs has to be established.

Coordination needs will differ among systems. It will make a difference whether a distribution system contains only an insignificant amount of DER, whether in contrast there is a large penetration of distributed generation with installed capacities considerably exceeding peak demand, or whether it contains a whole portfolio of DER including also non-negligible volumes of local storage and demand response potential. Moreover, it will make a difference which voltage levels are part of the distribution activity in the respective country and coordination needs probably will increase when DSOs also operate MV (or even HV) grids. For instance, in case the when the HV or UHV network is saturated, connection of generation to the MV network cannot be planned without taking into account the conditions at HV network.

With respect to EU involvement, procedures and principles of coordination between DSOs and TSOs should be defined at a European level in order to avoid distortions in competition and barriers for market entry due to different rules and market designs in different Member States. The possible set of distribution company functions needs to be extended. Also the currently developed EU network codes need to take account of the need for coordination and rules among system operators that rely on DER services. In this respect, the network codes should not hinder cost recovery of European DSOs and TSO, as otherwise the respective system operators do not have sufficient incentives to engage in their tasks.

5. Conclusions

Technological advances are reshaping today's electricity markets. More mature technologies for local renewable generation and decreased investment costs thereof, joint with national support schemes, led to a significant market penetration of distributed generation in many EU countries. In addition, new meter and appliance technologies allow consumers to react to local and upstream generation patterns and prices. Traditional downstream power flows from sources connected to the transmission grid to consumers at the distribution level are challenged by local distributed generation and local means of electricity trade. These changes are driven by the newly emerging broad range of distributed energy resources, be it distributed generation, local storage, electric vehicles or demand response, and pose challenges for DSOs and their regulation alike. Today, some challenges arising with DER technologies are only a possibility. Other challenges, foremost related to DG technologies, are already established facts and observable in many distribution systems. However, the same technologies that are causing substantial challenges already today can – with the right regulation and market design – be exploited to establish a more efficient and also cleaner electricity system than our current one.

This report argues that the priority task in regulation is not to try to predict what the future will be, but to make possible all welfare-enhancing business models under any future market development. Regulation needs to ensure that DSOs are not negatively affected by the market penetration of DER with respect to their ability to manage the system and to finance all needed system tasks. Nonetheless, the regulation of DSOs should not place any barriers, but create a level-playing field for all technologies and agents who want to make use of them under different formats. As DER might cause drastic changes to the architecture of power markets, all areas of DSO regulation have to be examined on if they might hamper an efficient integration of DER and the full use of these resources in the consumers' and producers' interest. In this respect, we identify four categories in which DSO regulation has to be reviewed: regulated DSO remuneration, distribution network tarification, the activities of DSOs vis-à-vis markets, and the activities of DSOs vis-à-vis their respective TSO.

First, remuneration schemes for DSOs need to be reviewed. On the one hand, increasing amounts of DER require substantial investments to properly connect all DER, to enable the system to deal with increased volatility of (net) peak demand, and to set up ICT infrastructure that empowers grid-users with better communication tools to align generation and consumption patterns. On the other hand, DER offer a new set of instruments for grid operation and have the potential to decrease the total costs of DSOs compared to business-as-usual (that is, a continued "fit-and-forget" grid management). With high levels of DER penetration, current approaches to distribution remuneration create financial risks for distribution companies, potential extra costs and degraded quality of service for the network users. A sound regulation that efficiently incentivizes DSOs to engage in active system management has to take account of i) changing OPEX and CAPEX structures, ii) the optimal choice among both, and on iii) how to incentivize DSOs to be innovative.

Second, the customary present design of network charges does not provide a level-playing field among all agents that use the distribution network. With an increasing penetration of DER and the likely creation of new business models at distribution level, ill-designed network charges will become very problematic, resulting in cross-subsidization and inefficient incentives. Moreover, grid users are becoming complex, sophisticated agents, which can have very diverse consumption and/or production patterns, and being able (and willing) to react to price signals. Tariffs, therefore, should reflect the true costs (or benefits) of different types of load and generation for the distribution system, which will depend on the agent's geographic location in the system as well as on the profile of injection/withdrawal from the connection point. This report proposes a reference framework to design sound distribution tariffs that meet the new demanding requirements, but it is beyond the scope of this report to offer a detailed method. Urgent research is needed to come up with proposals for distribution network tariff design that provide a level-playing field for all types of grid users, and that do not distort (or minimize the distortion of) economic efficiency.

Third, there are a number of areas in the newly emerging market environment where there is no consensus about whether the respective tasks should be under the responsibility of the DSO or not. The regulatory challenge here is to clearly define the roles, boundaries and responsibilities of DSOs. DSOs need to have a clearly defined legal basis for engaging in active system management. Especially as DSOs, when procuring system services, interact with the energy market in a more direct way than before, these processes must be in line with strict rules under coherent supervision. These rules imply that DSOs only buy flexibility offered from DER or aggregators thereof for their own sake of system management, and do not act like commercial players.

Different proposed (regulated as well as liberalized) models for (1) the ownership and management of metering equipment, (2) data handling and (3) EV charging infrastructure all have their advantages and disadvantages – these tasks may or may not be offered at lowest cost (due to sufficient synergies with grid operation) or in a more qualitative way by the DSOs as compared to other third regulated agents or commercial actors. The suitability of a certain model will depend on system-specific conditions, and therefore, the decision about whether to include such tasks into the DSOs' portfolio should be left to national authorities. The regulatory principle should be that whenever new responsibilities are best performed by competitive market actors, the DSO's role remains to facilitate local markets. In turn, whenever new responsibilities show sufficient synergies with the traditional tasks of regulated monopolies that operate the network, the DSO should be made responsible for these new services. Nonetheless, if new tasks can be performed by market players, but markets develop slowly relative to policy goals, markets may be (at least during the initial phase) kick-started via DSOs or other regulated entities. In this vein, if a full rollout of advanced meters (including data management), and also EV charging infrastructure, shall be provided in a timely fashion, advantages lie in the domain of the DSO. Regulators, however, have to take care not to foreclose market structures through DSOs that become incumbents once new technologies are deployed at scale and commercial actors want to enter the market.

Last, the main responsibilities of network operators with respect to grid management do not change, but the set of tools available to perform their tasks is enriched by DER. In general, DER can be used by both the DSO and the TSO and for both congestion management and balancing purposes. While the reason for different TSO or DSO actions might differ (restoring voltage or frequency, or relieving congestion), the sources used for these tasks may come from the same DER and clear rules for TSO-DSO responsibilities and coordination are needed. Furthermore, products that system operators use to ensure reliable grids (and often procure for this sake) should be clearly defined in terms of geography and timing. Coordination needs will differ among systems. It makes a difference whether a distribution system contains only an insignificant amount of DER, or whether it contains a whole portfolio of DER including also non-negligible volumes of local storage and DR potential. Moreover, it will make a difference, which voltage levels are part of the distribution activity and coordination needs probably will increase when DSOs also operate MV (or even HV) grids.

In the **European context**, regulation has to be kept at minimum level, respecting the principle of subsidiarity. Accordingly, we see neither the need nor a solid justification for an EU-wide comprehensive harmonization of the regulation of DSOs, although we recommend setting clear minimum requirements in a few key regulatory aspects, as well as the publication of EU guidelines to spread, encourage and monitor good regulatory practices in some of the critical areas that have been identified in this report.

- National regulators could benefit from sharing experiences on bad and good practices. EU guidelines for a sound regulation and adequate remuneration of DSOs should be formulated, followed by regular monitoring and benchmarking to reveal shortcomings of national regulatory approaches. Similarly, although distribution grid tarification is – and should remain – a national issue, again, it is urgent that research is conducted to develop a set of EU guidelines that should be recommended and monitored to reveal shortcomings of national regulatory approaches and to improve tariff design practices.

- The performance of new business models and the functioning of retail market competition rely on comprehensive consumer data. The EU should provide a minimum level of support in that respect, mandating – provided that individual consumers give their authorization for the use of their personal profiles – that consumer data are made available to registered agents. The definition of the specific format of data provision (i.e. one of the three proposed data models, or a combination thereof) can then be left to the Member States.

- Depending on system complexity and the number of tasks to be accomplished by DSOs, stricter unbundling requirements should be mandated. As system complexity increases, an insufficiently unbundled DSO could either stay with a restricted set of tasks, or the DSO could expand its portfolio of activities, but accompanied with an increasing level of unbundling. Increasing levels of unbundling could be implemented by "higher Chinese walls" between DSOs and their subsidiary retailers that engage in trading of distributed sources. The EU should provide guidelines for measures to reinforce "Chinese walls" between any DSO and the DER-related businesses that may exist under the same holding that owns the DSO.

- If general exemptions from unbundling for small DSOs prevail, additional regulatory means gain in importance. Therefore, especially for small exempted DSOs, new ICT or EV infrastructure needs to be sufficiently standardized such that third party market entry is facilitated as far as possible despite the lack of unbundling. Furthermore, it should also hold for small DSOs that market data relevant to accessing this ICT infrastructure and finally relevant for trading and retailing has to be made available such that barriers to market entry are further reduced. Hence for both the standardization of ICT infrastructure and according data availability EU guidelines should be formulated such that they explicitly include small DSOs.

- Finally, procedures and principles of coordination between DSOs and TSOs also should be defined at a European level in order to avoid distortions in competition and barriers for market entry due to different rules and market designs in different Member States. The possible set of distribution company functions needs to be extended. Also the currently developed EU network codes should take account of the need for coordination and rules among system operators that rely on DER services. In this respect, the network codes should not hinder cost recovery of European DSOs and TSO, as otherwise the respective system operators do not have sufficient incentives to engage in their tasks.

Necessary regulatory actions must be developed in a timely manner in order to minimize regulatory risk and barriers and increase investment activities in distribution and retail market segments as soon as possible.

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Annex A-1: Additional data and figures

Directive 2009/72/EC, Art. 26 – **Unbundling of distribution system operators**

1. Where the DSO is part of a vertically integrated undertaking, it shall be independent at least in terms of its legal form, organisation and decision making from other activities not relating to distribution. Those rules shall not create an obligation to separate the ownership of assets of the DSO from the vertically integrated undertaking.

2. In addition to the requirements under paragraph 1, where the DSO is part of a vertically integrated undertaking, it shall be independent in terms of its organisation and decision-making from the other activities not related to distribution. In order to achieve this, the following minimum criteria shall apply:

   a. those persons responsible for the management of the DSO must not participate in company structures of the integrated electricity undertaking responsible, directly or indirectly, for the day-to-day operation of the generation, transmission or supply of electricity;

   b. appropriate measures must be taken to ensure that the professional interests of the persons responsible for the management of the DSO are taken into account in a manner that ensures that they are capable of acting independently;

   c. the DSO must have effective decision-making rights, independent from the integrated electricity undertaking, with respect to assets necessary to operate, maintain or develop the network. In order to fulfil those tasks, the DSO shall have at its disposal the necessary resources including human, technical, physical and financial resources. This should not prevent the existence of appropriate coordination mechanisms to ensure that the economic and management supervision rights of the parent company in respect of return on assets, regulated indirectly in accordance with Article 37(6), in a subsidiary are protected. In particular, this shall enable the parent company to approve the annual financial plan, or any equivalent instrument, of the DSO and to set global limits on the levels of indebtedness of its subsidiary. It shall not permit the parent company to give instructions regarding day-to-day operations, nor with respect to individual decisions concerning the construction or upgrading of distribution lines, that do not exceed the terms of the approved financial plan, or any equivalent instrument; and

   d. the DSO must establish a compliance programme, which sets out measures taken to ensure that discriminatory conduct is excluded, and ensure that observance of it is adequately monitored. The compliance programme shall set out the specific obligations of employees to meet that objective. An annual report, setting out the measures taken, shall be submitted by the person or body responsible for monitoring the compliance programme, the compliance officer of the DSO, to the regulatory authority referred to in Article 35(1) and shall be published. The compliance officer of the DSO shall be fully independent and shall have access to all the necessary information of the DSO and any affiliated undertaking to fulfil his task.

3. Where the DSO is part of a vertically integrated undertaking, the Member States shall ensure that the activities of the DSO are monitored by regulatory authorities or other competent bodies so that it cannot take advantage of its vertical integration to distort competition. In particular, vertically integrated DSOs shall not, in their communication and branding, create confusion in respect of the separate identity of the supply branch of the vertically integrated undertaking.

4. Member States may decide not to apply paragraphs 1, 2and 3 to integrated electricity undertakings serving less than 100 000 connected customers, or serving small isolated systems.

Directive 2009/72/EC, Art. 18 – **Independence of the transmission system operator**

1. Without prejudice to the decisions of the Supervisory Body under Article 20, the transmission system operator shall have:
    a. effective decision-making rights, independent from the vertically integrated undertaking, with respect to assets necessary to operate, maintain or develop the transmission system; and
    b. the power to raise money on the capital market in particular through borrowing and capital increase.
2. The transmission system operator shall at all times act so as to ensure it has the resources it needs in order to carry out the activity of transmission properly and efficiently and develop and maintain an efficient, secure and economic transmission system.
3. Subsidiaries of the vertically integrated undertaking performing functions of generation or supply shall not have any direct or indirect shareholding in the transmission system operator. The transmission system operator shall neither have any direct or indirect shareholding in any subsidiary of the vertically integrated undertaking performing functions of generation or supply, nor receive dividends or any other financial benefit from that subsidiary.
4. The overall management structure and the corporate statutes of the transmission system operator shall ensure effective independence of the transmission system operator in compliance with this Chapter. The vertically integrated undertaking shall not determine, directly or indirectly, the competitive behaviour of the transmission system operator in relation to the day to day activities of the transmission system operator and management of the network, or in relation to activities necessary for the preparation of the ten-year network development plan developed pursuant to Article 22.
5. In fulfilling their tasks in Article 12 and Article 17(2) of this Directive, and in complying with Articles 14, 15 and 16 of Regulation (EC) No 714/2009, transmission system operators shall not discriminate against different persons or entities and shall not restrict, distort or prevent competition in generation or supply.
6. Any commercial and financial relations between the vertically integrated undertaking and the transmission system operator, including loans from the transmission system operator to the vertically integrated undertaking, shall comply with market conditions. The transmission system operator shall keep detailed records of such commercial and financial relations and make them available to the regulatory authority upon request.
7. The transmission system operator shall submit for approval by the regulatory authority all commercial and financial agreements with the vertically integrated undertaking.
8. The transmission system operator shall inform the regulatory authority of the financial resources, referred to in Article 17(1)(d), available for future investment projects and/or for the replacement of existing assets.
9. The vertically integrated undertaking shall refrain from any action impeding or prejudicing the transmission system operator from complying with its obligations in this Chapter and shall not require the transmission system operator to seek permission from the vertically integrated undertaking in fulfilling those obligations.
10. An undertaking which has been certified by the regulatory authority as being in compliance with the requirements of this Chapter shall be approved and designated as a transmission system operator by the Member State concerned. The certification procedure in either Article 10 of this Directive and Article 3 of Regulation (EC) No 714/2009 or in Article 11 of this Directive shall apply.

Table 5: Connection and access regimes & grid tariffs for DG

Source: Own depiction based on ACER/CEER (2012, Annual report on the results of monitoring the internal electricity and natural gas markets in 2011) & DG GRID (2007, Regulatory Review and International Comparison of EU-15 MSs)

	Connection and access regimes for RES-E in 2011		Grid tarification for DG	
Source	*ACER/CEER (2012)*		*ACER/CEER (2012)*	*DG GRID (2007)*
	Grid connection	**Grid access**	**Connection charge**	**Use of system charge**
Austria	Non-discriminatory (ND)	Guaranteed access	Deep	No
Belgium	Priority connection	Priority access	Shallow	Yes
Bulgaria	ND	Guaranteed access	Deep	
Cyprus	ND	Priority access		
Czech R.	Priority connection	Priority access	Deep	
Denmark	ND	Priority access	Shallow	Yes
Estonia	ND	Guaranteed access w/o priority dispatching	Deep	
Finland	ND	Guaranteed access w/o priority dispatching		Yes
France	ND	Guaranteed access w/o priority dispatching	Semi-deep	No
Germany	Priority connection	Priority access	Shallow	No
Greece	ND	Priority access	Shallow	
Hungary	ND	Priority access	Semi-shallow	
Ireland	ND	Priority access	Shallow	No
Italy	Priority connection	Priority access	Shallow	Yes
Latvia	ND	Absence of priority dispatching	Deep	
Lithuania	Priority connection	Priority access	Semi-shallow	
Luxembourg	ND	Guaranteed access w/o priority dispatching		Yes
Malta	ND	Priority access		
Netherlands	ND	Guaranteed access w/o priority dispatching	Shallow	Yes
Norway	ND	Guaranteed access w/o priority dispatching	Shallow	
Poland	ND	Priority access	Shallow	
Portugal	ND	Guaranteed access	Deep	No
Romania	ND	Guaranteed access	Semi-deep	
Slovakia	Priority connection	Priority access	Deep	
Slovenia	ND	Priority access	Shallow	
Spain	Priority connection	Priority access	Deep	No
Sweden	ND	Guaranteed access w/o priority dispatching	Semi-deep	Yes
UK	ND	Guaranteed access w/o priority dispatching (UK)	Semi-shallow	Yes

Table 6: Regulatory charges included in network tariffs

Source: Eurelectric (2013c)

Type of regulatory charge	Country
RES and/or CHP fee	AT, CZ, CH, ES, PT
Taxes paid to local authorities	AT, BE, CH, ES, FR, NO, PL, PT
Public service obligations	AT, BE
Other energy policy costs	DK, ES, FI, IT, LT

Table 7: Distribution network tariff structure in selected EU Member States

Source: Eurelectric (2013c)

Country	Structure of network tariffs for household customers					Structure of network tariffs for industrial customers				
	Fixed charge [€]	Capacity charge [€/kW]	Energy charge [€/kWh]	Reactive energy (€/kvarh)	Other	Fixed charge [€]	Capacity charge [€/kW]	Energy charge [€/kWh]	Reactive energy (€/kvarh)	Other
BE	Yes	No	Yes	No	N.A.	Yes	Yes	Yes	Yes	N.A.
CH	Yes (max 30%)	Seldom	Yes (at least 70 %)	No		Yes	Yes	Yes	Yes, often	N.A.
CZ	Yes	No	Yes	No	N.A.	No	Yes	Yes	Yes	N.A.
DE	Possible	No	Yes	No	N.A.	No	Yes	Yes	Possible, depends on DSO	N.A.
DK	Yes	No	Yes	No	N.A.	Yes	No	Yes	No	N.A.
EE	Yes	No	Yes	No	N.A.	No	Yes*	Yes	Yes	N.A.
ES	No	Yes	Yes	No	Meter rental	No	Yes	Yes	Yes	N.A.
FI	Yes	No	Yes	No	Metering fee	Yes	Yes	Yes	Yes	Metering fee
FR	Yes	Yes	Yes	No	N.A.	Yes	yes	Yes	Yes	Exceeding of the contract power and other minor charges
GR	No	Yes	Yes	No	N.A.	No	Yes	Yes	No	cosφ
IT	No	Yes	Yes	No	N.A.	No	Yes	Yes	No	N.A.
LT	Possible**	No	Yes	No	N.A.	No	Yes**	Yes**	No	N.A.
NL	Yes	Yes	No	Possible, depends on DSO	N.A.	Yes	Yes	Yes***	Possible, depends on DSO	N.A.
NO	Yes	Seldom[+]	Yes	No	N.A.	Yes	Yes[++]	Yes	Yes	N.A.
PL	Yes	No	Yes	No	N.A.	Yes	Yes	Yes	Yes	Exceeding of the contract power
PT	No	Yes	Yes	No	N.A.	No	Yes	Yes	Yes	ToU for energy and capacity charges
SE	Yes	Seldom[+],	Yes	No	N.A.	Yes	Yes	Yes	Yes[+++]	N.A.

* as of industry band Ic ** depends on payment plan *** for >MS [+] Implemented for few DSOs [++] For some customers usually over 100 000 kWh [+++] when the reactive power exceeds a specified limit

Figure 9: Electricity retail prices in 2011 (€/kWh for a representative household consuming 2500-5000 kWh/a)

Source: EC (2012c - SWD(2012) 368)

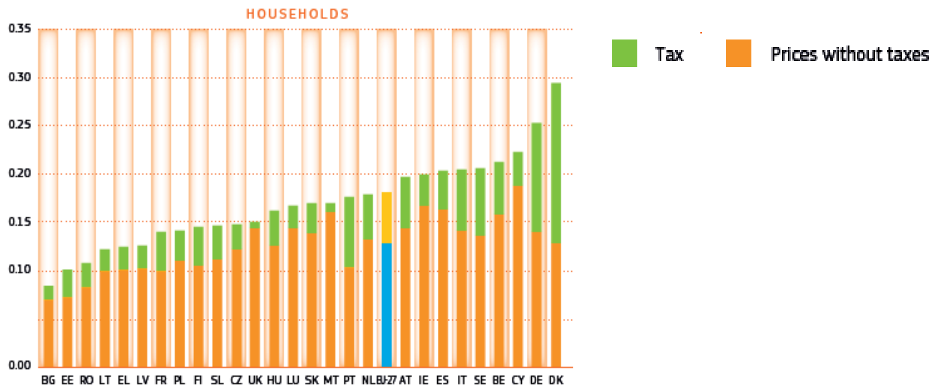


Figure 10: Distribution of cost factors within retail electricity prices in 2011 (%)

Source: EC (2012c - SWD(2012) 368)

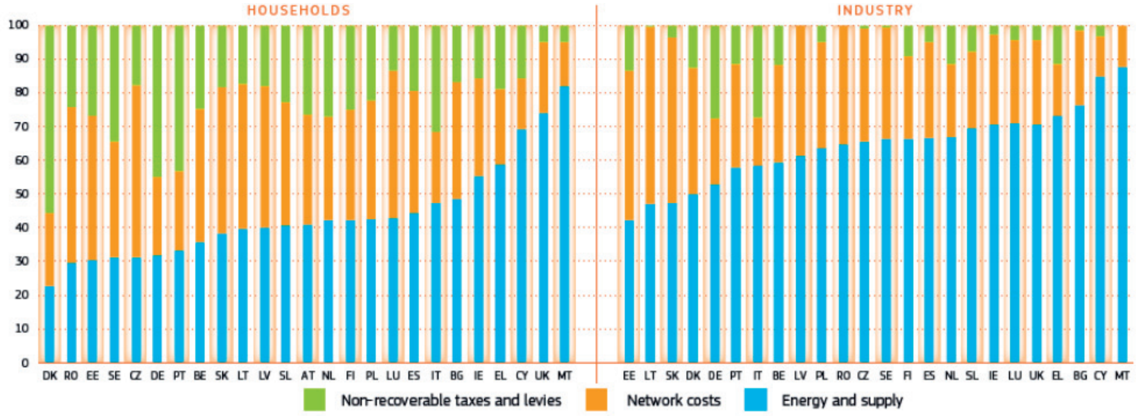


Table 8: Electricity switching rates in 2010 (%)

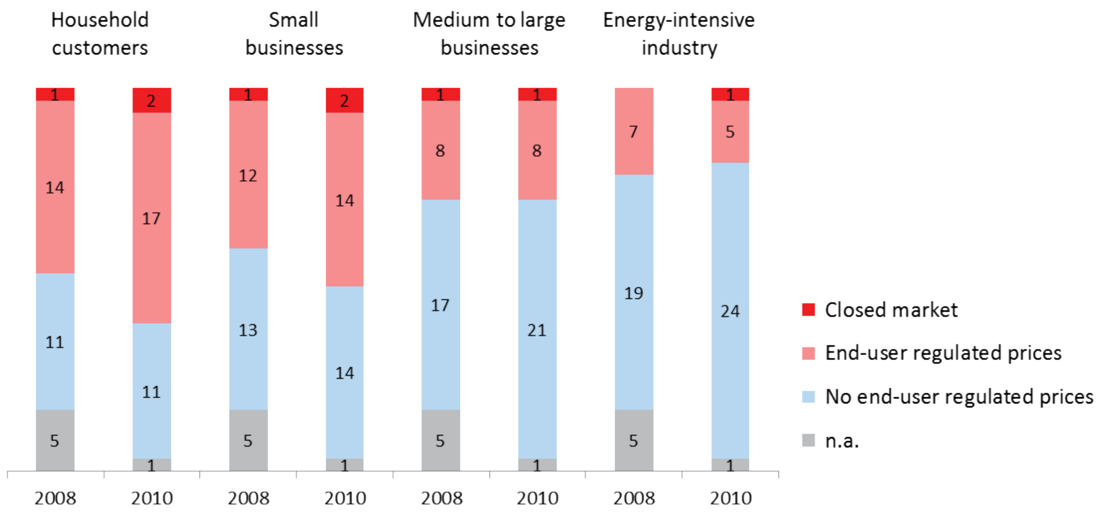
* Percentage by which the switching rate has changed from the value in 2009 to the value in 2010

Source: EC (2012c - SWD(2012) 368)

	Retail market, total		Household customers		Non-household customers	
	2010	Change to 2009 *	2010	Change to 2009 *	2010	Change to 2009 *
Austria	1.8	0.5	1.7	0.5	2.1	0.4
Belgium	10.0	3.1	8.8	2.4	16.0	5.9
Bulgaria	N/A	N/A	N/A	N/A	N/A	N/A
Cyprus	N/A	N/A	N/A	N/A	N/A	N/A
Czech R.	3.3	1.8	3.2	2.1	7.9	3.8
Denmark	4.3	-1.9	4.2	-1.9	11.4	-5.1
Estonia	N/A	N/A	N/A	N/A	N/A	N/A
Finland	7.6	-0.5	7.6	-0.5	N/A	N/A
France	2.0	-1.4	2.3	-1.4	0.9	-0.4
Germany	6.3	1.4	6.0	1.3	7.5	1.6
Greece	N/A	N/A	N/A	N/A	N/A	N/A
Hungary	N/A	N/A	N/A	N/A	N/A	N/A
Ireland	N/A	N/A	N/A	N/A	N/A	N/A
Italy	5.9	1.4	4.1	1.8	12.4	-0.1
Latvia	N/A	N/A	N/A	N/A	N/A	N/A
Lithuania	1.3	1.3	0.0	0.0	4.1	4.1
Luxembourg	0.2	0.0	0.2	0.1	0.6	0.1
Malta	N/A	N/A	N/A	N/A	N/A	N/A
Netherlands	8.9	-2.1	N/A	N/A	N/A	N/A
Norway	N/A	N/A	N/A	N/A	N/A	N/A
Poland	0.1	N/A	N/A	N/A	N/A	N/A
Portugal	2.3	0.0	2.1	0.0	27.4	8.2
Romania	0.1	0.1	0.0	0.0	1.0	N/A
Slovakia	1.0	0.1	0.8	0.3	1.6	-1.0
Slovenia	1.9	0.5	1.0	-0.1	9.6	4.7
Spain	7.4	6.6	2.1	1.6	17.3	8.2
Sweden	9.4	-1.8	8.2	-1.6	1.2	-0.2
UK	N/A	N/A	17.3	-1.1	N/A	N/A

Figure 11: End-user price regulation in different electricity market segments

Source: Own depiction using data from ERGEG (2010)



Annex A-2: Regulating data provision?

In what follows, we first present a summary of the three proposed data models (Table 9). Then, we argue that advanced meter data provision by nature involves infrastructure, or platforms, on which several market actors are demanding data. We briefly discuss missing incentives to invest in such platforms, and how demanding actors might be discriminated against, or payments for data access might by socialized across, platform users.

#1 – The economics of providing advanced meter data: Data hubs as platforms

Advanced meter data handling includes the aggregation and processing of data, as well as the provision of data to the relevant market actors at the distribution level. Therefore, data provision establishes infrastructure that delivers a *platform* for local energy market players. Such a platform brings together multiple users that have interest in using advanced meter data for engaging in mutual contracts and reduces transaction costs for all users. Retailers and various service providers (e.g. aggregators, ESCOs) need data to verify the fulfillment of their

Table 9: Data model description

	Option 1 – **DSO as a market facilitator**	Option 2 – **Central data hub**	Option 3 – **Data access point manager**
General model description	Model based on data hub(s) operated by the DSO Via hub(s), the DSO provides data to the market	Model based on data hub(s) operated by an independent third party, the so called "central data hub"	Creation of "trusted data access-point manager" = commercial role played by certified companies
Data hub? (i.e. standardized communication platform for authorized parties with a certain geographic scope)	Yes Centralized (e.g. national) or decentralized (e.g. sub-national)		No Enables activation of different actors to retrieve data directly from the meter
Party responsible for data handling = **regulated entity**?	Yes DSO = regulated market facilitator providing a platform	Yes Central data hub = regulated third party	No DAM = commercial role taken by certified companies
Metering	DSO responsible for all sub-processes	CDH does not meter; data collection and delivery would be with other parties (e.g. DSO, supplier) // CDH does only receive, process and deliver data	Different actors can directly retrieve data from the customers' meters
Customer interface	Supplier can remain main contact point		"Granularity and interfaces to be decided by customer"
Supplier switching	All transactions take place via the DSO	All transactions take place via the CDH	"technically similar to switch mobile phone supplier without changing SIM card"

contracts and to design better products for their contracted end-users. End-users need data to also verify contractual agreements or to react to (real-time) price incentives provided in such contracts. Also regulated players, such as the DSO, need steady access to data to ensure system reliability.

The economic nature of such a platform is well reflected in the EC Smart Grids Task Force discussion on data hubs. In fact, data hubs are platforms in the above sense. For two of the three models the Task Force is proposing, namely for the "DSO as a market facilitator" and the "Third party as a market facilitator" models, such data hubs are regulated. In the third model, data access-point managers (DAMs) offer their own platform each. Hence, for all three proposed models, providers of data offer a platform and face a multi-sided market with several types of actors being interested in advanced meter data.[30]

#2 – Supply: Investing in infrastructure for data provision - missing incentives

The benefits of implementing platforms for advanced meter infrastructure are distributed among several actors, and hence also investment incentives might be lower than the total gain obtained from such investments. Also McKinsey (2010) notes that "fragmentation across the value chain" has diluted investment incentives in advanced meter equipment for any single market actor. Moreover, externalities within one horizontal layer may reduce investment incentives. For instance, one retailer that invests in advanced meter data infrastructure establishes positive externalities for competing retailers, who tomorrow might take over customers and, when doing so, at least partly gain from this established infrastructure, too.

#3 – Demand: Paying for data provision - discriminating prices and socialization of costs

If not regulated, pricing structures on platforms usually price discriminate among platform users (see Evans and Schmalensee, 2007; and Evans, 2009). For instance, a retailer running a data platform might not charge consumers to increase its customer base and amount of data, but instead pass all costs on to aggregators or other traders wanting to have access to the data.

On the other hand, with additional regulation, socialization of costs for data provision can occur, for at least two reasons. First, it can occur if regulation is imposed on otherwise commercial players, say a government wants to increase participation of consumers in using advanced meter data. Suppose a retailer is running a platform but for this reason is not allowed to charge consumers who increasingly use the data platform. Then costs will be passed on to all consumers, those with traditional and non-price responsive demand patterns and those who actively use the data. Second, if a regulated entity is running a data hub, and not charging pay-by-use fees, costs for data provision are socialized, too, most likely via the grid fee.

Annex A-3: Conclusions Industrial Council Meeting (based on report version "V0", 03/2013)

Serge Galant

Technofi

The question

The issue at stake is to revisit the role of distribution networks from a regulatory perspective, in view of the several drivers, which push them to adapt to a changing electricity system. The question to be answered is two-fold:

1. What are the regulatory options to make distribution network enablers of the evolving electricity system, such options aiming at limiting/avoiding / removing existing or expected regulatory barriers conducive of market inefficiencies (or even market failures)
2. To what degree EU-based intervention /

30. A multi-sided market involves the provision of goods or services – via a platform – to at least two distinct groups of customers. Indirect network effects furthermore lead to positive externalities. The value that customers on one side can realize increases with the number of customers on the other side, i.e. the more consumers join a platform, the higher the value of using the platform.

coordination / harmonization might facilitate (accelerate) the deployment of such regulatory options for distribution networks which would in turn lead to a more competitive electricity market, in line with the two other EU policy pillars?

Completeness of the draft report

It is advised to introduce the following improvements in the next version, in order to ensure greater completeness of the study.

Mapping of DSO activities in EU Member States

First, a reminder of EU energy policy pillars (competitive electricity market, sustainability via the decarbonization of the full electricity systems, security of supply) must be provided since it will be one of the filters used to select potentially new regulatory options. Then, a more complete mapping of the 5000+ DSOs and retail markets in EU27 should allow to define a few classes of DSOs according to their capability to comply with EU policy pillars (a purely qualitative assessment). It is then assumed that, depending upon their policy compliance capability to-day and in the future (a dynamic perspective), regulatory changes should be recommended which would be selected according to:

- The type of change drivers which must be taken into consideration to comply with EU policy goals,
- The existing work performed at EU or Member State level which try to shed light on the most promising regulatory evolutions

This work is made very difficult due to the complexity of the DSO landscape in EU27. Yet, this rough ("quick and dirty") classification would certainly help justifying the studied options including the ones already described in the draft report:

- The role of DSOs, for data management and provisions,
- The role of DSOs for electric vehicle charging infrastructure,
- The evolving boundaries between TSOs and DSOs

State of the art

The following work must be taken into account:

- The Smart Grid Task Force outputs
- The CEER report on DSO good practices as viewed from the electricity consumers ,
- Large scale demonstrations which cover some of the wished evolutions of regulatory schemes (GRID4EU, ECOGRID….)

Drivers for change coming from several stake-holders

Several drivers for change, which go beyond the ones listed in the draft report, have been mentioned:

- The arrival of new technologies (Advanced meters, Distributed Generation, Demand Response, Electric Vehicles, Energy Storage), but also system challenges induced by network ageing which should require the implementation of new architectures, new network operations, new network maintenance processes
- The implementation of new retail models (aggregators, energy services, new service provision to the electricity system…) which bring new players to relate with DSOs
- The financing gaps to implement new technologies and new electricity retail models: there is a growing gap between investment selection criteria by banks and the economic background into which DSO are operating (for instance ROI very long with review periods of 4/5 years which create uncertainty on revenues)

They should be added in the report as drivers for other regulatory options than the ones listed in the first version of the report.

Justification of the regulatory involvement

For each of the above drivers, the objective of the study is to analyze the ones which would benefit from regulatory evolutions enabling DSOs to support the electricity system evolutions while keeping in line with EU energy policy pillars. Thus,

- There might more than three regulatory options worth studying
- The ones which will retain must be justified

Clarity of the draft report

The objective of the present work is not to rank the studied regulatory options able to lean on the drivers which, in the end, make the electricity system in line with EU policy pillars.

This work must rather detail the regulatory options at a level which can be grasped by non-experts, and in a dynamic, quantitative appraisal.

The expected impacts for each regulatory option will drive the priority for implementation. Amongst the studied impacts, resulting from their implementation the ones below are the ones which would maximize the probability of deployment:

- Creation of new services which value the distribution network: from DSOs to TSOs, from aggregators or energy service providers to DSOs, from DSOs to retailers and conversely.
- Optimization of the unbundling process: legal, ownership, with avoidance of market concentration if properly implemented, both.
- Improved links between electricity and gas/ telecom networks/regulations.
- Improved customer awareness, smartness and behavior.
- Improved network economics: adequate remuneration of network operators, adequate network changes for users.

On the basis of the studied evolutions, tentative implementation plans must be described in order to give more credibility to the study: implementation at EU level, implementation at national level, implementation at regional level.

Coherence of the draft report

Coherence of the study will improve when addressing the issues below:

- A full mapping of the DSO landscape is not possible: a disclaimer is needed on the type of DSOs classes that will be sorted out.
- A quantitative assessment of the impacts of the studied regulatory options is out of question: yet, there might be a need to uncover the type of R and D needed to provide in the future quantitative regulatory policy impacts.
- The report must stress the leading role of DSOs, as market facilitators.

Annex A-4: Summary Public Consultation

Serge Galant
Technofi

The public consultation

The report which was put into public consultation aimed at revisiting the role of distribution networks from a regulatory perspective, taking into account several drivers which push them to adapt to a changing electricity system. Two questions are then raised:

1. What are the regulatory options which would help making distribution network enablers of the evolving electricity system, such options aiming at limiting/avoiding / removing existing or expected regulatory barriers conducive of market inefficiencies (or even market failures)?
2. To what degree EU-based intervention / coordination / harmonization might facilitate (accelerate) the deployment of such regulatory options for distribution networks, which would in turn lead to a more competitive electricity market, in line with the two other EU policy pillars?

Overall, the respondents have challenged the report on the following topics:

- Ownership unbundling of DSOs to increase retail competition
- Role of the EC in defining guidelines for DSO roles and duties
- Distribution network tariffs
- New DSO tasks

- Real-time pricing of electricity
- Smart metering ownership and data handling
- DER-enabled cost savings for DSOs
- Cooperation TSO/DSO
- EV charging infrastructure
- Conventional versus smart grid investments
- Cost recovery of smart grid investments
- Smart distribution and IT investments

Ownership unbundling of DSOs to increase retail competition

The report claims that the observed lack of retail competition in EU27 is mainly due to insufficient unbundling of DSOs. It then recommends ownership unbundling and /or higher Chinese walls between distribution and supply activities, since many such organizations belong to the same utility.

As a matter of fact, the report should acknowledge that this statement would be true if the effects of two other possible causes for the lack of retail competition (which may be interfering with the competition level on the retail market) can be separated, viz. (a) the existence of regulated end-user tariffs, and (b) the regulated part of the electricity bill which is about 50% of the total electricity bill.

Little margin is then left over for savings on the client side and, consequently, there is little room for retail competition.

Ownership unbundling is therefore overemphasized as a key political measure to increase retail competition, whereas other cheaper options may exist like strong governance rules in line with the Third Energy Package, and the adverse effects of ownership unbundling do exist when considering customer's choice (reduced number of retailers in the market), and customer's bills (higher costs related to separated structures).

Last, but not least, it is stated that "insufficient unbundling clearly IS a problem, (…)". This suggests that – as a principle – the current situation concerning unbundling is not optimal, which is also not in line with the real life, as highlighted in the recent CEER report. The current issue of lack of retail competition comes also from the (ab-)use of market power of big incumbent suppliers in their home territory where they are the historically established brand.

Role of the EC in defining guidelines for DSO roles and duties

It must be noticed that the report recommend on p 47 that the Commission sets "some minimum requirements in a few key regulatory aspects, as well as the publication of EU guidelines", for instance for measures to reinforce the above Chinese walls. Such guidelines appear too early for many respondents since:

- The CEER Status Review on DSO unbundling published in April 2013 suggests that no premature actions should be taken as long as the 3rd energy package is properly transposed by the Member States.
- More research is needed about the economic efficiency of DSO unbundling. Let us mention several issues for which detailed impact assessment are needed:
- legal unbundling has not been applied so far to small distribution companies (those with less than 100.000 clients) for so-called "economic reasons"
- if unbundling is key to support retail competition, the same rules should apply to all DSOs, since conditions for retail competition should not depend on the size of the distribution company serving any particular geographical area
- there is no apparent correlation between the DSO size and the efficiency/quality of supply
- Implementing the 3rd Energy package should therefore remain a priority of the European Union until 2014, while pursuing in-depth research on the impacts of the 3rd Energy package.

Distribution network tariffs

The report lacks policy recommendations to propose concrete suggestions on how to design improved network tariffs. A common methodology to design regulated tariffs is indeed required at EU level since an internal energy market requires hopefully an agreed joint approach to allocate regulated costs. A majority of Member States still address network tariffs for households and small businesses using energy volume (kWh): it allows recovering at least 50 % of the allowed DSO revenues[31]. Yet, network costs are mainly capacity driven where volumetric tariffs set signals to reduce energy consumption: they do not reflect the specific costs coming from consumption at peak hours.

Future network tariff structures should therefore incentivize both demand response and energy-efficient behaviors, while, at the same time, providing a long term stable framework for both customers' bills and DSO revenues[32] and investments:

- For instance, a new model is possible where two-part network tariffs would involve a capacity and an energy component: capacity tariffs or volumetric time-of-use network tariffs would then allow different prices for peak and off-peak energy.
  - But also an increased coordination is needed for electricity prices which are strongly impacted by various taxes and levies, introduced by Member States in an uncoordinated way, and which further constrain the possibilities for customers to benefit from market liberalization and competitive wholesale prices.

Output-oriented regulatory schemes[33] also requires further research to allow DSOs gaining the capability to influence the measured outputs with consistent incentives, which, in turn, would limit DSO uncertainty and favor long term distribution network investments.

New DSO tasks

The report needs to better emphasize the needs for regulators to shape new tasks for DSOs. Increasing the electric system flexibility (while optimizing network investments to reach affordable costs) will indeed pave the way for new business at DSO level, with the proper remuneration of such flexibility services.

- Overall, regulators should make DSOs responsible for these new services with appropriate regulation and incentives to carry out these new responsibilities, wherever the new responsibilities are best suited to a regulated natural monopoly.
- DSOs should be responsible for investment in active management systems and necessary data acquisition infrastructure throughout the distribution network up to the point of interconnection of customer loads and generators.
- DSOs could be encouraged by regulators to initiate new remunerated services to procure system operator services from distributed energy resources located on their network that assist the DSO in meeting their regulated outputs, including system reliability and availability, voltage control, minimizing losses, and facilitating integration of distributed generation.
- DSOs as aggregators of system operator services procured by the TSO could facilitate these markets via its role as neutral data hub.

Real-time pricing or critical peak pricing of electricity

The recommendation of real-time pricing should be more detailed with pros and cons as well as comparison of other options, where, for instance, the design of time-of-use pricing can reflect the system costs of system. The specific very high price issue (1000 €/MWh and more) coming from real-time pricing should be addressed.

There is also a need for a transparent comparison between the different market design options when implemented in national energy markets using the principle of subsidiarity. It includes the costs of transaction and the temporality of the studied solutions: short term solutions (operational to reflect current costs) versus long term solutions (investment

31. See EURELECTRIC Report 'Network tariff structure for a smart energy system', May 2013.

32. Specific regulatory charges or taxes developed by Member States makes the comparison between DSOs extremely difficult.

33. See EURELECTRIC report Regulation for Smart Grids, February 2011.

to release constraints). For instance, Real-Time Tariff or Critical Peak Pricing has proven to be cost and technical effective (2 GW of peak is avoided in France through the EJP tariff).

Smart metering ownership and data handling

The report should further expand on the options available to support the role of DSOs about smart metering ownership and data handling. There is indeed a lot of controversy about smart metering investment and the Data Access Manager (DAM) model since raising a lot more questions than answers:

Option 1

- DSO as market enablers ensure the investment of smart meters, with a question on Data handling (The Data Access Manager, DAM)
- Market facilitation consists in allocating the right volumes of energy to the right market parties, with processes like supplier switching, moving etc.…Yet, the DAM does not provide an efficient solution for this process.
- Data handling processes are currently integrated and managed by a single entity in many Member States: separating them into multiple sub-processes managed by separate entities introduces costs and complexity (beyond the dilution of responsibility).
- Issues of interoperability[34] are more stringent when an entity different from the DSO is carrying out the rollout with consequences on the stranded investments and customer switching. The two countries mentioned in the report (UK and Germany) which have adopted the liberalized models have not been success stories in smart metering.

Option 2

- On another hand, assuming that DSOs are responsible for investment in active management systems and the necessary data acquisition infrastructure throughout the distribution network up to the point of interconnection of customer loads and generators, then advanced metering of loads and generators becomes the responsibility of the competitive metering market.
- National standards for advanced metering are established by a relevant standards agency, consistent with a common European framework.
- DSO's are empowered to require customers to install advanced meters capable of real-time measurement of two-way power flow for any customer classes for which benefits outweigh costs, including those with installed distributed generation, EV charging points, or any customers that seek to engage in demand response markets.
- The DSO becomes the regulated entity centrally responsible for acquisition and management of data on customer load and any generation connected to the distribution system, as well as the state of any monitored network components.
- The DSO provides access to any data necessary for system operators to ensure security of supply and optimal network planning, as well as create rules for non-discriminatory access to any data necessary to create a level playing field for various competitive markets.
- The DSO ensures the privacy and security of any personal data and identifying information collected from customers.
- Standards established for smart metering infrastructure provides for standardized data formats for the collection by the DSO of data on customer-sited generation and loads.

DER-enabled cost savings for DSOs

The draft report states: "there can be benefits from a reduction in losses and the ability of DER to release network capacity which can be used to accommodate future loads". "Netting" generation and demand brings poor or no reduction in network investment, especially in networks with high DER penetration. Electric vehicles may even increase the maximum load in the network. Moreover, the rise of decentralized

34. Incremental IT costs arise because the total number of systems increases and, in general, an increased coordination effort in IT system development and maintenance.

generation should increase the network costs since the grid ought to be designed to cover peak demand when there is no local production. New system services embedded in active distribution system management solutions are able to mitigate these cost increases compared to the business as usual solutions.

Cooperation TSO/DSO

The report must stress the need of a framework for effectively sharing operational information between network operators, and between network operators and end customers. TSOs are encouraging smart substations to exchange operational information with DSOs which they need from final customers or prosumers connected to distribution networks. The joint Research and Innovation TSO roadmap, which has just been reviewed by ACER[35], has included several R&I projects supporting increased cooperation amongst operators via AC-funded approaches.

EV charging infrastructure

The paper should be more explicit about the different models relating to the EV charging infrastructure. The infrastructure investments may be recovered either only by the e-mobility customers (independent e-mobility model) or can be integrated in the grid tariffs, thus socializing the costs between all grid users (integrated infrastructure model). Even though it is up to the Member States to decide on the most accurate market organization according to the national characteristics (both electricity market and mobility needs), EV charging infrastructure does not appear to exhibit cost structures that lend to natural monopoly (as discussed on p. 36-7). While the initial roll-out of charging infrastructure appears to have a public goods quality, there should be sufficient customer demand to support investment in charging stations once sufficient market adoption of EVs is achieved, (just as their exists sufficient demand today for investment in petroleum-based fuel stations). If "non-market" actions to jump-start sufficient infrastructure investment and customer adoption (as is likely the case) are needed, other public policies can be implemented such as competitive tenders for infrastructure roll-out on public property or subsidization of the first phase of roll-out by qualifying private entities. Technology standards for charging infrastructure should also be established by relevant national standards agencies in order to reduce investment risks associated with interoperability. The EC has for instance already designated the "Type 2" three-phase coupler as the Europe-wide standard for EV charging ports.

Conventional versus smart grid investments

The demand for investments in smart distribution solutions happens to peak at the same time as the need for renewal of the conventional grid is also urgent. Most of the conventional electricity grids in Europe were built in the post-war years and have now reached the age when they need to be replaced with modern (conventional or smart) solutions.

The rising demand for security of supply where the economy may greatly suffer from power outages of few seconds, pushes for an optimal combination of "smart" and conventional grid investments. To-day's regulatory schemes tend to focus in deploying Smart Grid solutions (which includes smart metering), while forgetting the need to maintain the more traditional grid infrastructure performance. Incentives may be needed to reward DSOs when balancing grid investments in order to avoid irreversible investments which would prevent distribution investments to switch to smarter operations of the distribution grid.

Cost recovery of smart grid investments

The report states that "Under a regulated model, where the DSO is responsible for metering, costs can be recovered through regulated charges which are directly passed on to customers."

It should however be recalled that costs of smart metering and of other network investments can also be recovered through efficiency gains in DSO operations, without necessitating recovery via grid use fees and passed on to end consumers. The part of the costs which can be recovered by increased operational efficiencies of course depends upon the specific situation of the DSO and the associated network configuration.

35. Opinion of the Agency for the Cooperation of Energy Regulators N° 11/2013, 28-th May 2013 on "The Entso-e research and development roadmap 20 13- 2022 and the implementation plan 2014-2016 of the research and development roadmap 2013-2022"

Smart distribution solutions using the background of telecom networks

The report addresses the concept of the "energy control box" where it must be emphasized that current regulations are responsible for a "silo" approach of (i) the roll out of smart meters by DSO's and (ii) the introduction of consumer energy management applications (CEM) by market parties.

The pros of existing models, together with an examination of the IT perspective of the investments (a common practice in the Telco/ITC markets), lead to the following recommendation: (a) the meter and its ICT platform (gateway) should be invested by DSO's, which requires a gain in expertise about complex IT systems; (b) applications will be run on top of this ICT platform: they should be developed and operated in the open commercial market.

Thus, the ICT platform/gateway would, as a market enabling service, facilitate market parties and customers in a very effective way: it avoids the investment burden from market parties (in the liberalized model), but, at the same time, would enable the liberalized model, where market parties could compete on applications.

When DSOs enter this type of innovation, they should be compensated for in the WACC, especially when realized in cooperation with the ICT/Telco sector. Yet, for DSO companies who are legally unbundled (but not ownership unbundled), OT OPEX and CAPEX are very often decided by the DSO organizational unit of the energy company. However, the IT OPEX and CAPEX is much more controlled/ decided at the organizational group level (especially if the IT function is organized as a group shared service center). A strict unbundling regulation for DSOs, which also stimulates the integration of IT and OT, should recommend that IT OPEX and CAPEX expenditures need to be decided at the DSO organizational level, and not at group level.

Box 1: Three-step evolution of distribution systems (Eurelectric, 2013)

The development towards 'smart' distribution systems can be described in three steps. First, the traditional ***passive distribution networks*** have been developed based on a "fit-and-forget" approach. With an increasing penetration of DER, also system 'smartness' should increase. An approach used already today in some countries with a high share of DG, therefore, is a ***reactive network integration***, or "operation only" approach. Congestion and other grid problems are solved at the operation stage by restricting load and generation, i.e. DSOs solve problems once they occur.

An ***active system management*** would allow DSOs to become "real system operators". The existing hosting capacity of the distribution network can be used more efficiently if an optimal use of DER is considered. Eurelectric (2013) proposes that DSOs should have the possibility to buy flexibility on so-called "flexibility platforms" to optimize network availability in the most economic manner and to solve grid constraints. Network reinforcement then could be deferred until it becomes more cost-effective than procuring services from DER. However, in-depth analyses going beyond the current more conceptual discussion are required to propose suitable concrete architectures and responsibilities, including an answer to the question on who should set-up and coordinate such a flexibility platform.

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