From smart technology to smart consumers: for better system reliability and improved market efficiency

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FROM SMART TECHNOLOGY TO SMART CONSUMERS: FOR BETTER SYSTEM RELIABILITY AND IMPROVED MARKET EFFICIENCY.

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Abstract:

The new pricing schemes, enabling smart grids technologies and remote control equipments allow retail consumers to procure demand response resources and participate more intensely in the efficient functioning of markets. This fact is inducing significant changes regarding the roles historically attributed to the different operators acting along the supply chain. It is also involving improvements in markets efficiency, system reliability, and of course regulatory models (Clastres, 2011).
This paper aims at focusing on two different benefits, although not incompatible, of smart technology and retail consumers' activation.

- The first focus lies on smart grids technology's potential and on smart consumers in enhancing the reliability of power systems.
- The second focus is based on the potential of smart grids technology to improve markets efficiency.

Regarding the many aspects contained in these two –restricted- sides of benefits, this paper studies smart grids and demand response (DR) programs adoption in California, Germany, Illinois and the UK and is articulated in four points. First, it describes the challenges linked to peak load and peak prices and discusses the instruments becoming available through short-term demand side activation as well as the barriers to procure greater flexibility. Second, this paper deals with demand response and smart metering as a way to enhance wholesale and retail markets efficiency. At last, it discusses the regulatory mechanisms available to the authorities to give the sound incentives for adopting smart grids technology, in order to respond to the real needs encountered by the systems.

1. Smart grids technology to enhance system reliability: the cases of California and Germany.

California and Germany provide good examples to illustrate the issue of activating the demand side in order to achieve greater system flexibility and reliability.

In 2000, only four years after the beginning of the reforms, California had to deal with the collapse of its power sector. The various structural, institutional and exogenous reasons that had become intermingled before the crisis were widely discussed in the literature (Joskow 2001, Woo 2001, Jurewitz 2002, Wolak 2003, Sweeney 2006). The sharp increase in the prices of gas, the dominant fuel for power generation, coupled with water

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reserves (which are strategically kept for use during peak periods) that were particularly low favored a considerable increase in spot prices.
In addition, California faced particularly high peak loads due to a very hot summer and the wide use of air conditioning that completed rising prices on the market and market powers. The California crisis remains famous for the system failures that led to the rotating blackouts administered by the CAISO. All these elements contributed to shape California's energy strategy, where peak-period supply security is a key issue.

Unlike California, Germany has overcapacity. Despite the phasing out of its nuclear power plants and estimates of high growth in demand, Germany's annual peak load is not expected to exceed 81.5MW in 2020, representing a secured capacity of 87.9GW (BDEW, 2011a).
This is above all Germany's energy policy for the development of renewable energies that poses new challenges for flexible system management. Since the 90's, the contribution of renewables has increased fourfold in Germany with a sharp increase in the 2000s, which serves as proof of the success of the incentives schemes that were implemented[2]. Wind energy experienced an average annual growth rate of 34% between 1990 and 2010, and solar PV grew by 49% between 2004 and 2010. The development of decentralized generation (DG), mainly solar PV and wind power, will play a key role in Germany's smart grids strategy. DG capacity connected each year to distribution grids tends to exceed the capacity traditionally connected to high voltage grids (Kema, 2011). 79% of the total installed capacity in 2009 was connected to distribution grids, 99% of which was intermittent (BNetzA, 2010). According to estimates by the German Energy Action Plan, DG is not expected to be less than 20% of the total installed capacity in 2020 (BMU, 2010). The most optimistic studies carried out by the authorities estimate that DG could account for half of the total generation capacity by 2020 (BDEW, 2011b).
Smart grids solutions in Germany are largely focused on enabling consumers to respond to load reductions or unexpected load increases due to intermittent energies, and on enabling distribution grid operators to facilitate the integration of DG by remote control and automation.

1.1. DSM as a solution for responding to peak load:

1.1.1. Demand-side to enhance the reliability of supply:

Traditionally, the price of a kWh fluctuates on the wholesale market depending on random variations in both demand and the generation technologies mobilized, according to the merit order (Schweppe et al., 1988). Under optimal technological conditions and installed capacities, the price is determined at the marginal cost of the marginal unit and can cover all of the fixed and variable costs of each infra-marginal technology. The problem lies in remunerating the marginal units that ensure that demand is met during peak periods. These peakers must sell their energy at a price that is higher than their variable cost (and therefore the marginal cost of the system) in order to be able to cover their fixed costs.
This difference between the market price and the marginal cost of generation represents the scarcity rent, which is essential for sending investment signals. However, the level of these signals can be set too high, particularly in situations where the market is dominated by a limited number of actors, as is the case in California and in most electricity markets. The introduction of price caps makes it possible to limit the scarcity rent, but has the adverse effect of masking the real investment needs. Moreover, since peak demand is random, it is not certain that a peaker will be able to effectively cover its investment costs over the lifetime of

[2] Notably in terms of feed in tariffs with the StrEG Act (Stromeinspeisungsgesetz) in 1991 and the EEG law on renewable energies (Erneuerbare Energien-Gesetz) in 2000. As described by Mendonça (2007), policies to encourage the development of renewables evolved over time. While a first phase was dedicated to encourage an effective penetration of these technologies, a second phase, still active, promotes learning curves.

the power plant. In addition in sending incorrect investment signals, the presence of price caps has reinforced the uncertainty associated with the risk of "missing money" as defined by Shanker (2003) and taken up by Hogan (2005), Cramton and Stoft (2006) and Joskow (2006b).
In a context of high stress on the system, DR appears to be a solution for transmitting efficient price signals. Therefore, the elasticity of demand has become central in California in terms of both enhancing reliability and, more recently, reducing peak spot prices.

1.1.2. Demand response programs in California: towards the integration of demand-side management on the markets:

Within a decade, California made many efforts to develop energy-efficiency measures. It first adopted the Loading Order (2003), which gives priority to demand-side management over the conventional supply-side to respond to balance the system during peak periods and sets a target of 5% DR resources during peak periods.
The DR programs that were initially put in place progressively evolved. At first, they were restricted to the biggest retail consumers (>200kW) who failed to reach the DR target of 5% of the annual peak load (FERC, 2010). They were then expanded to include the smallest users as well. According to the study conducted by Faruqui et al. (2007), obtaining 5% DR in the U.S. is a realistic target, provided that a smart technology is adopted at a very low cost and distributed to at least 50% of consumers.

In 2010, California authorized the participation of DR products on CAISO's markets through the introduction of the Proxy DR. This participation was made possible by the prior distribution of smart-metering technologies, which are essential for controlling the supply of DR resources and ensuring their payment. IOUs, aggregators and energy service providers are allowed to offer bids according to the quantity of load they are able to cut. Participants are paid according to the difference between a baseline, determined by their previous consumption and intended to reflect what would have been consumed without the participation of DR in the program, and what was actually consumed. The threshold price to activate DR resources is set according to the Ferc Order 745. Unlike conventional "participating load programs," Proxy DR is not a real-time balancing solution and is thus only eligible on day-ahead spot and ancillary services markets (Wilker et al., 2010).

1.1.3. Limits of the demand response :

Two criticisms emerge regarding the Proxy DR. The first has to do with the methodology of the service evaluation, which is provided by the consumers based on a baseline. The second, which follows from the first, concerns the excessive incentive to turn to this kind of program at the expense of other, more-effective DR measures.
The studies conducted by Chao that have sought to comment on the use of the baseline indicate that this instrument could excessively encourage consumers to participate in DR programs that are rewarded according to the baseline. Some participants are actually able to receive a double payment due to the program operator's informational disadvantage (for details, see Chao (2010) and Chao (2011)). The studies of Ruff (2002) or Crampes and Léautier (2010) demonstrate the economic inefficiency of such a system. They advocate a system for allocating ownership rights on the erasable load that would remunerate generators for unsold energy in a profit-sharing mechanism.

In addition to the problem of double payment, the Proxy DR raises the question of price. While many of these programs can reduce scarcity prices, they do not allow for the sending of a correct price signal. Several authors argue that the spread of dynamic pricing with a view to homogenizing retail prices and wholesale prices, at least during peak periods, is a more efficient solution for smaller consumers (Rochlin, 2009, Bushnell et al., 2009).

1.2. Active system operators for a better integration of intermittent energies:

1.2.1. The quantity risk with fluctuating energies :

Just like any other type of energy, intermittent renewables have benefits and drawbacks, their main drawback being their intermittency. Their non-dispatchable nature places heavy constraints on the real-time management of the system.

The uncertainty regarding the generation of renewables leads to major costs both to ensure that enough backup capacity is available at all times and to balance the system. These costs are the main costs associated with the development of renewable energies (Clastres et al., 2010; Wiser and Bolinger, 2010). One of the main challenges of integrating renewable energies at the lowest cost is to reduce the gap between the forecasted generation and what is actually fed into the grid. Forecast programs achieve a high level of accuracy (Wissner, 2011), however, the rapid development of DG involves strengthening the tools for both grid management and decentralized forecasting. In addition, DG reinforces the uncertainty of fed-in volumes and makes it necessary to develop tools that allow for communication between the distribution grid operators and the decentralized producers.

1.2.2. Quality risk and ancillary services:

Fluctuating energies also represent a risk for the quality level of electricity because of its impact on frequency variations. Quantity and quality risks converge as regard the solutions available to limit them. As for quantity issue, maintaining the frequency values of power lies on back-up capacities able to guarantee reactive power is available.

Providing ancillary services is central to the development of these energies as they provide short-term coordination. An adequate level of flexible reserve capacities – that is, mainly thermal-based – able to provide these services is necessary for the integration of intermittent energy sources. This level determines the reliability of the system and involves increasing costs with a growing penetration of intermittent energies. However, the level of reserve capacity also leads to a risk of substantial carbon footprint damage.

As for centralized renewable energy, the widely intermittent nature of DG further reinforces the need to ensure effective short-term coordination and available backup capacity (Bayod-Rújula, 2009).

The development of SG can minimize costs related to balancing and ancillary services while increasing reliability and limiting CO_2 emissions. Within this context, increasing the demand-side through DR programs also appears as a new solution enabled by smart technologies. To establish the link between DR programs and integration of fluctuating energies, Hesser and Succar (2011) categorize the DR measures according to the level of responsiveness and flexibility they provide. They distinguish three broad categories of programs.

- Direct load control (DLC) programs that are suitable for the provision of primary reserves. DLC allows the operator to automatically control the consumption of certain devices. It is then possible to adjust these loads more quickly than through the modulation of a typical generation unit and for a very short duration. The advantage of DLC for this application is that it does not cause a loss of comfort for the end user and it reduces the end user’s risk of taking over the control.
- Dynamic pricing seems best suited to address problems of daily reliability and facilitate the provision of secondary control during peak periods.
- Finally, reliability-based programs are best suited to manage intermittency. Traditionally, these programs are only eligible to larger consumers with high load-reduction capabilities. The development of SG should be accompanied by the development of interruptible rates that are able to aggregate smaller amounts of

load cuts. Similarly, the minimum threshold of capacity required to be able to participate in these programs should decrease with the development of smart grids (Wissner, 2011).

A wider use of metering, bidirectional communication and remote control of consumers' equipment should therefore improve the overall efficiency of the system and facilitate the participation of DG in the energy market (Brandstätt et al., 2011).

1.2.3. Smart grids technology and the expansion of grid infrastructure:

The efficient development of renewable energies is strongly linked to their location, which does not necessarily correspond to the architecture of the networks. In Germany, the geographical constraint is marked by the concentration of areas that are convenient for the development of wind power in both the north of the country and offshore in the North Sea and by the concentration of areas that are suitable for solar energy in the south. Although this concentration makes it possible to reduce the costs associated with the uncertainty of predicting generation in a given area (Menanteau and Finon, 2004), it also induces the constraint of adapting and strengthening the transmission and distribution grids to receive and transport this energy to the areas of consumption. This strengthening focuses on developing transmission grids to connect wind farms with the rest of the system and developing interconnections to smooth intermittency.

With regard to DG, studies have shown this energy's long-term potential to reduce distribution costs (Cossent et al., 2009). However, the growth of DG also requires significant investments to be made in strengthening and expanding existing distribution lines. The growth of DG has also created a new challenge regarding bidirectional flows, which are increasingly capable of causing new constraints in the management of networks and of having potentially negative impacts on the security of the system (Lopes Ferreira et al. 2011; Brandstätt et al., 2012). Finally, the concentration of DG, coupled with its intermittency, may cause new problems regarding voltage and congestion management (Strbac et al, 2006).

In Germany, investing in networks and actively managing them are the critical pillars for the development of smart grids. Smart grids technology should enable an automated and remote distribution management. It should facilitate the detection, localization and restoration of disturbances on the lines and enhance the reliability of the whole system. In addition, the dissemination of information leads to new opportunities for long-term coordination, for a coherent, system-wide development of the grid.

The development of demand-side management measures should eventually be decided with a view to facilitating the integration of intermittent energy (Stadler, 2008; Cossent et al, 2009; Moura Almeida, 2010) and reducing the need for reserve capacities (Strbac, 2008 Wissner, 2011). DSM should also reduce the risk of congestion due to the rapid growth of renewables and limit the increase of energy prices, which are expected to rise from 10 to 20% in Germany (Buchan, 2012). Although the integration of intermittent and decentralized energy is the primary reason for exploring the possibilities of smart grids technology in this country, the issues of energy efficiency for reducing demand also call for greater control of the demand-side (Wissner, 2011).

2. Smart technology to improve the efficiency of markets

2.1.Real time pricing to enhance markets efficiency and improve the welfare:

The cases of Illinois and the United Kingdom are good examples to illustrate these benefits. Indeed, Illinois is a pioneer in terms of developing real-time pricing (RTP) for retail consumers in order to homogenize retail and wholesale prices. The development of RTP is the element that initially drew smart grids investments and research in Illinois.

As regards the UK, the principle of "supplier hub" supports an unbundled supply chain where competitive activities are clearly separated from regulated activities. In 1999, the UK completely unbundled its network activities from supply activities, which became fully competitive. In 2003, the UK expanded the unbundling to the metering activity. Formerly the duty of regulated DNOs, metering is now performed by independent suppliers and meter operators. This organization has a significant impact on the deployment of smart metering and DR programs. Unlike the models of organization that are in place in the other areas studied, only the distribution activities in monopoly situations are regulated. The funding for SG technology will therefore be divided between updating the networks, at the expense of the DNOs through their regulated rates on the one hand and implementing smart-meter technology and running DR programs according to business models that are specific to each independent supplier on the other hand.

2.1.1. Short term efficiency with RTP:

The price of electricity has been increasing for retail consumers in Illinois since the opening of the market in 1997 (Swadley et al., 2011). In Illinois, the value associated with RTP can be split in two categories. First of all, it is getting closer to the vision of Schweppe et al. (1988) of an efficient electricity market. Secondly, RTP is understood to be a tool for limiting the energy bill of retail consumers and thus increasing their surplus by eliminating the premium associated with fixed rates.

Theoretically, setting demand against price variations should promote more-efficient markets and an average spot price reduction.

Studies have sought to evaluate the effects of real-time pricing on retail consumers. Theoretical research of Chao (2010) concludes that using RTP at all retail sites would achieve optimum allocation with no deadweight losses. The theoretical work of Schweppe et al. (1988) is based on the introduction of an efficient competitive market to determine optimal electricity prices and quantities. According to them, such a market involves letting prices fluctuate depending on consumers' actual willingness to pay. In a context where all consumers are able to receive real-time information on market price variations, their demand is sufficiently elastic to price. Generation is remunerated at the marginal cost at any time and the market equilibrium is Pareto-optimal. Similarly, demand is elastic enough to eliminate system failures (consumers decide to cut their consumption according to the value they attribute to electricity), and supply and demand are always balanced.

Many different short-term benefits can be expected from price-elastic demand. The first is a reduction in the cost of energy, particularly during peak periods, when demand and energy costs tend to be relatively high. In 2012, the annual peak hour on the PJM market, where ComEd Illinois operates, mobilized more than 90% of available capacity (PJM, 2012). Limiting demand during these hours can de-stress the system and limit price increases. In addition, elastic demand reduces the exercise of market powers on the part of producers (Chao, 2010).

In their study, Holland and Mansur (2006) analyze data from PJM to estimate the short-term benefits of RTP in terms of reducing spot prices and the fixed rate, and in terms of reducing load. They reached four major conclusions.

- The greater the share of consumers subject to RTP, the greater the impact on reducing the peak load. They figure that subjecting all consumers to RTP can reduce the average peak demand by 4%. However, the model also shows a substantial increase in the base load by an average of 1.5%. This last point seems to confirm the remark made by Borenstein (2005), who stated that "RTP is not an energy-saving rate."

- In addition, they show that participation in RTP has a positive effect on the fixed rate, which decreases with increasing participation in RTP. The fixed rate seems to decrease by \$0.6/MWh with 100% participation in RTP.
- They also observe a positive effect on the average spot price, which also decreases depending on the number of participants. The average spot price seems to decrease by \$0.3/MWh with 100% participation. They observe a similar effect, though more pronounced, on the maximum peak spot price. A participation rate of 100% can reduce the maximum peak spot price sevenfold compared to without RTP.
- Finally, they also show that there is a \$0.4/MWh increase in the base price when all consumers are subject to RTP.

The Brattle Group study (2007) provides new evidence focused on the impact of short-term reduction of peak demand on the PJM market. A load reduction of 0.9% during the extreme peak period would lead to a decrease in energy costs of \$8 to \$25/MWh. Assuming that these extreme peak periods correspond to the 2.7% of the hours of the year when the load on the PJM exceeded 2,500GWh (2010 data), reducing the load by 0.9% is equivalent to saving 232,738MWh (PJM 2010). Assuming that this 0.9% is divided between the producers on the PJM according to their respective share in exchange, ComEd, which represents on average 14% of the annual load on the PJM, should achieve a 0.117% reduction in its peak load. This equates to a cumulative reduction of 4,536MWh, or a potential gain of between \$36,288 and \$113,400, for the 2.7% of the busiest hours of the year[3].

2.1.2. Long term efficiency with RTP:

RTP is able to provide benefits in the long term. Generalized to all consumers, RTP can theoretically lead to the optimal level of investment (Schweppe et al., 1988. Hobbs, 2001, Borenstein and Holland, 2005). According to the theory, optimum capacity is determined by consumers' willingness to pay during the peak hours, when prices are the highest and investments in capacity are most likely to be needed. By reducing peak demand, investments in additional capacity can be avoided and the system's long-term efficiency can be improved.

Borenstein (2005) has modeled the impact that RTP has on the use of peakers in the United States, and he makes several observations.

- His results indicate that low elasticity can potentially have a significant impact on the composition of the energy mix, with a significant decline in the number of marginal plants.
- In addition, RTP induces a slight decrease in the need for semi-base capacity and an increase in the need for base capacity. The study conducted by Borenstein and Holland (2005) indicates that increasing the share of consumers subject to RTP does not automatically lead to a reduction in the balance of the amount of installed capacity needed. Using a price-elasticity of -0.05, which is the closest assumption to the results of Holland and Mansur (2006) and to the results found by the RTP pilot project implemented in Illinois (-0.047), peak load capacities could be reduced by 30 to 60% if, respectively, 1/3 or all consumers participated in RTP.

2.1.3. The effects of RTP on the welfare:

The same study by Borenstein (2005) states that RTP has a positive effect on social welfare, including under the low price-elasticity assumptions. His results suggest that the welfare generated by the adoption of RTP is higher than that generated by the fixed rate. Continuing with the assumption of an elasticity of -0.05,

[3] Those gains refer to the decrease of energy on the spot market only and do not take into account the potential gains from PJM capacity market.

subjecting 1/3 of American consumers to RTP would increase welfare by nearly $200 million. This figure increases to $380 million if all consumers participate in RTP. However, the study also highlights several limits of this rate.

- The expected benefits of RTP increase at a decreasing rate as the proportion of consumers subject to this rate increases. For most levels of price-elasticity studied, the first third of consumers under RTP reaches more than half of the profits obtained with 100% of consumers at this rate.
- In addition, it seems that an increase in the proportion of consumers subject to RTP increases the benefits for non-participants. Conversely, the benefits for RTP participants decrease as the number of participants increases.

The study by Stephen et al. (2006), which focuses on the PJM market, also reached the same conclusions regarding the movements of consumer surplus based on the relative number of consumers subject to RTP and the fixed rate. Moreover, the study also observed the impact of RTP on producers' profit, depending on the technology used in the PJM market.
The study shows that, with 100% participation in RTP, there is a decrease in the annual average spot price as well as a 1.3% decrease of the average peak load, which is slightly higher than the average increase in the base load (0.8%). However, since the number of base hours in the model is four times the number of peak hours, the overall effect is dominated by an average increase in the annual load. To offset this effect, the average consumption during peak hours should be reduced by between 6 and 12%, or 30% to more than three times the level of average price-elasticity observed in the pilot project conduced in Illinois.
Using a price-elasticity of -0.1, the study estimates the movement of profit for the three dominant generation technologies on the PJM as follows:

- The profit of coal-fired power plants, used to cover base and semi-base load, is expected to decrease by 3 to 5% due to the average price reduction if, respectively, 1/3 and 100% of consumers adopt RTP.
- The profit of natural gas power plants is also expected to decrease, driven by the reduction of peak prices, average prices and peak load. It is expected to be reduced by 26% and 34% under the same assumptions of adoption.
- Finally, the profit of oil fired power plants, generally the last unit called upon to balance the system, is expected to observe losses of profit ranging between 47% and 59% under the same assumptions of adoption.
- In contrast, nuclear power plants and hydroelectricity, used to respond to base load, should marginally increase their profit by 1.5% if all consumers join RTP.

This study concludes that the widespread adoption of this pricing system should lead to an increase in social welfare on the order of $17 million per year on the PJM market.

2.1.4. Main Barriers to implement RTP:

Although the theoretical arguments in favor of RTP are significant, its application among industrial consumers has been relatively limited. Generally, the two major barriers to an effective transmission of wholesale prices to all consumers are the lack of political will (Holland and Mansur, 2006), for example to eliminate fixed rates, and the lack of means to communicate price variations (Stoft, 2002, Borenstein et al., 2002; Chao, 2010). In addition, some authors emphasize the technical difficulties related to the implementation of RTP due to the physical attributes of distribution grids (Joskow and Tirole, 2006).

The technological advances with regard to smart metering have paved the way for further dissemination of such real-time pricing to retail consumers. However, the ability to effectively bring RTP into general use is a central issue, and the expected benefits of this pricing system are largely dependent on the number of consumers that participate in it with respect to the number of consumers who pay a fixed rate. In addition, it seems that without investments in load management technology, it is difficult for retail consumers to achieve the energy efficiency that is to be expected from RTP (Borenstein et al., 2002. Borenstein 2005; Chao, 2010). Coupling RTP with load-management technology and direct feedback is one way of overcoming this shortcoming. With automation, consumers can set a threshold price above which their marginal propensity to consume is zero, and leave it up to the operator to control their consumption automatically in real time.

Empirical studies on this pricing system as it applies to retail consumers have also revealed certain limits. The study carried out by Barbose et al. (2005), which synthesized the impacts of the introduction of voluntary RTP, including ComEd's rate for small and medium-sized businesses and industries, revealed this scheme's lack of attractiveness. Five of the six experiments that offered optional RTP had a participating rate of less than 2%. Possible explanations for this include the complexity of RTP, the misunderstanding by consumers, the presence of more advantageous fixed rates, and the fact that the program is so new. The RTP program offered by ComEd since 1998 is one of the five cases with low participation. It had 40 participants in 2005, which is less than 1% of the eligible population. This participation rate is considerably different from the sixth case (Georgia Power Company), which recorded a participation rate greater than 40%. Despite the similarities between the two programs, ComEd's poor results are explained by the firm's ban on conducting outreach and marketing campaigns regarding its pricing programs.

In addition, another pilot project in Illinois, the Customer Activation Program (CAP), conducted between 2009 and 2011 by ComEd, provides important conclusions regarding the acceptance of dynamic pricing, in particular with regard to RTP. The lack of acceptance of remote control technology suggests that the residential segment, at least, is not yet ready to accept the widespread use of RTP and DLC (EPRI, 2011). Finally, the pilot project revealed that dynamic pricing must be embraced by consumers and should not be compulsory to effectively generate DR resources. This tends to support the introduction of such pricing systems on a voluntary and non-mandatory basis, as suggested by Borenstein et al. (2002). Also, it seems reasonable to assume that most consumers will remain at a fixed price, at least in the short term, though the effectiveness of RTP depends on its widespread acceptance (Borenstein, 2012).

2.1.5. RTP with risk premium on fixed prices:

RTP appears to be a rate that poses substantial difficulties regarding its application and that does no receive much interest from consumers. However, in the case of Illinois, a risk premium applied to the fixed price, which was not considered in the studies mentioned, further strengthens the implementation of RTP.
RTP in Illinois was designed to actually send accurate price signals to consumers while passing the price risk along to consumers. Exposing consumers to the wholesale market's price variations eliminates the premium, which, depending on how the prices change, makes it possible for the participants to potentially reduce their bill without even modifying their consumption behavior. Therefore, the existence of the premium in Illinois eliminates the uncertainty regarding the potential benefits for welfare and its unattractiveness for consumers, as it has been observed in several states (McDonough and Kraus, 2007).

2.2. Smart grids technology as a way to strengthen competition on retail market:

According to the British regulator, Ofgem (2008), "smart meters could have a materially beneficial impact on competitive supply by providing consumers with better information, thus making it easier to compare prices and making it possible to switch suppliers more quickly." The entire liberalization of the retail market is expected to bring about innovations that will, in turn, stimulate competition. As noted by Haney et al. (2009), a truly competitive retail market depends on innovations with respect to metering.

Allowing for easier access to information and enhancing the process for switching suppliers are two elements that will lead to increased competition in the British retail market (Klemperer, 1987a and 1987b; Mollard, 2007). Looking up information and comparing competing offers is a key step in the process of making a decision regarding a purchase. Making this information clear and easily accessible reduces the uncertainty felt by the consumer vis-à-vis different alternatives. On the one hand, information is supposed to induce a positive attitude towards the process for switching suppliers. On the other hand, reducing the time of switching suppliers is expected to have a significant impact on the transaction costs associated with the necessary procedure to terminate and start a new contract. According to estimates by Ofgem, the switching costs represent on average £100 per year per consumer (€124) (Ofgem, 2008).

In addition, the deployment plan should also allow for a second benefit, to eliminate the foreclosure risk from DNOs.

Ofgem's studies show that DNOs have had a tendency to abuse their dominant position ever since the opening of the metering market. This abuse has manifested itself in two ways.

- The DNOs made the switching process complicated and non-transparent. Commercial arrangements between the DNOs and the suppliers or authorized third parties (meter operators) sometimes included anticompetitive clauses such as price floors on new meters or yearly quotas on the replacement of meters (Littlechild, 2005). Some utilities have been fined by the regulator. In particular, National Grid had to pay a fine of £30 million for having hindered free competition (Ofgem, 2008).
- Also, until 2006, the transfer of technical data[4] from metering between the meter, the DNO and the supplier was not standardized between the 14 DNOs. Any supplier change implied that the new entrant should contact the DNO in charge of the meter to obtain the necessary access codes to operate the meter and ensure that the equipment was compatible with his offer. Gaining access to meter codes required a specific administrative procedure for each DNO that resulted in significant delays in the process of switching suppliers and led to many errors in the consumer databases of suppliers who dealt with several DNOs. Consequently, the expected efficiencies of the liberalization of the retail market and metering activities were severely reduced.

As of today, the time required to switch suppliers can be up to 28 days, which further increases the need to shorten the process for switching suppliers (Littlechild, 2005). The adoption of smart meters that allow for the automatic communication of the meter's technical data would improve this process and increase competition. Studies conducted by Ofgem (2008 & 2010) indicate that despite the potential savings that can be expected from an efficient supplier switch, some consumers remain reluctant to initiate the procedure and some developed a negative attitude towards it. The barriers that arose with the liberalization of metering activities contributed to limiting the emergence of an efficient retail market.

Hence, the decision to mandate a full deployment of smart meters by 2019 should achieve the twofold objective of creating a perfectly competitive metering market and eliminating the foreclosure risk from the DNOs.

3. <u>The role of regulators to give sound incentives for investments in smart grids technologies:</u>

Smart grids technology can induce significant benefits for the system as well as for consumers. As a consequence, regulators should play a key role in giving fine-tuned incentives to support its development.

[4] The technical data refer to the information necessary to operate the meters such as the access codes of the meters, the owner of the meter, its functionalities and so on. These data represent all the data necessary for switching supplier. They are opposed to metrological data which are the data related to the level of consumption over time, as recorded by the meter.

3.1. Main elements characterizing a smart grids oriented regulation.

Regulators and authorities play a key role in the development of the SG and the adoption of DSM programs. Although the objectives of SG technology may differ from one country to another, SG characteristics in terms of investment are widely shared. Three points can be put forward to determine the best regulatory instruments for investing in the technology.

- The development of SG requires upstream incentives for innovation and stable support for RD&D, which is notably demonstrated through the test beds that are implemented. Pilot projects must have the triple objective of testing the technology and the DSM programs to identify the best practices before implementing them for general use. On the other hand, the pilot projects are intended to encourage utilities to test the solutions they deem to be most effective, and to do so at the lowest cost to consumers. Finally, the pilot projects must provide feedback to the regulator, who must provide a more accurate assessment of the utility's future deployment plans. Evaluating the pilot projects' costs as well as their methodology is an asset for limiting the information asymmetry between the regulator and the firm.
- Secondly, the decision to adopt SG technology involves very capital-intensive investments whose benefits are often diffuse and attainable over the long term. The role of regulation is to encourage the firms to behave cost-efficiently. Limiting adverse selection is paramount. Again, the regulator's considerable informational disadvantage makes it necessary to adopt mechanisms for sharing the informational rent while limiting managers' moral hazard. In addition, the issue of long-term benefits involves adapting the incentive for cost-efficiency over a period that is long enough to allow the firm to take advantage of the benefits of its efficiency and short enough to allow the firm to share part of the rent with the consumer.
- Finally, the adoption of SG technology must improve the overall efficiency of the system. It is therefore appropriate to encourage a higher level of performance and quality with its development.

3.2. Boundaries between regulated monopolies and competitive markets:

The four areas studied here have conducted experiments for both SG technology equipment and consumer activation. The first observation to be made is that the terms of pilot projects and the adoption of smart-metering technology rely heavily on the different organizational supply-chain models. The boundary between regulated and competitive activities largely modifies the regulator's scope. Thus, the California regulator, CPUC, which operates in a vertically integrated industry with regulated retail supply activity, has a much wider scope than the UK regulator, Ofgem, which only regulates the distribution activity as metering and supply activities in the UK are completely unbundled and open to competition. The scope of the ICC in Illinois focuses on both distribution and metering activities, although this state opened retail supply to competition. Finally, Germany partially unbundled its supply activities from its distribution activities in accordance with the European Directive 2003/54/EC. Only the largest utilities (>100,000 consumers) are actually unbundled. Also, similar to the case in the UK, the metering activity is deregulated in Germany, but this opening is partial as it also only concerns the largest utilities.

Given these organizational models, only California and Illinois implemented DSM pilot projects whose costs were passed through in the tariffs. Tracking the expenditures and steps of the pilot projects has served as the basis for current deployment plans. Germany and the UK prefer financing through public-private partnership.

Moreover, the four areas studied are involved in upgrading their networks through SG. This commitment is reflected in the regulatory models, most of which have recently undergone major changes, particularly to facilitate the development of SG.

3.3. Insights on the regulatory models used in the four areas studied:

Three of the four regulatory models adopted by these states rely on incentive-based regulation through the use of a revenue cap (Table 1). This model has two main advantages.

- The first concerns the limits of price cap regulation in terms of encouraging energy efficiency. A revenue cap erases the price cap incentive to maximize sales and is accordingly considered to be a "DSM friendly" incentive (Comnes et al., 1995; Moskovitz & Swofford, 1992; Marcus & Grueneich, 1994). The revenue cap formula is quite similar to price cap except that consumers are the only ones to bear the volume risk as opposed to price cap, where this risk is borne by the firm (Saguan, 2007; Saguan and De Muizon, 2007). Under price cap regulation, the firm takes on the risk that it will not cover all of its costs if demand is lower than expected. Under a revenue cap, the authorized revenue received by the utility is set ex ante by the regulator and no longer depends on sales. If demand is lower than that expected ex ante, there will be a rate increase.
- The second advantage of the revenue cap has to do with the limits of traditional cost of service (CoS) regulation. CoS regulation has been widely criticized (Sappington, 1994). It eliminates any incentive to produce efficiently as the firm is ensured to cover all of its costs (Hauge and Sappington, 2010; Jamasb and Pollitt, 2007). Moreover, the firm is not able to keep the benefits from its efforts, which leads to the problem of moral hazard associated with CoS regulation and potentially to gold plating (Averech & Johnson effect) (Laffont and Tirole, 1986; Baron and Besanko, 1987). Incentive regulation appears to be a solution to encourage firms to improve their efficiency. Under this model, a regulatory period is fixed and the allowed price or revenue is capped at the beginning of the period. It is then adjusted in accordance with an exogenous inflation index and an efficiency factor (X-factor) determined by the regulator. The X-factor is supposed to lower the revenue cap level over the course of the regulation period in order to induce greater efforts to minimize costs. Firms are given the incentive to reduce their costs during the period by being allowed to keep the difference between the price or revenue cap and their level of spending as profit. Any improvement in cost efficiency translates into more profit for the firm. The moral hazard problem identified in the cost plus regulation is eliminated (Joskow 2006a and 2008). However, incentive regulation is very likely to lead to adverse selection problems, where the consumer does not benefit at all from the firm's improved efficiency. Therefore, incentive regulation is generally associated with price -or revenue- sharing mechanisms (sliding scale) that are used to avoid excessively high or dangerously low revenues (Laffont and Tirole, 1993; Comnes et al., 1995; Joskow 2006a, 2008). This mechanism may be more or less complex and may act on all or part of the costs.

The three revenue-cap models go hand in hand with a revenue-sharing mechanism. California has established a mechanism for progressive revenue sharing, that is based on the efficiency gains realized on capex. The share of revenue redistributed to consumers decreases as the firm's rate of return (RoR) moves away from the RoR benchmark that was determined ex ante. A deadband of +/- 0.5% is provided where no sharing is expected. Then a boundary is fixed as regard the variation rate of the RoR in order to suspend the sharing mechanism when the variation reaches +/- 2% from the RoR benchmark (CPUC 2005). ComEd in Illinois also uses a sharing mechanism based on its rate of equity (RoE) perceived over the capex. Unlike California, the sharing mechanism is not progressive but total as soon as the RoE variation exceeds +/- 0.5% with respect to the RoE determined ex ante. A negative variation of the RoE according to the benchmark that exceeds -0.5% translates into a charge applied on consumers. Conversely, an increase above 0.5% is translated into a credit for consumers. Although this second model further limits the informational rent of the firm, it also increases the risk borne by the consumer and further reduces the incentive to achieve large efficiency gains.

The British model is the one that implemented the most sophisticated model by applying a sharing mechanism to both its capex and opex. The first mechanism for sharing informational rent related to the capex is supported by its contract-menu mechanism as proposed by Laffont and Tirole (1993). This sharing forces firms to conserve only a portion of any unused authorized capital revenue. Likewise, it ensures the firms that would have the most difficulty in predicting their investment needs to bear only part of the capex spent beyond the authorized amount. The sharing mechanism applies to these differentials and makes it possible to divide up unspent or exceeded amounts between the firm and the consumer symmetrically in proportions that are specified for each of the DNO's holding companies. Since 2010, the UK has expanded the sharing mechanism to its opex in order to avoid the effect of substitution between capital and maintenance & operation investments. This makes it possible to apply the same incentive for all types of efficiency gains.

Only Illinois implemented performance-based regulation. This model differs from conventional incentive regulation in the sense that no incentive mechanism to reduce costs over time is established. The price or revenue level is not associated with any efficiency factor supposed to optimize investments and link the firm's profit to its level of effort. The use of true up accounts ensures that ComEd can cover all of its expenses unless they are deemed "unreasonable" by the regulator. The new framework is designed primarily to reduce the informational rent of firms by securing, to some extent, their revenue with the sharing mechanism mentioned above. In addition, as the name suggests, the regulation incorporates a number of performance indicators that are supposed to encourage the firm to improve its quality by linking its level of revenue to performance targets.

Performance indicators are also set up in the other three models. They must provide a solution to the problem of reduced quality that is associated with incentive regulation. Indeed, incentive regulation is associated with a loss of quality issue (Sappington, 2003; Jamison 2007 Joskow 2008). Ter-Martirosyan and Kwoka (2010) mention that it leads to longer periods of outages due to maintenance expenditures that are kept relatively low for the sake of higher profit. Performance-based regulation, also called output regulation, appears to be a tool for preserving incentives for reducing costs without lowering operation and maintenance expenses and without deteriorating the quality of service. It makes it possible to vary the profit of utilities according to their level of performance, regardless of their level of sales or revenue (Shleifer, 1985; Vogelsang, 2006).
The target level of efficiency for each indicator is determined by benchmark and is associated with a bonus/malus mechanism. This provides an incentive not to underinvest, while limiting the regulator's informational disadvantage (Laffont and Tirole, 1993; Shleifer, 1985, Lowry and Kaufmann, 2006). In most cases, the SAIFI and SAIDI are included as a key indicator of performance. According to Ter-Martirosyian (2003), incentive regulation (price cap) usually leads to an increase in these indicators, which explains the necessity for controlling these outputs.

California is the state that developed the most complete range of metrics, including 10 indicators based on smart grids technology deployment (AMI + network equipment) and indicators based on network stress during peak periods. Germany has established an unmet-load indicator that measures the operating efficiency of the network in the presence of intermittent energy. Illinois and the UK are more focused on adopting indicators that reveal the quality of supply service and customer satisfaction.

Finally, the regulation periods span from 3 to 10 years, depending on the utilities. The length of the regulation period is central to the effectiveness of the incentives. As pointed out by Saguan (2007), the duration of the regulatory period profoundly modifies the tradeoff between incentives for improving efficiency and rent extraction. With a short regulation period, the firm's incentives are similar to those of a CoS.
On the other hand, a long regulation period allows the firm to reduce its long-term investment costs and anticipate longer-term investment returns while reducing the risk of uncertainty that they imply. In addition, it strengthens the incentives for quality improvement. However, a long regulation period also increases the uncertainty associated with regulatory risk (Brunekreeft and McDaniel, 2005).

In most of the cases studied here, the regulation period is five years. According to Williamson (2001), a period of five years allows the firm to retain 29% of the informational rent that it would have received under an infinite price cap.

3.4. Recommendations for fine-tuned regulatory mechanisms adapted to smart grids technology investments:

The regulatory models studied here have advantages and limitations with respect to the development of SG. First, it appears that Illinois is the state with the least-effective regulatory model. Although significant improvements in incentives have been recently adopted (abandoning CoS in 2012 for performance-based regulation), the rent extraction mechanisms remain too weak to give the firm an incentive to be more cost-efficient. It can be assumed that the development of smart grids technology in this state will be suboptimal. Moreover, this model is based on a regulation period of ten years, which allows all the more informational rent to be kept by the firm.

Californian utilities, on the other hand, face a shorter regulation period, ranging from 3 to 5 years. While 3 years can potentially be associated with a high investment risk for the company and can potentially reduce its effort to become more cost-efficient, 5 years seems to be an average length for a regulation period. However, as pointed out by the UK, the massive investments and innovations related to SG and that are necessary for modernizing the grids increase the risk borne by the regulated firms. This is the reason why the UK decided to extend the regulation period for DNOs from 5 to 8 years by 2015.

The UK appears to be ahead of the others when it comes to the regulation mechanisms that it has adopted. In particular, the UK was a pioneer in adopting the menu of contract mechanism with sliding scale. This combination represents the tradeoff between minimizing information asymmetry and maximizing incentives for improving efficiency. However, strong measures to reduce information asymmetry and rent sharing could be further supported with the adoption of more stringent performance goals, especially since smart grids technology is expected to allow for better grid operation.

This last observation goes for Germany as well, since its energy policy is expected to create strong incentives for maintaining a high level of quality. In addition, Germany is the only country that did not adopt a revenue-sharing mechanism. German DSOs are subject to a frontier-based benchmark with a capped efficiency target that allows for +/-40% variation. Beyond this cap, firms are not penalized nor rewarded. However, any efficiency gain or loss achieved between these boundaries is faced only by the firm.

Finally, in terms of performance incentives, it seems that California adopted the most comprehensive set of indicators for enhancing the level of quality expected from the adoption of SG technology. This is partly explained by the fact that California is one of the first movers in developing SG. Such indicators should be spread in order to support the modernization of networks.

Table 1 : Benchmark of the regulation models and regulatory instruments.

	California	Germany	Illinois	UK
Regulation moedel	Revenue-cap	Cost of service until 2009 and Revenue-cap since then.	Cost of service until 2012 and Performance-based since then.	Revenue-cap
Incitive for cost efficiency	Yes through X-factor	Yes through X-factor	No	Yes, through X-factor + menu of contracts applied to capex + Equalizing incentive applied to opex.
Régulation period	3 to 5 years	5 years	10 years	Currently 5 years, then 8 years from 2015.
Revenue sharing mechanism	Progressive sliding scale mechanism for efficiency rent extraction, based on capex, including deadband.	No	Sliding scale mechanism for efficiency rent extraction based on the RoE including deadband.	Symmetrical sliding scale mechanism for efficiency rent extraction based on totex.
Performance-based Index	- SAIFI. - SAIDI. - MAIFI. - Number and share of consumers facing more than 12 outages per year. - System annual load factor. - Number and nominal capacity of DG units connected to the grid. - Total monthly DG energy fed-in the grid. - Number and share of distribution lines equipped with remote control equipments. - 9 performance-based metrics for AMI deployment. - 2 storage and electric vehicle development metrics.	- SAIFI. - SAIDI. - *Unmet load*.	- SAIFI. - SAIDI. - Number of consumers exceeding reliability targets. - Decrease of billing costs. - Decrease of consumptions on inactive meters. - Decrease of theft. -Decrease of unpaid bills.	-SAIFI -Share of disconnected customers per year. - Customer satisfaction. - Losses reduction.

Conclusions:

Time has passed since the first efforts made to develop smart technology and to trigger smart consumers. Both the U.S. and the European Union are involved in ambitious smart grids projects and we, as consumers, will sooner or later increasingly be involved in our respective power systems.
The results drawn from the pilot projects led worldwide lead unanimously to the same conclusions; demand response resource brings major benefits in improving both system reliability and markets efficiency.
New mechanisms and products developed by load serving entities or system operators have been rapidly emerging for a couple of years now. Institutions are showing an increasing interest in driving the actors to undertake the best actions disregarding their own private interest. However an effective integration of such a resource depends on two main elements: the equipment of consumers in smart technology and the definition of clear and adapted rules.

Accordingly, regulatory authorities have to play a key role in making the system and markets converge with the demand side. Alongside with smart instruments, smart mechanisms and regulation are appearing. However, questions are arising as to whether or not the initiatives that have been adopted are the most suitable and how their implementation effectively integrates into a wider regulatory and organizational environment. This paper demonstrates that what is often considered as the best option in the literature is rarely implemented. Indeed, the gaps remain sometimes large between the optimal regulation for smart grids technology adoption and what is actually implemented. The reasons to explain this are numerous: lack of feedback, lack of political/institutional will, risk of inertia regarding consumers' behaviour changes, and lack of a truly integrated view of a smart system.

Of course, a trade-off has to be established between the long-run costs of the measures to be adopted and their marginal impact. What seems clear, however, is that the complexity and diversity of power systems impede an easy decision-making process regarding investments and regulation.

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