CHANGING THE REGULATION FOR REGULATING THE CHANGE

Innovation-driven regulatory developments in Italy: *smart grids, smart metering* and *e-mobility*

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Executive Summary

For a long time considered as technologically mature, electric systems are now facing a period of rapid changes. The advent of smart grids, smart meters and electromobility is creating new challenges not only in terms of technological innovation but also in terms of economic and technical regulation. This paper focuses on the latter and, taking Italy as a case study, analyses how energy regulation can change to embrace and to stimulate innovation in power systems and electricity markets.

Accordingly, we describe the most relevant and recent regulatory decisions on technical innovation, keeping the focus on the regulatory process. Indeed, the Italian case is interesting for a number of reasons, that go beyond its well-known leadership position in the area of smart metering and the related mandatory introduction of Time of Use pricing for a large share of consumers. Italy is facing a dramatic increase in RES (Renewable Energy Sources) penetration: several regulatory developments were introduced to favour the integration of intermitted generation and the transformation of distribution grids in active networks, capable of accommodating DG (Dispersed Generation) units. The paper details the regulator's commitment to provide the right economic incentives for distribution network operators to invest in demonstration projects for smart grids (and, in perspective, for a wide roll-out of active grids, on the basis of an output-based incentive scheme). Significant steps forward have also been made to ensure an efficient development of Electrical Vehicle recharging infrastructures.

We found that several lessons of experience can be drawn from this case study and we believe them useful for other national regulatory authorities. By looking at the regulatory process, more than at the specific solutions and mechanisms adopted (often related to country-specific factors), the main messages are the following.

- Power system will be profoundly impacted by technological innovation and regulators should invest in building a robust and up-to-date technical knowledge over which to ground their proposals;
- Key indicators are necessary to cope with RES integration: this paper presents two of them (Reverse Power-flow Time, RPT, and P_{smart}) that can be used elsewhere;
- In an initial phase, regulators can get valuable information from demonstration projects, that are an intermediate step between laboratory tests (and prototypes) and full deployment of innovative solutions;
- Moving to output-based regulation is the efficient choice for full deployment of innovative solutions;
- The role of regulation is crucial in ensuring that value for the customers is extracted from innovative investments (such as in smart metering);
- Innovation creates new challenges: regulators have to identify the new border between regulated companies and the competitive market (for instance in the case of electromobility)
- Integration of the different innovations (smart grids, smart metering, electromobility and storage) is probably the hardest challenge for regulators in the next future.

To make this case study more easy to read, all technical details are given separately in six different Annexes, each devoted to a specific topic more briefly mentioned in the main body of the paper.

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1. Introduction

After liberalisation, a second, large wave of change is going to sweep European power systems: like a "perfect storm", technical innovation is coming over the electricity sector. For a long time considered as technologically mature, electric systems are now going through a new, far-reaching transition, the "smart" revolution [1], [2], [3].

The most well-known aspect of this innovation storm are smart grids: electric networks, especially distribution networks, need to move from a "passive" to an "active" design and operation, under the high pressure of booming dispersed generation directly connected to medium and low voltage networks[1]. The smart revolution, however, does not stop at smart grids: it goes right to the very heart of the electricity system. Under the "smart" umbrella a number of profound changes are envisaged for the next years. First of all, smart meters, i.e. electricity meters that are able to collect data on energy consumption, power absorption, local voltage and other electrical parameters (including power factor, safety checks, etc.) and to send them automatically to a remote center, from which they can also receive instructions for remotely-controlled operations. Secondly, smart customers, i.e. end-users that become new actors in the market by responding to market price signals and defeat the classic paradigma of totally inelastic demand. This is possible also thanks to new uses for electricity and, in particular, to electric vehicles that could become a distributed system for energy storage, capable to contrast the intermittency of wind and solar generation. In summary, the challenges for future electric networks are indeed immense: a recent study conducted on behalf of the Office of the Gas and Electricity Markets (OFGEM, the British regulatory authority) has defined "unprecedented" the degree of innovation that electricity systems will either have to face up to in the very next future or that they are in fact already in part experiencing in some countries [4].

Indeed, the assumption that the electricity sector was technologically mature (and that only residual space was left for innovation) has pervaded the economic and technical regulation since liberalization. The preference accorded to price cap regulation is probably the clearest evidence of this, let us say, traditional assumption. Twenty year after, it is now evident that innovation is a new challenge not only for electric network operators or for energy utilities – because of the investment needs – but also for regulators and for their knowledge and tools (requirements and incentives). To cope with the upcoming changes – or, for some countries, with the ongoing changes – a few regulators have already started to search for and to consider new regulatory tools [5]. Among them, is the Italian regulatory authority (Autorità per l'energia elettrica e il gas, AEEG).

This paper is a case study on Italy: the objective is to outline the regulatory changes that the "innovation storm" has already inspired, together with the regulatory challenges still to come. In addition, the Italian experience is also the opportunity to discuss the lesson learned, under a broader, European-wide framework. Indeed, the Italian case is interesting for a number of reasons, among which, the most well-known is its leadership position in the area of smart metering. Thanks to the combined initiative of *Enel distribuzione*, the largest distribution company, and of the regulator (for the customers served by all the other distribution operators), Italy is the only country in the world with a full deployment of smart meters at Low Voltage (LV) level (more than 33 millions smart meters installed and working). This has also conducted to the largest experiment so far with Time-of-Use (ToU) electricity prices (mandatory for more than 25 millions household customers and for more than 3 millions small business customers). Apart from smart metering, the Italian incentive regulation has recently seen other remarkable developments. One was driven by the regulator's commitment to provide the right economic *stimula* for grid operators to invest in smart grid demonstration projects; the other is aimed at developing demonstration projects for Electrical

[1] Generation connected to the grid can be distinguished between large and medium/small-scale and between RES and Combined Heat and Power (CHP) technologies. Only the medium/small scale-units (<10 MVA) of both RES and CHP are considered as dispersed generation.

Vehicle (EV) recharging infrastructures –in the European Union (EU), this is the first initiative of this kind initiated by a national regulatory authority.

In other words, we believe that Italy is an interesting case for understanding how regulation (especially network regulation) can change, sometimes rapidly and radically, to embrace and to stimulate technical innovation. At the same time, we believe that solutions experimented in Italy are not to be exported as they are. Numerous country-specific factors have influenced the regulatory decisions and are to be considered carefully when transferring the same ideas in a different system. Nonetheless, in describing the most relevant and recent regulatory decisions on technical innovation, we are convinced that there are useful lesson to be learned from a country-specific case. In particular, our intent is to focus on the regulatory process, which goes from knowledge building to consultation and then from ruling to implementation and enforcing. Indeed, there is more to learn, about the building blocks of a regulatory framework, from this process than there is from the specific solutions and mechanisms that were adopted.

Accordingly, Section 2 briefly introduces the Italian electricity system, outlines a few regulatory and technical aspects that are useful to put this case-study in context and delineates the current focus of regulation in the new scenario. Sections 3 to 5 describe the main regulatory initiatives in the areas of smart grids, smart metering, and EV recharging infrastructures, devoting particular attention to the past three years (2008 – 2011) and, at the same time, delineating what lies ahead. Finally, from this country-specific experience we derive a number of lessons learned (Section 6). To keep the focus of the paper on the regulatory process, technical and regulatory details on these three areas are collected in six Annexes at the end of the paper. Namely, Annex A deals with the transmission networks and the influence of RES on power system operation and dispatching; Annex B deals with the DG integration on distribution network and the Nodal Hosting Capacity approach; Annex C deals with the Italian incentive regulation for smart grids; Annex D deals with the demonstration projects for smart grids and the development of ICT for an innovative protection, automation and management of distribution networks; Annex E deals with the development of Smart Metering and mandatory Time-of-Use implementation in Italy; and finally Annex F deals with the Electromobility.

2. The Italian context and the new challenges

In 2010, electricity demand in Italy was above 300 TWh, 86% of which was covered by national production, while imports accounted for the rest. Out of these 300 TWh, 75 TWh were produced by Renewable Energy Sources (RES), that saw a 9% increase with respect to 2009. A remarkable growth was registered in wind production (+29,1%), biomass /waste (+21,6%) and photovoltaic (almost 1600 GWh, compared to 677 GWh in 2009).

As regards customers, four years on from the opening of the electricity market for small consumers, the cumulative switching rate is around 17% for domestic users and 36% for small enterprises. This means that about 5 million households and 2.7 million small businesses have chosen their supplier in the free market. Final users that have signed a contract with a retailer constitute, in volumes 2010, 67,8% of total demand; the others (mostly household and small business customers, for a total of about 27 millions LV customers) have economic and contractual conditions defined by the regulatory authority (they have access to a form of ”universal supply regime”).

As for the distribution sector, *Enel Distribuzione* is the largest operator, with 86% of the total volumes, followed by *A2A Reti Elettriche* (4%), *Acea Distribuzione* (3,4%) and *Aem Torino Distribuzione* (1,3%). The other operators (seven of whom are comparatively large) hold marginal quotas. As regards the transmission network, after the national blackout in 2003, the Independent System Operator (GRTN) that coordinated, controlled and monitored the operation of the electrical power system, was substituted with a fully unbundled Transmission System Operator (TSO, Terna), that is both the owner and the operator of the transmission grid.

In terms of network regulation, a price-cap regime was introduced in the year 2000 (with a four year tariff period) and modified in 2004 by terms of law. An efficiency factor is now applied to operating costs, while capital expenditures are passed through to consumers with an average lag of eighteen months. Moreover, the regulatory authority has introduced a series of input-based incentives, in the form of an increase in the Weighted Average Cost of Capital (WACC), aimed at promoting strategic investments, in electricity transmission first, then in electricity distribution and finally in gas infrastructures as well.

In general terms, with the regulatory policies designed so far, the Italian regulator was focusing on extracting most of the benefits from liberalization: passing cost savings in operating expenses to final consumers, ensuring an efficient level of investments in the networks, stimulating competition at the wholesale and retail level, as well as increasing the level of service quality. As a result, for instance, the Italian distribution networks present an extremely high level of automation (on average, three secondary stations out of five are remotely controlled), mainly because of the incentives provided by service quality regulation[2]. In this regard, the initiatives of network operators have also played a prominent role: the project "*Telegestore*", boldly conceived of by *Enel Distribuzione* in the year 2000, has already brought smart meters to over 30 millions of LV customers (to date the only initiative of its kind on such a vast scale in the entire planet).

As of today, regulatory policies need to focus on new problems, stemming from the need to meet long-term, European-wide objectives. In order of urgency:

- Integration of RES, especially as dispersed generation (DG), in electrical networks: these intermittent production units are also expected to contribute not only to the European targets for RES penetration but also to the security of the overall transmission system (today this contribution is absent or negative) – smart grids;
- Introduction of techniques for load control, thanks to intelligence systems located at the point of conjunction with the customer and its end-uses – smart meters;
- Introduction of opportunities for all customers to become active participants in the electricity market, using electronically conveyed information related electricity prices (again smart meters) and adopting new technologies (electromobility).

Before proceeding, it is important to recall that the enabler of all these changes is ICT (Information and Communication Technology). Even if only briefly mentioned in the rest of this paper, communication systems have a crucial role in this process of reform. They also pose additional challenges to energy regulators, forcing them to interact more closely with other public authorities and technical bodies.

3. Smart grids: towards an output-based incentive regulation

As a member State of the EU, Italy is subject to the "20-20-20" targets or, in other words, it is committed to achieve by 2020 a large increase in electricity generated by RES – up to 20% of total electricity production, a significant reduction in Green House Gas (GHG) emissions, as well as a substantially higher efficiency in energy end-use.

[2] The reward and penalty scheme for continuity of supply was firstly introduced for the regulatory period 2000-03 for distribution networks only, and then regularly renewed every four years, as well as progressively enlarged to the transmission system [6], [7]. This regulatory scheme has drawn the attention of many academics and practitioners – mainly in Europe but also in other regions of the world [8]. Although country-specific factors could have played an important role, nonetheless the analysis of the Italian experience provided important insights to regulators who were facing similar challenges in different environments [9].

With regard to the first of these targets, Italy stands out, among the EU member States, as one of the countries most impacted by the increase of distributed and intermittent generation, i.e., electricity production that is dependent on climatic or other conditions – and, in particular, by the availability of wind and sun. In fact, due also to generous State incentives [10], the share of RES generation is already beyond the European average.[3]

The impact of RES on electric systems can be evaluated at a glance by looking at hourly data. There are days and areas in Italy (for instance, daytime hours of sunny, summer Sundays in the Southern regions), when RES generation (essentially, wind and photovoltaic) can supply more than two thirds of the total demand.

Wind farms in Italy at the end of 2010 are a few less than five hundreds, with a gross maximum capacity equal to 5814 MW; the energy generated is around 9 TWh. Most of wind parks have a maximum capacity greater than 10 MW and are connected to the transmission network at the HV level. A few regions host the vast majority of wind parks: the southern regions and the islands account for nearly 90% of wind power generation in Italy. The impact of wind parks connected to transmission networks is addressed in details in Annex A.

Photovoltaic plants (PV) already amount to more than 10 GW of installed capacity, in a country with less than 60 GW of peak demand. Further, PV installations are more concentrated in the Central and Southern regions, where the load is lower than in the North. The growth rate of installed capacity is impressively high. Only three years ago, at the end of 2008, PV installed capacity in Italy amounted to 0.4 GW and it is now expected to reach 11 to 12 GW by the end of 2011 (25 times the initial capacity in three years).

The significant level of energy injected by wind farms has already impacted the Italian system, both from a technical and from a regulatory standpoint. Nevertheless, the impact on the operation of the transmission network has been managed properly by the TSO, by means of special requirements in the national Grid Code[4], with the support of the regulating authority (see Annex A). For the sake of simplicity, it can be stated that the transmission network (thanks to a meshed topology, and to the presence of a complete and state-of-the-art control system) has already an active behavior. Large wind farms may have a significant influence on power system operation that are related to unpredictability and intermittency of the primary source; this requires that RES output is re-dispatched according to system needs.

On the other hand, high RES penetration, especially in distribution networks (where almost all the PV plants are connected, more than 99% of the total number of units), requires changes on several fronts of the technical and economic regulation, in order to efficiently integrate this production in the network. AEEG started addressing the issue a few years ago (between 2007 and 2008) with a research project focused on the Nodal Hosting Capacity (NHC) of Italian distribution networks at medium voltage (MV) level.[5] This research was commissioned by the regulatory authority to the Politecnico di Milano (Energy Department), and was based on a large sample of data on distribution network characteristics (detailed per single bus), created by means of a formal information request specifically made by AEEG to Italian Distribution System Operators (DSO). The project results were lately published as part of AEEG Resolution ARG/elt 25/09 [11] (all details can be found in Annex B).

The NHC research project was particularly important as it enabled the regulator to identify a key-indicator of network "activeness": the percentage of time in year during which power flows from

[3] According to the most recent IEA outlook, the "OECD-Europe" region, with its 5% of intermittent generation in 2010, is already the area with the highest portion in the world of electricity generation that has no guarantee to be available when needed to meet the demand [3]. According to the same outlook, Europe will keep its record position in the next decades (IEA estimates for OECD European countries more than 25% of intermittent generation in 2050).
[4] It has to be highlighted that the Italian Grid Code (issued by TERNA) is subject to the approval of the AEEG.
[5] In Italy MV is between 1 and 35 kV; ordinary MV levels are 15 and 20 kV.

medium to high voltage (Reverse Power-flow Time, RPT). This inversion of flow occurs because of a surplus in power production, i.e. a larger amount of power is injected in the distribution network by DG, compared with the load demand in that fraction of time. The RPT indicator was used on a short time later (in 2010), as one of the main parameters for assessing smart grid demonstration projects. In other words, in terms of regulatory development, a “knowledge building” phase provided the basis for and was soon followed by a “demonstration” phase.

The approach to the demonstration phase is designed around an input-based incentive scheme, to be awarded, on the basis of a competitive process, only to a limited number of projects. According to AEEG Resolution ARG/elt 39/10, selected smart grid demonstration projects can benefit from an extra remuneration of capital cost (a 2% extra WACC in addition to the ordinary return) for a period of 12 years [12]. The incentive is funded through the network tariff and it was awarded to eight proponents.

The selection of these projects (as of now, all running) was conducted, on behalf of the regulatory authority, by a committee of experts. In particular, in order to participate in the selection process, demonstration projects had to meet three main requirements, defined by AEEG:

- in the electricity distribution area covered by the demonstration project, a reverse power-flow must occur for at least 1% of the time in a year;
- all possible solutions are to be tested on real MV networks with both end-users and active users (loads and generators);
- only open and non-proprietary communication protocols are to be used for any communication applications involving network users.

The first requirement was aimed at selecting projects that would address a problem emerged from the NHC research: inverse flows, in the context of the existing MV networks, put at stake the protection system and the voltage regulation scheme currently adopted [13]. The second requirement was introduced to focus on real innovation opportunities for the networks: the MV level was intentionally chosen because 75% of renewable plants[6] are currently connected on MV networks (a second selection process is under study and it should be enlarged also to LV networks). The third requirement focuses on a key issue for smart grids: only standard protocols, of an open and non-proprietary type, allow a free market to develop and thus minimise the costs as well as the technological complexities that users of the intelligent network will have to face in exploiting the benefits of smart grids.

It is well known that a generous remuneration of capital expenses exposes the regulator to the risk of inefficient investment choices made by the regulated utilities. This is why the selection requirements were carefully defined. Similarly, also the selection process was rigorously designed and the comparative assessment of the different proposals employed a key-performance indicator , which considered both the benefits and the costs of the projects (for all details refer to Annex C). The quantitative indicator of benefits was particularly innovative and was called P_{smart}. The first objective of smart grids should be to remove the network constraints so as to accept a larger amount of DG, through a number of ICT based solutions (see Annex D). The indicator P_{smart} measures the maximum amount of energy that can be injected into the network from DG, with no network expansion and in secure conditions both for the local network (voltage, currents) and for the entire system (frequency thresholds of the Interface Protection Relays).

After this demonstration phase, what is next in the regulation of smart grids? Clearly, the next phase is smart grid “deployment” (where motivated by the high penetration of DG, especially RES-based); for reasons of efficiency, the Italian regulator is eager to move towards an output-based regulation. Firstly, a selection process of individual projects on a larger scale would be excessively

[6] In terms of energy injected into the grid.

time consuming; secondly, output regulation is less prone to inefficiency in investments decisions made by DSOs.[7]

The regulator's first thoughts on an output-based incentive scheme for full deployment of smart grids are outlined in a recent AEEG consultation document [14]. These ideas built on the previous steps and make use of the two key-indicators already mentioned (*RPT* and P_{smart}). In addition, a third indicator is proposed, to penalise DSOs when RES supply is curtailed for security reasons (energy from RES generation that cannot be injected in the network, due to curtailments in generation that occur even after the "smartening" investment).

In summary, the recent Italian regulatory developments had a strong focus on active grids. This is consistent with the final objective of enabling networks to host a higher share of RES: integration of renewable energy sources into the electricity sector is the principal benefit expected from smart grids, at least for the time being. Nonetheless, European goals for 2020 also necessitate the active involvement of end-users connected to energy networks. This leads us to introduce two other important issues recently addressed by the Italian regulation: smart meters and electromobility.

4. Smart metering: towards demand response and other opportunities

The Italian smart metering system is currently the largest in the world, catering for more than 30 million users [15], [16]. In its present configuration, the remote control system is composed of two parts: first, each MV/LV transformer station is equipped with a concentrator that collects all data coming from meters, via a power-line carrier (PLC), and it is capable to send instructions to individual meters;[8] second, from the concentrator upwards, communication is mainly based on the public TLC network (GSM/GPRS). This means that the present configuration does not allow a real time control of the end-point meters. Indeed, this was not among the objectives that guided Enel's decision to develop a smart metering system. At that time (around the year 2000) Enel objectives were four: *(i)* remote meter reading, both periodical or on request; *(ii)* remote control of operations such as connection and disconnection of customers or setting the maximum available capacity; *(iii)* reduction of thefts, thanks to alarms installed in the end-point meters and *(iii)* energy balance on the LV network below the concentrator.[9]

As far as smart metering is concerned, the fundamental challenges for the Italian regulator, were two: firstly, to provide smart meters to all customers (Enel serves 85% of the LV customers, but the rest of the distribution sector is fragmented into more than one hundred large, medium, small and micro distribution companies); secondly, to take advantage of the investment made by the first mover (of the order of 2.1 billion euro, with an average cost of around 70 euro per meter all included) [17].

As for the first objective, at the end of 2006 a regulatory provision defined minimum technical requirements for smart meters[10] and defined the timing for full deployment to all LV customers (over 95% of the entire LV customer-base is to be equipped with smart meters by the end of 2012). As a matter of fact, under these mandatory obligations, all distribution companies started their own substitution projects and most customers (also those located outside Enel's licensed areas) are now equipped with smart meters.

[7] Apart from smart grids projects, the Italian regulator does not approve or reject single investments in distribution networks.
[8] Mainly requests of spot or massive reading, but also other types of instructions, related to customer management – for instance, to energise the point of connection or, more rarely, to solve firmware problems.
[9] One the one hand, the DSOs' investments in smart metering is being recuperated by way of an increase in the tariff component that corresponds to capital investment (taking into account also the stranded value of residual depreciation, if any, of existing traditional meters). On the other hand, the efficiency factor which governs the reduction of operating costs has increased: since 2008, the X factor for metering is equal to 5% per year.
[10] In doing this, Italy was a frontrunner among European regulatory authorities [18] .

Achieving the first of the two objectives, has allowed the regulator to focus on the second. First of all, AEEG has introduced a number of requirements for DSOs to implement specific smart meter functionalities. For instance, smart meters are to be used to leave a minimal, vital service to the end user even in the event of non-payments (0.5 kW for a regular household customer, normally supplied with 3 kW) [19]. Moreover, smart meters are to be employed to remotely reconnect the customer as soon as he/she has completed the payment; reconnection must be carried out in a very short time (less than one day in all cases), or an automatic compensation is to be paid to the customer. These examples show that the statement, found in some international reports, that the focus of the Italian smart metering system is efficiency only [17] is not adherent to truth. Thanks to the regulatory intervention, service quality and effectiveness in customer service are also playing a crucial role.

Nonetheless, in terms of exploiting the value of the smart metering system, the most courageous regulatory decision was undoubtly the mandatory introduction of a Time-of-Use (ToU) electricity price for all LV customers (in fact, to those who are served in the "universal supply regime", i.e., household and small business customers who have not yet switched to a different retailer; for details see Annex E). This requirement has been in place since July, 1st 2010, will by fully phased-in by end-2011, and probably represents the largest experiment in the world of time-of-use pricing [20]. The aim of the initiative is for small users to be exposed to cost-reflective prices, as to provide them with information on the economic value of the choices they make about electricity use. Clearly, the initiative is expected to indirectly influence also manufacturers of electrical appliances, in particular those producing high-consumption goods.

With these regulatory decisions, Italy is again aligned with European Commission objectives. The European Directive 2009/72/EC for the internal market in electricity [21] (a component of the so-called Third Energy Package) indicates smart metering as a necessary measure to extend the benefits of retail liberalisation to all users. Nonetheless, the vigorous encouragement that the European Commission is giving to smart metering systems goes beyond the norms contained in the Third Energy Package. For instance, Mandate M/441 [22] to the European standardisation organisms (CEN, CENELEC and ETSI) has recently provoked an important change in the direction of opening the communications protocols. In this respect, the establishment of the consortium "Meters and More" has enabled the disclosure of the communication protocols used in all major European initiatives in the area of the remote control of LV meters [23]. Indeed, the availability of this protocol in a non-proprietary form constitutes a fundamental step towards the possibility of home and building automation: as the most effective demand response initiatives have shown, home and building automation lie at the very basis of energy saving in the residential use of electricity [24].

After providing the necessary means for cost recovery of the investment in smart meters, indicating a deadline for full deployment, introducing a number of mandatory customer services, as well as mandatory ToU pricing, what lies ahead in the regulatory agenda? As a matter of fact, a smart metering system designed today would probably look quite different from the one designed more than ten years ago in Italy. A connection between the electronic meter and the Internet, for example, would open the possibility to offer real-time services [25]. It is quite legitimate, then, to laud the foresightedness of Enel managers who, at the end of last century, approved and carried out such a large project: in retrospective, their choice has been more than compensated. It is no less legitimate, however, to start working on the second generation of meters, identifying new services that might benefit users and, from these, derive the technical characteristics that the new meters shall require.[11]

The next steps in regulation will thus continue to focus on demand response and customer services; a recent consultation envisages further demonstration projects for standard interfaces on the smart

[11] The useful technical-economic life of electronic meters, set by the regulatory authority, is fifteen years: we are by now well into the second half of this period.

meter, open to all retail suppliers wishing to offer innovative solution to their customers, equipped with visual displays or load management devices [14][12]. Moreover, regulators need to explore the possible forms of interaction between the two smart hemispheres: smart meters in LV networks and smart grids in MV networks. Particular attention must be given to their integration over the medium term. In the foreseen architecture of a smart power system, having the possibility to involve the network user in the management of the network appears, indeed, crucial. This leads us to examine the most radical perspective change in consumer behaviour that is expected to derive from new uses of electricity: electromobility.

5. Electromobility: the advent of the mobile electricity consumer

The electrification of individual transport is expected to change radically the logic of energy consumption. Current studies in nanotechnology are leading to the development of systems for the accumulation of energy, capable to provoke a complete change in the composition of the stock of road-bound vehicles in the course of only a few decades. Two factors will determine the speed of the electromobility revolution: first, the increased capacity of on-board vehicle batteries – together with high performance and limited size; second, the reduction of recharging times, such as to allow electric cars to stop briefly at a service station (instead of having to go through long stop-overs to recharge the battery). Plug-in Electric Vehicles (PEV), including both full Electric Vehicles (EVs) and extended-range Plug-in Hybrid Electric Vehicles (PHEV), will then appear as new loads for the electricity network.[13]

Although at the moment the amount of power that will be absorbed by those vehicles remains extremely difficult to predict, the advent of mobile electricity consumers poses a number of challenges to the design and functioning of power systems and electricity markets as well.[14] The new, mobile consumers will be entitled with the freedom to chose their own supplier, just like the more traditional electricity consumers; moreover, they will uncover a new electricity need: access to recharging facilities, not only in private locations (the garages of homes and companies) but also in public places or, at least, in places open to the public.

Current expectations are that 80% of the recharging activity will take place at home.[15] This means that PEV-related load, if left uncontrolled, will coincide with the typical increase in domestic load, when families come home from work. If this is the case, the system will be under even more stress than in case of recharges at service stations or at (new) public recharging infrastructures. In addition, it could also result in over-investments in low-power, public recharging infrastructures.[16] Nonetheless, the development of public recharging infrastructures is one of the main issues currently debated by public authorities in several countries, together with the role of DSOs in electromobility.

It is a shared view among national regulatory authorities in Europe that a competitive market should develop for PEV recharge. This might also allow a multi-vendor approach, where PEV-consumers choose their electricity supplier at the recharging station, provided that the recharging infrastructure

[12] The Enel project "Smartinfo" is a good example of this workstream [24], [26].

[13] Their contribution to total demand for energy will be, in any case, fairly limited and moreover extremely efficient in terms of the overall quantity of primary energy used for individual mobility – compared with traditional vehicles with internal combustion engines.

[14] World-wide market researches show a lot of interest among citizens (especially those living in urban areas) for electric vehicles, but also a lot of doubts as well as deep-rooted perceptions and believes that are difficult to change.

[15] Out of a total sample of 7.000 interviewees in 13 developed countries, "two-thirds of respondents would prefer to charge at home; other charging locations get a far smaller percentage of primary preferences, although when asking consumers to list their top three choices, charging at gasoline/diesel stations shows up well" [27].

[16] The latter also face the potential competition of next-generation, fast-charging stations with storage facilities (similar to the gasoline or compressed natural gas stations currently offering roadside service areas).

ensures open access to electricity suppliers, through non-proprietary protocols. The Italian regulatory authority went further and took an official position that developing PEV public recharging infrastructure is not part of a DSO's licence [28]. This has two consequences. Firstly, DSOs should not have an exclusive role in developing recharging infrastructures, apart for the connection (the infrastructure is simply another network user). Secondly, the costs of building the infrastructure should not be included in the Regulatory Asset Base (RAB). This approach acknowledges the need to balance competition in the PEV recharging activity and competition in the electricity retail market, as well as the need for preliminary tests to analyse and understand the behaviour of mobile electricity consumers.

Coming after a long consultation process, AEEG decision ARG/elt 242/10 [29] is probably the first regulatory action taken on electromobility development in Europe. Essentially, AEEG launched a call for demonstration projects which, differently from the call for smart grid, is open to both DSOs and other operators. In fact, the call is for Charging Service Providers (CSPs), who are expected to build and operate an EV public recharge system. DSOs can undertake this task but under an unbundling constraint: this activity must remain separated from regulated activities.

The demonstration projects can take different forms, that result from combining the CPS type and the number of retailers competing at the recharging infrastructure:

1. DSO (multivendor): the DSO is the operator of the PEV recharging infrastructure, but the latter allows the presence of several electricity retailers (among which the mobile consumer can choose) at the same recharging point;
2. CSP with an exclusive license in a geographic area (either multivendor or monovendor): this is the case of a CPS selected through a public tender by a local administrative authority (the municipality, the province, etc.);
3. CSP in competition in the same area (typically monovendor); the PEV recharging infrastructure sees the presence of one electricity retailer only and the mobile consumer can choose from different recharging infrastructures (as it is now for ordinary gas service stations).

As of today, the Italian regulator has selected five demonstration projects that include all three different approaches [30]; details on selection criteria of demonstration projects are given in Annex F. These projects are bound to share with the regulatory authority all their operational data, in order for AEEG to evaluate the next regulatory steps. In this regard, the effect of electromobility on electricity systems is potentially enormous and mainly lies in the integration of smart grids (i.e. RESs) with PEV recharging infrastructures [31].

The role of the energy regulators in electromobility is, in a sense, different from their role in smart grids and smart meters. As for smart grids the main actors in the innovation process are DSOs, and distribution is clearly a regulated activity. As for metering and the development of demand response, the issues are closer to the boundary between regulated activities and the competitive retail market. The issue of electromobility (and EV recharging in particular) is almost outside the boundary of the regulated distribution business; moreover, its future development is very much interwound with policy decisions that are made outside the area of electricity regulation. Regulation must be at the front line of this wave of change: on the one hand, by keeping all options open to the market solution that will meet the preferences of the new mobile electricity consumers and on the other hand, by being ready to extract the most value from the interaction of electromobility with smart grids and smart meters.

6. Lesson learned from the Italian case

Power systems are undergoing a profound change. Transmission networks are connecting increasing amounts of intermittent (mostly wind) generation. Larger shares of DG are forcing distribution networks to become active and at the same time create new opportunities for participation of active users to system security and reliability. Final consumers are expected to become more responsive to price changes and to expoit the different services offered by technology innovations, including electro-mobility, to create efficiency in the use of energy. The enabling factor of this smart revolution is, of course, ICT. As illustrated in Figure 1, the "smart revolution" is a complex process: without a "smart regulation" [32], it will hardly express all its potential benefits or, worst, it can lead to detrimental outcomes.

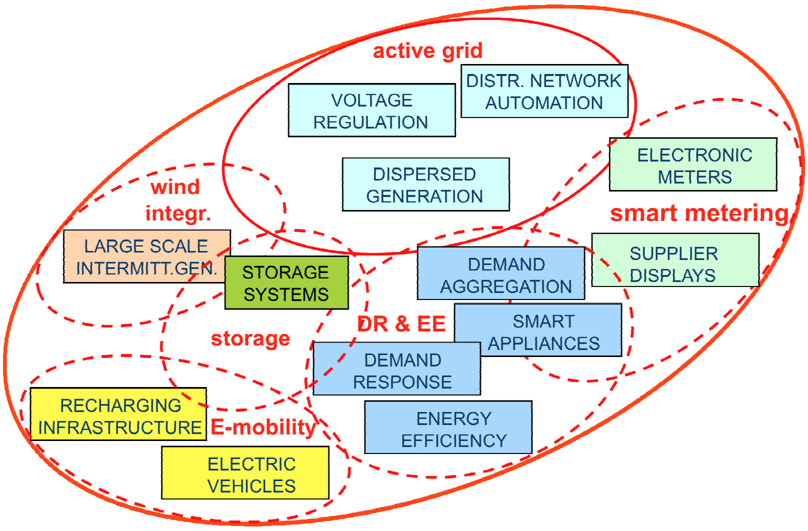

Figure 1. A smart power system (authors' elaboration from [33])

This paper presented a case study on Italy, focusing on the regulatory reforms that were recently adopted to embrace and promote innovation in the power system, describing both the ongoing projects and the challenges to come. From this experience we can distill a few lessons learned, on the role of energy regulation when embracing and stimulating innovation in the electricity system.

First, the introduction of new functionalities into a traditionally static environment requires a preliminary understanding of the technical grounds over which those innovations are going to develop. A sound regulatory approach to the RES integration in the grid begins with building a robust technical knowledge of the current system and its potential hosting capacity for DG. To this end, regulators need to cooperate with experts from the academia (or from the industry) as well as with other technical (standardization) bodies. As an example, the first action taken with respect to smart grids, was launching the NHC research project.

Second, technical understanding is functional to the development of correct metrics of the phenomena under scrutiny. The identification of useful key-indicators is the basis for monitoring the impact of the changes occurring on the networks. This is important when selecting and evaluating demonstration projects; moreover, the indicators will be crucial when moving to an output-based regulation (see below). Two examples presented in the paper are the *RTP* and P_{smart} indicators developed for smart grids.

Third, real-life demonstration projects are a necessary step between laboratory tests (and prototypes) and full deployment. The costs of these projects can be high (with respect to the unitary costs of large-scale deployment) and therefore a careful selection process is necessary, to incentivise only those expected to bring quantifiable benefits. Of course, cost coverage is also necessary and can be included in the RAB (expenditures on innovative projects on the part of the regulated utility can be considered as an investment for the future). Two examples were mentioned in the paper, concerning smart grids and electromobility.

Fourth, moving to output-based regulation is the efficient choice for full deployment of innovative solutions. This approach simplifies the administrative burden and lowers the risk of inefficient investment choices. Of course, it builds on the successful outcome and on the experience gained in steps one to three. As for Italy, this phase of the process was recently launched and the first regulatory thoughts on smart grids deployment are currently under consultation.

Fifth, innovation can bring regulation to move closer to the competitive sectors. This is certainly the case of smart metering. Deployment of smart meters in Italy was initiated by a company decision but regulation embraced the challenge and has led the path to full deployment. This does not rule out the (potentially more efficient) possibility to liberalize the metering activity and let the market guide the change. The role of regulation is, however, crucial in ensuring that value for the customers is extracted from this innovative investment. In this paper two examples were given: mandatory, new customer services and mandatory ToU pricing. As for the future, keeping the focus on what is valuable for the consumers and for the system at large, regulatory provisions can ensure the openness of the communication protocols as well as provide indications for further functionalities to be developed in smart metering.

Sixth, together with demand response, electromobility brings regulation to areas that are even closer to the competitive sectors. In this case, it is fundamental to identify the role of regulated companies among other actors, as well as the role of energy regulation among other policy-making bodies (and of course find an efficient way to interact). The example presented in this paper regards the demonstration projects for EV recharging infrastructures.

Finally, looking even further into the future, it is clear that most benefits will derive from the integration of smart meters in LV networks with smart grids in MV networks, as well as from the integration of smart grids (i.e. RES) with storage capabilities (i.e. EV recharging infrastructures). The role of regulation in enabling this additional passage will certainly be challenging as much as interesting.

Acknowledgement

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8. Annexes

Annex A – Transmission networks: the influence of RES on power system operation and dispatching

Annex B – Integrating DG in distribution networks: local and system constraints

Annex C – Demonstration projects for smart grids: Italian incentive regulation

Annex D – Demonstration projects for smart grids: ICT for an innovative protection, automation and management of distribution networks

Annex E – Smart Metering and mandatory Time-of-Use pricing: the implementation in Italy

Annex F – Selection of demonstration projects for EV recharging infrastructure

Annex A - Transmission networks: the influence of RES on power system operation and dispatching

Usually, transmission networks are already actively managed and do not require substantial changes in order to face the RES production increase: they were designed since the beginning to ensure the synchronous operation of conventional generators. Transmission networks, at least in Italy, are highly meshed: in case of a fault on a feeder section, this section is isolated without any outage for customers (all substations remain fed and users connected to these networks may experience voltage dips but no disconnection).
Nevertheless, the connection of a large amount of RES power plants to HV networks (typically, large wind farms) has to be properly managed, both from a technical and from a regulatory standpoint.
Furthermore, some attention has to be devoted also to the consequences of a large presence of DG units connected to the distribution networks on the dynamic behaviour of the transmission system.

As for technical issues, in the past the percentage of wind power penetration was extremely small compared to total power production: this is why interconnection requirements for wind farms were originally not included in the grid codes of TSOs. In the recent years power production from wind farms has increased considerably and may now have a significant influence on power system operation. For this reason, in Italy, the TSO has defined special requirements for the connection of wind farm (Italian Grid Code - Annex A17 [1]). It has to be mentioned that the Italian Grid Code (issued by Terna) is subject to the approval of the AEEG. These requirements are mainly based on existing grid code rules, written for conventional synchronous generators.
The most important requirements are listed below.

- *Limitation of active power injected into the grid*. The amount of power injected in and absorbed by the grid has to be instantaneously in balance. Changes in power supply or demand can lead to a temporary unbalance of the system and affect operating conditions of power plants as well as consumers. Under particular network conditions (related to temporary limitations to the transit on the transmission network/feeder underlying the wind farms) in order to avoid long-term unbalanced conditions the TSO is allowed to modulate/limit the active power injected by each wind farm or to control its forced shedding. Such requirements (active power control) ensure frequency stability in the system, prevent overloading of transmission feeders, ensure that power quality standards are fulfilled, avoid large voltage variations and inrush currents at start-up and shut down of wind farms.
- *Regulation of active power*. Frequency in the power system is an indicator of the balance between production and consumption. For the normal operation of power systems the frequency should be stable and close to its nominal value (50 Hz). To this end, wind farms shall be able to avoid the reduction of active power during underfrequency conditions, and to reduce, quickly and automatically, the active power during overfrequency conditions, without disconnecting from the network, as shown in Figure A.1.

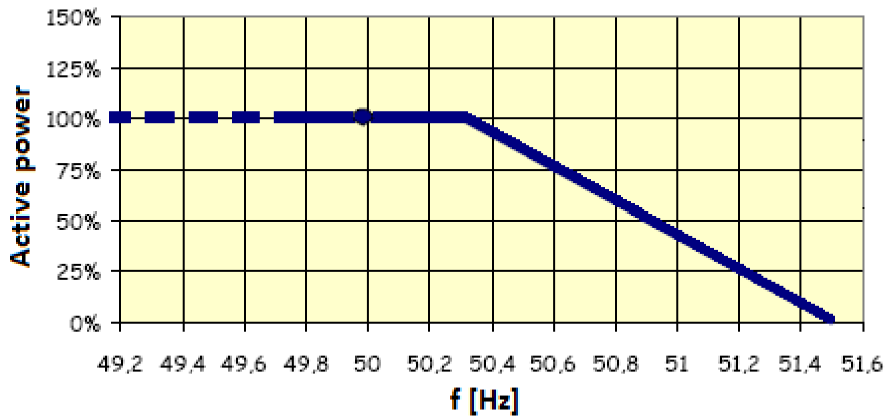

Figure A.1. Frequency range and control for wind farms connected to transmission network

- *Reactive power compensation*. Utility and customers equipment is designed to operate at a given voltage rating. Voltage regulators and control of reactive power at the generators (and consumers) connection point are used to keep the voltage within the required limits and to avoid voltage stability problems. Wind farms shall also contribute, as far as technically feasible, to the voltage regulation of the system; the requirements concern a certain reactive power compensation that should be provided: each generator shall be able to adjust the power factor between 0.95 leading and 0.95 lagging. In general, during normal operating condition, the power factor at the Point on Common Coupling (PCC) shall be equal to 1.
- *Protection and Low Voltage Fault Ride Through (LVFRT) curve*. When a fault (e.g., a short circuit) occurs in the HV network, an improper functioning of protection relays would lead to the immediate disconnection of large wind farms. This event, in turn, would put additional stress on the already perturbed transmission system. As a rule wind farms are required to keep connected in such cases, unless some predefined voltage limits are exceeded, as depicted in Figure A.2. The values reported in the figure (time durations; residual voltage) are typical of the Italian system, as they are related to the HV distance protection operation, which may differ from country to country. Similar requirements (even if with different values) can be found in the Grid Codes of all countries where wind penetration is significant.

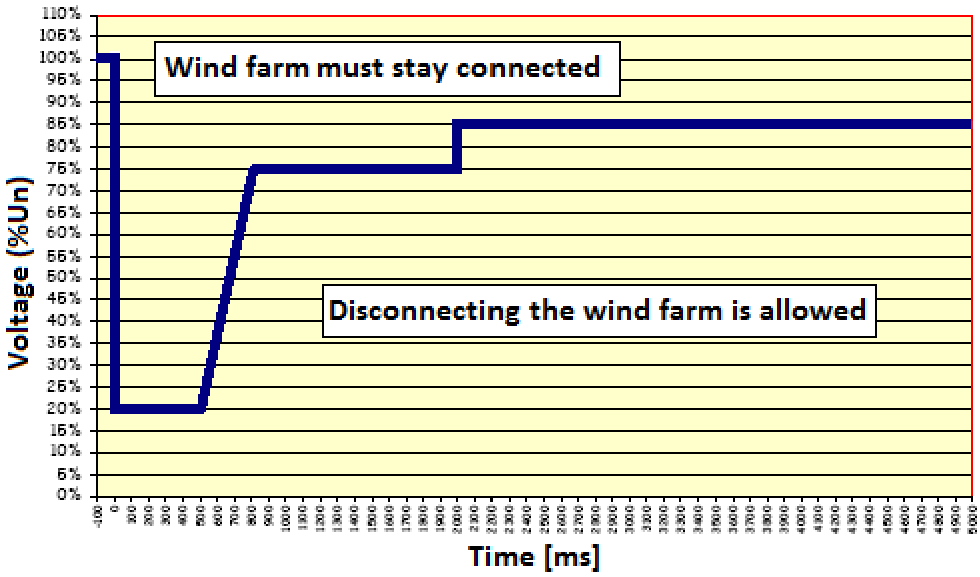

Figure A.2. LVFRT for wind farms connected to transmission network

Once technical requirements are enforced, there is the need for a suitable regulatory framework regarding dispatching actions that can be taken by the TSO. In some particular zones of Italy the expected level of wind penetration, as well as the concentration of wind plants in areas (e.g., in

Sardinia or in Sicily, with low load density) where the grid was not designed to accommodate that level of generation, may require that wind output is re-dispatched when system security and reliability are threatened. In particular, during the real time control phase, the Italian TSO dispatching system can modify the production of active (and reactive) power of wind plants: Regulatory order ARG/elt 5/10 [2] defines the compensations due to wind plants for the loss of production when dispatching orders (reduction of active power) are issued by the TSO to ensure the safety of the electrical system. During year 2010 the loss wind production is equal to 470 GWh, that represents the 5,6% of wind energy on the Italian transmission system: this percentage is halved compared with its level in 2009 (10,7%). The modulation, that could appear small at national level, is needed especially in some specific areas of southern regions, with a high concentration of wind parks and a low load density.
Furthermore, in order to enhance the integration of existing wind plants and to limit as much as possible re-dispatching orders by the TSO, the AEEG has promoted the integration of a centralized wind forecasting system into the TSO day-ahead and real-time market software, in order to better predict the output of wind plants in the TSO's system dispatch (according to Regulatory order n. 351/07 [3], the TSO is rewarded or penalized on the basis of the accuracy of the wind forecast).
Finally, an accurate wind forecast, along with the dispatching of other resources located in proximity of wind power plants, may be, however, insufficient to manage the expected levels of incoming wind generation. Further long-term solutions may include the need for additional transmission feeders to move wind power, and new operational rules to enhance system security. For instance, the Italian industry Ministry has recently allowed Terna to install energy storage devices to absorb excess power in off-peak hours, in order to avoid loss of production from wind plants [4]. As reported in an ad-hoc document by Terna [5], these innovative systems will be installed along some HV feeders in the South of Italy, where, as stated before, the problem of loss of production from wind plants is highly concentrated.

Apart from issues due to large wind parks, RES generation connected to MV networks (i.e., DG) creates a problem also for transmission networks operation. In particular, a large presence of DG units connected to the distribution networks can hinder the dynamic behaviour of the transmission system. In fact, DG units connected to MV and LV networks are protected by means of the Interface Protection Relay (IPR). The IPR is aimed at avoiding islanded operation and trips DG units on the basis of on local information[17] (voltage magnitude; voltage frequency).
The desired operation of IPR can have significant consequences at a system level (transmission network). In fact, narrow settings of IPR (49.7 Hz – 50.3 Hz) lead to unwanted trips because frequency values very close to 50 Hz are possible also if no loss-of-mains appears. These events (frequency transients on the transmission network, unescapably followed by a massive loss of DG units), have already happened in recent cases of transmission accidents (September 28th 2003 [6]; November 4th 2006 [7]).
Lately the level of risk has increased dramatically: the significant growth in PV systems in recent years, especially in Germany and Italy, has resulted in a PV installed capacity close to 25000 MW. About 15000 MW of that capacity disconnect whenever the European system frequency departs even by some hundreds millihertz from the nominal value. This instantaneous generation loss would exceed by far in 3000 MW, which is the generation-loss-ride-through design limit for the entire European system[18]. If this scenario is projected in the future, the massive penetration of DG makes it essential to overcome the limits of current IPR design and operation.

[17] With negative consequences also for distribution system operation (this problem is discussed in Annex B).
[18] In this context, the European Photovoltaic Industry Association (EPIA) and the Bundesverband Solarwirtschaft e.V. support ENTSO-E's call encouraging national regulatory authorities to address the inadequacy of current national standards for PV inverters [8].

As a matter of fact, AEEG has already taken action in this direction by means of an intervention[19] on the technical rules for the connection of DG units to MV and LV grids [9], [10]. As already mentioned, the problem is discussed in Annex B and the proposed solution is the focus of Annex D.

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[19] That overcomes these issues both at a local and system level.

Annex B - Integrating DG in distribution networks: local and system constraints

Traditionally, distribution networks (MV-LV) are operated radially, (i.e., the energy flows mainly from the primary substation to the lower voltage levels) and without an on-line control of voltages and currents in each DG's Point of Common Coupling (PCC). Such architecture was chosen when DG was very rare, but can lead to several problems when injections of DG become significant. This is the case of Italy: DG units (in particular PV and wind systems) are currently increasing in number, as a consequence of the incentive schemes in place; other benefits such as a simplified access to the grid and priority in dispatching reinforce this trend.
As of today, DG mainly affects the Italian MV distribution system (75% of energy produced by DG is placed on MV networks [1]).

This Annex describes the first actions taken by AEEG with respect to DG connected to MV networks: the regulator commissioned an assessment of the so called Nodal Hosting Capacity. Simplifying, we can say that the results of this study indicate that from a local point of view, the HC of MV distribution network is rather good. However, as discussed here, some further problems need to be addressed, mainly related to the operation of Interface Protection Relays. Addressing this problem is necessary, not only from a local point of view, but also for the entire system (as mentioned at the end of Annex A, IPR operation affects also the dynamic behavior of the transmission network).
Further actions, i.e. supporting a novel strategy to operate IPR, was a second regulatory step and it is described in Annex D.

B.1 Nodal Hosting Capacity
In order to cope with the recent dramatic increase in DG, the Italian energy regulator committed an assessment of the capability of Italian MV distribution networks to accommodate DG power injections. This analysis was carried out by the Energy Department of *Politecnico di Milano*; the relevant results were published as Annex II to Regulatory decision ARG/elt 25/09 [2].
In this study, according to the Nodal Hosting Capacity (NHC) approach [3], a new DG unit is simulated in a specific bus of a MV distribution grid: branch currents and bus voltages are computed by load flow calculations and compared with the operating limits; then the power injected by the dispersed generator is increased until an operating limit is violated. The maximum power injection which does not determine a violation is assumed to be the capability of the selected bus to accept DG power injections.
This study exploited a large data sample (Extended Data Set, EDS), consisting of about 100000 MV busses, belonging to the MV feeders fed by about 400 Primary Substations (hereinafter, PS, i.e. MV busbars directly connected to a HV/MV transformer). As the overall MV Italian system consists of about 4000 PS, EDS covers 10% of the number of Italian MV networks (Figure B.1) [4]. The PS belonging to the EDS are those equipped with the monitoring system QuEEN, promoted by the AEEG [5]. Additional data were collected from the larger Italian DNOs.

Figure B.3. 400 PS with monitoring units installed on MV busbars of HV/MV substations

In fact, for the aim of this study, a Reduced Data Set (RDS) was employed: it is composed of 260 MV networks (that cover the 8% of the Italian HV/MV transformation capacity).[20] For each bus, the database gives the nominal voltage, the contractual power (for MV customers) or the rated power of MV/LV transformers (for Secondary Substations, SS). In addition, the database gives the parameters of each branch: length, line resistance and reactance for each line; short-circuit voltage, copper losses and rated power for each transformer. The structure of the information contained in the database is shown in Figure B.2.

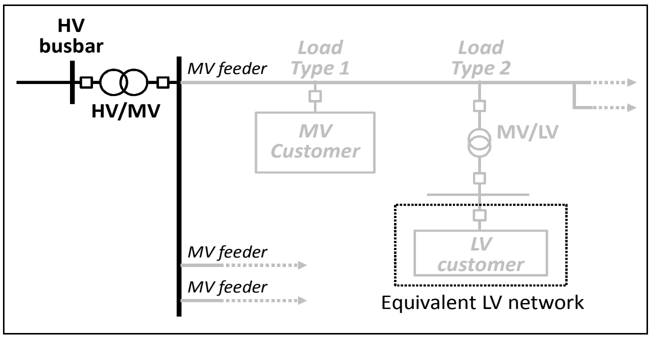

Figure B.**4. Structure of the network distribution system under analysis.**

In addition, for the purpose of this analysis, the yearly load profile of the grids was suitably modeled in order to calculate the NHC in the worst condition: the proposed yearly load profiles are characterised by means of 60 values (value #1 is peak load, value #60 is minimum load), the relevant procedure is detailed in [6].

Once the MV networks were modelled over a year of operation, the study consisted in defining the capability of each MV bus to accommodate power injections from DG with no modification in network structures and no deterioration in Quality of Service (QoS). In order to calculate the NHC of the RDS buses, the procedure entails increasing the power injected by the generator by 10 kW at the time until a limit is violated.[21] Only one new generator is assumed to be connected to a specific bus along a MV feeder. For each grid, three kinds of limits are taken into account by the procedure:

[20]The magnitude and composition of RDS were chosen in order to reach a suitable statistical significance.

[21]The new generator is simulated by means of an increasing power injection in a specific bus, with power factor equal to 1, complying with technical standard 11-20 by CEI (Italian Electrotechnical Committee) [7].

- line thermal limits (LTL), i.e. current limit of each branch;
- supply voltage variations (SVV) for each bus;
- rapid voltage changes (RVC) associated to sudden variations (e.g. trip) of DG power output.

Current and voltage limits are evaluated by a load flow calculation with the new generator in operation. As discussed in [8], RVCs strongly depend on the short circuit power in the PCC. Therefore, according to the definition given in [9], RVCs are calculated by the comparison of two load flow calculations, as differences between bus voltages obtained with the new generation in operation and bus voltages without the generator. Different load profiles are used for MV/LV substations and for loads directly connected to MV, which have a lower range of variation between peak and minimum demand.[22] MV/LV substations are modelled by means of an equivalent load.

Voltage profile is controlled by means of a fixed voltage set-point in the MV busbar of the HV/MV transformer, where an On Load Tap Changer (OLTC) control is installed. The set-point is determined in the condition of maximum load and no generation, as the minimum value which allows to fulfil lower voltage limits in all busses of the MV feeders belonging to the network.

As for LTL, a 250 A limit is assumed for all branches taking into account common ratings of MV overhead lines and cables (e.g. a 185 mm^2 aluminium) and the settings of overcurrent line protections in Italian MV grids.

As for SVV, according to technical standard EN 50160 [10], nodal voltages are allowed to range between 0.96 p.u. and 1.10 p.u., where the choice of the lower voltage limit takes into account the possible voltage drops (till 0.90 p.u.) in LV grids connected to MV/LV transformers. RVC up to 6% are accepted according to technical standard EN 50160, although this limit cannot really be considered as a hard constraint.

A 10 MW maximum exploration limit is considered: it represents the nodal limit for the connection of DG to Italian MV networks (standard CEI 0-16 [9]). Even if the analysis is based on the presence of one generator at a time, the use of a very high ceiling for the "equivalent" generator (10 MW) allows exploration of the network limits in case more real generators are connected. Figure B.3 displays the maximum injection compliant with all nodal constraints (LTL; SVV; RVC).

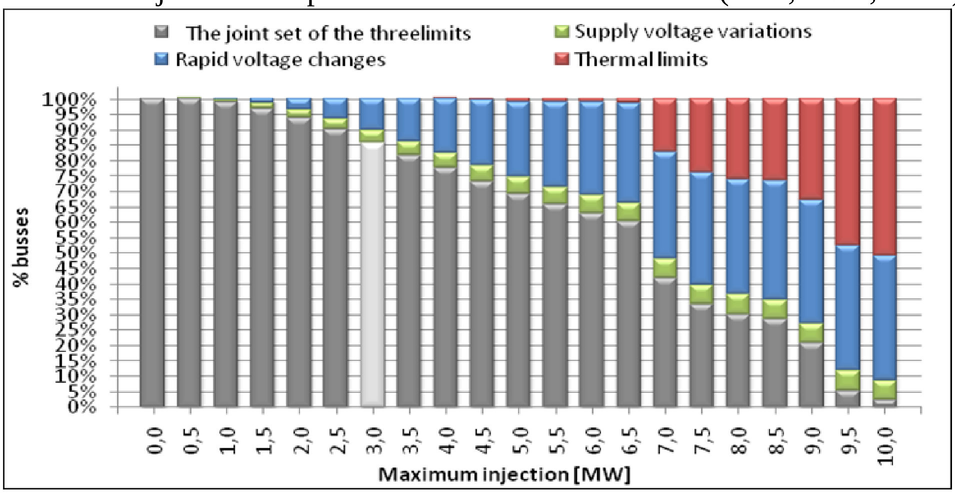

Figure B.5. Aggregation of busses (% of the sample) based on maximum injection [MW] due to all limits

Thermal limits affect the busses close to the primary busbars, whereas RVC limits[23] are stringent for busses far from primary busbars. Apparently, the SVV limit is less impacting than the other ones; its actual influence on NHC is indeed "masked" by the limits related to RVC.

Simulation results highlighted that, when considering the assumptions adopted in this study, Italian MV grids have a remarkable NHC: 85% of the busses in the sample can host at least 3 MW. Apart from RVC (that according to EN 50160 cannot be considered as a hard constraint), SVV limits can be overcome by a proper voltage regulation strategy, involving an active participation of DG units;

[22]Loads are assumed to have a power factor 0.9, which is the lowest power factor without reactive penalties in Italy.

[23] RVC limits however cannot be considered as an hard constraint, according to technical standard EN 50160.

on the contrary, LTL constraints really represent the network structural limits and are related to the cross sections of MV overhead lines and cables. Such structural limits cannot be overcome unless significant investments are put in place (traditional network expansion).

Moving from a nodal approach (each bus considered separately) to a circuit approach (set of MV busses considered jointly) or to a Primary Station approach (set of MV circuits considered jointly), or even to a system approach, the HC of Italian MV networks is only partially confirmed. Further constraints appear that have to be considered, and possibly removed.

B.2 The issue of Interface Protection Relays

The presence of a large amount of DG impacts the operation of Interface Protection Relays[24] (hereinafter, IPR), leading to

a) local issues for the DNO, related to QoS (islanding of DG; failures in automation systems);
b) global issues for the TSO, related to transmission system stability and security (unwanted massive DG tripping in the presence of frequency transients on the transmission system, as discussed in Annex A).

These problems, together with voltage regulation issues, have to be addressed to allow full exploitation of the distribution networks up to the so called System Hosting Capacity (SHC). This represents the maximum DG that it is possible to connect according to the thermal limits of the network (i.e., the rating of single branches considered together with the rating of the HV/MV transformers) with no traditional network expansion.

Focusing on local issues, we note that use of IPRs is common to almost all EU networks;[25] guidelines vary from country to country but requirements normally include the following:

1. DG shall be disconnected in case of abnormalities in voltage or frequency;
2. in case of interruptions, all DG units shall be rapidly disconnected;
3. if auto-reclosing is applied, dispersed generators shall disconnect before reclosing, to allow enough time for the fault arc to extinguish, and to avoid damages to DG units.

IPRs in Italy have very narrow settings (in terms of voltage/frequency permitted operation) and trip very fast (to allow for fast reclosure of MV lines[26]): these characteristics aim at ensuring high levels of continuity of supply, as prescribed by the relevant regulation.

In practice, IPR operation will lead to local issues for the DNO, when DG injections are comparable to the load withdrawal. In case of a loss of mains, a high probability of local balance (DG produced power equal to load absorbed power), brings voltage/frequency values very close to the nominal values, causing unwanted islanding operation (and therefore jeopardizes QoS and operational safety). Moreover, during the reclosing sequence dead time, the dispersed generators could drift out of synchronism with the grid; an out-of-synchronism reconnection may damage the generators.

Nonetheless, it is well documented in the literature that the alternative ways of managing unwanted islanding, using only local information (active and passive methods), cannot solve this problem.

Only a novel strategy for IPR operation can overcome both local QoS issues as well as global issues. Indeed, a suitable communication system can be designed, capable of protecting distribution networks and DG units from islanded operation, without the need of dangerous overfrequency/underfrequency settings. The practical implementation of this new protection strategy, along with other innovative solutions for the active management of distribution networks, is described in Annex D. Here we recall only that, looking for a possible gradual implementation of

[24]These relays are installed at the DG premises, and are designed to disconnect DG from the grid in particular network conditions (basically, in case of loss of mains due to a fault).

[25] EN 50438 “Requirements for the connection of micro-generators in parallel with public low-voltage distribution networks”; IP characteristics given in the standard are common to DG units connected at MV level.

[26] Fast reclosure (few hundred milliseconds), extensively used in Italy, is aimed at ensuring higher levels of power quality (in case of non-permanent faults, only a transient interruption is perceived by customers).

new operation/control/protection strategies on MV distribution networks, both local IPR issues and possible voltage regulation issues can be identified by means of the Reverse Power-flow Time (RPT) indicator, i.e. the percentage of yearly time in which energy flows from MV to HV in a given PS. In fact, when the energy produced by DG is higher than the energy consumed by end users connected to the same MV distribution network, the network protection, automation, and voltage regulation techniques are at stake. This is why the RPT indicator gives valuable information to identify the level of network activity.

References for Annex B

[1] ARG/elt 223/10 "Monitoraggio dello sviluppo degli impianti di generazione distribuita in Italia per l'anno 2009 ed analisi dei possibili effetti della generazione distribuita sul sistema elettrico nazionale"

[2] ARG/elt 25/09 – Annex 2 "Impatto della generazione diffusa sulle reti di distribuzione".

[3] J. Deuse, S. Grenard, M.H.J. Bollen, EU-DEEP integrated project – Technical implications of the "hosting-capacity" of the system for DER, Int Journal of Distributed Energy Resources, Vol.4, No.1 (2008), pp.17-34.

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[5] F. Villa, A. Porrino, R. Chiumeo, S. Malgarotti, "The power quality monitoring of the MV network promoted by the Italian regulator. Objectives, organisation issues, 2006 statistics", Paper 0042, Proceedings CIRED 19th Conference on Electricity Distribution, Vienna, 21-24 May 2007.

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[7] Italian Electrotechnical Committee (CEI), 2000, Technical standard CEI 11-20 *"Electrical energy production system and uninterruptable power systems connected to I and II class network"*, in Italian, CEI, Milan.

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[11] Italian Electrotechnical Committee (CEI), 2008, Technical standard CEI 0-16 *"Regola tecnica di riferimento per la connessione di Utenti attivi e passivi alle reti AT ed MT delle imprese distributrici di energia elettrica"*, in Italian, CEI, Milan.

Annex C - Demonstration projects for smart grids: Italian incentive regulation

Demonstration projects for active grids are among the few classes of investments worth of extra-WACC according to the Tariff Regulatory code for period 2008-2011. In 2010, the Italian energy regulator has launched a selection process for smart grid demonstration projects, focused on "active MV networks". The selection process was initiated by the Regulatory decision ARG/elt 39/10 [1] that contains also the main criteria for cost/benefit assessment of the projects proposed by distribution companies. The selected projects are granted an extra-WACC of +2% (on top of the "ordinary" WACC equal to 7% for distribution network investments) for a period of 12 years. The AEEG decision of incentivising demonstration projects for active distribution grids represents the second step of the Italian energy regulator towards smart grids, after the assessment of Nodal Hosting Capacity described in Annex B.

According to the Italian energy regulator, the progress in the direction of smart grids can only begin through field initiatives that involve *real networks*, with both active and passive users (generators and loads), where it is possible to test the solutions investigated in theory or experimented in the laboratories. Such incentives for demonstration projects are today the exception rather than the rule; as a matter of fact, according to a recent survey of the European energy regulators' association [2], so far only in Italy and in UK[27] regulators have taken up this challenge.
In more detail, the Italian selection for Smart Grid projects is based on tariff incentive regulation. Theoretically, a good regulation is concentrated on outputs, i.e. on the effects of a given activity or service, instead of trying to influence internal processes of the regulated company. Regulation of outputs can be done by direct regulation (i.e., minimum requirements for some given parameters), and/or by an output-based regulation, providing penalties and rewards related to certain criteria and targets in performance. Although Italy has a good experience in output-based incentive regulation, in particular for Quality of Service [6] [5], developing an output based regulation of smart grids has proven difficult so far. In fact, performance measurement requires clear and fair indicators, well consolidated, strictly related to the pursued objectives and cleansed of external effects outside the control of network operators. Because of these difficulties, the existing regulatory frameworks (both in UK and in Italy) are so far input-based:[28] in the meaning that incentive is applied to incurred project costs (input) rather than to the actual value of the project for the whole system or for the customer (output). A move toward output-based incentive is currently under consultation in Italy.

The Italian smart regulation takes into account three complementary dimensions: grid technology innovation, new grid services, and grid user participation. The admission procedure for demonstration projects[29] is based on a set of minimum requirements listed below.

- the demonstration project has to affect a real existing MV network with passive users (end customers) and active users (dispersed generators) - *real grid*;
- the selected MV network has to show, in the existing conditions, a RPT (energy flows from MV level to HV level) of at least for 1% on a yearly base - *active grid;*
- the selected MV network has to be equipped with real time control systems able to record all data needed for the evaluation of the project – *automatically controlled grid;*
- non-proprietary communication protocols are required for communication with active users (dispersed generators; storage systems), in order to minimize customer costs at the network interface - *open communication*.

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[27]OFGEM has implemented the Low-Carbon Networks (LCN) fund to support RD&D projects on networks in the UK with a budget of 500M£ [3].
[28]It is also of paramount importance that no regulatory scheme or requirement represents an (unintended) barrier for necessary development in technology and applied solutions in the grid.
[29] Evaluation cost on the shoulders of applicants.

In addition to minimum requirements, the demonstration projects can implement further smart functionalities: providing bidirectional communication with final customers in order to develop demand response strategies (including recharging infrastructures for electric vehicles), or other storage solutions, in order to guarantee active power modulation at TSO/DSO interface.
The selection of the projects was based on a comparative assessment of different proposals to be presented by DSOs (by November 2010), according to a key-performance indicators scheme which considers both the benefits and the costs of the projects.
In order to develop the most fruitful Indicator of the Benefits (IB), the proposed IB is a combination of quantitative and qualitative indicators. The quantitative indicator (P_{smart}) is defined as the increase in DG power that can be connected to the grid without network refurbishment in safe conditions of voltage, current and frequency thanks to the “smart investments” in the network. The qualitative indicator (ΣA_j) is a technical score attributed by experts on the basis of their engineering judgement about the technical solutions proposed in the project application.
In practice, P_{smart} represents the main benefit to be achieved with the project: as previously discussed, the first objective of smart investments should be to remove the network constraints that prevent from accepting a larger amount of DG. For this reason, the projects will allow a full exploitation of the SHC of the relevant network. P_{smart} represents the maximum generation that is possible to connect above the minimum load threshold with no network expansion, and is calculated as follows:

$$P_{smart} = \frac{EI_{post} - EI_{pre}}{8760}$$

where:

- EI_{post} is the yearly electricity by DG that can be injected in the network in suitable technical conditions after the “smartening” project [MWh];
- EI_{pre} is the yearly electricity by DG that can be injected in the network before the “smartening” project, i.e. without any risk related to reverse power-flow [MWh].

It has to be highlighted that both EI_{post} and EI_{pre} are calculated with respect to the network structure, according to the Hosting Capacity approach, regardless of the DG units actually connected to the network before and after the project. In fact, considering the DG quantity really connected to a network before and after the project (as done in [6]) would expose the DNO to some risky assumptions, being the new DG initiatives outside its control. By contrast, with this specific definition of P_{smart}, it is possible to obtain an indicator related only to the characteristics of the asset managed by the DNO, and not biased by the behaviour of other parties.
In more detail, the indicator P_{smart} (expressed in MW) gives a conventional measure of the DG generation power that can be connected to the distribution network in analysis after the “smartening” project in suitable technical conditions (voltage, currents and frequency), in excess of P_{min_load} that instead represents, conventionally, the maximum amount of generation that can be connected to the network with no risks related to reverse power flow ($P_{min\_load} = EI_{pre}/ 8760$).
According to the different functionalities of the “smartening” investment, P_{smart} can reach different levels, as indicated in Figure C.1. The first level of P_{smart} represents the DG power that is possible to connect without violating the supply voltage variation limit; such limit is overcome by the voltage control introduced, based on a communication with limited requirements (latency of some seconds, till 20 s). On top of this, the second level of P_{smart} represents the DG power that is possible to connect without violating the limits (both at a local and system level) given by the IPR design and operation: in fact, a novel strategy for IPR operation is achievable, that overcomes both local and global issues, by means of a suitable communication system with challenging requirements (latency of some hundreds milliseconds). This novel technique is capable of protecting distribution networks and DG units from islanded operation, without the need of dangerous overfrequency/underfrequency settings. Finally, the last level of P_{smart} represents the DG that is

possible to connect with the use of storage systems that absorb the excess power in off-peak hours and inject power in peak hours with a further increase in DG connection.
As detailed in Annex D, the full exploitation of the hosting capacity is allowed by ICT (Information and Communication Technology), that will make possible for DG to provide a real contribution to the security and reliability of the whole power system.

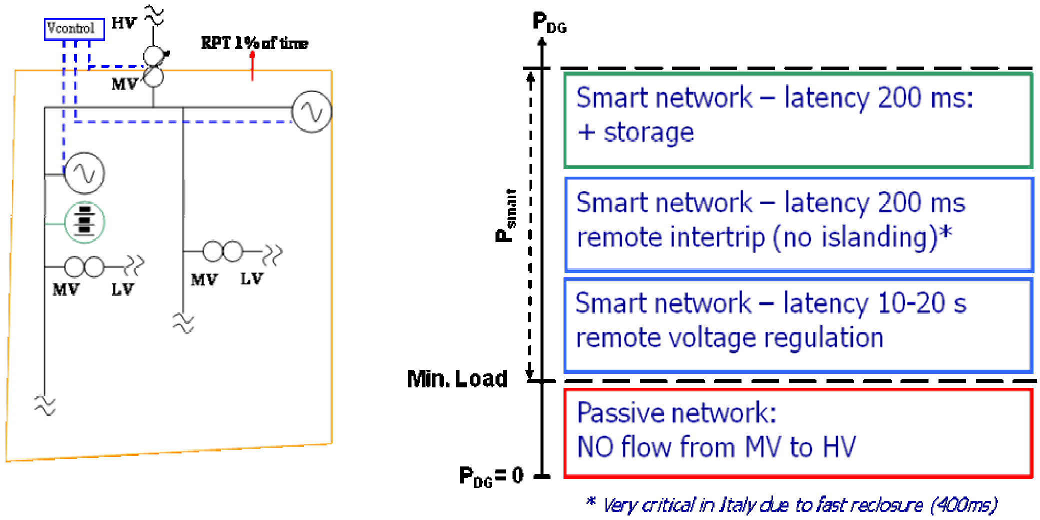

Figure C.6. P_{smart}: SHC at network level.

As regards the technical score, it is divided into four sections.

- A_1. *Size*: considers the number of active users involved, the size of the area involved in the pilot and the effects of the project on increasing production from DG.
- A_2. *Degree of innovation*: considers the degree of innovation that the pilot project will introduce in the distribution system, with reference to the ability of aggregating of DG, of regulating voltage and of managing the production diagram, by making use of communication systems, for a better control and management of distribution networks.
- A_3. *Feasibility*: considers the timing of the project and the impact on quality of supply. A project that could lead to a decrease in the levels of continuity is considered not feasible or poorly viable.
- A_4. *Replicability on a large scale*: considers the requirement of reproducibility on a large scale of the technical solutions proposed in the pilot project.

The maximum score for each section is shown in Table C1.

Table C.1. Benefit score (Aj)

A1	SIZE	N. generation plants/storage	6
		Increase of electricity production injected into the grid	12
		Increase of ratio "electricity production / electricity consumption"	8
		N. primary substations involved in the project	4
		Max A1	**30**
A2	INNOVATION	Participation of disperse generation to voltage regulation	6
		Presence of control system (SCADA)	6
		Bidirectional communication and demand response	6
		Presence of storage systems and active power modulation	12
		Participation of DSO to ancillary service market	10
		Max A2	**40**
A3	FEASIB ILITY	Project schedule	4
		Quality improvements	6
		Max A3	**10**
A4	REPLICA BILITY	% of costs on not regulated subjects (DG and storage)	2
		Standard protocols	8
		Consistency between investment costs and expected benefits of the project	10
		Max A4	**20**
		Max Project	**100**

The key-Performance Indicator (PI) is calculated as follows:

$$PI = \frac{P_{smart} \cdot \sum_{j=1}^{4} A_j}{C}$$

where C is the cost of each project.
The selected projects, rank-ordered on the basis of therelevant PI, are shown in Table C.2.

Table C.2. Selected smart grid projects

Position rank	Primary Substation (PS) involved in the pilot	*Psmart* [MW]	Project Benefit (A_j)	C [k€]	PI
1	A2A □ PS Lambrate	53170.69	65	733	4715
2	ASM Terni	16176.47	68	800	1375
3	A2A - PS Gavardo	7701.00	65	755	663
4	ACEA Distribuzione	44934.25	73	4.970	660
5	ASSM Tolentino	6211.44	66	689	595
6	ENEL Distribuzione - PS Carpinone	36996.85	96	6.242	569
7	Deval - PS Villeneuve	12951.76	68	1.616	545
8	A.S.SE.M. San Severino Marche	3661.41	64	642	365

The eight selected projects have common characteristics (innovative IPR, voltage control in presence of reverse flow, standard protocols), and specific features with respect to the type of environment (urban, rural), the size of the project, and the technological solutions developed.
As regards the size of the project (Table C.3), some projects include a few MV feeders related to a single HV/MV transformer, other projects consider all MV feeders underlying a Primary Station (PS); one project considers two PS with the possibility of network reconfiguration.

Table C.3. Impact on MV grids (size of the projects)

	TOT	P1	P2	P3	P4	P5	P6	P7	P8
DG plants/storage	**49**	*7*	*4*	*5*	*5*	*8*	*8*	*6*	*6*
Thermoelectric	1	-	*1*	-	-	-	-	-	-
Cogeneration	4	*3*	-	-	-	*1*	-	-	-
Biogas	2	-	-	-	*1*	-	*1*	-	-
Biomass	2	-	-	-	*1*	*1*	-	-	-
Photovoltaic	15	*4*	*2*	-	*2*	*3*	*1*	-	*3*
Hydroelectric	23	-	*1*	*5*	-	*3*	*5*	*6*	*3*
Storage system	2	-	-	-	*1*	-	*1*	-	-
Number of PS	**9**	*1*	*1*	*1*	*2*	*1*	*1*	*1*	*1*
Number of MV feeders	**80**	*32*	*7*	*4*	*4*	*12*	*5*	*11*	*5*
Total investment [M€]	**16.5**	*0.8*	*0.8*	*0.8*	*5.0*	*0.7*	*6.2*	*1.6*	*0.6*

Table C.4 shows the technologies included in the different projects: all projects make use of a bidirectional communication system; almost every project considers the future participation of the DNO to the ancillary service market; some few projects develop a storage system and a recharging infrastructure for electric vehicles; one project only includes demand response strategies.

Table C.4. Technical solutions of selected projects

Innovation	**P1**	**P2**	**P3**	**P4**	**P5**	**P6**	**P7**	**P8**
Bidirectional communication	YES	YES	YES	YES	YES	YES	YES	YES
Participation of DSO to ancillary service market	YES	YES	YES	NO	YES	YES	YES	YES
Presence of Storage systems	NO	NO	NO	YES	NO	YES	NO	NO
Infrastructure for electrical mobility	NO	YES	NO	YES	NO	YES	YES	NO
Demand response	NO	NO	NO	NO	NO	YES	NO	NO

An important condition for the selection of demonstration projects was the publicity of the results; for this reason all results will be made public through the website of the AEEG, in order to allow the dissemination of experiences and a more realistic evaluation of the real outcomes of the projects in the perspective of full scale smart grid deployment.

References for annex C

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Annex D - Demonstration projects for smart grids: ICT for an innovative protection, automation and management of distribution networks

As discussed in the paper, the enabling key towards smart grids is given by ICT (Information and Communication Technology). Indeed, ICT will enable DG to provide a real contribution to the security and reliability of the whole power system, while allowing a full exploitation of the hosting capacity. Furthermore, ICT will introduce more flexibility in the connection and access services, and facilitate the participation of DG in the ancillary service and energy markets.

All smart grid demonstration projects selected by the AEEG in the framework of the smart regulation present innovative functions that are based on the superposition of a suitable ICT layer on the electricity distribution network; different communication techniques will be exploited, according to local opportunities/constraints. In the majority of cases, available public networks will be used: Wi-Max, the existing Internet (both wired and wireless, with possible Wi-Max extensions); in particular circumstances, private connections will be put in place (by means of fiber optics, radio-systems, wi-fi links). In general, the communications are based on a broadband, "always on" infrastructure used to connect MV producers, passive customers, main secondary substations and HV/MV substations in order to realize the concept of “extended substation”[30]. Communication among all the devices is mainly based on IEC 61850 standard [1]. As for cyber security, Virtual Private Networks (VPN) will be implemented when public connections are used. A typical architecture is reported in Figure D.1.

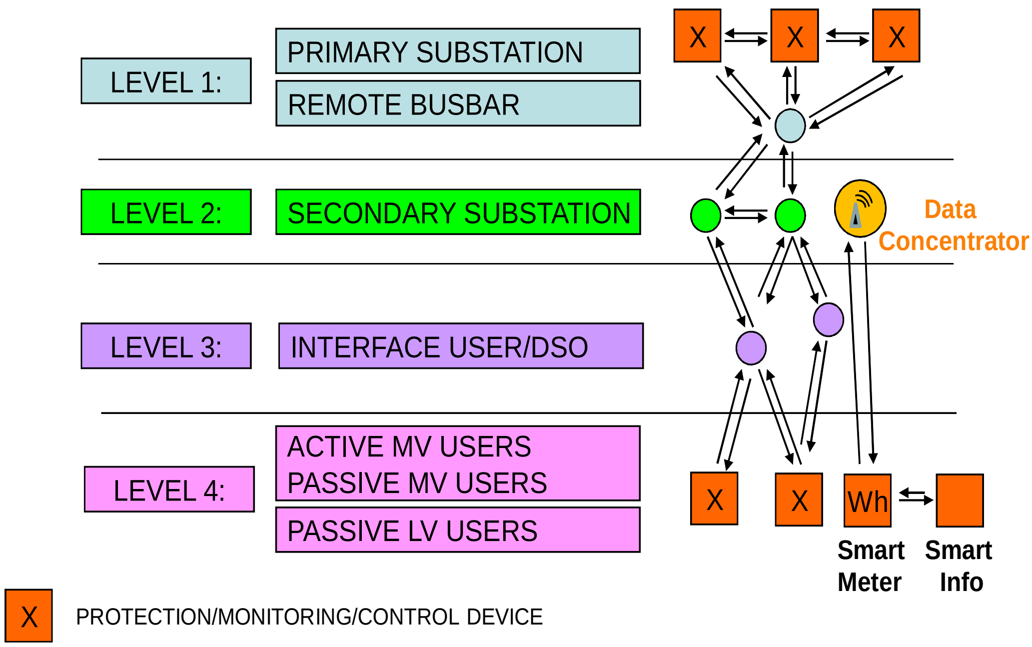

Figure D:7. ICT architecture for the most complex selected project

The demonstration projects will foster the integration between energy networks and information networks, to exploit the possible synergies, to minimize costs, but also to avoid duplication of infrastructures, with negative impacts on the territory. By this new approach, the power grid and the information network would be rather complementary, both in their functions, and in their

[30] The extended substation is an extension of the control and protection system (a concept which is already applied according to IEC 61850 philosophy, only to the primary substation) to all busses (active and passive users) of the MV distribution network.

development. In contexts already highly developed (urban environment), the information network can be employed as a support function for the electricity network; in less densely populated areas (rural environment), new developments in the electricity network are the support for the information network deployment.
The two main features to be guaranteed by ICT systems are:

- extremely short latency (some hundred milliseconds);
- high availability and reliability, even when the electric system faces critical situations (incidents on the transmission system; local faults on the MV distribution system).

A first evolution, made possible by ICT, is related to innovative Loss of Mains (LoM)[31] protections for DG. The main goal of this function is to exchange information between MASTER relay (feeder protection, located in the Primary Station, PS) and SLAVE relay (Interface Protection Relay, IPR, located at the DG premises) in order to overcome the present poor operation of IPR based on local information (voltage magnitude and frequency). The protective relays and the communication system implement the following messages:

- "transfer trip", that master relay[32] (Figure D.2) transmits to slave relays in order to disconnect DG when LoM occurs;
- "keep alive", cyclically exchanged between master and slaves relays to monitor the communication channel.

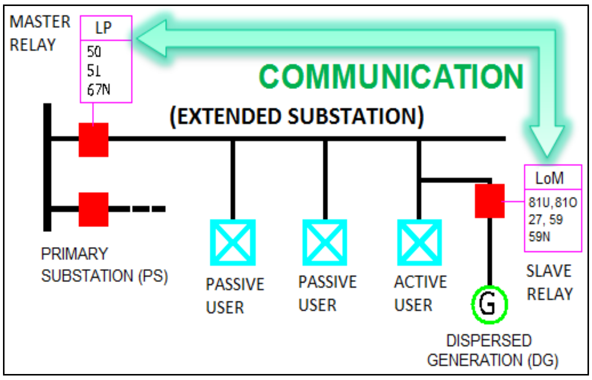

Figure D.2. Transfer trip message in active distribution networks.

Transfer tripping is intended as primary LoM protection and it can disconnect DG also if balance between load and generation exist on the faulted feeder (i.e., when a non-detection zone would appear if only local information is available). The proposed architecture operates in a fail-safe mode: in the presence of the communication system, IPR has wider settings. On the other hand, should the communication fail (a keep alive test is performed f.i. every 5 s), the DG relays come back to the "local" operation (the same of today).
This innovative feature allows a suitable IPR performance also for the cases of active distribution networks, with a significant RPT. A time limit of 200 ms is admitted between the transmission and reception of transfer trip messages; this allows DG being surely disconnected before the first cycle of automatic reclosing (about 400/600 ms on the Italian MV distribution network). When communication is active ("keep alive" received) a low sensitivity setting profile of voltage/frequency protections is enabled in IPR (f.i. 47,5-51,5 Hz), together with transfer tripping, in order to disconnect DG only if LoM occurs. By adopting this protective strategy, also nuisance tripping for faults on MV adjacent feeders is avoided: thus, all local issues of IPR are overcome.

[31] Loss of Mains happens at the opening of the feeder circuit breaker in the Primary Station.
[32] The master relay may be in PS (case b) or in SS (case a). When a fault occurs in a section of the feeder, in the first case the circuit breaker at PS transmits the transfer trip message to IPR, in the second one, the FPI (that is located in SS) nearest to the fault sends a transfer trip message to the IPR of downstream producers, through the relevant network sections; the IPR does no longer need local measurements of voltage/frequency

Moreover, we stress on the fact that such settings allow overcoming the transmission system risk, related to the massive disconnection of DG in case of severe frequency transients on the interconnected European system.
Since the significant power of DG units already installed DG systems has a dramatic influence on network stability in the European electricity grids, there is an urgent need to introduce immediately a regulation of retrofitting to all DG systems, not only those related to the demonstration projects. Among all European countries, Germany and Italy represent pioneering experiences in this field, as a consequence of the important share of RES already connected (especially to low voltage and medium voltage networks). As a matter of fact, AEEG has already taken action in this direction by means of an intervention on the technical rules for the connection of DG units to MV and LV grids [9], [10].

A second evolution made possible by the presence of a communication system that reaches DG units is related to voltage control. According to voltage quality standards, the steady-state voltage limits in the MV distribution system are ±10% of the rated voltage (EN 50160[33]). In a passive network the voltage profile decreases along the feeders. On the contrary, DG can lead to overvoltages that could affect also other customers. In order to overcome this strong limitation and to increase the hosting capacity of the network, all the demonstration projects implement novel voltage regulation strategies based on DG reactive support.
In a first stage, a *simplified control strategy* [4] is adopted: each generator operates without coordination with other generators or network devices (local voltage control). In order to mitigate overvoltages given by DG units, when a particular voltage threshold in the Point of Common Coupling of DG is reached (such as 1.08 Vn), the generator is controlled to absorb reactive power with a fixed power factor (such as 0,95).
In a further stage, that will be made possible by the presence of a suitable ICT network, the control actions of each DG unit will be coordinated at a centralized level (PS level).
A third evolution is related to DG active power curtailment operated by the DSO. Under particular network conditions, linked to temporary limitations to the transit on the distribution network/feeder underlying the DG, the DNO is enabled to modulate/limit the active power injected by each DG unit and, eventually, to control its forced shedding. Such a remote control on DG active injections can be useful also in case of fast remedial actions required by the TSO (Transmission System Operator) in emergency situations on the transmission system (need to limit/shed DG contribution in particular network conditions). Obviously, the demonstration projects will enable for this innovative function but its practical use in real cases will be possible only in a revised (and still to come) regulatory framework, where also DG will be subjected to control actions by the network operators.
The possibility to communicate with DG for the purposes described above enables the acquisition of some interesting parameters of the DG too. In this way it is possible to collect “real time” information on the load and on the power generated by DG along of the MV network (and, eventually, LV). The amount of generation aggregated by each feeder, transformer, and substation, as well as separated according to generation technology (solar, wind, biomass, etc) will be available. Through this system, network operators will be able to effectively manage networks with high DG presence, in the perspective of a local dispatch to be carried out by the DSO. It will be possible to act in real time on the generators so as to ensure a proper management of the distribution system, also including services useful for the transmission system operator. In fact, the system will also serve an interface with the TSO in order to provide data useful for transmission network control.
In summary, the technologies proposed in the projects aim at removing the network constraints so as to accept a larger amount of DG: distribution networks will be operated dynamically, i.e. verifying constraints and security criteria in real time. In this way, differences between operation of

[33] The last edition of EN 50160 allows a deviation up to 115% for 1% of time on MV networks.

distribution and transmission network will be strongly reduced. Further benefits can be summarized as follows: reduction in the total capacity needed within networks; reduction in peak provision by upstream network; reduction in power system losses; higher efficiency in energy delivery; reduction in the large-scale centralized generating capacity.
The overall objectives of demonstration projects, in order to be shifted from field testing to a real extended deployment, need a further evolution (also with respect to [9] and [10]) of the standardization framework (a technical evolution, with both national and international consequences) and of the regulatory framework (with mainly national consequences).

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Annex E – Smart Metering and mandatory Time-of-Use pricing: the implementation in Italy

E1. Smart metering

In 2001 Enel Distribuzione, the largest Italian DSO, launched a project, named Telegestore, aimed at building a comprehensive Automated Metering Infrastructure (AMI) for its entire customer base (over 30 millions LV customers). Telegestore is now a system made of 32 millions electronic meters, more than 350,000 data concentrators (located in secondary substations) and some thousands of meters in selected secondary substations, fully dedicated to energy service applications. As of today, Telegestore is still the frontrunner smart metering application in the international context [1].

The smart meters, installed on each point of delivery of the LV network, are controlled by the AMI system through internal procedures (that necessitate data on network topology, i.e. connections between smart meters and data concentrators) and are remotely managed. Smart meters provide consumption data, load profiles of the customers and voltage quality data. In particular, smart meters can detect violations of the supply voltage variation (SVV) limits given in the standard EN 50160[34]. Enel uses Power Line Carrier (PLC) for the communication between smart meters and the relevant data concentrator, and the public telecommunications network for transmitting the data further to a central data system. PLC communications send signals over power lines between secondary substations and meters; therefore, the LV distribution network is used as a communication medium.

The Telegestore system is the result of a voluntary strategic choice of Enel Distribuzione, based on a business case in which different productivity and efficiency aspects were considered (including the recovery of lost revenues for energy thefts). Other Italian distribution companies started their own smart metering projects after Enel Distribuzione, for instance DSOs operating in the capital Rome (Acea) and in some cities in Northern Italy (first ASM Brescia, then AEM Milano and AEM Torino).

In regulating smart metering, the Italian regulatory authority (AEEG) was pursuing four different objectives: *(i)* enable competition in electricity supply for LV customers; *(ii)* exploit the value for customers of the smart metering investments; *(iii)* give customers a price signal that was aligned with the cost of the electricity; and *(iv)* gather information for load profiling within the dispatching service [16][3] .

After an extensive public consultation, and a thorough, open dialogue with distribution companies and meter manufacturers as well, AEEG issued a decision at end of 2006 that introduced mandatory roll-out of smart meters for all DSOs. The most interesting aspects of this regulatory resolution are described below [3] [5].

First, the regulatory authority has specified minimum functional requirements for smart metering systems, at meter level as well as at central system level. This “technical” decision was motivated by two concerns. The first one was to ensure that all consumers in Italy could benefit from the same opportunities, whether they remained under the customer protection scheme or switched to a new free-market retailer.[35] The second was to ensure interoperability, especially in case of a change in the operator of a given distribution network. In fact, minimum functional requirements are intended to be independent from AMI architectures, in order to avoid any hindering of the technological

[34] Smart meters count the number of voltage samples that, during each week, are within the tolerance range (Vn-10%; Vn+10%) [6].
[35] Even DSOs with a small customer base are obliged to install electronic meters: customers served by small DSOs should have access to the free market with the same opportunities as customers served by large ones.

innovation as for architectures different from those currently used but which may be just as efficient as well. In summary, the key functional requirements relate to:

- ToU pricing: up to four bands, up to five intervals per day (1 totalizer + 4 band registers);
- Interval metering (min. 1 hour, depth: 36 days);
- Remote transactions: consumption reading (registers and intervals), supply activation and deactivation, change of the contracted maximum power, change of the ToU tariff, maximum allowed power level reduction;
- Security of data (inside the meters, during the transmission to the control centre, prompt transmission to the control centre in case of meter failure);
- Freezing of withdrawal data (billing, contractual changes, switching);
- Breaker on board of meters for controlling contractual power limit;
- Registration of the peak power per ToU band;
- Meter display (current totalizer and activated ToU band registers, last freezing);
- Recording of supply voltage variations (according to EN 50160);
- Upgrade of the software: for instance, upgrades must preserve the withdrawal totalizers and registers that have been recorded up to that time as well as the meter's existing contractual settings (price scheme, contractual power, etc.); during upgrades, the meter must be able to measure and record in the appropriate registers the energy withdrawn and keep up the clock/calendar.

Second, as shown in Table E.1, the regulatory authority has defined an installation and commissioning timetable, in four phases and for all DSOs, based on the percentage of LV customers with smart meter installed (independently from their contractual power or their consumption).

Table E.1 – Installation timetable for smart meters

Phase	% of LV customers with smart meter installed	Deadline for installation
1	25% of LV customers < 55 kW and 100% of customers > 55kW	31 December 2008
2	65% of LV customers < 55 kW	31 December 2009
3	90% of LV customers < 55 kW	31 December 2010
4	95% of LV customers < 55 kW	31 December 2011

Note – commissioning deadline: 6 months later than installation

Third, the regulatory authority has defined rules for the metering tariff, differentiating allowed revenues according to the type and quantity of meters actually installed and envisaging to reduce the allowed metering revenues for DSOs who fail to accomplish installation and/or commissioning deadlines.

Fourth, the authority has introduced an incentive for DSOs that use their smart meters to record interruptions at single customer level (on top of the existing requirements for monitoring continuity of supply by means of remote control and SCADA system on MV networks and by means of manual recording for interruptions related to faults on LV networks).

The introduction of smart metering on a large scale was certainly satisfactory for all interested parties. For instance, thanks to smart meter capabilities, non-payant customer have now the right to be served with a vital minimum power equal to 0,5 kW for 10 days before being totally disconnected; as for the market, smart meters allow a low-cost spot reading in case of supplier switching; finally, distribution companies can now control better the performance of the network as for losses and voltage quality [6].

E2. Mandatory Time-of-Use pricing

Since July 2010, even smart meters for household customers must be able to record consumptions on the basis of three price bands: peak, mid-level and off-peak, defined by AEEG as illustrated in Figure E.1 [7]. This provision applies now to all meters with available power lower than 55 kW (around 99% of all meters). Above this threshold, measurement at hourly intervals is mandatory.

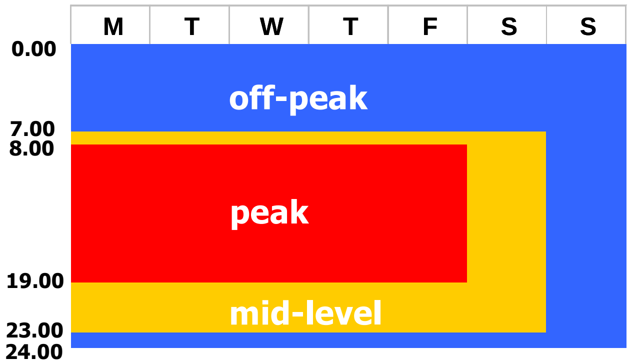

Figure E.1 – Time bands in Italy

In fact, this provision has opened the door to the most important change made possible by smart meters: mandatory deployment of Time-of-Use (ToU) electricity pricing, for all LV customers[36]. More precisely, the Italian regulator has introduced mandatory ToU pricing for all small business and household consumers in the so called "regulated universal supply" (around 25.5 millions customers who did not choose a free market offer but still rely upon regulated electricity price); only the energy component of the final price is differentiated according ToU, not the network charges, but the energy component accounts for more than ¾ of the total bill for an average household customer (typical profile: rated power 3 kW, average yearly consumption 2.700 kWh/year) .

The ToU mandatory regime involves three time-bands for small business customers. For household, two different energy prices apply:

- one price for the peak band;
- one price for the mid-level and off-peak bands.

These ToU prices have been implemented gradually. As a first issue, a direct communication campaign was organised; each household customer received for three times, enfolded in its own electricity bill (issued every two months) a written alert on the change of the pricing system. The regulatory authority imposed Universal Supply Regime provider to wait 6 months from the smart meter reparametrization before applying the ToU prices. In this way, each household consumer could verify in the alert its own electricity consumption metered in the new time bands before the starting of new ToU pricing. As a second issue, the regulatory authority decided that for the first 18 months (from July 2010 until December 2011) the difference between the two prices is limited to 10%; from January 2012 the full difference between peak and off-peak prices given by the electricity market will apply. This is probably the world largest experiment with ToU energy prices for LV customers, household included [8],[9].

[36] The decision, as usual, was the result of broad consultation process that involved all interested parties (customer associations, network companies, regulated universal suppliers, free market suppliers, etc.).

Further regulatory developments in this area can arrive from the recent disclosure of the PLC communication protocol. This has been recently disclosed to be tested as an open standard (within the European project "OpenMeter"). The no-profit association "Meters and More" [10] was constituted purposely to promote this open protocol that could be used for domotic applications.

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Annex F – Selection of demonstration projects for EV recharging infrastructure

On November 2, 2010 the Italian regulatory authority (AEEG) published on its website a consultation document on regulatory issues related to recharging infrastructures for Plug-in Electric Vehicles, PEVs [1]. This was the first piece of the regulatory proceedings initiated by AEEG to promote and support the diffusion of clean and energy efficient vehicles.

The development of electromobility and related green technologies is considered highly beneficial for many reasons: it promotes energy conservation, thanks to savings in primary energy achievable with the electrification of transport; it stimulates the dissemination of innovative technologies with low environmental impact; it reduces the dependence on fossil fuels; and, most importantly, it is one of the most effective tools for reducing pollution in urban centers.

Considered a critical factor for the development of electromobility, recharging infrastructures can rely on different technological and organizational solutions. The idea was that only in-field testing would provide the necessary expertise for designing a regulatory framework that would support electromobility while, at the same time, promote competition in the electricity retail market. Thus, the consultation document focused on two issues: *(i)* the infrastructure design, building and operation, and *(ii)* the different business models that can be applied to an EV recharging station.

Taking a neutral approach to different combinations of technologies and organizational solutions for recharging services, AEEG proposed to test, for a limited time-span, several pilot projects, based on three different configurations:

4. a business model based on Distribution Network Operators (DSO): the DSO is the operator of the PEV recharging infrastructure, but a “multivendor” approach is mandatory, i.e. the infrastructure offers the choice of several electricity retailers, at the same recharging point;
5. a business model based on licensed Charging Service Providers (CSP): a licensed CSP, selected through a public tender by a local administrative authority, in a given territory (the municipality, the province, etc.), builds and operates the PEV recharging infrastructure; this model is open to both a multivendor or a monovendor approach (depending upon the licensing tender conditions);
6. a business model based on competition among CSPs in the same area; this case, that requires high standardisation, envisages several CSPs competing in the same territory; the mobile electricity consumer can choose from different (monovendor) recharging infrastructures, exactly as it is now for diesel/gasoline service stations.

The authority received comments and contributions of a large number of stakeholders: environmental organizations, equipment manufacturers, charging management systems, energy suppliers, distribution companies, consulting and engineering firms. The outcome of the consultation process was the definition of the criteria to be adopted in the selection of the demonstration projects. These were published in a regulatory resolution issued in December 2010 [29] and are listed in Table F.1. Differently from the case of smart grids, the tendering procedure was to be open not only to DSOs but also to other, interested parties. It was even more important in this case, to ensure a non-discriminatory access to the incentive scheme and, thus, a fair and transparent selection process.

As of March 31, 2011 the Authority had received applications for ten projects and in May 2011, the project evaluation phase was complete. The selection was conducted by a technical committee composed by staff of the regulatory authority as well as by a number of experts from RSE (Ricerca

Sistema Energetico[37]). To ensure transparency, the evaluation form of each single project was made public [30]. Incentives were awarded to five projects and include a financial contribution for each charging point, to be paid until the year 2015. The regulation envisages also a protection scheme directed at electric drivers: in addition to the electricity cost, they will pay only a network tariff, set by the Authority and inclusive of the costs of the recharging infrastructure. Finally, every six months all relevant information about selected projects must be reported to the regulatory authority. In this way AEEG will enable to disseminate the main outcomes of the project. Lack or inadequacy of the information provided can lead to a reduction of the incentives.

Table F.1 Evaluation criteria for EV recharging infrastructure demo projects

		Weight
Area A **Technological interest and completeness of the project**		**50**
A1	Size and territorial scope	*21*
A2	Diversification and innovation level of the proposed technical and organizational solutions	*14*
A3	Reliability and feasibility of the project	*8*
A4	Scalability/replicability of the project	*7*
Area B **Economical burden posed on the electrical system**		**14**
B1	Rebate with respect to the standard incentive (728 €/charging-point/year)	*14*
Area C **Relevance of the infomation made available to the electrical system**		**20**
C1	Infomation collected through monitoring	*10*
C2	Monitoring system and data publication	*3*
C3	Period of observability	*7*
Area D **Transaction costs in contractual relationships**		**16**
D1	Efficacy and efficiency of the system the manages the information flow	*8*
D2	Adequacy of the contract between Service provider e local DSO	*8*
TOTAL		**100**

Selected projects include the following.

- one “DSO-based” project, presented by Enel Distribuzione, together with a local company, Hera (serving Modena and Imola); the project, expected to be fully operational by 2013, consists of 310 LV charging points in Pisa, Bari, Genoa, Perugia, several municipalities of the Emilia Romagna region, and the hinterland of Milan;
- two “licensed CSP” projects, the first one proposed by A2A (52 columns with two charging sockets, in Milan and 23 columns in Brescia, to be fully operational in the first half of 2013) and the second one presented by the Municipality of Parma (200 charging points with two independent sockets, operational by the end of next year);
- two “CSPs in competition” projects, one presented by a retailer, Enel Energia (26 charging points in the suburbs of Milan and in downtown Rome, to be operational by the second half of 2013), and one proposed by a no-profit organization, Class Onlus (150 columns, 43 in the province of Monza Brianza and 107 in the parking of some supermarkets in Rome, Milan, Naples, Bari, Catania, Genoa, Bologna and Varese, operational by the second half of 2014); within these two projects a fast charging technology will be tested, capable of recharging electric vehicles in less than 30 minutes with a high power direct current (over 50 kW).

[37] RSE’s mission is to conduct research projects on topics of public and general interest, regarding the overall Italian energy system. RSE is funded with a small levy collected through the electricity tariff.

In addition, thanks to another intervention by AEEG, recharging electric cars directly in private garages at home or in companies' parking is now possible. In April 2011, AEEG removed the legal constraint that prevented electric drivers to "fill up" their electric cars in the household. In fact, according to an old law, domestic electricity consumers were not allowed to have a dual power supply in the same housing unit and this strongly limited the availability of recharging points. As of today, one or more supply points, each with its own meter and specifically dedicated to power electric vehicles, can be installed in private houses or in common areas of a housing building. This measure also applies to parking spaces for vehicle fleets and thus extends the possibility to create charging points to business users. These recharging points will pay the same network tariff that is already in use for non domestic customers, regardless of whether the final user is a family or a business company. As for the cost of electricity, the price will depend on the contract stipulated with the retailer, chosen in the competitive market and not necessarily the same selected for the home supply.

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