TSO-DSO coordination and market architectures for an integrated ancillary services acquisition: the view of the SmartNet project

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SUMMARY

The energy world is facing major challenges as fossil fuel generation is replaced with renewable generation, which is often characterised by variable behaviour. This increases the need for resources to be used to guarantee frequency stability, congestion management, voltage regulation and power quality. At the same time, an increasing number of flexible demand and storage systems is located at distribution level. These resources could potentially be available to provide network services if they are aggregated effectively. To achieve this, however, the roles of the diverse network stakeholders – transmission systems operators (TSOs), distribution systems operators (DSOs) and aggregators – should be reshaped. In tandem with this, the way real-time electricity markets are organised also needs to be adapted to reflect the new operating environment.

The project SmartNet (smartnet-project.eu/) compares five different TSO-DSO interaction schemes and different real-time market architectures with the aim of finding out which one could deliver the best compromise between costs and benefits for the system. An ad-hoc-developed platform is used to carry out simulations on three benchmark countries – Italy, Denmark and Spain Conclusions are drawn on possible regulatory gaps both at European and national level. A Cost-Benefit Analysis (CBA) is implemented to compare the costs needed to implement the five TSO-DSO coordination schemes (e.g. to improve the system ICT) with the benefits drawn by the system.

In this way, the SmartNet project aims at answering the following key questions:

- how should real-time markets be optimally organised for enabling flexible generation and load to provide their contribution to system services?
- which interaction scheme between a TSO and a DSO would prove the most efficient one? What concrete economic benefits could the system draw from this?
- what is the trade-off between these benefits and the extra costs for ICT deployment to implement these new schemes?
- what regulatory impact could all of this have on the present European and national regulation?
- which technological solutions could make it possible to realise a seamless monitoring and control of distributed energy resources (DERs), typically located in distribution?

The present paper summarizes the achievements of SmartNet during the first two project years. Main focus is on the set-up of the simulation platform and on the modelling of the different components (transmission and distribution networks, ancillary services markets, aggregation processes, system regulations). The main information related to the expected 2030 Italian scenario (which will be object of simulation and cost-benefit analysis assessment later in the project) will be provided together with some preliminary reflections on ICT constraints and regulatory implications.

KEYWORDS: ancillary services markets, TSO-DSO interaction, distributed energy resources bidding and aggregation

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INTRODUCTION

During the last years, all Europe has witnessed a significant deployment of renewable generation characterized by variable behaviour. This increased the need for system reserve to be used for providing ancillary services to the system (in particular: system balancing, congestion management and voltage control) in order to maintain system stability. Such reserve was traditionally provided by centralized generation from large power plants, based on coal and gas technologies. For this reason, nowadays ancillary services markets are usually managed by the national Transmission System Operator (TSO). However, recently, large amounts of centralized generation have been dismissed, resulting more and more economically out of merit order in the electricity markets. By contrast we witnessed an increased penetration of Distributed Energy Sources (DER) - distributed generation and flexible loads – typically located in distribution grids. So, it is of great interest to investigate to what extent DER might replace large generation sets in the provision of ancillary services to the system. This would require a change in the role of the Distribution System Operator (DSO) and an increasing level of cooperation between TSO and the different DSOs. As the Council of European Energy Regulators (CEER) points out in [1] "*Some actions can have a negative cross-network effect. For instance, TSO use of distributed resources for balancing purposes has the potential to exacerbate DSO constraints. Equally, whilst DSO use of innovative solutions, such as active network management, can deliver benefits to customers, if not managed properly they may in some cases counteract actions taken by the TSO*".

The Clean Energy Package proposal issued by the European Commission in November 2016 assigns a role to DSOs for local congestion management but not for balancing, whose management would remain in the hands of the TSOs[1]. This separation could seem functional to the network evolution in the short-medium term. However, one could wonder whether maintaining a rigid decoupling between balancing and congestion management potentially risks to lead to inefficient system operation.

All the above allows to understand how the theme of TSO-DSO interaction for the acquisition of ancillary services (AS) from DER connected to distribution networks is presently an important investigation issue. This is the central investigation subject for the European research project SmartNet (http://smartnet-project.eu), a European research project over three years (2016-2018) featuring 23 partners from 9 countries among which 2 TSOs and 3 DSOs.

Different roles are possible for DSOs, depending on the responsibilities they are awarded with respect to the TSO. The project SmartNet identifies five reference coordination schemes:

1. Centralized AS market model – The TSO contracts AS directly with DER owners connected to the DSO grid. The DSO can procure and use resources to solve local grid issues, but the procurement takes place in other timeframes (different from near real time, e.g. long term ahead) than the centralized AS market. Resources in distribution are subject to DSO pre-qualification to be allowed to bid into the centralized AS market.
2. Local AS market model - The TSO can contract DER only indirectly. First, the DSO, via a local market, may procure resources for solving local problems and then an aggregation of the remaining resources is transferred to the TSO AS market.
3. Shared balancing responsibility model - The TSO transfers the balancing responsibility from the distribution grid to the DSO. The DSO has to respect a pre-defined schedule and uses local DER (obtained via a local market) to fulfil its balancing responsibilities. The pre-defined schedule is based on the nominations of the Balancing Responsible Parties (BRP), possibly in combination with historical forecasts at each HV/MV interconnection point.

[1] EC (2016) Proposal for a DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on common rules for the internal market in electricity – Art.32.

4. Common TSO-DSO AS market model - TSOs and DSOs contract DER in a common flexibility market. The main goal is the minimization of total procurement costs of flexibilities contracted by TSO and DSO.
5. Integrated flexibility market model - TSOs, DSOs and Commercial Market Parties (CMPs) contract DER in a common flexibility market. TSOs and DSOs can both buy flexibility or sell previously contracted DER to the other market participants.

SmartNet compares these five reference coordination schemes on the basis of costs and benefits with reference to three national simulated scenarios (Denmark, Italy and Spain) at the 2030 time horizon: different kinds of system benefits are computed, monetised and compared with costs related to Information and Communication Technology (ICT) to implement each coordination scheme. This assessment is complemented by a micro-level analysis, which is aimed at checking if the benefits and costs are correctly allocated, so that all the involved actors have a profitable business case.

An overview of the project SmartNet can be found in [2]. The present paper focuses on providing details on the following aspects:

- the structure of the simulation platform used by SmartNet simulating the three national scenarios,
- the modelling adopted to describe transmission and distribution grids and the aggregation process as well as the enhanced ancillary services market structure investigated by SmartNet, which is conceived in order to take full advantage of the peculiarities of DER connected to distribution networks,
- the main characteristics of the Italian scenario adopted for simulations and cost-benefit analysis,

The project SmartNet also features three technological pilots aimed at showing requirements in terms of communication processes for the monitoring of distribution networks and enabling the participation to ancillary services provision by specific categories of DER (small hydro power stations, thermostatic loads, local storage units). Details on two of them are shown in the companion CIGRE papers [3][4].

THE SIMULATION PLATFORM

Analysis and validation of the proposed TSO-DSO coordination schemes are performed by means of a dedicated simulation platform, which has been developed within the SmartNet project in order to integrate all the investigated concepts. The simulation platform has been structured in three main layers:

- **The market layer**: integrating the market clearing algorithms, which process the bids submitted by the different players and return the optimal activations aimed at restoring the system balancing and solving/avoiding network congestions. Depending on the coordination between the network operators, the outputs provided by this layer are the outcome of a combination of separated market clearing algorithms (typically one local market for each distribution network and one central market for the entire system).
- **The bidding and dispatching layer**: incorporating the algorithms used by the market players participating in the markets described above and aimed at capturing the available flexibility of a big number of energy resources within a few bids and translating market clearing results into activations. In addition to the traditional energy traders and retailers, it models the action of the aggregators, who optimally combine flexibilities of several small energy resources (located at distribution level) into few representative bids. After market clearing, aggregators also decompose the market layer results into the individual power set points to be sent to all the aggregated units.
- **The physical layer**: simulating the effects of the activations on transmission and distribution networks, including the physics of each (flexible and non-flexible) device connected to them. This layer is also inclusive of algorithms aimed at representing the automatic and low-level operations (carried out by TSOs and DSOs) which are not directly triggered by market results but may have an impact on them (state estimation/forecasting, automatic frequency control, intervention of protections, etc.).

Depending on the expected evolution of the current market architecture for the three considered countries, the three layers mentioned above may show different interaction times. For this reason, the SmartNet simulation platform has been designed considering an arbitrary selection of market clearing frequency (how often the market is cleared) and latency (how long the market takes to process bids and carry out the clearing procedure). This option allows investigating different market dynamics (also faster than the current ones), without neglecting the network evolution occurring during the clearing process, which can result in deviations between actual and forecasted network status.
These timing concepts also apply to bidding and dispatching layer routines, which are called according to input requests and availability of results from the market clearing algorithms. For simulation purposes, the physical layer (which is continuous in the real world) has been subjected to time discretization as well, opportunely selected to be in line with the dynamics of the other layers.
The simulation platform allows these three layers to be run in sequence while interacting by means of a dedicated database. This database, in addition to storing simulation results, keeps the log of the communication between the different actors of the considered TSO-DSO coordination schemes. This information plays a fundamental role in another SmartNet activity strictly related to the simulation: the laboratory tests. In fact, the project foresees dedicated laboratory tests on real equipment (controllers for flexible devices, SCADAs, etc.) operating in real-time simulated scenarios where the concepts proposed by SmartNet are implemented. In particular, the operation of these devices will be evaluated in presence of real/realistic information and communication technology, looking at the effects of non-ideal characteristics of the system and at of the interactions between the involved parties.

MODELLING ASPECTS

Within the SmartNet simulation platform described in the previous section, the market module considers only two AS: balancing and congestion management (both at transmission and distribution medium voltage level). Additionally, the market formulation aims at avoiding over- or under-voltages at distribution level. The implemented AS market is a real-time resources-activation market: reserve markets are not represented. The market clearing algorithm decides which bids are (partially or totally) activated and at which price, by optimizing an objective function (e.g. minimizing costs) while satisfying the relevant constraints (e.g. grid, market products). Five key market design ingredients need to be considered and are discussed below:

1. **Network**: transmission and distribution grid models are incorporated into the market clearing algorithm in order to solve congestion and/or avoid creating it while balancing the network. Ideally, Kirchoff AC equations should be used for both transmission and distribution networks in order to obtain best accuracy, but since these equations are non-linear, the market clearing optimization problem would become computationally intractable. Hence the need for an intermediate model between full AC and copper-plate (i.e. no network constraints taken into account). As a minimum requisite, network models need to be convex and fit for being used in an optimization algorithm. The models chosen for transmission and distribution grids are different because of different challenges (lines more resistive in distribution grid, distribution grid operated radially): a traditional DC linear approximation is used to model the transmission grid (losses and reactive power exchanges are not modelled), while a more detailed convex Second Order Cone Program (SOCP) model is chosen for the distribution network, allowing to model losses, voltage magnitudes and both reactive/active power losses. Further details on the reasons for choosing these models can be found in [10]. These models can be used for all considered TSO-DSO coordination schemes, both centralized and decentralized.
2. **Timing**: there are several important timing parameters to consider in market design: 1) time horizon of the market, i.e. the time period for which AS providers trade their flexibility within one market session (e.g. 30 min), 2) time granularity, i.e. how the time horizon is split in smaller periods of time to better define the flexibility demand and offers (e.g. 5 min), 3) market clearing frequency (e.g. every 30 min), 4) gate closure time and 5) activation time. Many combinations are possible. For instance, we can consider a time horizon with several time steps and a clearing frequency equal to the time horizon, but also a rolling time horizon (e.g. clear every 5 min for a 30 min time horizon, with the results of the first time step being firm decisions and the next ones

being advisory information). The market module is configured to permit several timing configurations so as to allow these parameters to be tuned to the specificities of each country.

3. **Bidding**: a catalogue of different technology-neutral market products is proposed with the goal to provide a level playing field to AS providers and leave the freedom to bidders to express, in a more or less complex way their constraints. Thus, market products range from simple (curtailable or not) quantity-price pairs to complex bids spanning multiple time steps with inter-temporal constraints (e.g. ramping, minimum duration, integral constraint) or logical constraints (e.g. exclusive constraints between bids). Some bid constraints require the usage of binary variables in the optimization problem (e.g. a simple non-curtailable bid). Taking also into account the adopted distribution network model, this means that the optimization problem to be solved is a MISOCP (Mixed Integer SOCP) problem [11].
4. **Clearing** : The objective function of the market clearing is to minimize the activation costs of the system operator(s) (depending on the coordination scheme), except for the *Integrated Flexibility Market model* for which the objective is to maximize the welfare. Note that minimizing activation cost was preferred over maximizing the welfare since the latter could decide to activate a zero-sum selection of opposite sets of bids (upwards and downwards) just because it increases social welfare, while it is not necessary for the system operators to fulfil their AS needs.
5. **Pricing**: The pay-as-clear approach is chosen (as opposed to pay-as-bid), as recommended by EC network codes. Also, to reflect the true value of the flexibility, the locational marginal price (LMP) approach is chosen as a pricing scheme: this means that the price can potentially vary from one node to the other, due, for instance, to losses, current congestions and over/undervoltages [12].

In the decentralized TSO-DSO coordination schemes, there is a need to couple different markets. For the Local AS market and Common TSO-DSO market (decentralized variant), the DSO needs to transfer the flexibility bids received in its local market to the global (TSO) market. A smart way to do it is for the DSO to build an aggregate parametric curve, minimizing the activation costs while taking into account its own grid constraints. In the Shared Balancing Responsibility model, DSO and TSO markets do not interact: they are only linked by the common flows schedule agreed at the border between TSO and DSO.

As electricity markets are usually organized in cascade (day-ahead, intraday, ancillary services), supply and demand are typically progressively modified passing from one market to the subsequent one along with the updated production and consumption forecasts in near real-time. This opens an opportunity for controllable loads, which can value (trade) energy back and forth across markets: a generation asset could sell energy on a weekly future, buy back energy in the cheap night hours in the spot auction, and ramp up again in the intraday or ancillary markets in case of energy balance shortage.

This mechanism of flexibility optimization across markets is a tangible reality already today, exploited by most advanced utilities and Independent Power Producers (IPP). In SmartNet we also make available the same option to the Aggregator, whose role is to maximize the value of flexibility under his command. Although flexibility can only be sold once (in real time), its forward value can be churned, i.e. be bought and sold several times, across markets layers. The last position adopted by a flexibility in the markets preceding the AS market conditions the direction in which flexibility can be offered in the market.

For illustration purposes, let’s take the example of a demand asset able to curtail its load. Assuming that in the spot auction the aggregator choses to consume (not curtail), in the intraday its flexibility is to curtail consumption (it cannot consume more). If the aggregator sells volume in the intraday (i.e. it exercises its curtailment flexibility), the next option becomes to consume again, and hence it should sell volume only if it is economically feasible; otherwise it would be better-off waiting. This chain of logic is implemented in the SmartNet simulation environment in order to emulate a risk-averse but rational behaviour of rational aggregators, thereby requiring a risk-premium in order to exercise its optionality now rather than later; this risk-premium will therefore be added to the flexibility cost discussed below.

Eight different DERs categories, i.e. electric energy storage (EES) units (stationary and electric vehicles), distributed generation (variable renewable energy sources, combined heat and power (CHP) units and conventional generators) and demand response (shiftable and curtailable loads, as well as thermostatically controlled loads (TCLs)), have been defined and modelled in [13]. Since DERs are typically small in terms of the flexibility quantity they can individually provide, aggregator's role is to gather the flexibility provided by many DERs, and forward it, in the form of complex price-quantity bids, to the AS market. Flexibility cost[2], is an input needed for attributing a bidding cost to individual DERs. Most of DERs cannot compete individually in electricity markets since a) the power offered must be above a certain threshold, which is defined differently country by country [14] and b) an increased number of market participants can have a negative impact on the performance of the market clearing algorithm. Therefore, aggregators play a key role, by reducing the amount of data passed onto the AS market, whilst making it possible for small DERs to participate in AS markets and obtain additional revenue streams. Out of the four distinct aggregation approaches used in the electricity markets, i.e. physical [5], traces [6], hybrid [7] and data-driven [8], the physical approach, representing in detail the physics of each flexibility provider, is found to be the most suitable one, due to lower number of devices which are being aggregated into each MV node. Traces approach characterizes flexibility providers by their load profiles, and a cost assigned to each of them. This could be convenient when, due to confidentiality reasons, prohibitive complexity or insufficient accuracy of the available models, physical characteristics can't be provided. In the data-driven approach, the input parameters of the cluster being aggregated, are estimated based on the available historical, or simulated, data. The hybrid approach represents the entire population of aggregated devices by using a single or a limited number of individual devices. The eight abovementioned DERs categories are grouped, on the basis of their technology similarities, into five aggregation models [9]: atomic loads, CHP units, curtailable generation and curtailable loads, EES units and TCLs. The model for atomic loads, which aggregates non-interruptible processes, adopts the traces approach, whereas the remaining aggregation models adopt the physical approach. Although the physical approach implies the aggregator knows the parameters of each device, its advantage is to allow a simple aggregation process and straightforward disaggregation procedure.

The actual behaviour of each device, has to be considered together with the overall evolution of the electrical network, in order to evaluate the effectiveness of both market clearing and aggregation/disaggregation strategies. For this reason, a dedicated part of the simulator (physical layer) has been developed in order to process the set-points applied to the different players and to return an updated status of the network by considering the response of each single connected unit.

For this purpose, the power exchanged by each device has been calculated by using zero- and first-order state-space equations modelling the dynamics of the flexible units, which are comparable with the time resolution of the SmartNet simulator (i.e. 5-15 minutes). These models also include stochastic variables, aimed at representing the natural noise introduced by their internal non-controllable variables.

The network status is then updated by processing a conventional power flow for both the distribution and transmission level of the considered electrical system. In order to limit the dimension of the whole problem, only distribution systems with local market potentialities (subjected to frequent congestions) have been modelled in detail. The remaining ones have been assumed to behave (from the market perspective) as copperplates and they have been represented as a single-bus networks (to which all the related devices are connected).

As anticipated above, in addition to the network and devices physics, the physical layer also simulates the extra-market actions taken by network operators' SCADA. These actions are mainly aimed at constantly maintaining the grid within its constraints and they mainly consist of voltage regulation, reactive power compensation, automatic Frequency Restoration Reserve (aFRR) and network protections.

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[2] When the flexibility cost is positive, flexibility cost represents the minimum amount of money a bidder is requesting to receive for providing flexibility. In the case it is negative, it represents the maximum amount of money a bidder is willing to pay to the market for providing flexibility.

Finally, another important aspect to be modelled is network monitoring accuracy. For this reason, realistic state estimation errors are constantly added to the network physical quantities in order to evaluate their impact on the entire simulation loop (physical, bidding, market and dispatching layers).

THE ITALIAN SCENARIO

The Italian scenario reflects a likely situation in 2030, in line with ENTSO-E Vision 3, with the additional assumption that demand response is only a portion (50%) of its full potential and cross-border interactions will not be expanded with respect to the current situation [18]. For this scenario, a data set representing the northern half of Italy has been created for the simulations: it includes 3648 transmission grid nodes, and 2410 distribution grid nodes. As anticipated in the previous section, only 50 distribution grids are modelled in detail, while the remaining one as single nodes (copperplate assumption). These 50 networks have been selected on the basis of the amount of installed distributed generation, as well as the availability of flexible resources and their potential for solving local congestions.

Flexible devices, i.e. all kinds of controllable loads, generators, and other resources, are assigned to network locations in the most realistic way possible. On generation side, the most significant difference with respect to present is that the capacity of photovoltaic panels is more than doubled, while on consumption side, the highest flexibility potential is expected from residential loads.

Since individual devices are singularly modelled, the resulting dataset is very large: It includes 655,323 photovoltaic panels, 31 wind farms, 20 large CHP plants, 1,833 run-of-river hydropower plants, 308 conventional fuel-based generators, 13 pumped hydro stations, 212,704 electrical cars, 1,489,193 residential wet appliances (washing machines, dishwashers, tumble dryers), 68,481 residential heat pumps, 33,783 dimmable street-lights, as well as non-controllable loads in all distribution grids and some transmission nodes. Heuristic statistical distributions are used in order to select the most realistic model parameters for each device allocated on the simulated network.

Time profiles are used to describe both scheduled and forecasted devices behaviour, such as power exchange of PV power plant, availability and driving pattern of electrical cars, day-ahead/intraday market schedules etc.

One very important aspect in creating the simulation scenario is the association of individual devices to network locations. Sometimes, especially for large generators, this information is readily available. However, this is often not the case (especially for distribution resources) and this information must be derived from other data, such as population density, renewable energy resource availability, etc.. For this purpose, regional statistics from Eurostat [19] have been used in a systematic way to split national numbers into regional/provincial ones. For example, the number of washing machines in each distribution grid was determined by first estimating its amount per province, based on assumed ownership level and projected population in 2030, and then splitting this figure amongst the distribution grids within the given province. Finally, locations within each distribution grid were determined such that the resulting locations of all devices gave rise to a realistic amount of congestion.

CONCLUSION

Beyond the Italian scenario, described above, SmartNet will consider other two reference models: one for Denmark and one for Spain. For all the three scenarios, simulations and CBA will be carried out in order to asses which TSO-DSO coordination scheme shows the best performance from the technical and economical point of view. Such CBA methodology will take into account on one side costs to activate frequency regulation reserves (secondary and tertiary regulation) and, on the other side, expenditures attributable to ICT upgrades to implement every single TSO-DSO coordination scheme.

After the results of the CBA analysis for all considered scenarios become available, they will be compared with trends for regulation, both at national and at European level in order to understand how realistic is the implementation of these optimal solutions, and, if so, what could be the time horizon at which this becomes possible, which are the enabling factors and which are the barriers to this development.

A thorough analysis of the solutions proposed by SmartNet project, and their comparison with the current set of roadmaps, regulatory frameworks and recommendations will help us formulate a set of observations and recommendations aimed at regulators and policy makers who have a key role in implementing TSO-DSO coordination schemes and supporting further DER integration. Meanwhile, based the experience gained during the first two project years and on the very lively on-going debate taking place in Europe on the issue of TSO-DSO coordination, we propose the following preliminary considerations:

- If the current forecasts on the evolution of the generation park in Europe prove true (e.g. progressive phase-out of nuclear and conventional generation – especially coal-fired – further increase in the penetration of RES and, in particular, DER, increased flexibility of loads), this will drive DSOs to abandon the fit-and-forget policy and **implement real time network monitoring** in order to identify the real time state of the system. At the same time a significant increase in the share of ancillary services procured at the distribution network level will make this real time network information crucial for preventing congestion and ensure dispatchability of the procured services. This will force **TSOs to share with DSOs part of their responsibilities** in the AS procurement process.
- Regardless of which TSO-DSO coordination scheme is selected for the final implementation, actions taken by **TSO and DSO must not cause counteracting effects** (e.g. interferences between local congestion management and balancing), as discussed in [1]. This can be facilitated by implementing a "**common marketplace**" across the different AS markets [15], meaning that common merit order lists are formed and put in common between the different markets managed by TSO and/or DSO in order to avoid duplicated bids and double activations.
- Before implementing those coordination schemes which foresee a separate market for local congestion management at the distribution network level, **market liquidity** of such local AS markets should be carefully evaluated. Typically, network oversizing resulting from the current fit-and-forget strategies and the inherent radial structure of nowadays distribution networks do not help create liquid markets for congestion management. Then, ad hoc solutions should be sought.
- Restructuring of the national AS markets should take into account possibility of a **seamless integration with preceding energy markets** (day-ahead, intraday) so to avoid providing gaming opportunities (e.g. between non-nodal energy markets and nodal AS markets).
- Any new AS architectures should be carefully implemented so as to allow a seamless **integration with on-going transnational integration process** (ENTSO-E "platforms"): sharing reserve between countries is regarded as a key for allowing further RES integration. This adds a horizontal dimension of TSO-TSO coordination to the discussed vertical dimension of TSO-DSO integration. A balance has to be sought between local optimality of the implemented solutions (e.g. exploiting peculiarities of a given country) and the implementation of a harmonized pan-European design: making an effort for **implementing harmonized AS markets and TSO-DSO interaction schemes** throughout Europe could be essential in order to prevent distortions when these markets become coupled.
- The DSO landscape in Europe is manifold (i.e very big DSOs coexist with quite small ones which may even not be directly connected to the TSO network). If coordination schemes giving more responsibilities to DSOs are to be implemented, **smaller DSOs will most likely have to integrate their efforts and pool together** in order to get fit to take on new responsibilities. To this purpose, a single independent AS market operator could be appointed, acting on behalf of several DSOs on a given territory.
- **Real-time market architectures** must take into account the characteristics/constraints of the potential flexibility providers connected to distribution grids in order to allow them to compete with traditional generators on a level playing field basis.
- **Viable business models** must be available for all market participants, including DERs, aggregators and other customers, while regulators should ensure that market participants draw an adequate remuneration from the market. For critical cases and for an initial period, some incentivization mechanisms could prove useful.
- An equilibrium should be sought in **distribution networks planning** between network oversizing (usually stemming from the old "fit and forget" philosophy) and creating liquid markets for local congestion management. It will be up to the Regulators to provide the right incentivisation

towards limiting less critical infrastructure investments to overcome structural congestion, while leaving up to the markets to manage congestion wherever the cost of a new line/equipment is not matched with corresponding benefits.

Finally, ICT is one of the most important ingredients for implementing a robust TSO-DSO coordination and, whatever solution is implemented, a thorough analysis of information requirements is unavoidable. In SmartNet ([16][17]), an iterative and incremental design and analysis process was developed to break down the AS provision processes into information objects, interaction events, and corresponding ICT requirements. The process was applied to the selected ancillary services in each TSO-DSO coordination scheme. To support this process, a configurable Smart Grid Architecture Model (SGAM) was developed, where ICT requirements for each information exchange event can be altered. This is vital, since ICT systems and communication technologies evolve fast and it will take some time before new TSO-DSO coordination scenarios are realised. The developed process and complementary tool are beneficial for choosing suitable communication technologies for different parts of the energy system and to assess the OPEX and CAPEX costs of the ICT deployments in different TSO-DSO schemes.

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