**Distributed Renewable resources Exploitation in electric grids through Advanced heterarchical Management**

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**ABSTRACT:**

This document describes the scientific barriers that have to be overcome to enable distributed balancing market place at the distribution level. The first part of the document is dedicated to a short analysis of scientific barriers and advances related to the introduction of distribution level marketplaces; the second part of the document proposes a risk analysis perspective to integrate the contingencies into the new marketplace framework.


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1 PU =Public PP = Restricted to other program participants (including the ECservices); CO = Confidential, only for members of the Consortium (including the EC services), RE = Restricted to a group specified by the Consortium (including the EC services).

2 R = Report; R+O = Report plus Other. Note: all "O" deliverables must be accompanied by a deliverable report.

3 Filename must follow the semantic defined in the Handbook (eg DX.Y_name to the deliverable_v0xx). v1 corresponds to the final release submitted to the EC.

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# Executive Summary

This document presents the scientific advances to enable distributed balancing marketplaces at the distribution level. The document presents at first an overview of the current responsibilities of the DSOs accompanied with the arising challenges regarding the grid operation and reinforcement. After identifying the barriers, a series of new roles for DSOs to cope with the challenges has been described. The most significant opportunities for DSOs include:

- Pooling of flexibility
- Flexibility Aggregation
- Flexibility procurement

The identified scientific barriers include also restrictions introduced by the data handling for the marketplace to be created, as well as the reliability and data privacy and security barriers inserted by the new market schemes to be designed.

A behavioral analysis of the grid users is also presented as a service offered to DSOs in order to discover and use flexibilities. While the sustainable electricity sources are penetrating more in the electric energy production, renewable and intermittent energy sources could be used to offer reserve with limited reliability. This raises new problems for operators who prefer to rely on trustworthy but expensive offers, rather than on unreliable and cheaper offers. Consequently, in this document we deal with the evaluation of these new local reserves' reliability.

The core advances and methodology to implement the distribution level marketplaces are presented from the contingencies point of view. A brief risk analysis is given in this document explaining the impact of power system (un)reliability, the proper reserve dimensioning and the creation of a capacity market following the risks.

System operators have access to balancing services to maintain the real time balance by adjusting generation and consumption, using contracted reserve capacities. Balancing reserve capacities provides flexibility to react to sudden changes on the supply or on the demand side.

The methodologies to incorporate the externalities introduced by the aforementioned uncertainties are also provided in the document; they can be seen as deterministic, probabilistic and fuzzy logic methods. Although the risk management can be thoroughly designed to "forecast" the majority of contingencies, the time and spatial granularity of markets and the related usage of flexibilities have also been identified as potential risks by themselves.

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# List of acronyms / abbreviations used in this document

| Acronym / abbreviation | Definition |
|---|---|
| DER | Distributed Energy Resource |
| DG | Distributed Generation |
| DSO | Distribution System Operator |
| DSR | Demand Side Response |
| HV | High Voltage |
| LV | Low Voltage |
| MV | Medium Voltage |
| RES | Renewable Energy Sources |
| TSO | Transmission System Operator |
| WAMC | Wide Area Measurement and Control system |
| WP | Work Package |

# Glossary of terms used in this document

For a full glossary of terms and how they are used within the DREAM project, see the publication D5.1 “DREAM Reference Object Model and Dictionary” [DREAM-D5.1]

# Introduction

The aim of the DREAM-project is the design and implementation of a distributed balancing market place at the distribution level to enhance the role of DSOs towards the efficient usage of flexibilities within the DREAM framework.

Under this perspective, the responsibility of DSOs to provide reliable energy to end-users, can be translated into the aggregation of possible available local flexibilities; the usage of these flexibilities under certain circumstances can be seen as a kind of ancillary services to the upstream power grid. Therefore, the DSOs are exploiting the hidden flexibilities of intermittent power sources and end-users, not only to answer to TSOs' requirements but also to address locally the newly raised problems introduced by either the higher penetration of intermittent power sources into their grid or any contingencies after a given event in the grid, in the distribution level grid.

However, the design and implementation of such functionalities and distributed marketplaces assumes the installation of new background functionalities and infrastructures, as well as new roles and player in the market. Parts of currently under deployment infrastructure can be extended and used as part of the newly described applications of distributed marketplaces, although they are carrying their weaknesses together.

ICT applications constitute the backbone of the smart grid infrastructure. The aggregation and extraction of possible flexibilities requires reliable communication for measuring and control functionalities. Another significant barrier, which combines legal and technical challenges, is the definition of new roles for DSOs as part of the distributed marketplaces, and the consequent data ownership and data security.

The uncertainties introduced into the application of the distributed marketplaces by the intermittent character of the renewable power sources and by the end-customers demand profiles should not be forgotten; in distribution level we are facing small scale demand and production, meaning that the uncertainty is much higher than in the transmission network.

Within the DREAM framework an attempt to mitigate the aforementioned scientific barriers is carried out, by means of risk analysis and management. The introduction of a capacity reserve market in parallel with the day-ahead balancing market will be validated in the DREAM Project.

# 1. Barriers and scientific advances for the balancing market at the Distribution level

## 1.1. Introduction

The European distribution systems are evolving from the traditional passive distribution networks which were designed to receive bulk power from transmission system and distribute it to customers, to more active distribution networks that present enhanced capabilities for monitoring and control of the power flows as well as the facilitation of energy markets. In the context of DREAM project and especially in work package 3 the dream electric power balancing marketplace is presented.

## 1.2. Key Challenges for Current Distribution Networks

The Distribution System Operators (DSOs) are facing new challenges. The traditional mission of a Distribution System Operator is to operate, maintain and develop an efficient electricity distribution system [EURELECTRIC, 2010].

A new role that the European DSOs are asked to fulfill is: *the facilitation of effective and well-functioning retail markets* [EURELECTRIC, 2010].

Effective retail markets are markets that give options to the customers allowing them to choose the best supplier and allow suppliers to offer options and services best tailored to customer needs.

The evolving role of the DSO includes also the efficient access to and integration of distributed generation. The DSOs need to assess novel regulatory frameworks that would be capable to:

- Enable and enhance the increased integration of Distributed Generation in the premises of the Distribution Grid
- Allow the DSOs and DG operators to become involved in the delivery of ancillary power system services
- Permit the involvement of grid customers (demand-side participation). This way active consumers (demand-response) help the DSO to ensure an even supply of electricity by smoothing out peaks (demand-side management). This active involvement can bring benefits for consumers, suppliers as well as the operators of the distribution grid.
- Optimize the network operation (by reducing operational costs while increasing the robustness and reliability of the network) through the appropriate utilization of all the previous capabilities.

Distributed generation is characterized by being proximal to the loads. Therefore it is expected to contribute to the security of supply, power quality, reduction of transmission and distribution peak load and congestion, reduced need for long distance transmission, avoidance of network overcapacity, deferral of network investments and reduction in distribution grid losses (via supplying active power to the load and managing voltage and reactive power in the grid).

But in practice the integration of distributed generation into distribution networks represents a capacity challenge due to DG production profiles, location and firmness along with the fact that DG production is mostly non-controllable. Therefore, production does not always coincide with demand (stochastic regime) and it is possible to lead to unsecure situations for the grid operation. In addition, power injections to higher voltage levels need to be considered where the local capacity exceeds local load. This poses important challenges for both distribution network development and operation [EURELECTRIC, 2013].

Consequently, the evolution from traditional passive distribution networks to active distribution networks may cause the following problems:

- Increased need for network reinforcement to accommodate new DG connections
- Increased complexity for extension and maintenance of the grid

Technical problems that arise with the operation of the active distribution grid:

- Local power quality/operational problems, in particular variations in voltage but also fault levels and system perturbations like harmonics or flicker
- Rising local congestions when flows exceed the existing maximum capacity, which may result in interruptions of generation feed-in or supply
- Longer restoration times after network failure due to an increased number of faults and the severity of such faults [EURELECTRIC, 2013].

### 1.2.1. Distribution Network Operation

Distributed generation and in particular renewable generation, poses a challenge not only for system balancing, but also for local network operation. The security and hosting capacity of the distribution system is determined by voltage (statutory limits for the maximum and minimum voltage ensure that voltage is kept within the proper margins and is never close to the technical limits of the grid) and the physical current limits of the network (thermal rates of lines, cables, transformers that determine the possible power flow).

A distribution system can be driven out of its defined legal and or physical operating boundaries due to one or both of the following:

- *Voltage variations*: Injection of active power leads to voltage profile deviations. Voltage increase (overvoltage) is the most common issue at the connection point for DG units in the same grid area. Reversed power flows (flows from distribution to transmission) occur when DG production exceeds local load. The more local production exceeds local demand, the stronger the impact on voltage profiles. DSOs may have difficulties in keeping within limits the voltage profile at the customer connection points, in particular on LV level, as active voltage control is not in place. In most countries, monitoring of grid measurements is missing and most distributed generators are not properly equipped to participate in the energy management systems, hence no active contribution of generation to network operation is expected. As a result, operational system security may be endangered and security of facilities (both customers' installations and the network) put at risk.

- *Congestions*: When excessive DG feed-in pushes the system beyond its physical capacity limits. Congestions may occur in distribution networks. This may lead to necessary emergency actions to interrupt/constrain off generation feed-in or supply.
  A similar situation can occur in case of excessive demand on the system. This could apply to high load incurred e.g. by charging of electric vehicles, heat pumps and electrical HVAC (heating ventilation and air-conditioning).

Generation curtailment is used in cases of system security related events (i.e. congestion or voltage rise). The regulatory basis for generation curtailment in such emergency situations differs across Europe. Curtailment/feed-in management rules are not defined by law at all (e.g. Austria), defined at the Transmission System Operator (TSO) level only (e.g. Spain or Italy) or defined at both the TSO and the DSO level (e.g. UK or Germany according to the revised feed-in law). In some countries (e.g. in Italy, Spain, Ireland), the control of DG curtailment is de facto under TSO jurisdiction: the DSO can ask the TSO, who is able to control active power of DG above a certain installed capacity, to constrain DG if there is a local problem. As the TSO is not able to monitor distribution network conditions (voltage, flows), DSOs can only react to DG actions. This can result in deteriorating continuity on the distribution system, which will impact both demand customers and DG [EURELECTRIC, 2013].

In systems with a high penetration of DG, both types of unsecure situations already occur today. As a result, DSOs with high shares of DG in their grids already face challenges in meeting some of their responsibilities. These challenges are expected to become more frequent, depending on the different types of connected resources, their geographic location and the voltage level of the connection.

### 1.2.2. Network Reinforcement

The network reinforcement consists of the grid upgrade but also of the grid extension in order to improve the overall service delivery. The ability of DG to produce electricity close to the point of consumption alleviates the need to use network capacity for transport over longer distances during certain hours. However, the need to design distribution networks for peak load remains undiminished and the overall network cost may even increase. For example, peak residential demand frequently corresponds to moments of no PV production.

## *1.3. The role of DSOs in tomorrow's electricity market*

### 1.3.1. Pooling of flexibility

System operators (TSOs and DSOs) have the responsibility to ensure system stability and security of supply. Today, the main tool used by DSOs to overcome increases in electricity consumption or generation in their network is to reinforce the grid by laying down more electricity cables, upgrading transformers, etc., but the alternative approach of making the most of flexibility offered by grid users is gaining momentum [EDSO for smart Grids, 2014].

Grid users' flexibility can be defined as the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service within the energy system.

In the DREAM balancing market, flexibility will be considered as the possibility of a grid customer to change his active/reactive power production or consumption (and get remunerated for this action). The distribution grid operator afterwards can appropriately utilize itself this flexibility in order to optimize the network operation or deal with (minor) contingencies. The parameters used to characterize flexibility include the amount of power modulation, the duration, the rate of change, the response time, the location etc.

The distributed generation curtailment, mentioned in the previous chapter, can be considered as a form of utilization of flexibility. It is in the scope of DREAM project to properly define the balancing marketplace and create a platform for trading of flexibilities.

The possible market uses of flexibility are the following [EURELECTRIC, 2014]:

- **Portfolio optimization**: It is used by market players to meet their energy obligations resulting from energy markets at minimum costs by arbitrating between generation and demand response on all different time horizons.
- **Balancing**: This refers to the procurement of balancing services (capacity) and activation of balancing energy by the TSO to balance demand and supply through the balancing energy market. This is related to all actions and processes, from balancing gate closure time until real-time through which TSOs ensure, in a continuous way, the maintenance of the system frequency within a predefined stability range.
- **Constraints management in transmission and distribution networks**: Besides portfolio optimization and balancing, flexibility will also help to relieve constraints in transmission and distribution networks. Flexibility services will allow network operators to tackle network constraints in all timescales, maintaining reliability and quality of service and maximizing integration of distributed energy resources.

In addition, a fundamental distinction has to be made between flexibility used by *market players* and flexibility used by *network operators* [EDSO for smart Grids, 2014]:

- **Market players** always refers to activities performed with a commercial interest in mind, and actions focused on satisfying the energy needs of customers
- **Network operators** always refer to DSOs and TSOs, which are regulated companies and pursue an objective of efficient grid planning and operation. This kind of flexibility is related to security of supply and quality of service.

*Table 1: Difference between flexibility used by commercial parties and regulated parties [EDSO for smart Grids, 2014]*

| Party | Activity | Business model based on | Will procure | Flexibility use | Final aim |
|---|---|---|---|---|---|
| Commercial Party (supplier, aggregator, balance responsible party) | Buy and sell electricity (MWh) in a market | Price set by market rules | Portfolio Optimization | System-wide | Profit maximization |
| Regulated party (Transmission System Operator) | Channel electricity between generators and consumers | Regulatory mechanism to cover costs | System Flexibility Service | System-wide | Grid planning and operational efficiency maximization |
| Regulated party (Distribution System Operator) | Channel electricity between generators and consumers | Regulatory mechanism to cover costs | System Flexibility Service | Local, regional or national | Grid planning and operational efficiency maximization |

A system operator can procure the option to activate flexibility (directly from a generator or a customer who is a Balancing Responsible Party (BRP) or acts via an intermediary). The TSO and DSO, respectively, should be responsible for the remedial action in their own grids [EURELECTRIC, 2014].

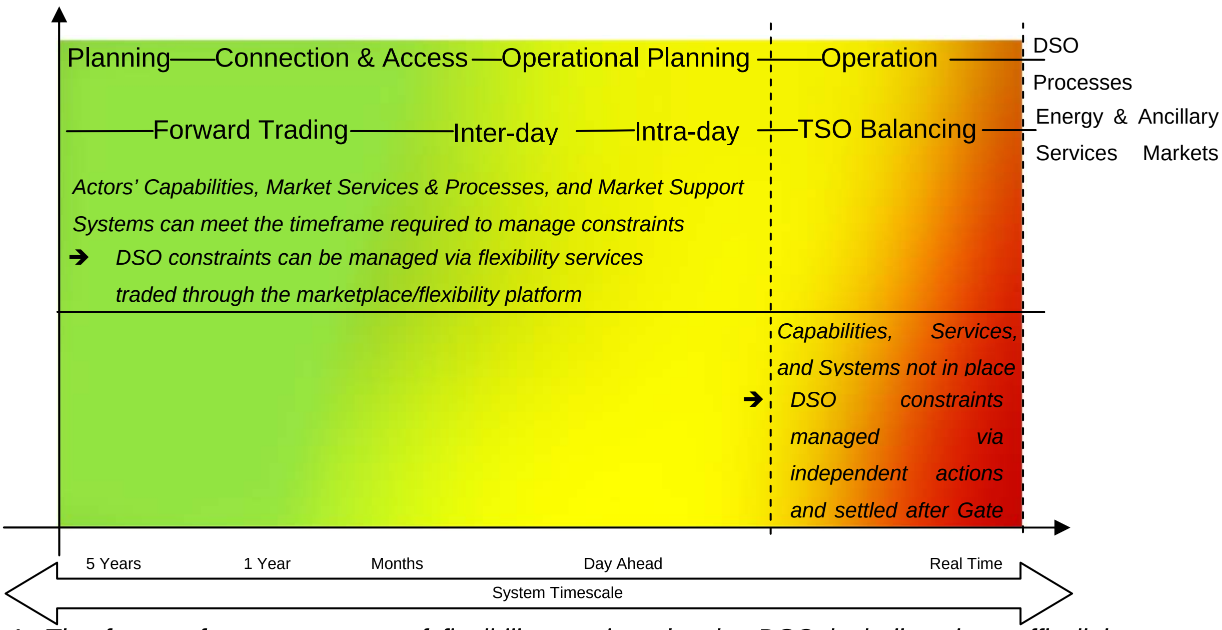


*Figure 1: Timeframes for procurement of flexibility services by the DSO including the traffic lights approach [EURELECTRIC, 2014]*

A rising share of variable generation in the system increases the need for the remainder of the capacity - both on the supply and the demand side - to complement flexibly this variable output. In systems with a high share of variable renewables (RES), lower predictability in the market as well as for network operators implies a high need for flexibility to cope with this volatility.

### 1.3.2. Flexibility Aggregation

In DREAM project, the flexibility will also be used in an aggregated form. This way, it would be possible to utilize a larger potential of flexibility. A number of technologies can provide flexibility, including centralized or decentralized generation, demand side participation and energy storage. However, only very large customers, e.g. industrial customers, find it easy to sell their flexibility on an individual basis and participate in the flexibility market today. Smaller residential and commercial customers may face high barriers in accessing these markets. Transaction costs of such participation are too high if managed at individual level.

Aggregation offers the opportunity for smaller residential and commercial customers to exploit their flexibility potential. Aggregation is a commercial function of pooling decentralized generation and/or consumption to provide energy and services to actors within the system. Aggregators can be retailers or third parties. They may act as an intermediary between customers who provide flexibility (both demand and generation) and the party responsible to utilize this flexibility. They would identify and gather customer flexibilities and intermediate their joint market participation. This could be done via flexibility products or simply by selling and buying aggregated energy (kilowatt-hours) at optimal points in time.

The role of commercial aggregator is considered to be of high importance within the DREAM project.

Potential providers of flexibility are the following [EDSO for smart Grids, 2014]:

- **Small industrial and commercial users**

  Small industrial and commercial users could provide services to DSOs, either under the umbrella of an aggregator or individually.

- **Household customers**

  An important source of flexibility for network operators could be the household customers, as long as providing flexibility is a transparent and effortless process. On the other hand, individual household provision of system flexibility services is highly unlikely due to its weak impact on the system. However, household customers could potentially contribute to a pool of flexibility through their supplier or an aggregator.

- **Distributed energy resources**

  A number of different DERs could be used to provide flexibility. Large DER units could act individually in flexibility markets but on the other hand, small units such as solar panels on a single house, will have to be represented by an aggregator to provide services. It should be noted that DER controllability and forecasting will be of great importance for making the most of its flexibility potential.

As mentioned before, flexibility is an additional tool through which the DSO can plan and operate its network in the most cost efficient way. However, safeguards should be created to avoid market players from "gaming". Some flexibility services could be delivered to a balancing responsible party for his own portfolio optimization in a specific area, with the aim of creating a local peak, thus forcing the DSO to contract a system flexibility service at a high price [EDSO for smart Grids, 2014].

### 1.3.3 Flexibility procurement

In order for the DSO to utilize system flexibility services a coordination scheme between TSO and DSO becomes crucial. The coordination is only possible if some information exchange is in place. DSOs have to gather information from all users connected to its networks and pass on the necessary data in an aggregated way to the TSO. The same communication channels, going through DSOs, will be used by the TSO to give instructions to DSO, and DSOs will also use them to give their own instructions. Sharing communication channels is an easy solution to limit double investments. In this context, a TSO's actions on DSO network users should be monitored, and potentially blocked by the DSO if it jeopardizes the security of supply and quality of service [EDSO for smart Grids, 2014].

## *1.4 Who has access to data (measurements and grid topology)?*

As it has been described in the context of this document, data exchange is of essential importance for the vision of balancing marketplaces in distribution grids. In fact, the large number of participants in the market and the great variety of actors in different voltage levels raises the complexity of the whole system. Therefore, communication standards are needed for a secure exchange of data between DSOs and flexibility providers, as well as between the DSO and the TSO, while a high level of control over the electricity supply service level parameters of DERs and other players is required, particularly through the use of advanced sensors and metering data; monitoring networks and making timely use of available meter data is apparently essential for DSOs [Hadjsaid N., 2010].

However, a major question to be answered before setting up the balancing marketplace for distribution grids is related to the ownership of ICT infrastructures and the consequent accessibility to the data. The ICT infrastructure should be in place to facilitate the observation of the normal and abnormal situations in the grid operations as well as give the appropriate background to the implementation of the market as a set of bidirectional control signals.

According to the Expert Group for Regulatory Recommendations under the Smart Grids Task Force work programme a market reference model exploiting the synergies with the ICT sector should be created in order to protect consumers and empower DSOs roles. Under this perspective a set of three different setups has been identified regarding the data access dependencies; the unique characteristics of the electricity system are taken fully into account, while the security and integrity of electrical systems has been identified as of paramount importance and any consideration on data handling is in line with the system's physical operation.

The three cases described below, independently or in combination, should cover all the possible scenarios of handling Smart Grids data [EG3 First Year Report, 2013].

### 1.4.1 DSO as market facilitator/enabler

This model is composed by a data hub owned by the DSO; the data hub is the standardized centralized or decentralized point for the market parties to collect all operational data as well as all necessary data to facilitate the market (data about customers, their technical possibilities, and their consumption or production). DSO provides data to the market, as a regulated neutral market facilitator and it depends on the market entities to enhance data with their own information in order to become competitive and provide new services. The ownership of data remains in the customers, who are responsible for approving the transmission of their personal data to third parties via the data hub.

DSOs are responsible for the normal operation of the technical infrastructure, including data hubs; they are in charge of reliable distribution grid operation and act as neutral market facilitators for prosumers. DSOs have the knowledge to plan and manage the risks related to the new grid operations, taking into account all market participants' actions. DSOs are also in contact with TSO for generators connected to their networks towards TSOs and for services provided upstream. Within this case, DSO has the ownership of ICT infrastructures and the assurance of proper operation of the grid relies mainly on DSO's actions.

### 1.4.2 Third party as market facilitator (independent central data hub)

This model is based on an independent central ICT infrastrucure based on one or several data hubs which will interact with different market participants, each of them potentially storing a subset of data and processing it. The most significant functionalities of the independent data hub include access control, receiving data from different parties and delivering it to the authorized parties, as well as aggregation and data storage for retrieval of historical data by end consumers, or by their authorized third parties, which could be electricity providers/retailers, ESCOs or aggregators. This case coincides with the previous one, in case of one single DSO in a country.

### 1.4.3 Independent managers of the data access-points

This case describes a new business model, the trusted data access point manager to become the partial facilitator of the market and the provider of the OCT infrastructure. The new role can be undertaken by certified companies, which act on behalf of end customers (prosumers) as data keepers. They are foreseen to provide the data access to any other certified market participant upon request. The new role is designed to handle access to data and facilitate the remote management of functionalities needed to create added value services within the market. The Data Access Point Manager shall maintain and apply access rights of any regulated and non-regulated market actor (service providers and consumers) via any implemented communication network over the whole lifetime of relevant smart grid resources (prosumers) within the given regulatory requirements.

### *1.5 Description of ICT infrastructure for distribution grids*

The identification of the ICT infrastructures for measuring and control at the consumer level, at the distribution system level, and the requirements for aggregate information taking into account all the distribution systems is needed as the first step of the balancing marketplaces. Bi-directional communication mechanisms are required between the grid and the consumer premises - facilitating the consumers to notify their demand requirements to the grid and for the grid to feedback availability/pricing information to the consumers.

Wireless sensor networks research could be extended to smart grid and metering, since it has been an active research topic for nearly ten years and has found many applications Smart grid/metering appears to be a major application for WSN, especially related to Internet of Things and machine-to-machine (M2M) communications.

Existing industry efforts include IETF 6LoWPAN and ROLL. Based on smart metering user scenarios, the overall M2M network architecture, service requirements, and device capabilities are yet to be defined. Recently ETSI has established a new M2M technical committee to address these issues.

Interworking of communication protocols and dedicated smart metering message exchange protocols such as DLMS/COSEM is an open research issue. The DLMS/COSEM standard suite has been developed based on two concepts: object modelling of application data and the Open Systems Interconnection (OSI) model. This allows covering the widest possible range of applications and communication media. Work has already started in the industry trying to address the issue of carrying DLMS data over various networks such as GPRS and power line communications (PLC) networks (for an overview of PLC and its applications to the smart grid, please refer to [S. Galli, 2010] [Lobashov, 2011]). Recently, the DLMS User Association also established a partnership with the ZigBee Alliance and the two organizations are working on tunnelling DLMS/COSEM over ZigBee networks to support complex metering applications. Inside IEEE 802.15.4, the 802.15 Smart Utility Networks (SUN) Task Group 4 is working on a PHY amendment to 802.15.4 to provide a global standard that supports smart grid network applications with potentially millions of fixed endpoints.

Because of the scale and deployment complexity of smart grids, telecommunication network systems supporting smart grids are likely to rely on the existing public networks such as cellular and fixed wired access technologies, as well as private and dedicated networks belonging to different administrative domains. The purpose of such networks can be seen not only as a communications medium to exchange monitoring and control information, but also as an enabler of new services and applications. In many ways, the complexity and heterogeneity characteristics of smart grid communications networks will be similar to that of a wireless radio access network supporting voice and data services. However, stakeholder expectations, QoS requirements and load patterns will be significantly different from those of a typical mobile voice/data network because of the nature of the applications and services supported. Both will share, at least partially, problems related to managing and operating a complex and heterogeneous network where tasks such as network planning, operation and management functions, and network optimization are important. We believe that a self-organizing network overlaid over existing infrastructure could be the way forward to support wider deployment of smart grid systems. Such a self-organizing network should support functions such as communications resource discovery, negotiation and collaboration between network nodes, connection establishment and maintenance to provide the performance guarantees required by smart grid/metering applications. Recently, novel network architectures such as cloud-based systems have been proposed for smart grid data collection and control [Yan Ye, 2013].

## *1.6 Issues regarding the Reliability and Challenges posed by the communications*

While the conclusion in terms of ICT requirements can only be limited to this particular network and wide-area control design, the results can still raise discussion about the dependency of the WAMC (Wide-Area Monitoring and Control) system on their supporting ICT infrastructure. Ideally, it is convenient to have unified and integrated common data processing where all measurements are sorted and processed with the same fashion. However, to some applications with more stringent requirements in terms of input data, it is difficult to meet their requirements by implementing a universal architecture. Therefore, it is necessary to propose a hybrid architecture in response to the particular needs from WAMC applications. Generally, for the monitoring applications, such as state estimation presented in, the required input is of a large data set containing global information and sometimes the data are not collected within one single grid utility's responsible territory. The monitoring applications are intended to assist operators for decision-making. The participation of operators indicates that there are less stringent constraints on data delay. On the contrary, the closed-loop control performed by wide-area control applications, a valid automatic control as such, in most cases, has to be executed with a time scale of hundreds of milliseconds or seconds. On the other hand, control applications, as such, are, in most cases, performed based on a subset of the entire data set. In response to the aforementioned data delay requirements, a generic two-level hierarchical architecture enabling applications for both control and monitoring purposes is presented in Figure 2 [Zhu Kun, 2011].

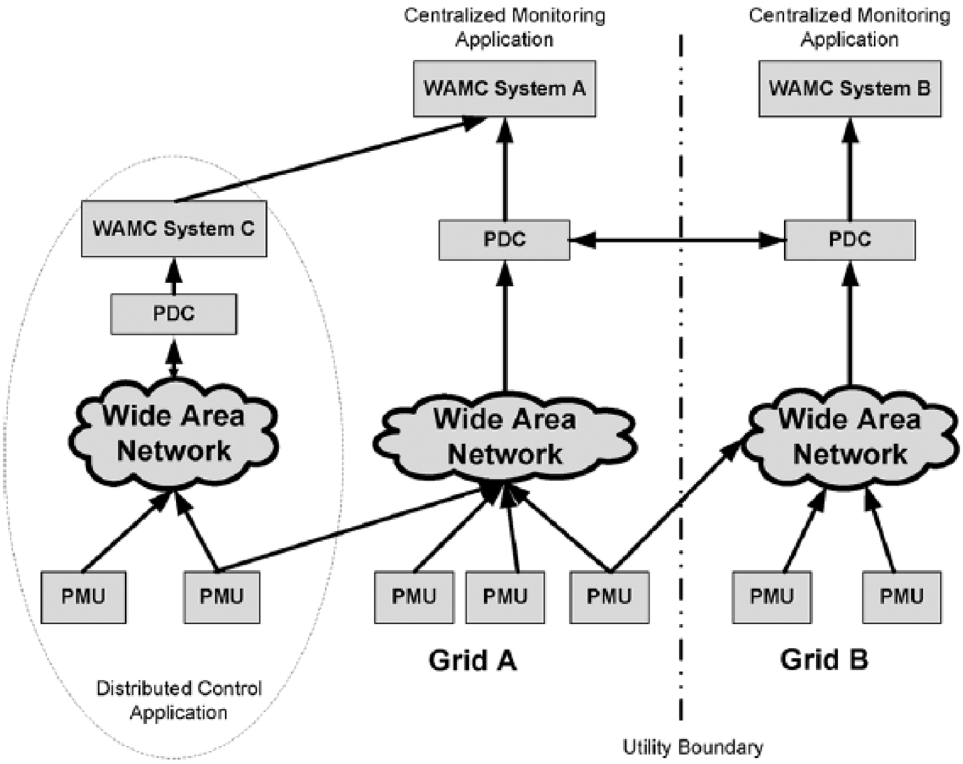


*Figure 2: The generic two-level hierarchical architecture*

In this architecture, a dedicated concentrator or clusters of concentrator are assigned to each wide-area control application. A distributed control design, as such, could not only ensure a low communication delay but mitigate data loss for the monitoring applications as well. The concentrators' clusters could also assemble measurements from the extended portion of networks prior to forwarding data to centralized locations. Moreover, this design could reduce the communication complexity as well as facilitate time control on data communication.

## *1.7 Behavioral analysis of the grid users, bad forecast, regulation/incentives*

As the installation in the distribution network of generation units with variable production increases, and in combination with the increasing involvement of the consumers, system stability is more difficult to be maintained. Different levels of penetration of various types of loads (e.g. flexible or shiftable loads) and distributed generation technologies will transform the current distribution networks and increase the complexity in actively managing such networks. Furthermore, balancing of supply and demand becomes more challenging as it will be performed locally.

### 1.7.1 Incorporation of demand response services to the operation and planning of the energy system

Demand response services can be integrated into the various system operations, such as system planning, day-ahead scheduling, and real-time operation. Depending on the timescale of each operation, different types of DSR are appropriate (Figure 3) [U.S. Department of Energy, 2006].

In *price-based DR programs* the signal sent to the customer is a price signal. According to that, each customer that has enrolled to such a program and in combination with his personal preferences he will decide whether or not he will respond to the price signal and how much electricity consumption he will forego or shift. As it is clear, price-based DR programs have a voluntary character and the resulting load curtailment or shift is not easily predictable.

*Incentive-based DR programs*, on the other hand, involve certain agreements between the consumer and the entity offering such programs for specific predefined changes in the electricity consumption. In these programs apart from the reward offered to the participating consumers, a penalty can be also established in case of non-conformance to the agreed electricity load modification.

Evidently, the price-based DR programs involve high risk regarding the achieved modification in the electricity consumption of the participants, and as such these kinds of loads can only be incorporated during the long- to mid-term planning. In contrast, loads participating in incentive-based DR programs, and more specifically offer direct load control, can provide value in responding to system contingencies and offer additional options to policymakers to help solve an area's or market's problems, since they can be deployed within minutes. For example, they can help address reliability problems or can be tailored to achieve specific operational goals, such as localized load reductions to relieve transmission congestion.

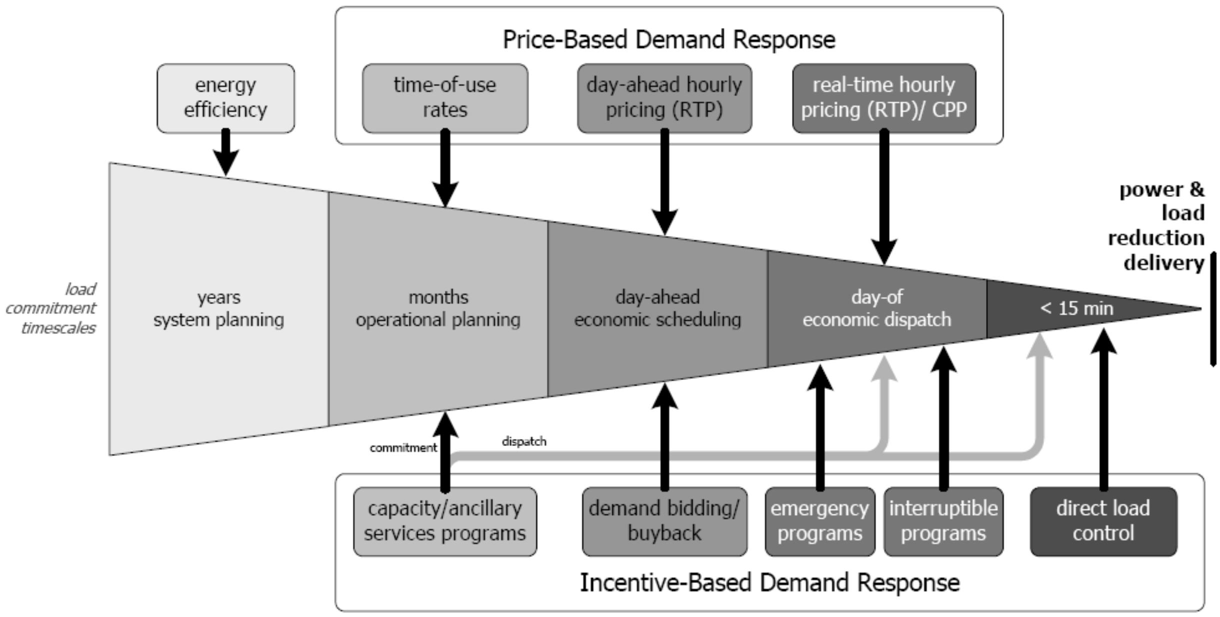


*Figure 3: Role of DSR in system operation and planning. [U.S. Department of Energy, 2006]*

### 1.7.2 Demand-side response services provided to power system participants

Demand-side response (DSR) is seen as a key component of today's distribution networks that not only supports the development of RES, but also facilitates the solution of network constraints and provides services to different power system participants. [CIGRE Working Group C6.09, 2010]

**DSI services for DSO's**

i. Load limitation to respect power supply contracts with the TSOs

   DSI can be used to limit the load at the sub-stations between the transmission and distribution networks in order to avoid paying a penalty in case the actual maximum power demand is higher than the estimated maximum demand.

ii. Load limitation to defer network investments

   DSI can contribute in lowering the peak loading of the electricity lines, thus postponing the necessary investments in new lines for increasing the transfer capacity.

iii. Frequency control from the DG units and load shedding in case of frequency drop

   With the evolution of distribution networks to active systems and the installation of Distributed Generation (DG) units DSOs may be requested to contribute to the control of frequency.

   On the other hand, load shedding could be also replaced by load reduction, thus contributing to frequency control with minimum customer inconvenience.

iv. Voltage control and reactive compensation

   Correction of the power factor, a service already implemented at large or medium customers, might also be considered a DSI initiative, although appropriate monitoring is required in order to avoid adverse effects.

v. Relief of HV network congestion

   As with the distribution system, congestion in the transmission system could also be avoided by appropriate control over the loads participating in DSI initiatives.

vi. Network restoration

   Limiting the consumption after blackout or after a loss of supply from the transmission or the distribution network will help the load take-up from the generators.

vii. Islanded operation and micro-grids

   Islanded operation of distribution networks, although difficult to achieve, is important in case of generation capacity loss or for providing higher quality of supply. Keeping the local load and generation balance can be greatly facilitated by demand management initiatives.

**DSI services for TSO's**

i. Facilitate electricity market operation

   Enhanced market operation is achieved by the increased elasticity of the demand due to DSI initiatives, as it reduces the possibilities of abusing market power and the financial risks of market participants.

ii. Frequency control

iii. Load shedding in case of frequency drop
iv. Voltage control and reactive compensation on transmission networks
v. Power system voltage stability (or voltage collapse)
vi. Load limitation to defer network investments
vii. Relief of HV network congestion
viii. Network restoration
ix. Islanded operation and micro-grids

**DSI services for other power system participants**

i. Energy efficiency (and reduction of fossil fuel consumption)
ii. Reducing the peak load (or high level loads)
iii. Reducing the sourcing costs (and the energy prices)
Load shifting from peak hours to non-peak hours results in avoiding dispatching of the expensive generation units, and, thus, lowering the energy prices and the generation cost.
iv. Management of load and generation variability (and balancing services)
Load management assists in meeting the variability of intermittent energy sources, such as wind energy.
v. Provision of ancillary services
vi. Reduction of CO2 emissions

## *1.8 Scientific barriers towards balancing marketplace*

The overview of the state-of-the-art bibliography has revealed a series of scientific barriers for the application of distributed marketplace in the DSO level. These are summarized below:

- Legislation issues that don't permit the DSO to take remedial actions for his own grid.
- Information access and retrieval about consumption/production of the customers connected at the distribution grid.
- A reliable communication infrastructure that will enable the efficient and reliable coordination of the different actors.

At this point it is very important to mention the link between WP3 and WP4; It is mainly associated with the implementation timeframe of taking actions to solve minor contingencies that the market-based procedures are unable to handle. Therefore, WP4 is considered as a potential real-time back-up mechanism to support the actions taken in balancing markets of WP3.

## *1.9 Evaluation of impact of minor contingencies on Decentralized control with peer-to-peer optimization*

The evaluation of impact of minor contingencies on decentralized control will be focused on the mechanisms to reflect results from trades on the market into actual operational configurations. In decentralized control with peer-to-peer optimization the optimization algorithm copes with voltage problems and line congestions that may arise in a distribution network. The voltage deviation problem (or the congestion management problem) is resolved taking as input certain parameters (i.e. voltage in certain nodes of the network from measurements, estimations, etc.). The algorithm makes certain assumptions such as the ideal grid user behavior along with the reliability in communications. In reality though, it is possible that in some cases different assumptions should be made taking into account possible communication deficiencies and declinations from the ideal grid user behavior. For the assessment of the effect of these declinations from the primary assumptions in the real-world application the following steps are considered:

- Slight changes (in terms of pseudorandom distortions) in the input parameters are made, that correspond to “last-minute” alterations of the customer behavior and/or failures in communication in the real-world application or, in general, in any other causes of poor estimation of the resources incorporated in the optimization process.
- The algorithm runs with all different inputs. The obtained results are compared and the sensitivity outputs relative to small changes in the input parameters are studied.

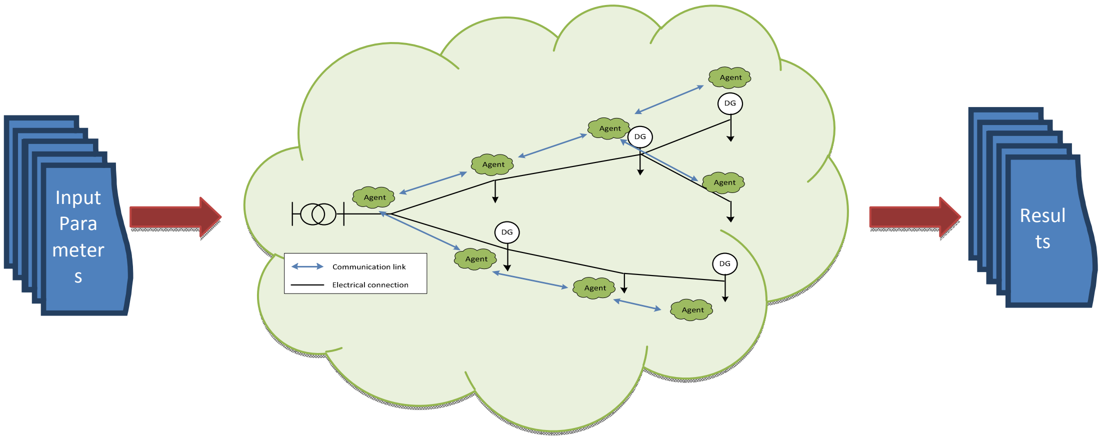


*Figure 4: The peer-to-peer optimization model*

The proposed approaches for the sensitivity analysis are:

- Sensitivity analysis for different “last-minute” changes of the customer behavior and study of their affect in the voltage of the grid
- A fair future treatment (or even compensation) of the customers which were forced to contribute more in order to solve the problem because of the withdrawal of other customers

# 2. Risk management and contingency plan for DSOs

## 2.1 Definition of the politic of risk management

Risk management is the process of identification, analysis and either acceptance or mitigation of uncertainty in investment decision-making. Essentially, risk management occurs anytime an investor or fund manager analyzes and attempts to quantify the potential for losses in an investment and then takes the appropriate action (or inaction) given their investment objectives and risk tolerance. Inadequate risk management can result in severe consequences for companies as well as individuals. Investors are classically managing risks, and allocating capital with the expectation of a return in the future (return on investments or ROI). The value of the investment at initial time is certain, but the future incomes are uncertain. Hence, the probability density function of the net return of investments is introduced. Depending on the expectations of the investors and their definition of value at risk, different strategies could be chosen. For example, a strategy could be to invest in any cases where there is a probability of 50% or more that the average of ROI is positive or above a certain level.

Generally, investors do invest in cases where there is a probability of more than 95% (or 99%) that the ROI is positive. It means that they are considering the net value of their investments at risk 5% (or respectively 1%). Different criteria are considered depending on the risk management policy chosen by the investor to adopt a commercial strategy.

Network operators are investing and operating electrical grids. The energy regulator generally defines a risk management policy for these investments, and especially for transmission systems. A compromise between the cost of the power system and his reliability has to be reached. It is often influenced by political choices.

Distribution system operators will have more and more responsibilities and decisions to make. As for transmission system operators, risk management policies will have to be determined. The objective of this document is to focus on the risk management policies done by transmission system operators and to highlight new problem areas if these types of norms are transposed to the distribution networks level.

## 2.2 State of the Art of risk management and contingency plan for TSOs

Power systems are conventionally planned to meet a defined level of failure of different individual system assets concerned with transmission, generation or the connection of demand/distribution networks. Even with this inherent security, the risk is not completely mitigated: failures of power systems can and do occur. Moreover, due to the growing complexity of power system operations and electricity trading arrangements, networks are increasingly operated to their technical limits. This drives systems operators to more and more risk management and contingency analysis.

The objective of this part is to expose how TSOs deal with risk analysis and contingency plan at the transmission level and try to analyze if it will be easily transposable to the DSOs scale. This will thus allow to extract the major scientific and technical barrier DREAM framework as proactive system (to prepare the reactive part of WP4 and following the active part of WP2) will face to be implemented at the distribution level.

### *2.2.1. Contingency plan*

To ensure the best operating of the electrical grid, system operators are generally performing contingency plan in order to know the possible critical states of their network.

#### 2.2.1.1. Types of contingency

Power systems are frequently subject to disturbances that might limit the capacity of the network. The outage of primary power system assets such as overhead lines, underground cables, transformers, busbars, circuit breakers and generators can severely affect the transfer of the power and consequently the balance between generation and demand.

There are different kinds of disturbances which can be registered and cause contingencies in the power system. They include for example [CIGRE Technical Brochure, 2010]:

- Internal failure of transformers, lines, switchgears, etc.,
- Weather conditions leading to short circuits and subsequent trips of network components, especially overhead lines,
- Failures of transformers, overhead lines or underground cables due to overloading,
- Failure of control and/or protection systems,
- Generator or power station subsystems failure,
- Variable power output from stochastic generation (such as wind or solar),
- Changes in demand due to a connection failure, generation process shut down, or users' behavior…

In addition, at the moment of any one disturbance, parts of the network may already be unavailable due to previous failures or planned maintenance.

#### 2.2.1.2. Reliability of the power system

Many of these disturbances should normally have a very low probability of occurring within some given time period. A number of indices of power system reliability have been defined to represent the overall level of risk to service in different timescales [R. Billinton, 1996].

A system that is operationally secure is generally assumed to be one with a low probability of blackout. The secured events are conventionally defined in terms of N-k scenarios where N represents the initial state of the system and, depending on the convention used in the particular standard, k represents either a number of primary components going out of service or a number of events [RTE, 2005]. Conventionally, the secured events are those that are considered as credible events, it means contingencies or faults which have been foreseen in the planning and operation of the system.

The power system has to guarantee that customer supply and scheduled power transits are not affected within given limits by the predefined credible contingencies. To this aim the N-1 rule is practiced in most large power systems worldwide. This rule ensures that the power system is always operated in a robust condition with sufficient safety margins in order to withstand single fault events followed by the loss of one system element (transmission line, transformer, generating unit etc.). Under these circumstances the power system is considered to be in the “normal” state.

All possible scenarios of the loss of a primary power system asset are studied and system operators consider which consequences they will have. Some fast techniques [G.C. Ejebe, 1979] using Tellegen’s theorem to generate the sensitivities of a system-wide performance index with respect to the outages, have been developed for the automatic ranking and selection of contingency cases for a power system contingency analysis study. A contingency list is built containing line and generator outages which are ranked according to their expected severity as reflected in voltage level degradation and circuit overloads. Risk can be defined as “effect of uncertainty on objectives” and may be quantified by means of the product of the probability of an event’s occurrence and the extent of its impact [CIGRE Technical Brochure, 2007]. Depending on the risk of the occurrence for the power system, contingency events are classified as illustrated in the RTE reliability handbook [RTE, 2005].

In Figure 5, a first set of events is considered as so rare that it is not cost effective to secure against them (zone 1). A second zone gathers together events that are so significant in terms of their impact that they must be secured against (zone 2). A third set has both relatively high probability of occurring and quite significant impact and so should also be secured against (zone 3). Finally a last zone groups together events that might be quite common but with less impact, and for which a technical and economic analysis should be done to define preventive measures (zone 4).

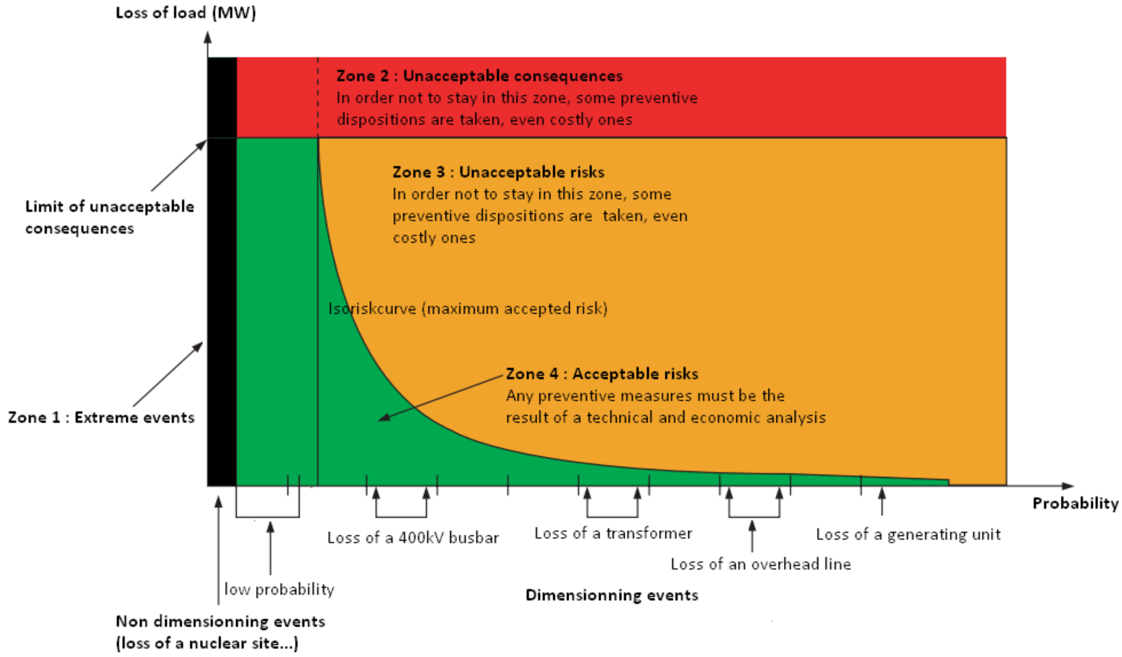


*Figure 5:* Diagram of classification of contingencies, depending on their consequences and risks

Due to the fact that both network and generation investments are expensive and time consuming, perfect security of supply is not realistic. One of the key challenges for system operators, generation investors and policy makers is to find the appropriate trade-off between investment in system facilities and security of supply.

Major unreliability events are often initiated by system fault events in combination with circumstances that are not concerned with outages of primary power system assets. These circumstances can be for example, a demand forecast error, a generator reactive power limit error, or the unavailability of an accurate estimate of the system's current state [CIGRE Technical Brochure, 2010]. Uncertainties have to be applied on production and consumptions plans, to prevent power system from these types of vagaries that can lead to severe outages. TSOs need to establish a forecast of global consumption and to compute how much reserve power is needed to cover the different types of uncertainties. System operators assess all the available reserves, and call for adjustments if necessary, to respect the exact equilibrium.

Thanks to a more decentralized approach and a more controllable network, the use of a contingency ranking algorithm in real time system could enable system operators to locate the areas of weakness under the present operating conditions, permitting them to take into account less uncertainties due to forecast of production and consumption.

A possibility to have an idea of how robust is the model of the power network, is to categorize the system as a whole, doing an exercise in risk analysis where the risk associated with a specific hazard, that is intended to be protected against by a specific, is calculated without the beneficial risk reduction effect of such safety functionality. That "unmitigated" risk is then compared against a tolerable risk target. The difference between the "unmitigated" risk and the tolerable risk, if the "unmitigated" risk is higher than tolerable, must be addressed through risk reduction of the safety functionality. This amount of required risk reduction is correlated with the safety level.

There are several methods used to categorize the safety level of the system. These are normally used in combination, and may include:

- Risk Matrices
- Risk Graphs
- Layers Of Protection Analysis (LOPA)

Of the methods presented above, LOPA is by far the most commonly used by large industrial facilities.

### *2.2.2. Reserve sizing*

Although major system unreliability events have a low probability of occurrence, their potential impacts on customers can have wide social and economic effects. It implies a need to consider all possible sudden disturbances and to evaluate the possible effect of each one. The power system has to be designed in a way to be operable under the majority of minor disturbances and to be rapidly recovered when failures occur. Reserves of both active and reactive powers and of network capacity have to be dimensioned and thus, many sudden disturbances have little or no immediate impact on the whole power system.

Furthermore, there are several balancing processes with different full activation times, presented in Table 2, which present the different balancing processes with characteristics of activation and activation times [eBadge project Deliverable D2.2, 2013].

| | **Activation** | **Full activation Time**<br>max. time for full activation |
|---|---|---|
| Primary control -<br>Frequency Containment Reserve (FCR) | Automatic | < 30 sec |
| Secondary control -<br>Frequency Restoration Reserve (aFRR) | Automatic | < 5 min |
| Tertiary control -<br>Manual Frequency Restoration Reserve (mFRR) | Manual | < 15 min |
| Replacement Reserves (RR) | Manual | < 1 h |

*Table 2:* Different balancing processes with characteristics of activation and activation times

The Frequency Containment Reserve (FCR) is activated to stabilize the frequency after the disturbance at a steady-state value within the permissible maximum steady-state frequency deviation. The frequency restoration process brings back the frequency towards its set point value by activation of Frequency Restoration Reserve (FRR) and replaces the activated FCR. The FRR can be segmented in an automatically activated (aFRR) and a manually activated (mFRR) reserve. The Replacement Reserve (RR) replaces the activated FRR and/or supports the FRR activation by activation of RR.

#### 2.2.2.1. Sizing

Based on studies on references incidents, the total amount of both active and reactive reserve is estimated. As an example, in the RGCE Synchronous Area an N-2 criterion is used leading to determine the size of the reference incident in 3000MW which is the equivalent to two nuclear power units of 1500MW, the biggest there are in the system. Therefore 3000MW seems a reasonable reference incident for RGCE, conservative enough to assure that larger imbalances will be rare, but assuming that all larger imbalances are caused by generators trips and that the FRR always replaces FCR as designed [CIGRE Technical Brochure, 2006].

In France, the UTCE rule requires permanently a minimum of 700MW (up to 750 MW in the winter) for the primary reserve which can be activated automatically, and a minimum of secondary reserve depending of the load which can also be activated automatically. The tertiary reserve is divided in two parts: a first part (mFRR) of minimum 1000MW which can be activated in less than 15 minutes, for a duration of minimum one hour for each activation and which can be called at least twice a day. The second part (RR) has a minimal value of 500MW and must be activated in less than 30 minutes for a duration of a least six consecutive hours, and which can be called one time a day [RTE, 2005].

The difficulty in controlling individual power flows rises rapidly with the distance and complexity of the network. Any change in generation or topology of the transmission network will change loads on all other generators and transmission lines in a manner that is difficult to control. The deregulation of the electric industry leads the market to tend to be a great influence on generation dispatch and the location of new generation facilities. It becomes increasingly difficult for longer term horizons to predict the location and dispatch of generation and thus be able to plan for transmission upgrades and reinforcements [CIGRE Technical Brochure, 2007].

The changing situation integrating more and more intermittent energy sources, most notably wind generation, has meant an added level of uncertainty to the generation dispatch and flow patterns [CIGRE Technical Brochure, 2006]. This added variability to the generation also results in significant challenges in dimensioning the transmission system and operational planning which lead to more and more needs of reserve.

Last but not least, market rules may interfere with system operation, because commercial arrangements for reducing the spinning reserve are quite common. Maintaining the balance of active power in the system will include the use of interruptible loads as a substitute for spinning reserve. These loads can cover a wide range of contracted capacity, ranging from tens of megawatts (industrial customers) to thousands of megawatts (pumped storage). A more recent development is that of contracts with commercial customers for grid peak load reduction, either by disconnection of non-critical loads or by transferring all or part of demand to emergency generators [CIGRE Technical Brochure, 2010].

These new considerations lead to a conclusion that the regulatory framework and various incentives should take care of the impact they create on the grid and infrastructure, and new mechanisms and rules should be created to alleviate congestion and stress of the electricity grid.

#### 2.2.2.2. Toward a capacity market

In link with the investments politic trends, the low return on investment of peaking plants is a first motivation for the instauration of a capacity market. System operators are faced to a large deficiency of peaking production plants, which have a limited return on investment because of a non-suitable remuneration: peak plants produce only during peak periods. These types of situations can be observed as well for all types of flexibility owners, which will have a low return on investment of their equipment [Méda, 2014].

The instauration of a capacity market would permit to increase the number of offers on the balancing mechanism, and would emphasize the interest of using all types of flexibility and at all levels of the power system for recovering contingencies and stress of the grid. The attempt to derive quantitative information on the demand for additional capacity at the critical bottlenecks has turned out to be a particularly difficult task [IAEWTransport, 2001]. However, thanks to a decentralized power system as designed within the DREAM project, a possible scheme could be the instauration of different local capacity markets allocated at the different levels of the electrical grid.

This capacity mechanism will guarantee a specific remuneration for flexibility productions, which will be independent of the wholesale markets. This will ensure to system operators that there will be enough reserve of both active and reactive power for any envisaged scenario of consumption, and particularly during peak periods.

#### 2.2.2.3. Reliability of the reserves

Another problematic issue to cope with is the guarantees of the reliability of the reserves, both at balancing responsible parties' level and at transmission system operators' level.

**At BRP's level**

Every BRP has to ensure reliability of the balance between production and consumption at their level. In any case of unbalance caused by a BRP, the latter has to pay a penalty which is based on the cost the system operator has to spend to solve the congestion. As this fee might be costly, BRPs have generally their own available reserves in their portfolio to cover some changes in the amount of their offers and limit the risk of unbalance. Consequently, BRPs have also to establish risk management strategies, evaluating the reliability of their production and consumption offers.

**At TSO's level**

As explained in the previous sections, the global unbalance of the transmission power system is managed by the transmission system operators, who are dealing with different types of reserves. These reserves might also have a limited reliability: for example, a producer could have offered a certain amount of energy to the balancing mechanism that TSO cannot activate in real time because of a technical problem leading to the unavailability of the offered flexibility. In order to cover these risks, TSOs have to specify and to ensure a margin of reserves (a higher level of reserves that required).

With the development of sustainable electricity sources, renewable and intermittent energy could be used to offer reserve with limited reliability. This raises new problems for system operators who will maybe prefer to rely on trustworthy but expensive offers, rather than on unreliable and cheaper offers.

Consequently, remaining questions are dealing with the evaluation of these new local reserves' reliability.

## 2.3. Transposition to the active distribution network

With a decentralized approach as adopted within the DREAM project, these transmission level mechanisms should be transposed to the distribution network. Transmission system operators and distribution system operators' coordination will be essential in operational timeframes. Restricted visibility will limit the ability to prepare contingency plans for critical and emergency situations.

The aim of this part is to present existing tools which can help to transpose these contingency plan and risk management mechanisms to the distribution system, taking into account a lot more uncertainties in the distribution part of the electrical grid. In a second time, it highlights the time scales difficulties that can arise in the optimization processes, which will have to be closed to the real-time scale. Finally, a third part presents what could be economical and technical strategies for distribution system operators.

### 2.3.1. Digital methods to represent vagaries and uncertainties

Liberalization and the introduction of markets have created competition in the generation sector. Transmission investment is closely aligned to generation investment and the lack of transparent long-range plans for generation has consequently created uncertainty for transmission planners. Further, the introduction of new technologies, especially renewable technologies like wind generation, change the performance requirements of the transmission grid. Specifically, variable output and scalability of some renewable generation investments create further uncertainty for transmission planning and investment [CIGRE Technical Brochure, 2007].

These arguments can be extended to the distribution network, where distribution system operators and aggregators are dealing with both active and reactive decentralized power reserves. First of all, consumptions in the distribution network are not precisely predictable and some models including vagaries are used to represent it. Renewable generation plants as solar panels and the expansion of demand-response management are adding a lot of uncertainties to the generation dispatch and flow patterns.

Some digital methods are suitable and quite performant to represent these types of uncertainties. Deterministic methods as state enumeration, probabilistic ones as Monte Carlo Simulation (MCS) and fuzzy logic tools are three types of techniques that can be applied to power system processes. While state enumeration is straightforward, the full enumeration is usually not possible because of the prohibitive number of system states, or combinatorial explosion. Hence only some of the system states satisfying a predefined criterion are considered. MCS are capable of dealing with complicated systems and considers all possible events, but it imposes a heavy computational burden. Finally, fuzzy logic tools are performing a lot less computations.

### 2.3.2. Deterministic methods

Applying the N-1 rule in order to construct the contingency list involves a large number of computer simulations defined by selecting a set of network configurations, a list of outage events and the performance evaluation criteria, leading to a combinatorial explosion. A further consideration is that some non-transmission uncertainties on forecast, such as generation or a coordinated demand side response, may not have the same reliability as a transmission outage. A deterministic model does not allow comparisons between these options. Some fast screening methods [G.C. Ejebe, 1979] are used to speed up computations but generally, ranking algorithms do not give a perfect ordering and require the user to tune the adaptive stopping criterion to balance the overall execution time with the desired margin of error to assure that all possible troublesome combinations are covered.

Focusing on the most severe event and ignoring consequences and probabilities may lead to over investment in the transmission system or inappropriate prioritization of investments. The challenge is to refine the investment decisions without reducing security margins.

### 2.3.3. Probabilistic methods

Because of the dimensionality introduced by the uncertainties in data and forecasts, an impossibly large number of deterministic studies might be required to compute an analysis of each possible combination. Among probabilistic methods, there are two fundamental approaches to assess system reliability evaluation - analytical enumeration and Monte Carlo simulation. Monte Carlo methods are generally more flexible when complex operating conditions and system considerations (such as bus load uncertainty and weather effects) need to be incorporated [R. Billinton, 1995].

The contingency enumeration method relies on knowing each of the possible failure modes and the probability of each occurring. The overall probability of a failure affecting security can be assessed by considering each sequence of failures that result in a loss of supply by direct calculation. The Monte Carlo method essentially uses a random sampling of the possible failure modes with the sampling frequency related to the probability of a failure occurring. Monte Carlo simulation method is often applied for reliability evaluation of generation and transmission system or distribution system [S. Tao, 2012], [A Sankarakrishnan, 1995], [W.S. Andrade, 2009] where inputs are defined as probability density functions taking into account uncertainties. However, in order to obtain an aggregated result that has converged to a stable mean, the number of simulations can be very large. As each sample may require quite detailed analysis (at least a power flow but possibly time and/or frequency domain analysis as well), the computational effort could be considerable [CIGRE Technical Brochure, 2007].

### 2.3.4. Fuzzy logic methods

Fuzzy logic is another mathematical method that could model uncertainties, with fuzzy logic variables which may have a truth value that ranges in degree between 0 and 1 [G.J. Klir, 1995]. The fuzzy logic method allows to model uncertainties applied on input variables such as bus load uncertainty and effects of the weather. The obtained results give the upper and the lower boundaries of electrical constraints to apply in an uncertain environment with much less computation effort [W.C. BRICENO VICENTE, 2011]. This method could be a very performant tool to model vagaries in distribution network and could be very helpful to perform contingency analysis and reserve assessment for large distribution networks.

## 2.4. Time scales concerns

On transmission level, the forecast and reserve needs are assessed at relatively long time scales (long term, day-ahead, intraday). In the long term, electricity can be traded within electricity markets in advance. In the middle-term, electricity can be traded on the day-ahead and on the intraday markets. The objective here is to introduce availability objectives in a short-term optimization process.

Taking the advantages of the distributed control, it could be possible to establish local flexibility markets (with short-term bids which are declared too late to be transmitted up till the TSO). This concept is not possible for a network controlled in a centralized approach, where all bids have to be transmitted to the TSO who is the only user of the flexibility.

In the DREAM framework, access to the balancing market will be available for all the different market players offering bids of reserves capacities. Bids will be aggregated at different levels in order to permit all actors to have access to the markets. Offers could be sent by large power producers with large and fast overproduction capacities (through spinning/non-spinning reserves), by energy suppliers or also by end users (through demand response).

These flexibility bids can be proposed and planned during the day-ahead or intraday process, but other bids can also be sent during a more short-term process. Finally in real-time, after receiving the non-declared flexibilities, the activation process of reserves capacities can be done.

### 2.4.1. Day-ahead flexibilities

In day-ahead and intraday phases, all market parties can propose their availability of reserve capacity by sending a bid to the TSO. Particularly, flexibilities bids connected to the distribution system can be aggregated by commercial aggregators and sent to the TSO. By aggregating bids in a pool, the reliability of services provided individually by end users can be improved: for example, if a particular unit is not able to deliver the planned capacity, the aggregator can still provide the service using other units of its portfolio. Having a relatively large pool enables the DSO to better manage and define his own “internal” reserve and risk.

Another advantage of the aggregation is that registration, communication and settlement are performed at the level of the aggregator, facilitating the participation of small units. It permits end users to have access to the markets, but it has also a positive effect on the security of supply and decreases the balancing prices, as more participants can participate into the market. The aggregation mechanism will permit to value the flexibility of prosumers at national markets level. Hence, it is a good process for flexible market players (of all different size) to act on the market.

### 2.4.2. Short-term flexibilities (for DSO usage)

In a short-term time scale, a mechanism of local flexibilities provision can be implemented in order to assess possible others local reserves that have not been declared in day-ahead or in intraday, enabling to meet short-term and real-time network constraints (congestions, voltage deviations). At this time-scale, the day-ahead and intraday processes are assumed to have been completed, leading to an optimal plan of energy balance and knowledge of available declared flexibilities, taking into account network constraints. These local markets could be handled at LV and/or MV levels.

A control of the local market prices will have to be established in some way in order to avoid parallel markets and possible speculations.

### *2.5. Local investors' behavior*

This last section is raising the question of local investors' behaviors, whether for aggregators, producers or DSOs. New local reserves or new capacity mechanism will create new local markets. At a local scale, the number of local flexibilities is likely to be low: in a likewise situation, the market might not be fair and equitable. There is a high probability that actors make common implicit agreements, raising the market price in order to increase their benefits.

At a more global scale, the behavior of system operators will have a large impact on the behavior of other actors. Depending on his choice for the overall reliability level of the power system he is responsible for, the system operator can either choose to invest in reinforcements of the grid and consequently use not much local flexibility (in this situation, the market price of the flexibility will be relatively low), or choose to rely on available local flexibility and not to invest too much in reinforcements (in this situation, the market price of the flexibility will be higher). System operators will choose their strategies after economical and technical analysis.

# 3. Profiling, forecasting, metering flexibility

More extensive metering and monitoring infrastructures at low Voltage levels allow also current profiling and forecasting methods to be revisited. For the small retail customer and small business segment currently the financial reconciliation of the behaviour of the market is done using profiles. In this mechanism, customers, having a certain load profile, are divided into the same category. Of these categories only a small number of customers is monitored in real-time via telemetry and their behaviour is used to build the average profile for the whole category in the scope of the system. So for all customers in the profile, a once-a-year meter reading suffices to construct the bill. With the advent of the smart meter en smart metering infrastructures in the retail and the SME-segment, a wealth of data becomes available on the electricity consumption and production of individual profile customers. This pertains to metered values, which are collected and stored as a timeseries over a day within a predefined number of days after realisation, as well as monitoring values, that may be collected in real-time and may support operation of the portfolio in real-time. For example, the Netherlands smart meter [NTA-8130] has a metering P3-port with 15 minute readings and a P0-port delivering 10 second monitoring data. This information also is useful for forecasting on the long term to support buying options on future electricity. For the medium term the data may support operation in the (next) day-ahead market and on the short term for operation on the balancing market. In the Scandinavian countries, a next step now is introduced. Contracts with retailers can be selected, in which an allocation of electricity usage on a 15 minute interval base, for the next day of a household or SME has to be given. Using the readings of the smart meter, the realisation is compared to the estimate and part of the cost of the electricity is calculated using the deviation. In this way, it is possible to exchange the top-down averaged profiles for more individual, localizable profiles and to enable refined demand response mechanisms, granular in time resolution. Of course, smart automated energy management is the only possible way to handle smart meter allocation; the retail user or the SME owner will not set a load pattern for every next day.

# 4. Conclusion

In this deliverable the main scientific barriers that need to be overcome to enable distributed balancing market place at the distribution level are briefed. The main paths to address the barriers are outlined as related scientific advances. The dependencies of the different grid entities and market participants are combined by means of contingency analysis, while the appropriate management to tackle with risks and balance within markets has to take into account the flexibilities identified at first place, as well as the future risks.

The further development of sustainable electricity sources, opens new possibilities for provision of reserves by renewable and intermittent energy sources as a countermeasure to their limited reliability. However, system operators who prefer to rely on trustworthy but expensive offers, rather than on unreliable and cheaper offers are asking for emergent solutions the new raised problems. In this document an evaluation of these new local reserves' reliability is described. The variability of intermittent sources is taken under consideration by applying deterministic, probabilistic or fuzzy logic methods, following the state-of-the-art scientific trends.

The use of balancing markets at distribution level is inspired by the corresponding transmission level markets, although the basis and the whole setup are totally different. The creation of capacity markets and the definition of reserve flexibilities at distribution level should be based on certain customers' profiles and are similar to demand-response background information. Timeframe for using flexibility should be taken into account while creating the local balancing markets to overcome the unnecessary parallel markets. The choice between day-ahead and short-term declaration of flexibilities is dictated by different problems to be solved during the intraday grid operation.

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