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Project Deliverable Report

Smart Building – Smart Grid – Smart City

http://www.interreg-danube.eu/3smart

DELIVERABLE D5.1.1.

Grid-side EMS concept and information exchange interfaces definition

Project Acronym	3Smart
Grant Agreement No.	DTP1-502-3.2-3Smart
Funding Scheme	Interreg Danube Transnational Programme
Project Start Date	1 January 2017
Project Duration	30 months
Work Package	5
Task	5.1
Date of delivery	**Contractual:** 31 May, 2017 **Actual:** 29 December, 2017
Code name	**Version:** 2.0 Final ☒ Final draft ☐ Draft ☐
Type of deliverable	Analysis
Security	Restricted
Deliverable participants	UNIZGFER, HEP, E.ON, ElektroP, E3, EPHZHB
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Abstract (for dissemination)	Operational and planning principles for Active Distribution Management modules on the grid side
Keyword List	Operation of Active Distribution Networks, Distribution Network Planning, Grid-Building interface, flexibility

Revision history

Revision	Date	Description	Author (Organization)
v0.1	15 January 2017	Template, Questions for DSOs	Tomislav Capuder (UNIZGFER)
v0.2	21 February 2017	Information on planning and operation principles of Bosnia and Herzegovina DSO	Marin Bakula, Mile Međugorac (EPHZHB)
v0.3	21 February 2017	Information on planning and operation principles of Croatian DSO	Tomislav Capuder, Matija Zidar (UNIZGFER), Tanja Marijanić, Petar Rašić (HEP)
v0.4	24 February 2017	Information on planning and operation principles of Hungarian DSO	Katalin Decseine Giczi (EON)
v0.5	20 April 2017	Information on planning and operation principles of Slovenian DSO	Nina Carli (Elektro Primorska)
v0.6	1 June 2017	Information on planning and operation principles of Slovenian DSO	Andrea Moser (EEE), Martin Zloklikovits (E-Gűssing)
v0.7	10 July 2017	Summary of answers from DSOs	Mirna Gržanić, Tomislav Capuder, Matija Zidar (UNIZGFER)
v0.8	20 July 2017	Market concepts in active distribution networks	Tomislav Capuder, Mirna Gržanić, Matija Zidar (UNIZGFER), Ivona Štritof (HEP)
v0.9	23 July 2017	Building-grid coordinated operation from the distribution grid perspective	Tomislav Capuder, Mirna Gržanić, Matija Zidar (UNIZGFER),
v0.10	26 July 2017	DSOs feedback and comments	Katalin Décseiné Giczi, Peter Gabor Mihaly, Zoltán Hajdú-Benkő (EON), Zlatko Zmijarević (HERA), Mario Vašak (UNIZGFER), Ivona Štritof, Tanja Marijanić, Petar Rašić (HEP), Nina Carli (Elektro Primorska), Marin Bakula, Mile Međugorac (EPHZHB)
v0.11	27 July 2017	Quality assessment manager feedback control	Hrvoje Pandžić (UNIZGFER)
v1.0	31 July 2017	Final draft version	Tomislav Capuder, Mirna Gržanić, Matija Zidar (UNIZGFER)
v2.0.	30 December 2017	Final version	Peter Gabor Mihaly, Katalin Décseiné Giczi (EON), Tomislav Capuder (UNIZGFER)

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Executive summary

The project Smart Building – Smart Grid – Smart City (3Smart) aims to develop tools for integrated and modular energy management of buildings and distribution grids. In Work package 5 of 3Smart the focus is put on grid-side energy management modules. The developments start with defining a viable and flexible concept for grid management that is applicable in different current practices of DSOs in the Danube region. This deliverable thus focusses on the concept of grid-side energy management.

An important part of the deliverable is defining the role of a DSO, as well as that of a distributed demand response, in the market environment. Currently, neither the DSO nor the demand response providers participate in the market. The market, in this deliverable, is seen through participation of multiple stakeholders exchanging money and services in a transparent way either through tenders or, more preferably, at power exchange. This means that the DSO does not have any information of the accepted demand profiles from its users and operates the network based on vast experience and available historical data. On the other hand, not enabling market access to the distributed energy sources results in overbuilding and underutilization of the DSO assets.

Defining the role of an aggregator is one of the tasks of this deliverable. While descriptions, concepts and comment made in this deliverable should be subject to changes depending on future regulatory changes and upcoming research results, the general idea is given - defining aggregators as new system entity enabling market participation for flexible demand sources. Their role is to utilize available flexibility of distributed flexibility sources and optimize their market strategy with the goal of creating highest benefits for multiple systems entities. While it is possible for suppliers to add the role of aggregators to their portfolio, there is also the danger of doing that in systems where retail market is insufficiently developed.

The deliverable also brings an overview of current practices of the DSOs in the Danube region. The analysis recognizes the existing good practices and future plans as well as detects critical points which might prevent DSOs from efficiently operating their distribution networks. The complexity of the work performed by a DSO is difficult to capture in full. The deliverable focuses on detecting future distribution challenges and makes suggestions how to implement new concepts with minimal intrusion of the existing power system operational principles.

1. Introduction

Goals of Work Package 5 (WP5) of the project Smart building – Smart Grid – Smart City (3Smart) are multiple, ranging from creating open software for active distribution network management tool (for both operation and planning aspects) to defining a unified interface between grid and flexibility providers. Focus of this project is demand response. The flexible pilot buildings/locations will have different setups and will thus capture all types of flexibility providers, i.e. storage, electrified heating, controllable renewable energy sources, combined heat and power (CHP).

To create open software platform for active energy management system, integrating building and grid side management, there are couple of key initial steps which precede the platform itself. In this deliverable, key factors are identified and elaborated. The summary of the results in this Deliverable is as follows:

- Defining the best practices of Distribution System Operators' (DSOs) operation and planning principles, focusing on the DSOs in Croatia, Bosnia and Herzegovina, Slovenia, Austria, and Hungary. The term "best practices" is used here for currently applied practical aspects, issues and challenges which DSOs face in their everyday business of operating the distribution network and ensuring reliability and quality of supply to all their users.
- Recognizing the current and the future challenges of DSO operation by focusing on how well the DSOs are prepared for those challenges. The main idea is to define the missing tools and concepts and create guidelines for achieving them.
- Recognizing flexibility providers (grid users) and their role in the future distribution system. A significant result of the deliverable is recognizing multiple and complex aspects of the new power system framework, particularly the relationship of the DSO and the flexibility provider and the way they communicate and exchange data, energy and services. The concept of a new market entity aggregator is discussed in details, emphasizing the importance of this research aspect for the entire project.

Inputs and contributions of this Deliverable will serve as guidelines for future work in WP3 (such as D3.3.1. and 3.4.1.), but also for WP5 results. They should be observed as initial views and analyses, which are subject to modifications as the research of 3Smart project progresses and results in new findings.

2. Structure of WP5

Figure 1 visualizes the structure of Work Package 5 of the 3Smart project. This deliverable is part of the A5.1. and aims at recognizing the current good practices of the DSO. It defines pathways for making a transition to active distribution network management (ADNM). Together with D5.4.1. of A5.4., it will give relevant inputs for definition and creation of ADNM models (A5.2. and A5.3).

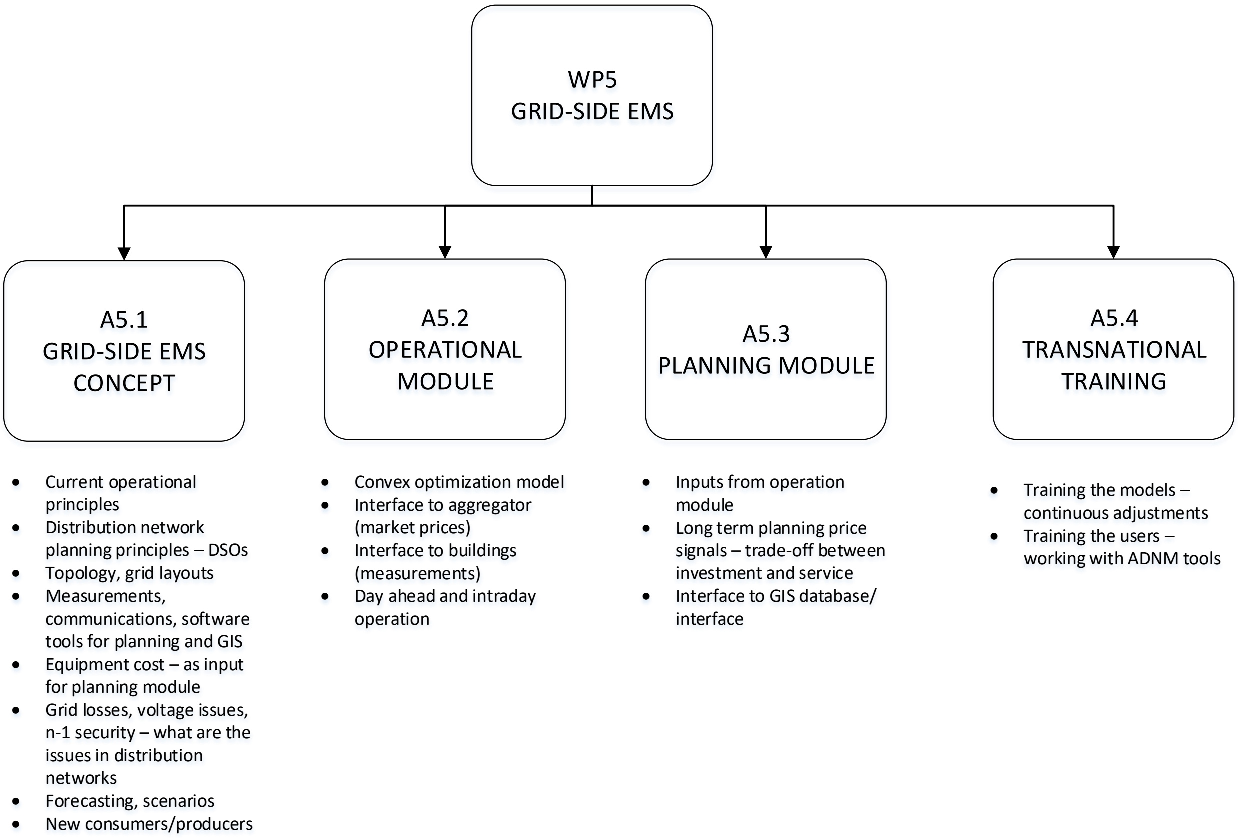

Figure 1: Concept and structure of the Work Package 5 of the 3Smart project.

3. Current state of operational and planning aspects of Distribution System Operators of the 3Smart project

The initial step in defining concepts of the integrated building and grid energy management is to define the current practices of different DSOs in the Danube region. For this purpose, a questionnaire was created trying to capture relevant aspects of distribution network operation and planning. The questions were focused on:

1. *Definition of the DSO status in each Danube region country, focusing on role of the DSO, size of distribution areas and the entire distribution network as well as number of DSOs operating the network in the Danube region countries.*
   The answers collected have shown that all countries recognize DSOs role in a similar way, with the exception of Bosnia and Herzegovina where the unbundling of the power sector is still not finalized. Croatia and Slovenia have a single DSO that operates, maintains, plans and is responsible for the entire country distribution network. On the other hand, in Austria as much as 130 DSOs operate the distribution network.
2. *Technical characteristics of the Danube distribution networks.*
   All distribution networks in Danube region operate at similar medium level voltage levels (10, 20, 35 kV, with specific nominal values depending on the country) and identical low voltage level (0,4 kV). Only major differences are in the fact if the DSOs operate 110 kV (or 132 kV) network or not. Since higher voltage distribution networks are not in the focus of the project, this aspect is not further discussed.
   In the entire Danube region, the DSOs have set a goal to reduce network energy losses while maintaining or preferably improving the reliability of supply for their network users. Looking at the statistical data of the network losses, two things can be noticed: i) the percentage of energy losses highly depends on the distribution network size and type. While for example Slovenia is being very successful in keeping these values around 5%, other countries have reported higher values; ii) The trend of reducing the energy losses is present in all countries (especially Hungary), however this remains the main challenge for all DSOs.
3. *Operational principles and tools used in Danube distribution networks.*
   Different distribution network topologies can be found in all the Danube region countries with a common practice that they are all operated as radial networks. These topologies are more common in urban areas where it makes economic sense to plan and construct meshed or ring layouts of distribution networks. The optimal topology (optimal separation point of the ring/meshed networks so that they operate as radial) is defined based on experience, usually set once or twice a year and with very limited capabilities of remote controlling (the exceptions are 35 kV and 20 kV network where these remotely controllable switches are more commonly installed). Similar analogy can be applied for transformers which do not have on-load tap changers (OLTC) installed (only a few of these are installed, with the exception of transformers interfacing transmission level which are equipped with OLTC). This means that the tap level is set once a year and not changed during operation.
   The entire Danube region DSOs recognize that these operational principles need to be revised and changed. Preliminary analyses of changing the existing equipment with on-line remotely controllable one have been conducted in most of the Danube region countries.

DSOs use different software, however a common denominator is that they all have network analyses software with GIS and supervisory tool implemented or with ambitious plans to implement them in their everyday business within the next 3 years.

4. *Planning principles and tools used in the Danube region electricity distribution networks.* Distribution network planning aspect is a complex process and all DSOs tend to unify it considering different aspects. Long term plans are done for 20 years ahead (or more) with a smaller resolution snapshot. These plans/studies are usually internal documents of the DSOs, helping them to gain a detailed perspective of activities and investments in distribution control areas (DCAs) and the entire DSO. As a way of standardizing the inputs for all DCAs most of DSOs have established a standardized set of input data for the planning process as well as for the expected outputs. Integration of distributed generation (DG), storage, electric vehicles (EV), flexible demand etc. is not taken into account in these standardized planning procedures and is recognized as a downside of current practices. This is also one of main challenges DSOs have set for the upcoming period: including new technologies and new concepts while keeping the approach of standardized inputs/outputs of the future distribution network plans.
These internal DSOs' 20-year planning studies are then used as inputs for 10-year development plans for the entire DSO (again, some specifics can be noticed, however a general concept is applicable to all Danube region countries). Furthermore, they are translated into annual financial plans which reflect next year's investments and equipment maintenance (this is rather simplified, yearly financial plans are very detailed documents specifying all the DSOs next year's activities through expenditures. Investments and equipment maintenance are only a very small aspect in them). Again, the challenge, recognized by all DSOs, is timely consideration of new technologies and their potential benefits compared to other alternative actions/investments (both on operating expenditure or OPEX and capital expenditure or CAPEX) and integrating them into annual financial plans.

The following table summarizes answers of DSOs' operational principles in 5 countries which are targeted with pilot projects of the 3smart project: Austria, Bosnia and Herzegovina, Croatia, Hungary and Slovenia.

1.1.1. How many DSOs are there in your country? Is there an additional division into smaller operational units? If yes, are those Areas independent in their everyday operation from the central DSO or not (coordinating their activities, of course, with neighbouring DCAs)?	
Austria	In Austria there are around 130 DSOs and the full list can be found at http://stromliste.at/verzeichnis.
Bosnia and Herzegovina	There are three electric utility companies in Bosnia and Herzegovina: a) JP EP HZHB d.d. Mostar b) JP EP BiH d.d. Sarajevo c) MH ERS MP a.d. Trebinje. Each of the three listed companies has an organizational unit related to the distribution of electricity, which implies the existence of 3 DSOs. There is a division into smaller working units. EPHZHB DSO division [1]: a) DP Sjever (Distribution Area North) b) DP Centar (Distribution Area Center) c) DP Jug (Distribution Area South).

	Each of them is also divided into smaller units. EPBIH DSO division **Error! Reference source not found.**: 1. ED Bihać 2. ED Mostar 3. ED Sarajevo 4. ED Tuzla 5. ED Zenica. Each of them is also divided into smaller units. ERS DSO division [3]: 1. ZP Elektrokrajina a.d. Banja Luka 2. ZP Elektro Doboj a.d. Doboj 3. ZP Elektro Bijeljina a.d. Bijeljina 4. ZP Elektrodistribucija Pale a.d. Pale 5. ZP Elektrohercegovina a.d. Trebinje Each of them is also divided into smaller units. In daily operation the smallest organizational units operate in coordination with larger units under whose responsibility they belong. All units are under the direct responsibility of one of the 3 DSOs.
Croatia	In Croatia, a single DSO operates the entire distribution network – HEP-ODS. The distribution network supplies consumers on 56.696 km^2, dividing them into medium (consumers at 35, 20 and 10 kV) voltage consumers, low voltage entrepreneurships, households and public lightning. HEP ODS is divided into 21 distribution control areas (DCA) each responsible for its every day operational aspects (there is an additional operational division, not relevant for the scope of the question). However, planning and investment decisions are centrally coordinated. In everyday operation (such as maintenance) and planning (such as execution of the planned activities) neighbouring DCA-s collaborate. An example is that each DCA performs its own future network planning, however all activities are communicated to neighbouring DCAs and are centrally coordinated by HEP-ODS headquarters.
Hungary	In Hungary, there are 6 DSOs and EON represents half of them. The EON DSOs have the following number of regions (DCA): EED – 5 DCA; EDE – 4 DCA; ETI – 3 DCA. These regions make their everyday operation fairly independently (the staff in normal situation do not cross their operational boundaries) but planning their CAPEX and OPEX, and supervise their performances (expenditures and service reliability) are related to the central departments of DSOs (e.g. control centre department, network information department, network strategy department, logistic department). These central departments of EON DSOs are the same for EDE, EED and ETI. (In other words the EON's DSOs are legally independent but they work as a virtual single company.)
Slovenia	There is a single electricity distribution system operator (DSO) in the Republic of Slovenia, which is licensed to practice energy activities - SODO. Based on a concluded contract on leasing of the distribution network and carrying out the tasks of the electricity DSO on behalf of SODO, the electricity distribution activities are carried out by electrical distribution companies (EDCs): • Elektro Ljubljana d.d. • Elektro Maribor d.d. • Elektro Celje d.d. • Elektro Primorska d.d. • Elektro Gorenjska d.d.

1.1.2. How many voltage levels are there in your distribution network?	
Austria	Within Energy Güssing’s power grid there are two voltage levels: 20 kV and 0,4 kV.
Bosnia and Herzegovina	Currently there are 4 voltage levels of EPHZHB distribution network (35 kV, 20 kV, 10 kV and 0.4 kV) with a tendency to make a full transition of 10kV voltage level into 20kV voltage level.
Croatia	The distribution network in Croatia has 4 voltage levels with different roles and stages of development: • 35 kV network, which is the main supply for rural • 10 kV and 20 kV networks, • 0.4 kV network supplying the majority of final consumers.
Hungary	In Hungary there are 5 voltage levels for distribution: 132 kV (it is the main distribution network), 35 kV (in old industrial areas, their relevance is declining), 22 kV (it is the backbone of our distribution network, predominantly overhead line, but in some towns it is cable), 11 kV (it is cable network, characteristically in urban environment), 0.4 kV (overhead line in rural environment, cable in urban environment).
Slovenia	Distribution network has 5 voltage levels, which include electricity lines and utilities at: • HV level - 110 kV, • MV level - 10 kV, 20 kV and 35 kV (being phased out), • LV level - 0.4 kV (230/400 V) and 1 kV.

1.1.3. Is a specific software tool used for everyday operation of distribution networks? If yes, please elaborate which options do you use/need.	
Austria	Different DSO-s use different tools in their everyday operation. It is unknown if there is a specific real-time supervision tool in other DSOs, E-Güssing does not have one. At the moment E-Güssing uses ArcGis and GIS tool and Matpower for network calculations and analyses.
Bosnia and Herzegovina	EPHZHB: For "everyday operation of distribution networks" we are using software: • SCADA system: in distribution area South, we are currently using ProzaNet SCADA System for controlling and managing 50 switch disconnectors of type ABB Sectos NXB (D) in overhead networks. The new SCADA/DMS/OMS system will be implemented by the end of 2019. on the DSO level which will include all distribution areas with Central Dispatching Centre in Mostar. [13] • for network analysis and network planning: DIgSilent Power Factory, PowerCad. Other software for daily operations: AMR/AMM system Advance from Landis+Gyr, Billing.
Croatia	Several software packages are used in everyday operation, depending on the specifics, ranging from network maintenance, planning and investment, billing, SCADA system (used for real-time network supervision, measurement and remote control in HV/MV substations and MV networks) and central systems for information on interruptions (DISPO). In the focus of this project are only software tools relevant for network simulations and planning. Several GIS software tools were used previously, with 3 most dominant ones. Over the past couple of years, GE Smallworld DeGIS is adopted as a single platform integrating GIS interface and common central database unifying multiple historic HEP-ODS datasets/databases. Depending on the DCA different levels of the distribution network have been integrated, in general large percentage of medium voltage network is in the DeGIS system. Several software tools are used by the HEP-ODS for network simulations and analyses depending on the DCA, mostly due to historical reasons. In this line NEPLAN, Prao and PowerCad are used the most, where NEPLAN is number one in terms of inputs for operational (usually integration of DG) and planning aspects of networks.
Hungary	For supervising the network: **SCADA system** for HV networks, HV/MV substations, and MV networks. The SCADA functions are: full remote control of primary equipment but the remote setup of protection is not available. **Quasi LV dispatch system** (some kind of outage system for LV): It is a tool under development. Main goal of the system is to register any kind of deviation from the normal state of the LV network, and register up to date information about the work of the operational staff. There is no remote detection, in other word on-line diagnostics, the identification is based on customer phone calls, after that the location of the failure is put on the map. **ÜIR system**: It is a kind of a simple outage system on MV. Main goal of this tool is to register the outages of the specific failures of the network elements and sort out their root causes. The ÜIR system is interconnected to SCADA system and MV switching procedures are exported to ÜIR system, the MV grid fault is detected automatically through protection relays-> RTU-> SCADA system. All MV faults are detected remotely. For asset management: **E-form:** It is a software tool for register of the inspection data of MV and LV network and calculating their health index. It helps to formulate specific work orders to maintenance as well. **E-file:** It is a software tool for registering specific CAPEX projects proposals and it helps to make priorities among them.

	Primary diagnostic tool: It is a software tool for main equipment of primary substations to decide whether their degradation has reached a specific risk level. **NEPLAN network calculation system:** E.ON HU use NEPLAN for network calculation and for network planning activities. The network planning activities cover both the long term strategical planning and short term analysis (e-g new customer connection).
Slovenia	We use GREDOS (see question 1.4.3) for planning of distribution networks. Two additional software tools are being introduced in the future, namely a new version of GIS and distribution management system (DMS).

1.1.4. Explain the structure of tariffs for final consumers (domestic, small business, larger business)?	
Austria	The network charges are regulated by E-Control. They consist of several components: • Grid utilisation charge: via the grid utilisation charge, the network operators are reimbursed for the costs of the construction, expansion, maintenance and operation of the grid. It is fixed by E-Control (in the annual *Systemnutzungsentgelte-Verordnung* (Electricity and Gas System Charges Ordinances) and consists of a capacity rate and a consumption-based price per kWh (unit rate). • Charge for grid losses: in the course of the transmission and distribution of electricity from the power plants to consumers, network losses are inevitable due to laws of nature. The charge for grid losses compensates system operators for the cost of the losses of electrical energy occasioned by the physical characteristics of the network. The charge for grid losses is regulated by E-Control. • Metering charge: via the metering charge, the network operators recover the costs of the installation and operation of metering equipment and the costs related to their calibration and meter reading. E-Control sets ceilings for these charges. Additional components of the system charges are designed to cover grid connection and admission and system parts necessary for international trade and congestion management at transmission level.
Bosnia and Herzegovina	Detailed answer can be found in Appendix A[1]

Croatia	The structure of the tariff system is a post stamp, with four different tariff items depending on the customer category – capacity charge (kW), active energy (kWh), excess reactive energy (kvarh) and fixed monthly fee. Not all customer categories pay for all tariff items.
	Tariff structure consists of two tariff rates for active energy and peak load based on time of usage - higher and lower rate. Depending on the time of the year, the rates are divided as follows:
	Winter period:
	• Higher tariff rate – from 07.00 hrs until 21.00 hrs
	• Lower tariff rate – from 21.00 hrs until 07.00 hrs
	Daylight savings time period:
	• Higher tariff rate – from 08.00 hrs until 22.00 hrs
	• Lower tariff rate – from 22.00 hrs until 08.00 hrs
	HEP-DSO tariff models are publicly available under the following names:
	• Visoki napon Bijeli 110 kV (High voltage White) – industrial,
	    o Active energy consumption during period of higher tariff rate (kWh)
	    o Active energy consumption during period of lower tariff rate (kWh)

<table>
<tr><td></td><td>
o Billing peak load during period of higher tariff rate (kW)
o Excess reactive energy (kVArh)
Fixed monthly fee, Srednji napon Bijeli 10 (20) and 35 kV (Medium voltage White) – commercial and industrial
Active energy consumption during period of higher tariff rate (kWh)
Active energy consumption during period of lower tariff rate (kWh)
Billing peak load during period of higher tariff rate (kW)
Excess reactive energy (kVArh)
Fixed monthly fee, Niski napon Crveni 0,4 kV (Low voltage Red) – commercial and residential
Active energy consumption during period of higher tariff rate (kWh)
Active energy consumption during period of lower tariff rate (kWh)
Billing peak load during period of higher tariff rate (kW)
Excess reactive energy (kVArh)
Fixed monthly fee
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<tr><td>Hungary</td><td>
The network tariff system is a kW, kWh and connection point based static tariff system.
The fee elements are the following (Not all users pay all fee elements)
takeover fee (for covering TSO costs)
distribution base fee
distribution capacity fee
distribution turnover fee
distribution reactive power fee
distribution loss fee
distribution schedule balancing fee
public lighting distribution fee (only for public lighting users).
The amount of the above fees depend on the voltage level of the connection point, which can be:
high voltage connection (132 kV or higher)
high/middle voltage connection (The user connects directly to high/middle voltage transformer station on 35, 22 or 11kV)
middle voltage connection (35, 22, 11 kV)
middle/low voltage connection (The user connects directly to the middle/low voltage transformer station on 0,4 kV)
low voltage connection (0.4 kV).
The last two voltage levels have further sub-cases, depending on whether the user is:
remote measured (not profile-settled)
profile-settled (not more than 3*80 A connection low voltage users, and independently from the connection capacity of the domestic customers)
We divide the profile-settled users category into normal (whole day) utilization, and the controlled utilization, which means the consumption of the appliances that can be remotely controlled. (E.g. electric kettle, heat storing stove).
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<tr><td>Slovenia</td><td>
In the distribution network, final costumers are divided into several categories, namely consumption on 110 kV, consumption on 1-35 kV and consumption on 0.4 kV, which is further divided into households and small business (other consumption).
The Energy Agency determines the tariffs for calculating the network charge for:
transmission network
distribution network
ancillary services
connected load
excessive reactive energy
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	Consumers also have to pay supplements for the use of the network, which are intended to cover the costs of the operation of the Energy Agency (regulator), the operation of the market operator (Borzen d.o.o.) and costs for the activities of the Centre for RES/CHP support. The amount of mentioned fee elements depends on the voltage level of the connection point. All consumers, whose type of consumption is based on an amount of annual operating hours also have different tariffs for high (Jan, Feb, Mar, Oct, Nov, Dec) and low season of the year (Apr, May, Jun, Jul, Aug, Sep). The connection points of consumer are: • HV connection • HV/MV connection (the user is directly connected to the distribution transformer station - DTS) • MV connection • MV/LV connection (the user is directly connected to the transformer substation - TS) • LV connection LV connection has further sub-cases, namely charging of electrical vehicles, costumers that are remotely measured and households (profile-settled). The connection fee is payed for at the time when end consumer is connected to the network.

1.1.5. Are large consumers paying for maximum power as well as energy consumed? Do they pay for "power forecasting errors" and if yes – how much (e.g., if their peak power is 10% more than forecasted)?	
Austria	Yes. Large consumers pay for the energy consumed as well as for the maximum power consumed in the respective accounting period. No - consumers do not pay for forecasting errors. They pay the peak power consumed and if the peak is higher than anticipated, they pay the price for this high peak. There are no additional charges.
Bosnia and Herzegovina	Consumers with contracted connection power of 23 kW or more, pay for maximum power within the accounting period (month). They do not pay for forecasting errors.
Croatia	Yes, all large consumers (all consumers with connection power over 20 kW) are, in addition to energy consumed, paying for maximum power over a period of one month. In case realized power consumption exceeds forecasted power by 30%, the consumer pays additional penalties. In case the actual power is lower than forecasted there are no penalties.
Hungary	Consumers having remote reading pay the distribution capacity fee per kW and annually (1/12 of that monthly). The basis of the distribution capacity fee is the "contracted capacity" in kW, which has to be given by the consumer in advance for the contracted years. (Increase of contracted capacity is possible within contracted year, but decrease of that is not.) In case the consumer exceeds the contacted capacity in a given month (capacity is determined from the 15min consumptions), then for each started kW of the exceeding he has to pay ¼ of the annual capacity fee. During the contracted period the consumer has the possibility to ask for occasional surplus capacity in three calendar months, in advance. In this case the occasional surplus capacity fee that has to be paid monthly is 1/10 of the annual capacity fee.

Slovenia	Yes, large consumers are paying for maximum power as energy consumed. No "power forecasting errors" are paid by the power market, it only depends in which balancing group (to receive electrical supply) the consumer is.

1.1.6. How does the DSO procure distribution network losses? Are annual network active power/energy losses available for your DSO? If yes, please provide values for last 5 years.	
Austria	The energy lost is physically proportional to the square of the transported energy and, depending on grid function and transmission level and amounts to 1 % to 7 % of the transported energy. In case of Energy Güssing these are typically 3-5% per year. The grid operators are responsible for the compensation of grid losses. To this end, they purchase appropriate quantities of energy in form of a scheduled supply with the required load profile. Domestic grid operators have to compensate grid losses of around 3.5 TWh in the Austrian electricity transmission and distribution grid every year. Based on an agreement reached by Oesterreichs Energie and the regulatory authority E-Control, a common procurement strategy was agreed to procure electricity to cover grid losses in the Austrian transmission grid. As of 2011, Austrian Power Grid AG (APG) will act as a major buyer of electricity on the international wholesale markets and centrally procure around 85 percent of electricity needed to cover grid losses throughout Austria. A declared aim of Austrian Power Grid AG (APG) is to address as many potential interested parties as possible by ensuring the transparent, market-based and non-discriminatory procurement of the required electricity to cover grid losses. By conducting a common tender for the required volumes for most Austrian grid operators in the form of tradable products (annual, quarterly and monthly base and peak products), it serves the largest possible market and thus a liquid market. On the other hand, this should also be reflected in the lively participation of European bidders (traders, producers) as suppliers. Overall in 2015, the share in the electricity to compensate grid losses that is procured by APG amounts to around 97 % of grid losses in Austria. In sum, APG therefore procures some 3 TWh annually to cover grid losses.
Bosnia and Herzegovina	Bosnia and Herzegovina did not implement separation of distribution system operator and electrical energy for covering the losses in DSOs cannot be bought separately. Data on energy losses in EPHZHB distribution network, for energy losses over the 5-year period (2011 – 2015, the data for 2016 are not available at the moment) is: • 2015: EPHZHB 11,09 % [4] • 2014: EPHZHB 10,83 % [5] • 2013: EPHZHB 11,83 % [6] • 2012: EPHZHB 14,50 % [7] • 2011: EPHZHB 13,61 % [8]
Croatia	The energy for DSOs losses is procured through tenders; only bilateral contracts were practiced so far. There was no procurement of energy for covering losses from local/distributed generation of storage (or any other source of flexibility at the distribution network). The distribution system operator is not allowed to actively participate in the electricity market, with an exception of buying energy for covering active power/energy losses in the

	network. The DSO can buy energy for covering these losses at the electricity market transparently and not favouring anyone. If this is not possible, the DSO has an obligation to inform the Regulatory Agency (HERA) and make a request to the generators to offer priority electricity to cover losses in the distribution network. In reality, active power losses in the distribution networks are procured by DSO through tenders; only bilateral contracts were practiced so far. There was no procurement of losses from local/distributed generation of storage (or any other source of flexibility at the distribution network). Active power losses for previous years are available at the official website of HEP-ODS in their annual financial reports. The total amount of losses for 2016: **1,234,782,628 kWh (7.64%)** The total amount of losses for 2015: **1,294,847,241 kWh (8.05%)** The total amount of losses for 2014: **1,257,331,297 kWh (8.14%)** The total amount of losses for 2013: **1,459,418,514 kWh (9.16%)** The total amount of losses for 2012: **1,402,635,104 kWh (8.68%)**
Hungary	TSO and DSO are obliged to tender and purchase the network loss in a way that is public to the national and international generators and traders. DSO has the right to sell the electric energy purchased for recovering the distribution network loss that exceed actual network loss on the regulated electric energy market. There is theoretical possibility for this, but the tender preferred applicants able to offer “complete supply”. So in reality the distributor has contract with one trader (who purchases the electric energy from the power plants). The network power losses in the last years (EON Tiszántúli Áramhálózati Zrt.): • 2009: 11.24% • 2010: 11.83% • 2011: 11.48% • 2012: 11.88% • 2013: 11.48% • 2014: 10.6% • 2015: 9.54% • 2016: 8.8%
Slovenia	The DSO is obligated to procure for network losses, emergency supply of electricity, unwarranted consumption and incorrectly registered measured data in the entire distribution network of Slovenia. Because the DSO is not allowed to actively participate in the electricity market, network losses are procured through tenders, with bilateral 1 year contracts. Active energy losses for previous years: • 2009: 616.1 GWh (5.7%) • 2010: 636.1GWh (5.7%) • 2011: 544.9GWh (4.9%) • 2012: 576.8GWh (5.3%) • 2013: 549.8GWh (5.0%)

1.1.7. What is the allowed operational range of voltage in the distribution network (eg. ±10%)? Please elaborate the specifics for both medium and low voltage networks.	
Austria	The allowed operational range in both MV and LV is ±10% of the nominal values.

Bosnia and Herzegovina	In normal operational conditions the distribution system operator has to maintain voltage at the point of electrical energy delivery to the end users within the following limits: a) for 35, 20, 10 kV network within ± 10% of nominal value, b) for the low-voltage network between + 5% to -10% of nominal value. In case of any disturbance caused by force majeure, voltage deviation may be higher than the ones listed above. [9]
Croatia	Typically, the distribution networks are allowed to operate within ±10% of their nominal value. However, a value of ±8% of nominal value is usually considered as an indicator that either operational changes are needed (switching taps on the upstream transformer or changing topology, as an example) or as an indicator that new investments are needed in the next planning horizon should be mentioned that low voltage networks are not continuously monitored and that all voltage deviations (power quality issues) are usually measured only after receiving official complaints (in those cases continuous measurements are performed on site of complaint over a 7-day period).
Hungary	**HV network:** Rated voltage: 132 kV Minimum voltage of the network: 114 kV (normal state) 108 kV (n-1 state) Maximum voltage of the network: 138 kV **Medium voltage** **35 kV** Rated voltage: 35 kV Minimum voltage of the network: 29.75 kV (normal state, as a 10-min average of 100%) 31.5 kV (normal state, as a 10-min average of 99%) Maximum voltage of the network: 40.25 kV (normal state, as a 10-min average of 100%) 38.5 kV (normal state, as a 10-min average of 99%) **22 kV** Rated voltage: 22 kV Minimum voltage of the network: 18.7 kV (normal state, as a 10-min average of 100%) 19.8 kV (normal state, as a 10-min average of 99%) Maximum voltage of the network: 24 kV (because of the Hungarian Standard) **11 kV** Rated voltage: 11 kV Minimum voltage of the network: 9.35 kV (normal state, as a 10-min average of 100%) 9.9 kV (normal state, as a 10-min average of 99%) Maximum voltage of the network: 12 kV (because of the Hungarian Standard) **LV network** **0,4 kV**

	Rated voltage (Hungarian Standard): 400 V Minimum voltage of the network: 340 V (normal state, as a 10-min average of 100%) 360 V (normal state, as a 10-min average of 95%) Maximum voltage of the network: 440 V At the connecting point of the costumer on the network (Hungarian Regulator): -rated voltage ± 7.5% (normal state, during a 10 days period, as a 10-min average of the 95%), -rated voltage +10/-10% (normal state, during a 10 days period, as a 10-min average of 100%), -rated voltage +15/-20% (normal state, during a 10 days period, as a 1-min average of 100%). It is measured if there is any kind of complain from a customer. If there is a complaint, a DSO has to execute the measurement by an device capable of data storing during the required period (here for 10 days). Moreover, there is a technical proposal of HEA, 1% of the LV grids should be measured every year.
Slovenia	The distribution networks (LV and MV) should operate within ± 10 % of their nominal value.

1.1.8. Is there a practice of defining optimal operational structure (optimal topology)? If yes, when is this done? Is the DSO considering introducing remote control switches for daily changes of topology? If yes, is there a strategy for doing that? And what is the main driver of the strategy (example, reducing active power losses)?	
Austria	There is no practice of optimal topology and we do not have remote control switches.
Bosnia and Herzegovina	Due to radial topology of EPHZHB’s MV network, especially overhead network, there is very limited possibility for managing optimal topology. This could be possible for parts of urban MV cable networks, however in normal conditions there is no daily changes of topology. At the 10(20) kV voltage level, there are 50 remotely controlled and monitored switch disconnectors type ABB SECTOS NXB (D) at overhead lines, with tendency of increasing this number, and connecting them to the SCADA system. They are installed on radial overhead lines typically at the middle of the line or in long branches and are used primarily for sectionalizing and location of faults.
Croatia	The main driver for setting the optimal distribution network topology is primarily increasing the reliability of supply (as an example, creating the so called rings or loops to be able to provide ancillary supply in case of interruptions) and recently also reduction of power losses. The optimal layout is usually not done on a daily basis, however the frequency of determining the optimal layout depends on the DCA and specifics of the network. It should be mentioned that there is very little possibility to change the topology online (meaning remotely, under full operating load). More remote switches are being gradually introduced, however starting from higher voltage levels (35 kV network, then 20 kV). Majority of DCAs already have made an automation plan and program, meaning they are already installing remote control switching devices. The

	main motivation for this is not reducing power losses (although they are an important aspect) rather increasing reliability of supply and restoring power for significant consumers. It should be mentioned here that HEP ODS was a partner in just finished EU FP7 project Dymasos (Dynamic Management of Physically Coupled System of Systems, www.dymasos.eu). One of the ideas and tasks within the project was dynamic management of the power distribution system. In that sense, continuous (daily) dynamic switching in MV grid for setting the optimal topology, considering energy losses, was analysed on a pilot project network in DCA Koprivnica. The pilot results indicated interesting solutions and potential for everyday application, however no new locations or dates for testing and implementation have been determined.
Hungary	The main aspect of the optimal network structure is to minimize the network losses but we consider the SAIDI effect as well. Every year there is an evaluation and if necessary then a calculation: with the present network load whether the opening points of the network represents the optimum (as a minimal network loss aspect)? To make an optimum we use the present remote control switches but very rarely make new ones for network loss reduction. We overview the network once a year in general (there was some kind of signal from the voltage monitoring system; or any considerable load changes of the feeder), but every significant new customer connection triggers a new calculation on the circuit with a possible need for correction. As a solution, a new simple version of primary substation was introduced: the so called “micro” substation: it causes network loss reduction and KPI improvement. This results in more substations, shorter line lengths, lower load per feeder and lower network loss. As regards to the Key Performance Indicators (KPI): SAIDI and SAIFI are proportional to the number of customers affected by a single fault. If the lines are shorter, then the number of customers connected to these shorter lines is lower, so a single fault affects fewer customers and the KPIs become more favourable.
Slovenia	The main aspect of optimal distribution network topology is reduction of power losses and increase of the reliability of supply. To provide ancillary supply in case of interruptions, additional rings or loops are being created. The optimal layout is not created on daily basis, however the frequency of determining the optimal layout depends on each EDC and specifics of the network.

***1.2.1. What types of network topologies are most common in your country (radial, ring, meshed, etc.)? Please elaborate if there are any specifics*.**	
Austria	Different structures, depending on the location, density of consumption etc., mostly operated as radial structures.
Bosnia and Herzegovina	Distribution network consists of MV feeders, almost exclusively in radial operation, often without the possibility of secondary supply.
Croatia	Different distribution topologies are possible and applied in Croatian DSO. However, operation of all voltage levels is radial. In cases when this is possible a preferred structure/layout is to ensure n-1 supply through ring (suburban areas usually) or meshed (urban areas) topologies. Other topologies are less common (such as 35 kV ring topology, which is more an exception than a rule).
Hungary	The HV distribution network is a looped network in ordinary operational state. Basically it consists of overhead lines. For MV distribution, 3 voltage levels exist: 35 kV, 22 kV and 11 kV. The most common structure of the MV distribution network is the 22 kV network with overhead lines. The fundamental characteristic of this network is the arced-ringed layout with radial operation. The MV/LV transformer stations are connected with “T” connection. 86% of the MV grid consists of overhead lines. The 22 kV and 11 kV cable network distribute the energy in the major cities. Its layout is arced and ringed and operated in radial way. The MV/LV transformer stations are connected to the network by series connection. The layout of the LV network for the most part is radial network or ringed-arced network with radial operation. 81% of the LV grid consists of overhead lines.
Slovenia	Different distribution network topologies are applied and it differentiates on the network voltage level. The 110 kV network has meshed topology, typically with overhead lines and some cables, which can be mostly found in city areas. The MV network (1-35 kV) has open loop structure topology, but it operates radially. Urban networks are mostly underground. The LV network has radial topology, with open loop structure ensured only for more important consumers.

1.2.2. What type of network topology is at the pilot site in your country?	
Austria	20 kV arced-ringed cable/overhead lined.
Bosnia and Herzegovina	Cable network, radially operated. Substation Vučilov Brig (pilot supply) is 6th substation in a series of 7 on MV feeder called Latice. 1st substation on MV feeder Latice can also be supplied from the other substation called Latice 2 which is supplied from the other MV feeder called Plastika. This means that substation Vučilov Brig can also be supplied from both MV feeders Latice and Plastika.

Croatia	Medium voltage, meshed network topology, operated radial. Since the two pilot buildings are on different MV feeders (10 kV), there is a possibility of switching and having both of them supplied from a single feeder (again radial topology).
Hungary	It is an arced-ringed 11 kV cable network with radial operation.
Slovenia	Radial network topology.

1.2.3. Since most of the distribution networks are operated as radial networks today, is the DSO considering introducing meshed network operation as the number of prosumers increases?	
Austria	No.
Bosnia and Herzegovina	There is no such strategy on DSO level. Strategy is to build n-1 line, when possible.
Croatia	No, there is no distribution system level strategy of doing this. However, a general strategy is to have a redundant (n-1) network topology built where economically feasible. In certain cases involving important customers or DER, 35 kV MV networks may be operated in a meshed configuration.
Hungary	No.
Slovenia	No, at least not in the near future.

1.3.1. What is the biggest challenge in operating distribution network today (e.g., losses, congestions, imbalances, harmonics, voltage fluctuations)? Please elaborate and provide examples if available.	
Austria	The main challenges of distribution network maintaining the level of voltage and supply quality in the line with customer expectations. On the other hand, the investments need to be more optimized due to continuous pressure to reduce the network tariffs and climate change need to be considered (environmental damage, distributed renewable generation). Most of the capital investments and are therefore into the ageing network which has high frequency of faults interrupting the supply to the end-customers.
Bosnia and Herzegovina	The main challenges in operating distribution network today are as follows: • Energy losses reduction • Quality and reliability of supply for the final consumers • Distributed Sources of Energy connection and network operation with integrated Distributed Sources of Energy
Croatia	Several challenges arise in recent years driving the improvements of HEP-ODS. Most important challenges are: i) increase of quality and reliability of power supply,

<table>
<tr><td></td><td>ii) increase of network capability to connect new distributed generation,
iii) increase in level of distribution automation and
iv) increase of energy efficiency of network operation in general</td></tr>
<tr><td>Hungary</td><td>The main challenges of distribution network are the expected continuous network service quality improvements (because of customer expectations) and limited resources (because of to curb the end user’s burden) while climate change (environmental damage, distributed renewable generation) and ageing network (high fault frequency).
<u>Environment impact</u>:
Most of the faults occurred in the overhead line network related to external impacts. (Possible main causes: falling trees from outside of the safety zone area, negligent utilities consultation for field work, lack of professional supervision at work site, negligent damage etc.)
<u>The structure of the network in Hungary:</u>
The load density is fairly low so the feeding point density of the network is low as well therefore the average line length is high. The consequence: a single fault affected fairly high number of customers (to curb SAIFI and SAIDI a challenge). [4]</td></tr>
<tr><td>Slovenia</td><td>The main challenge are voltage fluctuations, due to presence of distributed generation. There is also a tendency to improve the reliability of supply for final consumers. This will result in decreased power losses, and improvements of SAIFI and SAIDI factors.</td></tr>
</table>

<table>
<tr><td colspan="2">1.3.2. Is there a requirement for reliability of supply (expressed as SAIDI, SAIFI etc)? This can also be related to planning aspects (and usually is a KPI in distribution network planning).</td></tr>
<tr><td>Austria</td><td>The Elektrizitätsstatistikverordnung (Electricity Statistics Ordinance) 2016, the Elektrizitäts-Energielenkungsdaten-Verordnung (Electricity Intervention Data Ordinance) 2014 and the Netzdienstleistungsverordnung Strom (Ordinance on Electricity System Service Quality) as amended in 2013 mandate that statistics on outages and disturbances on the electricity system be drawn up and published annually.</td></tr>
<tr><td>Bosnia and Herzegovina</td><td>Yes, the request for reliability of supply parameters (SAIDI, SAIFI) exists. In documents [4], [5], [6], [7] and [8] the reliability of supply parameters (SAIDI, SAIFI) are shown and they are submitted by EPHZHB following requests made by FERK.</td></tr>
<tr><td>Croatia</td><td>Reliability of supply in Croatian distribution networks is expressed through SAIDI and SAIFI indexes based on outages longer than 3 minutes – this is considered as an important KPI defined by HEP ODS management and is also defined in “Terms of power supply quality” passed by the regulator (HERA).
In the "Terms of power supply quality", the following guaranteed standards have been defined:

<table>
<tr><td rowspan="2">Continuity of Supply indicator</td><td colspan="2">Guaranteed standard</td></tr>
<tr><td>Underground line</td><td>Overhead line</td></tr>
<tr><td>Duration of an individual long planned interruption of an individual end customer on medium voltage</td><td>360 min</td><td>600 min</td></tr>
<tr><td>Duration of an individual long unplanned interruption of an individual end customer on medium voltage</td><td>600 min</td><td>900 min</td></tr>
<tr><td>Duration of an individual long planned interruption of an</td><td>360 min</td><td>600 min</td></tr>
</table>
</td></tr>
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<table>
<tr><td></td><td>
<table>
<tr><td>individual end customer on low voltage</td><td></td><td></td></tr>
<tr><td>Duration of an individual long unplanned interruption of an individual end customer on low voltage</td><td>600 min</td><td>900 min</td></tr>
<tr><td>Total duration of all long unplanned interruptions for an individual end customer on medium voltage</td><td>240 min/year</td><td>720 min/year</td></tr>
<tr><td>Total duration of an all long unplanned interruptions for an individual end customer on low voltage</td><td>240 min/year</td><td>720 min/year</td></tr>
<tr><td>Total count of an all long unplanned interruptions for an individual end customer on medium voltage</td><td>4 /year</td><td>9 long interruptions/year</td></tr>
<tr><td>Total count of an all long unplanned interruptions for an individual end customer on low voltage</td><td>4 long interruptions /year</td><td>9 long interruptions /year</td></tr>
</table>
</td></tr>
<tr><td>Hungary</td><td>Requirements of the Regulator:
Target set by the Regulator in 2005: „…to reach the present level of similar European countries, performing similar quality measurements, within 12 years.”
The Hungarian regulatory system is quite challenging even when compared to European Union. There is only negative financial incentive so the goal of the DSOs are to avoid penalty.
Minimal quality requirement is valid for 3 indices:
Unplanned SAIFI
Unplanned SAIDI
Outage rate
The most critical KPI is the unplanned SAIDI which aggregated mainly on the MV overhead-line network. The most cost effective way to curb SAIDI and SAIFI to elaborate a network automation concept (basically remotely operable pole mounted switches on the MV overhead line network).[5]</td></tr>
<tr><td>Slovenia</td><td>The reliability of supply is expressed through SAIDI and SAIFI indicators, which are defined in the terms of power supply quality, which are given by the regulator (The Energy Agency of Slovenia).</td></tr>
</table>

<table>
<tr><td colspan="2">1.4.1. Is there a long term distribution network strategy?</td></tr>
<tr><td>Austria</td><td>Thera are no changes planned. We will keep 20 kV and 0,4 kV voltage levels.</td></tr>
<tr><td>Bosnia and Herzegovina</td><td>There is a long-term strategy of the distribution network and it contains:
a) solutions related to the technical characteristics of the network (selection of voltage levels, the transition from 10 kV to 20 kV voltage level, changes related to the grounding distribution system neutral point, strategy automation, remote management, monitoring and collecting data on operating and accounting sizes, system development for data transmission, etc.),
b) a list of substations and power lines distribution voltage level that are designated for the construction or expansion of energy capacity with annual dynamics of construction,</td></tr>
</table>

	c) total number of substations and line lengths of all distribution voltage levels designated to be constructed or are considered for expansion of capacity with annual dynamics of construction, d) inspection of facilities provided for the construction which will be connected to the distribution network, e) single line diagram of the distribution network with the basic technical data, f) the maximum and minimum power generation units in the distribution system, g) losses in the distribution network, h) short circuit calculation for each node, i) demand forecast by consumer groups, j) information about the planned free capacities of the distribution network, k) information about the expected short-circuit currents in the distribution network, l) the assessment of improvement of reliability of the distribution network, m) assessment of the necessary investments for implementation of the proposed plan, n) special study about necessity of construction or reconstruction of power facilities of company Elektroprijenos BiH that are affecting the development of the distribution system. [9]
Croatia	Apart from TYNDPs, no particular long-term plans exist. However, for over 2 decades now, the DSO is aiming to transform the distribution system from a 110 kV/ 30(35) kV/ 10 kV / 0,4 kV system to a more advantageous system using 110 kV, 20 kV and 0.4 kV voltage level network. And while "abandoning" 35(30) kV networks is already being done in multiple places, simultaneously changing the 10 kV network to 20 kV network, specifics of some areas will make this more difficult and challenging in the long term, since this transformation also means switching to 110/20 kV transformer stations.
Hungary	The elimination of the 35 kV network – the preferred MV levels are 22 kV (overhead and cable) and 11 kV (cable only).
Slovenia	The long term distribution network plans are: a) on HV level – multiple reconstructions and some new 110 kV lines, b) on MV level – the aim is to enlarge the percentage of cables in the network, c) on LV level – mostly improvement of quality of supply (SAIFI, SAIDI).

1.4.2. Is there a standardized input for distribution network planning? Is there a standardized form of inputs from characteristics of distribution network equipment (lines, transformers etc)?	
Austria	Unknown
Bosnia and Herzegovina	There are standardized input parameters for distribution network planning, this is in domain of smaller DSO units. Also, there is a standardized form of input parameters related to the characteristics of the distribution network equipment which is also in domain of smaller DSO units.
Croatia	HEP-ODS is in charge of planning and developing the distribution network (among other tasks) in a transparent way. Thus the methodology and criteria for planning the distribution network is publically available (in Croatian) online: Kriteriji_metodologija_planiranja.pdf

	In addition, HEP-ODS publishes a 10-year plan with granularity for the first and first three years. The TYNDPs are coordinated with the TYNDPs of the TSO. Each distribution control area (DCA) is additionally in charge of making more detailed plans and analyses, assisting in strategical decisions and investments. Plans are created for a 20-year period (planning horizon) with granularity of every 5 years. The main role of DSO headquarters in these 20-year DCA plans is making sure the standardized procedure exists and there is a more or less unified input and output from plans made. The standardized input would include: - Topology of the entire analysed network, preferably georeferenced in GIS (available most cases) for medium voltage network (no LV is included in those plans); - Database containing all technical information on network assets (lines, transformers, compensations etc.); - Database containing age of equipment as this might serve for investment indicators; - Historical load and consumption, preferable granularity is as high as possible. Typically, it includes consumption curves in 35 kV substations (consumption of the substation and, mostly, curves per feeder) and 20(10) kV maximum load information. It should be emphasized that this information is not available equally for each DCA and this might be the biggest challenge in HEP-ODS data collection, organization and planning standardization; - Information and load curves for significant consumers (usually over 30 kW with installed AMR); - load profiles for households, public lighting and small entrepreneurship (available at HEP-ODS website); - Information on Distributed generation (connected and with planned connections in the near future) – e.g. basic technical information, max. production, scheduling, etc.; - Urban and regional planning data related to power consumption; - Planned network investments inherited from previous planning period and to be realized in the near future; - Planned and estimated future significant customers connections; - Network and equipment costs. Expected results of long term (20 years) network development plans are: - Load flow and voltage profile analysis during maximal loading and normal operating conditions, including n-1 analysis, for every 5-year stage of the 20-year period; - Timelines and priorities for the network transition to two level transformation (110 kV and 20 kV operating voltage become dominant, abandoning when possible 35 kV and 10 kV voltage levels). This is a result of internally developed method based on Analytical Hierarchical Process (AHP) analysis; - MV network development plans for 5-years stages of the 20-year period, including transition to 20 kV voltage level; - Cost estimation of planned network development, by 5-year stages of the 20-year period; - Short circuit current analysis; - Reliability analyses for each 5-year period over the entire 20-year planning horizon;
Hungary	Network topology and equipment data are exported from GIS. For HV and MV network planning, we use measurement data from national measurement days and the SCADA system. Consumer numerical data, critical consumer contracts and statistics of service

	quality (such as breakdown data, data of planned and executed power-downs, evaluation of consumer complaints, calculated technical service quality data) are also available.
Slovenia	SODO as DSO is in charge of planning and developing the distribution network. It publishes a 30-year plan, which is revised and updated every 2 years. The mentioned 30-year plan is based on network planning from each EDC, that follows a standardized input: • topology of entire network with GREDOS (LV level are being added to the topology), • database containing all technical information on network assets (lines, transformers and compensation, etc.), • load forecasts, which results from maximal network loads

1.*4.3. Do you use GIS for distribution network planning? What GIS software do you use? How much of your distribution network is available in GIS? Do you use GIS for other operation/planning activities?*	
Austria	We will finish our GIS project to implement the 20 kV grid within end of 2017. The 0,4 kV voltage level will be done in 2018. We use the software ArcGIS from ESRI.
Bosnia and Herzegovina	EP HZHB does not use GIS for distribution network planning.
Croatia	As mentioned above, HEP-ODS uses DeGIS software, covering 90% of the medium voltage network, while low voltage networks are still to be integrated into GIS (positive examples are DCA Koprivnica and Zagreb where inclusion of LV network in GIS has already reached significant percentages). GIS data is used for asset management, distribution network maintenance, planning and development as the central database for geographical and technical data. GIS data is used in distribution network maintenance, planning and development as the central database for geographical and technical data.
Hungary	We use a GIS software named INIS (Integrated Network Information System). The total HV, MV and LV distribution network is available. The used database is the Oracle Spatial. GIS is the base of network calculation, of the SCADA and also of the asset management EFORM. For network calculation we use the NEPLAN, with an interface between GIS and NEPLAN.
Slovenia	For distribution network planning we use GREDOS with GIS support. GREDOS is a program with interface that enables easy data entry, fast calculations of power flows, short circuits and reliability, optimization modules and possibility of import and export of data from databases AMI and system SCALAR, as calculation results for other GIS tools (ArcGIS/QGIS). It is used by all EDCs as GREDOS includes the entire MV level grid of Slovenia with its topology and electrical model. The LV level grid is being added in the last few years, as are the existing data constantly refreshing and updating. Now there are 92 DTS, 17.500 km of lines and 16.500 TS included in the program.

1.4.4. What is the time frame for the distribution network planning ?	
Austria	The time frame for distribution network planning is 5 years.
Bosnia and Herzegovina	DSO continuously monitors and analyses the data on the capacity utilization of the distribution network, monitors the electrical parameters of the network and provides the development of consumption, and prepares both short-term and long-term plans for development and construction of the distribution network. Long-term development plans are made for a period of 3 to 10 years. Ten-year development plan is being prepared on the basis of 3 possible scenarios for consumption growth (low, medium and high consumption growth). Short-term plans for development of the distribution network is prepared for a period of one year. [9]
Croatia	HEP-ODS creates a 10-year plan for development of the distribution network, it can be found online in Croatian at: http://www.hep.hr/ods/UserDocsImages/dokumenti/Planovi_razvoja/10g_2017-2026_2016_12_19.pdf It needs to be mentioned that publication of 10-year plan is subject to approval of the Croatian Regulatory Agency (HERA). In addition, each DCA performs 20 year plans with 5-year time sub frames (milestones in planning for re-checking progress and adjusting future plans).
Hungary	We use adaptive planning methods. The usual time frame is ten-year planning perspective with a 5-year snapshot.
Slovenia	DSO publishes a 30-year plan that is revised and updated every 2 years. There is also a project REDOS, which is made by a Slovenian electrical institute EIMV (Elektroinštitut Milan Vidmar), that takes the whole grid of Slovenia as a whole for the future distribution network planning. They make 30-year plans with 5-year sub-frames.

1.4.5. What methodology do you use for future load forecasts? Are energy efficiency measures taken into account when forecasting future load? What is the average load increase/decrease for the next 5 years (please feel free to provide as many details as possible on this question)?	
Austria	At the moment we work on a project with technical university Graz to define processes and develop a tool for future load forecasting. Due to the increase of renewable energy feeding we are going to the limits of our distribution net.
Bosnia and Herzegovina	Future load forecasts, for the purpose of planning, are made based on available historical load/consumption data using trend methods. Average load increases for the next five years vary depending on each distribution area, from under 0.5% to over 2% per year. But with increase of renewable energy, depopulation, power market and reducing energy loses, weather conditions in future might be quiet different than expected.
Croatia	Future load forecasts, for the purpose of planning, are made based on available historical load/consumption data using trend methods. On occasion, if additional information is available methods such as econometric is used to compare results with trend methods.

	Average load increases for the next five years vary significantly depending on the analysed network, from under 1% to over 3% per year.
Hungary	Long term load forecast is based on time series forecasting. Series of past measurements are available for trend analysis. The estimation is then modified based on the correlation between economic development and the change in electricity demand. Exceptional events (e.g., new HV/MV station, large consumers, distributed generation) are taken into consideration during the process. The load estimation is revised annually. The average load increase for E.ON Tiszántúli Áramhálózati Zrt. is 1,62%.
Slovenia	Future load forecasts are made on available past load or consumption data using trend methods. Average load increases are ranging from 2,1 % to 2,6 % per year, depending on each EDC for the next 5 years. The biggest impact on future load forecast is the value of GDP.

1.4.6. Is distributed generation considered when planning future distribution networks?	
Austria	Yes, it will be covered (see 1.4.5).
Bosnia and Herzegovina	Currently, future DGs are generally not considered when planning future distribution networks, only existing DGs are considered.
Croatia	DGs are generally not considered in long term planning of future distribution networks, as they are not obliged to actively participate in network operation and security of supply and it is not possible to define the dynamics or their connection to the network. Additionally, DGs are not included due to uncertainties related to pace and total DG capacity to be connected to the grid in the future. For these reasons future peak load (and correspondingly, new grid investments) is forecasted based only on consumption. However, when planning and defining future DG connections (within a year time) technical aspects and requirements for DG connections are considered (load flows, short circuits, n-1 security, reliability, network changes/reinforcements, selectivity of protection devices etc.). DGs are into account only when considering n-1 availability of the network and, even then, only the DGs for which we can presume year-round generation (such as biogas or biomass power plants). It should be mentioned that currently no DG is not allowed to provide electricity to islands of the distribution grid during outages, although the DSO may allow a DG to provide auxiliary services (after testing).
Hungary	The planning of the MV network is based on the scenario with no dispersed generation infeed. The measured distributed generation is added to the measurements at HV/MV substations in order to determine the maximum load of each MV line. For LV network planning both scenarios are considered, i.e., with and without DG infeed.
Slovenia	For planning future distribution networks, currently only existing distributed generation is considered, exceptionally the future distribution generation, which cannot be yet connected to the gird.

1.4.7. Who pays for additional grid investments in case of new connections; is it the DSO or the investor (for example DG investor)?	
Austria	
Bosnia and Herzegovina	In case of new consumer connections, the new consumer always pays the requested connection power. If the new consumer, which is being connected, is not a subject of so-called “Special Zone” (*Posebna Zona*), then the additional grid investments are being paid by DSO. Otherwise, investment is split between DSO and new consumer; usually in 50:50 ratios. “Special Zone” is described in document “Opći uvjeti o isporuci električne energije” (General terms for electricity supply) [11]. In case of DG connections, the same applies as for new consumers. Exception is for DG connections with connection power between 2 kW and 23 kW (Micro-producers) which are at the same time consumers for the same amount of connection power. In that case, DG investors are free from paying the requested connection power [10].
Croatia	For consumers, a predetermined payment is based on their requested connection power. In case additional network upgrades are needed and the cost is 20% higher than the predetermined payment, the consumers pays for all required network investments. Producers always pay the entire required network investments. If the new network user is connecting as a prosumer, it pays the larger amount of the two (consumer or producer costs). If the new network user is connecting as a prosumer, it pays a larger amount of the two (consumer or producer costs).
Hungary	Paying for new connections are dependent of the type of customer (consumer or generator) and the voltage level of the connecting point on the network. In general the fee for connection to the LV and MV is independent of the actual cost of strengthening the network but simply proportional to the network lengthening and the required power. [6]
Slovenia	Additional grid investments are paid by the DG investor.

1.4.8. How many DGs or large consumers go through with connecting to the system (as opposed to just making a request for connection power)? It can be an “experience” guess if more precise statistics are not available.	
Austria	unknown
Bosnia and Herzegovina	In case of large consumers, most of them go through with connecting to the system. In case of DGs, it is usually related to Feed-in-tariff quota for specific technology.
Croatia	This depends on DG technologies, state or readiness and other difficult to predict factors. In case of large consumers majority of them connect to the network in the end, however usually with significantly smaller connection power than initially requested. In case of DG this percentage varies and is usually subject to incentives and quotas for specific technology.

	Approximately 5.800 DGs requested network connection in 2010-2016 period, while 1.577 of them were connected to the system. The majority of connected DGs have feed-in tariffs. Around 350 large consumers with connection power above 100 kW connect to the system annually.
Hungary	E.ON has experienced a drastic increase in DG connection requests over the past year. Due to the new Hungarian renewable energy support scheme, it is too early to estimate how many of those requests will actually be realized. Regarding DGs above 50 kVA, the number of connection requests by year: • 2013: 349 requests • 2014: 255 requests • 2015: 383 requests • 2016: 1757 requests[7]
Slovenia	Realization of consumers that go through with connecting to the system is quite small. It is more common to go through with connecting to the system for small consumer then for large ones.

1.4.9. Do the DSOs have a standardized input for planning of new equipment costs?	
Austria	unknown
Bosnia and Herzegovina	When planning new equipment costs for maintenance and connection of new customers we have standardized input with determined prices, which are based on earlier prices for equipment and current market prices. When planning new investments (e.g. new 10(20) kV substation with connection line) every distribution area uses their own estimation which is also based on earlier equipment prices and current market prices.
Croatia	Yes, these costs are used as input for planning the DCA distribution network development as well as when connecting new users (both consumers and generators).
Hungary	Yes, uniform guides are created and updated periodically. These guides contain per unit costs of installation, per unit costs of operation and maintenance, breakdown indices etc.
Slovenia	Yes, for investments planning new equipment costs are based on our “planning prices”.

1.4.10. Do you consider additional planning concepts besides reinforcing the network? If yes, please elaborate having in mind that we also welcome pilot project experiences.	
Austria	unknown

Bosnia and Herzegovina	There are no additional planning concepts besides reinforcing the network for the time being.
Croatia	No. However, besides basic medium voltage network reinforcement (construction of a new lines, new HV/MV and MV/MV substation, increase of transmission capacities of existing lines or transformers…), alternative solutions are considered, such as: i) transition of a part of the network to the higher voltage level (such as the above mentioned strategy of substituting 10 kV by 20 kV network), ii) the use of special devices (i.e. remote control switches, line voltage regulators), iii) change of switching state for feeders.
Hungary	The DSO is considering the following ideas: - Load control (heating storage equipment) based on LV network demand and generation - In line voltage control - MV/LV automatic regulated transformers - Photovoltaic (PV) regulation - Energy storage
Slovenia	No, there is no additional planning of the network besides reinforcing the network.

1.4.11. Are there specific network plans for the pilot location (this is relevant for the entire network neighbouring the pilot site, for example all radial lines from which the pilot site can be supplied)?	
Austria	unknown
Bosnia and Herzegovina	There are no specific network plans for the pilot location.
Croatia	Based on the planning report for the next 20-year period (network development study was finalized at the beginning of 2016), medium voltage network (10 kV) at the location of pilot buildings does not need any reinforcements or investments nor are any large projects planned for any of the two feeders. It should be mentioned that there is a capability of changing the switching state and 10 kV network layout, however for technical reasons this is not a preferred state for supplying the customers.
Hungary	The last long term plan for this area was prepared in 2011. This shows that it’s not needed to strengthen the network or modify the topology due to the load prediction. The network in the pilot area is in good condition, so reconstruction is not needed now.
Slovenia	No, there are no specific network plans for the pilot location.

1.5.1. At what voltage level (or consumer type) do you have continuous measurements? How do you approximate the non-measured load (load allocation)?	
Austria	unknown
Bosnia and Herzegovina	Continuous measurements are made at 35, 20, 10 and 0.4 kV voltage level and they are integrated in AMR/AMM system. Non-measured load is estimated using HEP Billing system.
Croatia	Customers` metering equipment for billing, control and exchange purposes are installed at 110, 35, 30, 20, 10 and 0.4 kV voltage levels. Load profiles are recorded and stored for most customers with rated connection power over 30 kW (20 kW by the end of 2017) and for all DGs. Point of common coupling for DGs with rated power over 500 kW is included in the SCADA system (current, voltage, power quality, event log…). Grid data and historical measured information (current, voltage, event log, power…) of HV/MV and MV/MV substations is stored in SCADA system database.
Hungary	At HV and MV levels we have measurement data acquired from the SCADA system. We also have continuous measurements of consumers with an available capacity more than 3x80 A. As a result of a pilot, some smart meters are installed on our network, but measurements acquired from smart meters are not considered for network planning purposes. On LV network we use the yearly consumption of the consumers and profile types.
Slovenia	There are two types of measurements: a) "Operational measurements" – used for network management (SCADA - measurements at the following spots: DTS and TS, transformation from HV/MV, remote switches and remote control TS). b) "Electrical consumption billing measurements" – smart meters (control measurements in TS)

1.5.2. Is there a common database where you store demand/load information for planning purposes (or any other purposes)?	
Austria	unknown
Bosnia and Herzegovina	Yes, AMR/AMM database.
Croatia	Currently, there is no one common database where demand/load information for planning purposes is stored. The data is distributed throughout several databases: -SCADA system database: HV and MV substations load measurements history, -AMR database: customer metering spots measurements, -Custom application for development planning (Aplikacija Planiranje razvoja): distribution area maximum load data (summer, winter, time of occurrence), energy consumption, losses and maximum load forecast (10-year period).

Hungary	The HV and MV measurements are available from the SCADA system. Measurements of consumers are stored in our measurement centre. In general we use 15 minute resolution data. Consumer data such as contracted capacity and new requests for power are stored in SAP. At MV level we also have current measurements at remote control switches – for E.ON Tiszántúli Áramhálózati Zrt., this is under development, the aim is to collect data with hourly resolution. At LV level week-long voltage and current measurements are performed occasionally. The results are stored in a system called Reginfo. In addition to the above, we have a voltage monitoring system for MV and LV problem areas.
Slovenia	No, each of the 2 mentioned types of measurements in 1.5.1 have its own database, which are not connected.

1.5.3. How many values do you measure at sites where you have continuous/advanced measurements?	
Austria	unknown
Bosnia and Herzegovina	Substation smart meters and large consumers (contracted connection power 23 kW or more) smart meters measure: - A+, A-, R1, R2, R3, R4, P+, P-, I, U, I0, cos phi. Small consumers (contracted connection power less than 23 kW) smart meters measure: - A+, A-, R+, R-, P.
Croatia	Please refer to answer under 1.5.5. In addition to AMR (explained in 1.5.5.) SCADA system generally records and stores current, voltage and power values, as well as event logs. If there is a PQ device located in a substation, measured values are limited by the type of device.
Hungary	SCADA measurements include the following: - transformers (HV and MV side): active and reactive power, voltage, current, frequency, temperature - busbars: voltage - MV lines: current Active and reactive power consumption of large consumers is measured in 15-minute intervals.
Slovenia	There are different values measured with smart meters at: • Industrial infrastructure: P, Q, S, I, U, event log. • Residential infrastructure: P, Q, event log.

1.5.4. Do you have the capability of remote control for advanced/smart meter reading devices?	
Austria	unknown

Bosnia and Herzegovina	Yes, we have capability of remote control.
Croatia	Yes. However, not all devices have these abilities.
Hungary	We have the possibility, but additional developments are needed.
Slovenia	Yes, but only remote connection and disconnection are possible.

1.5.5. Do you have the capacity to install such devices (AMR or smart meters) at all large consumer connection points for pilot distribution network site?	
Austria	unknown
Bosnia and Herzegovina	EPHZHB's business strategy is to cover as much as possible substations 10(20)/0,4 kV and as much as possible consumers with AMR/AMM system. Currently, the vast majority of substations and around 28% of consumers have already installed smart meters which are integrated in the AMR/AMM system. For consumers, the goal is to install smart meters and integrate in AMR/AMM system 80% of consumers till the end of 2020. **Error! Reference source not found.** Substation which supplies pilot location (MBTS Vučilov Brig) is already in the AMR/AMM system.
Croatia	Yes. Every large consumer (contracted power of 30 kW or greater) is equipped with an advanced meter that, besides energy consumption peak load and reactive energy, can record active, reactive and apparent load profiles, voltage, current, power factor profiles, 3-phase and single phase energy 15-minute profiles (both demand and cumulative), etc. These parameters are remotely monitored by HEP-DSO AMR system and stored in joint database for further analysis.
Hungary	Currently we use AMR for the main building of the pilot site, furthermore our intention is to install smart meters at the PV array inside the building, at the customer premises nearby the pilot building from network topology point of view (that is at some customers who are located on the same MV cable line, some customers who are located within the same MV/LV tr. distribution supply area) and at the MV/LV tr. stations which are on the same MV cable line than the MV/LV tr. station directly connected to the pilot building. For these secondary tr. stations we will apply either AMR or Smart meter, our capability is available to install such kind of meters. The place of the installed meters depends on the final pilot conceptual plan.
Slovenia	Yes, we do.

4. Understanding market concepts in active distribution networks - aggregators

In low carbon power system, majority of energy is generated in variable renewable power facilities, such as wind and solar power plants. Flexible, dispatchable generation is gradually being phased out and new sources should be commissioned in order to provide continuous balancing for maintaining generation-consumption equilibrium. Generators cannot provide balancing services without incurring lost opportunity costs thus creating potential business cases for them to be provided by demand side. This concept of balancing services being provided by demand facilities appears under different names; within 3Smart project the term “demand response” will be used. The concept is based on utilizing flexible, dispatchable demand as a tool to reduce the overall energy cost and mitigate system imbalances. Prequalified demand facilities change their scheduled day-ahead consumption patterns in real-time following system operator’s requirements and aggregators signal (currently only Transmission System Operator provides such signals, however the goal of 3Smart project is to define when and how Distribution System Operator should provide them as well). Since demand facilities are smaller in magnitude, as compared to conventional generation, and connected to distribution network accessing markets and receiving signals driving change of consumption patterns is somewhat limited. As a way of bridging this gap concepts of aggregating multiple distributed and flexible entities, through a new entity called aggregator, are being proposed as an efficient way of bringing demand flexibility to markets.

Different documents have been published recently explaining the role of the aggregator and focusing on different market, such as, NordReg discussion of different arrangement for aggregation of demand response in the Nordic market [15], and regulatory responsibilities, such as ACER recommendation on the Network Code on Electricity Balancing [16]. These documents are proposing different concepts and views for integrating aggregators into the existing market concept. In general, two main concepts for aggregators of demand response can be defined:

- *Supplier and aggregator are the same entity, expanding the portfolio of suppliers business to provision of flexibility services by demand response*. These additional services are offered at the intra-day and balancing market. In addition, the supplier can optimize these new resource with the goal of adjusting the demand to energy already bought (self-balancing).
  There are very few regulatory and market obstacles for implementation of the first module, however in cases where the system does not have sufficiently developed retail market (limited number of suppliers, low dynamics of customers changing suppliers etc.) this concept might not have the desired effect of liberalized multi participant market.

- *Supplier and aggregator are two different market entities.*
  In this case, the supplier offers energy supply service to the demand response provider, similar to current situation. How these services are procured depends on suppliers strategic decisions, meaning some will choose to have bilateral contract and some will play more on day-ahead or intra-day markets – depending on their strategy. It should be mentioned that the tendency of the EU document “Clean Energy for all Europeans” [17-19] is that suppliers offer consumers prices that reflect market prices, potentially resulting in dynamic price

profiles. This approach should stimulate flexible consumers to optimize their energy usage on a day-ahead basis.

On the other hand, aggregator is a new market entity clustering demand side providers of flexibility and participating in balancing market. It optimizes flexibility of its demand response portfolio and creates a strategy to gain most benefits for itself and its flexibility providers. In this case the aggregator needs to build his own network of users (his portfolio) and convince these users that they can gain additional benefits compared to interacting only with the supplier.

Both aggregator and supplier have the same clients, electricity end-consumers, but they provide different services to them. Electricity suppliers provide service of electricity supply, i.e. they buy electricity at wholesale markets (long-term/day-ahead/intraday markets) and sell it to end-consumers. Suppliers and end-consumers have mutually signed supply contracts. In order to maintain generation-demand balance in real-time each supplier is responsible for imbalances caused by their end-consumers. In other words, scheduled/planned demand should be equal to actual demand in real-time of each end-consumer. If imbalance still exist, transmission system operator activates balancing service providers and the cost of such services is paid by end-consumers who caused the imbalance indirectly through their suppliers. Suppliers, as well as other wholesale market participants (producers, traders), are therefore named balancing responsible parties (BRP) within power system operation terminology. BRP must be part of a Balancing group (as sole participant or jointly with other wholesale market participants). Suppliers participate at wholesale electricity markets as electricity buyers, however they participate in balancing markets only as imbalance creators. Aggregators provide services of system balancing, i.e. they sell end-consumers' flexibility at reserve auctions or regulating power markets to transmission system operator. They have signed aggregation contracts with flexible end-users. If imbalances in real-time exist, transmission system operator activates aggregator's end-consumers to provide balancing services. Aggregators do not participate in day-ahead wholesale electricity markets, they participate only at balancing markets as service providers. They are paid for balancing services through capacity reservation fee (EUR/MW) and activation fee (EUR/MWh). Part of those payments are forwarded to aggregators' end-consumers and part to suppliers for imbalances caused by activation of flexibility services.

For the second model, the biggest issue is resolving the challenge of having two balancing responsible parties at the same metering point (there are also some reports considering that the aggregator is not balancing responsible party). These two market parties need to have a contractual agreement on settlement aspects such as data exchange and financial aspects.

Technical prerequisites for above-described roles of end-consumers, suppliers and aggregators are smart metering devices at connection points between end-consumers and grid. If ahead-planned schedules and real-time measurements at connection points deviate and there was no call and provision of balancing services (for example by the aggregator), the end-customer pays imbalance costs to system operator through supplier/BRP. If the end-consumer is called to provide demand response (intentional deviations from ahead-planned schedules) and there is no ordinary imbalance (unintentional deviations) the end-consumer is payed for balancing services through aggregator. If both intentional and unintentional deviations exist, the real-time measurements, ahead-planned

schedules and activated balancing services are compared and the end-consumer gets payed for balancing services but also pays for imbalances on top of balancing services.

While it might be simpler for functions of supplier and aggregator to be defined within one entity, since the same measures and metering devices are used for both functions, two entities could operate with same end-consumers without procuring additional or unjust costs.

There is no unified solution fitting all markets and the regulatory framework should define the role of the aggregator in each market considering the existing retail market situation. While smart metering is often emphasized as key technical aspect, regulatory concepts, guidelines and definitions, together with standardization of contracts, mutual relationships and rights (not only financial) should be considered as additional key element in creating liquid retail market unlocking prosumers flexibility.

5. Defining operation and communication of integrated building – grid modules

The initial concepts and modules of integrated building-grid communication are to some extent described in D4.1.1. However, they only relate to general framework of information exchange between modules and do not put it into the context of entire power system operation.

The main principle of power system operation is maintaining a continuous balance between generation and consumption considering losses in the transmission and distribution systems. A number of services, energy and ancillary, are needed to fulfil this complex task and these are procured by different power system actors and on multiple time frames. Traditionally energy services are traded between producers and suppliers who buy energy for their customers. This energy can be trader long term (such as long term bilateral markets) of closer to time of delivery (such as day-ahead and intra-day markets). In those cases where imbalances between bought and sold energy still exist after the closure of intra-day markets, the system operators need to activate previously reserved capacity for balancing services. When this is put into the context of 3smart project the operation and exchange of data is envisioned as follows:

<u>Supplier → end-user</u>

The supplier buys electricity for its final consumers on a day-ahead market. Recent EU document promote the concept of suppliers providing their end-consumers prices that reflect real market prices. This means a dynamic price profile will be sent from supplier to the end-customer. These prices will be defined by the supplier and they can be as volatile as 24 different price-energy blocks or, more simple, as tariff blocks reflecting peak load periods when electricity is more expensive. ***These 24 hourly €/kWh profiles are sent to the end-users, in our case buildings, 12 hours before end of n-1 day of the delivery***. On top of these supplier generated/forecasted energy prices, the building is charged for the peak power by the DSO (€/kWp). Notice that already two instruments are in place to discourage the building from having high peak load demand. Based on these price profiles, buildings define their optimal schedule (building energy management system, or BEMS, is in charge of this) and send a ***profile of 24 hourly energy blocks back to the supplier (kWh/h)***.

During the day of delivery, on day n, the supplier (as any other power system balancing responsible party, BRP) could deviate from its day-ahead schedule and cause imbalances. In case of the supplier, it can only act as the causer of imbalances. These imbalances can be then traded at the intra-day market. For this reason the building needs to continuously adjust its operating points to minimize deviations from the announced day-ahead profile.

The data format and data exchange mode between the supplier and the end-user will be modelled in 3Smart project according to the D.4.1.1. Building –side EMS concept and information exchange interfaces definition.

Namely:

G2. Cost of energy, day-ahead: The supplier is a market entity and it participates in the market by bidding demand profile (e.g., 24-hour kWh/h blocks) for a certain day-ahead (DA) price (here we assume all bids are successful). DA prices are a result of market clearing process, however in the project

they will be considered as known values based on historical data (HUPEX, SIPEX, EEX). They will be used by building-side EMS as known values for the optimization process, i.e. for cost minimization which results in optimal demand profiles for given prices. The values for day-ahead prices and the resulting demand profile need to be known 12 hours prior to start of the observed day, meaning 12 to 36 hours before the dispatch between the two midnights. It should be mentioned that the building-side EMS receives day-ahead energy prices (24 prices, for each hour). The building will (e.g. at 9:00 each day) send to the supplier the energy consumption profile it would apply between the following two midnights in case of a fixed price determined as the average price for the previous day, such that the supplier can better bid on the market and finally send prices to the building/buildings. (Example for the G2, Day-ahead price table are given in appendix, 5.)

G3 Intra-day pricing for maintaining the declared day-ahead profile. At the intra-day market, the building-side EMS needs to pay for energy which is missing/surplus from the profile announced day-ahead. There are two options for valorising the intra-day prices related to this in the project: i) simpler one: values will be taken as day-ahead energy prices multiplied by a factor of 1,2 (20% higher) and thus the cost for the hour when the deviation occurs will be expressed as: (energy in the hour * DA hour price)+(absolute value of energy deviation from DA * 1.2 DA hour price); ii) instead of DA*1,2 existing intra-day prices are used (we will actually consider them as forecasts and use historic values from markets with available intra-day historical price data).
(Example for G3 Intra-day prices are given in appendix, 5.)

<u>Aggregator → end user</u>

The aggregator serves as a mediator between the building and system participants (or power exchange) offering flexibility services which could be provided during the day of delivery (selling to balancing responsible parties). To be able to do this, the aggregator needs to have the information of the available flexibility from the building. This building flexibility could be provided:

- After the closure of the day-ahead market (after submitting the day-ahead profile to the supplier) the DSO can define the need for grid flexibility services based on network security check (this can be done through AC power flow analysis) or optimization of its operating points (the developed operational ADNM modules can be used for this - ***Grid Side EMS***). In case the DSO needs additional flexibility, it makes a request for ***reservation blocks which are then sent back to the aggregator (service hour; €/kWh***). These signals are passed on to the flexibility provider (building) which optimizes its ***available 24 energy blocks for every hour (or more detailed such as 96 energy blocks for every 15 minutes, kWh/15-min). This Modified Day Ahead Schedule of the building is sent back to the aggregator. Theoretically the Aggregator could trade with the available/offered flexibility of the building not only with DSO but TSO or other Balancing Responsible Party (Example can be found in appendix, 5.)***
- During the intra-day adjustment, when BEMS is capable of more accurately assessing the available flexibility. The aggregator can offer these blocks at the intra-day market as €/kWh (to suppliers or generators) or at the balancing market (for transmission system services).
- It should be noticed that it is unlikely that one single building will be offering additional flexibility for multiple services and on different markets. However, in cases where there are multiple demand response providers it will the task of the aggregator to strategically optimize

its resources bidding on different markets to gain most benefits for the buildings in its portfolio and maximize earnings for itself.

Note: in the 3Smart project, there will not be a separate entity acting as an aggregator (flexible buildings will offer services to the DSO or in the market). The above concept will be followed without creating additional third party in form of aggregator. It is expected that in case of multiple demand response providers signing a contract with a single aggregator, such format of information will be available to the aggregator as well. In this case an aggregator would have a position of so called central level aggregator, meaning it would have sufficient resources (sufficient level of demand response MWs in required time) to be a player on a wholesale market.

In 3Smart project the role of Aggregator will be simulated by Grid Side EMS, at each pilot site the Grid side EMS will behave partly as a virtual aggregator, i.e the Grid side EMS will optimize based on Supplier / DSO needs and the capability of the Building (namely the schedule of the Building, and the possible provided flexibility of the Building).

The tables which are used for communication between Aggregator- End user and Supplier-> End user can be found below as embedded file: 3Smart_Data tables_Retailer_v1.xls›

DSO → Aggregator

In the environment where there are multiple flexible users connected to the distribution network, the DSO should strive to utilize these resources to increase the efficiency of distribution network operation. In case the DSO decides to procure services from local demand response providers the aggregator acts as a mediator.

These services can be procured on a long-term basis such that the DSO defines required flexibility as an alternative to investments, and announces reservation of the capacity of resources at adequate locations in the network. This is called availability fee and presents a tool for the DSO to hedge the risk of service not being available. The building can provide capacity as (€/kWh/h, duration) and the DSO decides if procuring such services is an acceptable alternative to more traditional methods (such as for example laying down a cable of larger cross section and higher thermal rating).

In reality, the DSOs develop network plans and detect in advance locations of possible overloads (or voltage magnitude issues) in the future. Therefore, long term analysis (AC power flow analysis based on customer profiles or/and feeder measurements) is necessary both for identifying the critical network parts and the cost of network upgrading in order to avoid overloading. Based on the cost of network upgrade the DSO will set the possible value (price) of the needed flexibility. In case of 3Smart project the DSOs will apply this only to the pilot sites.

Where there are long term contracts between DSO and Aggregator (i.e the basis of the reservation block, as mentioned above) there can be two ways for utilizing the needed flexibility:

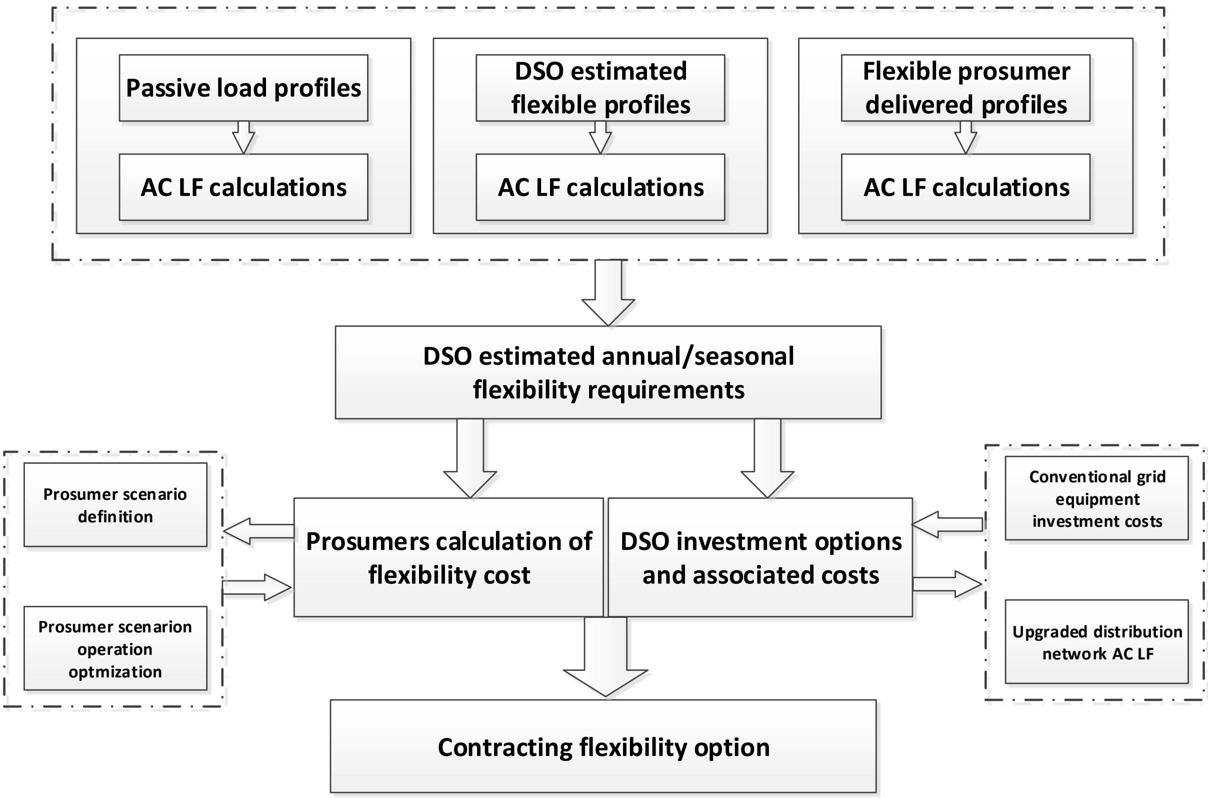
1. After the day-ahead market closes, the DSO should receive all accepted offers of its network users (from suppliers). The DSO receives these profiles (typical demand profile for users, expressed as 24 hours curve, kWh/h) since it needs to conduct a security check and make sure that the market accepted

offers do not compromise the security of supply for all end-users. This can be done by running AC power flow in network analysis tools currently used in Danube region DSOs, however it needs to be mentioned that in such cases the process of demand profiles input needs to be automated (in cases where there is no measurements or profiles, the loads will be estimated based on replacement curves used by the DSOs). In case of security constraint violations, the DSO looks into available flexibility bids received by from aggregator (see the above paragraph under Aggregator → end-user). These bids are combined with previously received demand profiles and fed into the developed DA and ID Grid-side EMS module – AC optimal power flow model. The outputs of this model are optimal operational points for the DSO utilizing additional demand response flexibility.

2. Closer to real-time operation the DSO could use measurements from the network (from all available measurement units in a given feeder) and compare them to predefined standards for flexibility activation. For example: the DSO sets the limit for flexibility activation at the 70% of the maximum feeder loading and if the real load (or measured load in real-time of operation) exceeds the given limit the DSO will send a trigger signal to aggregator to activate the needed flexibility). This approach also needs to consider the response capability of the Building (e.g after the DSO trigger the building can serve the needed flexibility after 1 hour), meaning that adequate load forecasting methods should be applied considering such delay (e.g before reaching predefined load limit of the feeder the software will provide load forecast for the next 1 hour, and based on this forecast the trigger sign will be sent).

The above points give a high level description of DSO interaction with Aggregator. Details of long term planning and short term operation stage are described as follows.

DSO long term planning and contracting method



We can divide the planning module into 4 main steps:

1. Initial distribution network state calculations
2. Calculating DSOs flexibility needs
3. Calculating costs of flexibility depending on the source
4. Contracting flexibility – planning future distribution networks

Step 1: Initial distribution network state calculation

The main idea is to perform daily "load flow with load profiles" calculations for specific days/weeks/seasons (the phrase comes from option in NEPLAN but refers to calculations done with load/generation profiles for the entire day). The proposal is to do 3 conceptually different AC Load Flow (AC LF) calculations (AC LF means including both active and reactive power characteristics):

i) AC LF as in conventional approach to demand/loads, where the DSO does not consider any load to be flexible. This includes demand/load growth/reduction forecasts as traditionally done today;

ii) The DSO creates additional "flexible load substitution demand curves". This is inspired by todays approach where demand on sites with none or incomplete data on consumption are replaced by substitution curves. This might be useful if a specific flexible prosumer did not announce these changes to the DSO (e.g. private investor decides to do a reconstruction that might affect its current demand profile). These substitution curves might also be useful to estimate future "switch" of specific consumers to flexible prosumers and their impact on the network;

iii) Demand patterns are provided by flexible prosumers. These profiles are then run through the AC LF.

Step 2: Calculating DSOs flexibility needs

Based on calculations in step 1, the DSO estimates if certain technical network constraints are violated (e.g. voltage, thermal line limits) or specific technical parameters that need to be improved (e.g. quality of supply). These violations or improvements are translated into flexibility needs in terms of power/energy (e.g. define for example 10 kW overload), duration of service (e.g. 30 minutes) and time slots when specific violation occurs (e.g. expected to occur on a work day between 11am and 2pm with maximum duration of 30 minutes).

These improvements can be achieved through response of flexible network users (we call them here prosumers, although this can be also DG or storage/EV) or network upgrades and additional equipment investment.

Step 3: Calculating costs of flexibility depending on the source

Inputs from step 2 are used to calculate values of providing flexibility. We consider two possible options for resolving issues detected in step 2: i) traditional approach through network

upgrades/investments; ii) procuring flexibility from prosumers. To make a decision there is a need to financially quantify both of these options.

DSOs usually have databases with “typical” costs for new network investments; these include costs for new transformers, protection equipment, cables and overhead lines. Selecting adequate equipment and running AC LF calculations to check if the detected issue/violation is resolved gives one parameter of flexibility costs.

Prosumers will make their optimal operational cost calculations for the case when they do not provide any DSO flexibility. This operational cost will serve as a benchmark and will be compared to operational cost when prosumers provide the flexibility service. The difference of these two operational costs will be defined as prosumers flexibility service cost.

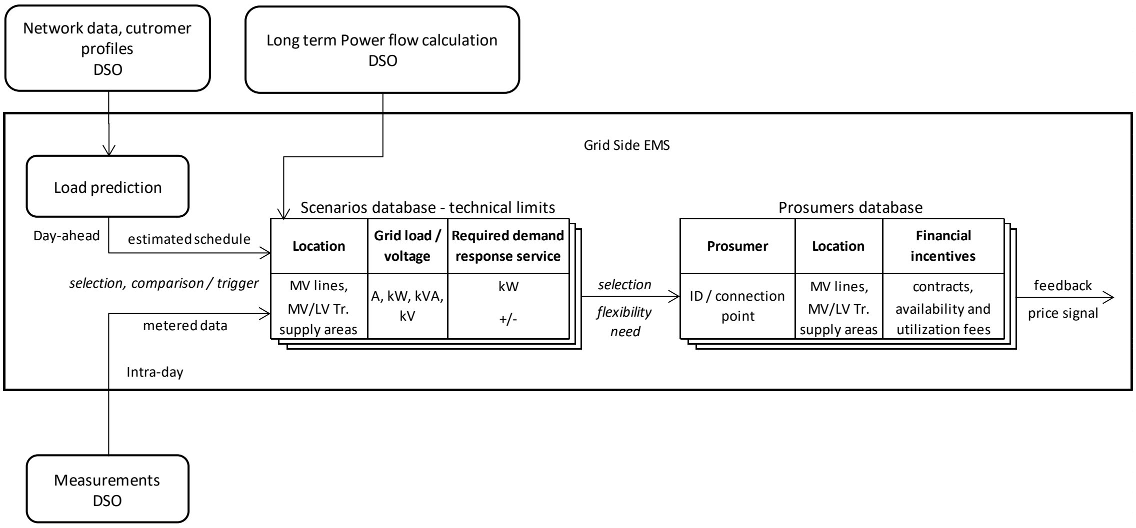
Based on the 3 steps described above the DSO makes a decision on ***contracting flexibility when planning future distribution networks***

Functional description of long term operation, DSO

Using the load-flow calculation results, traditional grid investment concepts are elaborated. These plans need to be compared with the potential demand response services and decide whether an investment can be deferred. To determine if sufficient amount of demand side flexibility is available to postpone the investment, a load gap is calculated between the forecasted peak load in the period/year when the investment is supposedly postponed and the maximum load the grid can handle without the investment (this maximum load is not necessary 100% of thermal line rating of ±10% of voltage deviation from nominal value, it can be a lower limit defined by each DSO), limited by technical constraints. This load gap should be the guideline for long-term contracting negotiations with the aggregator or flexible building prosumers.

In the process of comparing the alternatives and defining price incentives, not only the cost of equipment upgrade but also the following aspects of grid investments should be considered as well.

The functional structure of the long-term Grid Side EMS module:



The structure of the long term module

- Scenarios database: the incorporation of LF calculation results, this is where the predetermined technical limits and calculated and flexibility needs are extracted. These tables should be updated seasonally/yearly and when there is a significant change in network topology or in the consumption of customers or when new customers/generators are connected to the network.

Day	Type of Day	Month	DSO flexibility requirement (kW)	c€/kWh	Duration	Penalty c€/kWh
01.jan	Sunday/Saturday /work day	1...12	direction, range in kW			
03.jan	workday	1.	down 20	20	17:00-20:00	15
03.jan	Work day	1.	down 20	20	21:00-22:00	15
jun. 30	Sunday	6.	up 15	15	11:00-15:00	10

- Prosumers database: Theoretically the Grid Side EMS module can monitor several customers and basic data of these customers must be available for long term modules. A flag indicates that a contract exists and that the customer is available for demand response services. The data should be updated if changes occur.
- Load prediction: to estimate the day-ahead flexibility need of the DSO. Demand response availability is reserved for the DSO accordingly -> it is relevant for short term operation
- Measurements: the EMS processes the meter data (e.g. calculation of average values, conversion of measurement units, electrical calculation formulas may need to be used) and compares it with the relevant limits. The measurements trigger real-time demand response utilization -> it is relevant for short term operation.

Theoretical Operation: using the incoming day-ahead prediction or intra-day meter data, the EMS must recognize the matching scenario (location) and compare the values with the appropriate limits selected from the scenarios database. If the limit is exceeded, the EMS determines the demand response action for the case. Then it selects flexible consumers according to the location and sends requests for services and price signals based on predefined terms. The customer provides service in consonance with the contract and, if it fails to do so, sanctions stated in the contract take effect.

Prosumers/customers database contains a unique variable for identification, multiple columns to locate the consumer (describe the grid environment corresponding to the scenarios) and a "flag" for the long-term contract. Further contract details (technical parameters e.g. kW/15 min characteristic, time of availability etc.) may have to be added to the grid-side module for it to be able to send the requested actions to the consumers.

In 3Smart project the application will be modular and in case of city scale it makes sense to involve more customers and create a portfolio and introduce the aggregator as a mediator in providing and trading services.. However, in case of one or two buildings, the operation will be more simple than the above mentioned operation mode (e.g manual setups, limit modification, etc.).

Functional description of short term operation, DSO

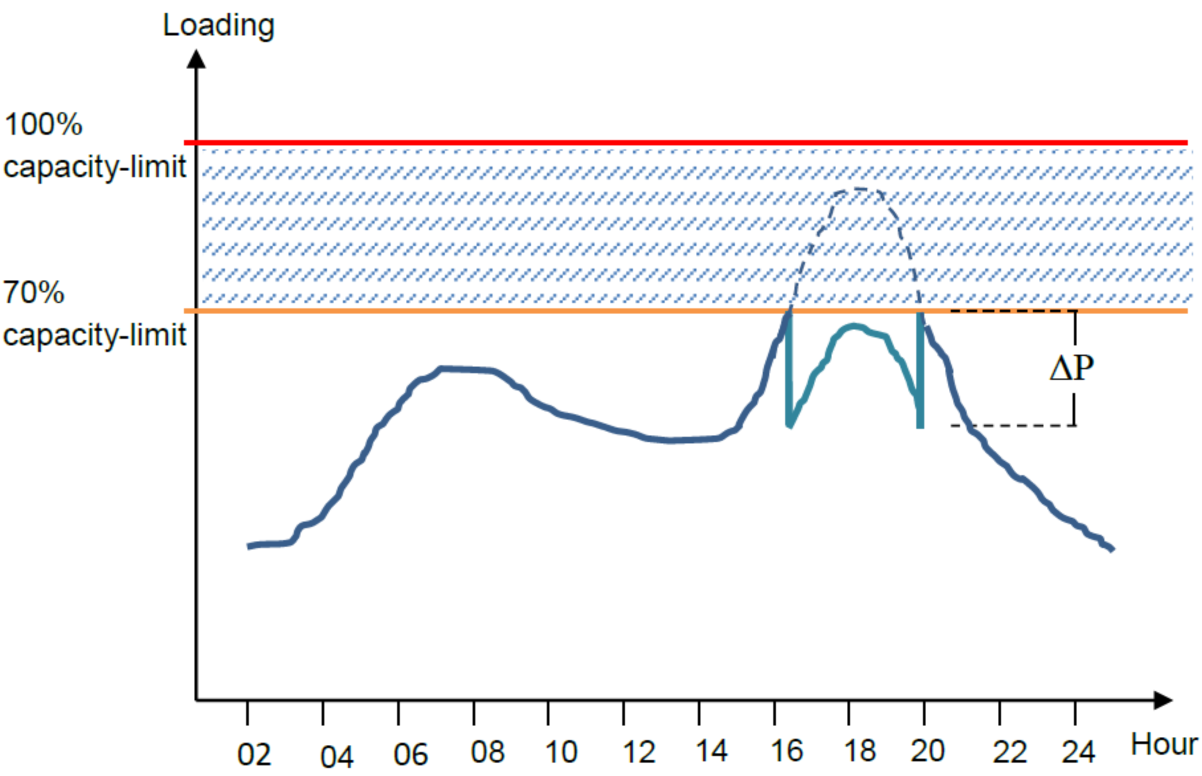
Where there are long term contracts between DSO and Aggregator (i.e. the basis of the reservation block, as mentioned above) there can be two ways for utilizing the needed flexibility:

1. Day-ahead load forecast specific to the grid zones supervised by the EMS is required in order to determine if demand response services need to be at disposal the next day and to estimate the period of time the service should be available. The DSO will not send daily updated estimations during the course of the project; a simpler solution will be implemented. The grid-side EMS module will make predictions for the monitored grid area primarily based on predefined data (e.g. load profiles from the customers, network parameters, etc.). The grid-side EMS compares the predicted load against network limits set in a predefined table of the respective grid zone/scenario, defines the flexibility need for each time period and asks for service execution for the needed flexibility. The outcome is the estimated flexibility need for the next day, ideally a quarter-hourly quantity demand with direction.
2. Continuous measurements and grid monitoring ensure the intra-day operation of the grid-side module. Ideally the measurement time step is 1 minute and the data is collected every 5 minutes, at the most 15 minutes. The grid-side EMS module can make predictions for the monitored grid area primarily based on predefined data (e.g. load profiles from the customers, network parameters, etc.): The grid-side EMS compares the measured load against network limits defined in a predefined table of the respective grid zone/scenario and activates the needed flexibility. Then the real-time flexibility need is sent to the customers in the same format as the day-ahead availability need; starting time of flexibility utilization can be for instance the start of the next quarter hour if the response time of the building makes that possible. The DSO should consider that there might be a time gap between the demand response trigger and utilization, and define technical limits to be used by the EMS accordingly (make sure the grid has some reserve capacity on these occasions).

The proposal for the network limits table concept is given below:

Description	Dimension	Variable	Notification
Maximal voltage of the MV cable line	V	Umax	3 phases separately
Maximum of load of MV cable line	kW	Pmax	
Minimum voltage of the MV cable line	V	Umin	3 phases separately

The theory of the flexibility usage can be depicted with the help of the below picture:



If the day-ahead AC power flow calculation is used to estimate network security it is possible to extract the time and profile of the extent of the needed flexibility (Δ P), i.e. to when and by how much will the load exceed the operational limit (in this case we use the 70% because of n-1 practice, if the adjacent cable line will fail then the examined cable line has to take over the adjacent load. Therefore, it could be overloaded if we did not use this operational limit practice).

Using real-time measurements provides a more precise information in terms of activation time. Of course measurements of the line/or cumulated customer loads cannot provide adequate information about future event, i.e. the needed amount of the flexibility (Δ P). Therefore, this method has to be complemented with a load estimation either on a day-ahead estimation horizon or on a long term load

estimation. If the DSO cannot provide data which can be used for day-ahead load estimation then it should use the long-term load estimation. This approach is a necessity to determine the avoided cost of network investment, the question is on the load estimation method used to determine the Δ P. Of course there can be a range between very simple long term load estimation and day-ahead load estimation, e.g. the above example of the Scenario database shows an example of generated scenarios tree (e.g. with monthly, three type of day granularity we can generate 36 long term load estimation scenarios).

Here we have to admit that the most promising approach would be to apply the day-ahead load estimation by AC power flow calculator and the measurement of the load together. In this way we can determine more precisely both the needed flexibility (since we are closer to the day when the flexibility is needed and if we are closer to an estimated variable in time the more precise the estimation is) and the activation time (since the measurement can inform us about the real operation of the network).

Date	Time	Estimated load [kW]	Estimated load which exceeds the Operational limit [kW]	Measured P [kW]	Operational limit P_{op}[kW]	Network limits P_{max} [kW]	Predefined Operational limit (% of P_{max})	Activated Flexibility needs (=Estimated maximum load- Operational limit(%)*P_{max})[kW]	Calculated Flexibility needs (=Estimated maximum load- Operational limit(%)*P_{max})[kW]	Activation Price/kWh	Duration	start	end
2017.05.22	15:30	60	0	61	70	100	70,00%	0	0	25 Eurcent	3 hours	Signal from the DSO	3 ours from "on"-signal, or by earlier signal from the DSO
2017.05.22	15:45	65	0	66	70	100	70,00%	0	0	25 Eurcent	3 hours	Signal from the DSO	3 ours from "on"-signal, or by earlier signal from the DSO
2017.05.22	16:00	75	75	71	70	100	70,00%	23	5	25 Eurcent	3 hours	Signal from the DSO	3 ours from "on"-signal, or by earlier signal from the DSO
2017.05.22	16:15	75	75	75	70	100	70,00%	23	5	25 Eurcent	3 hours	Signal from the DSO	3 ours from "on"-signal, or by earlier signal from the DSO
2017.05.22	16:30	80	80	80	70	100	70,00%	23	10	25 Eurcent	3 hours	Signal from the DSO	3 ours from "on"-signal, or by earlier signal from the DSO
2017.05.22	16:45	80	80	82	70	100	70,00%	23	10	25 Eurcent	3 hours	Signal from the DSO	3 ours from "on"-signal, or by earlier signal from the DSO
2017.05.22	17:00	85	85	87	70	100	70,00%	23	15	25 Eurcent	3 hours	Signal from the DSO	3 ours from "on"-signal, or by earlier signal from the DSO
2017.05.22	17:15	87	87	88	70	100	70,00%	23	17	25 Eurcent	3 hours	Signal from the DSO	3 ours from "on"-signal, or by earlier signal from the DSO
2017.05.22	17:30	90	90	87	70	100	70,00%	23	20	25 Eurcent	3 hours	Signal from the DSO	3 ours from "on"-signal, or by earlier signal from the DSO
2017.05.22	17:45	92	92	94	70	100	70,00%	23	22	25 Eurcent	3 hours	Signal from the DSO	3 ours from "on"-signal, or by earlier signal from the DSO
2017.05.22	18:00	93	93	87	70	100	70,00%	23	23	25 Eurcent	3 hours	Signal from the DSO	3 ours from "on"-signal, or by earlier signal from the DSO

The above table presents the possible operation mode of the flexibility calculation and activation by Grid Side EMS module in case of measurement.

Date	Time	Estimated load by AC power flow [kW]	Estimated load by AC power flow which exceeds the Operational limit [kW]	Operational limit P_{op}[kW]	Network limits P_{max} [kW]	Predefined Operational limit (% of P_{max})	Activated Flexibility needs (=Estimated maximum load- Operational limit(%)*P_{max})[kW]	Calculated Flexibility needs (=Estimated maximum load- Operational limit(%)*P_{max})[kW]	Activation Price/kWh	Duration	start	end
2017.05.22	15:30	60	0	70	100	70,00%	0	0	25 Eurcent	3 hours	Signal from the DSO	3 ours from “on”-signal, or by earlier signal from the DSO
2017.05.22	15:45	65	0	70	100	70,00%	0	0	25 Eurcent	3 hours	Signal from the DSO	3 ours from “on”-signal, or by earlier signal from the DSO
2017.05.22	16:00	75	75	70	100	70,00%	23	5	25 Eurcent	3 hours	Signal from the DSO	3 ours from “on”-signal, or by earlier signal from the DSO
2017.05.22	16:15	75	75	70	100	70,00%	23	5	25 Eurcent	3 hours	Signal from the DSO	3 ours from “on”-signal, or by earlier signal from the DSO
2017.05.22	16:30	80	80	70	100	70,00%	23	10	25 Eurcent	3 hours	Signal from the DSO	3 ours from “on”-signal, or by earlier signal from the DSO
2017.05.22	16:45	80	80	70	100	70,00%	23	10	25 Eurcent	3 hours	Signal from the DSO	3 ours from “on”-signal, or by earlier signal from the DSO
2017.05.22	17:00	85	85	70	100	70,00%	23	15	25 Eurcent	3 hours	Signal from the DSO	3 ours from “on”-signal, or by earlier signal from the DSO
2017.05.22	17:15	87	87	70	100	70,00%	23	17	25 Eurcent	3 hours	Signal from the DSO	3 ours from “on”-signal, or by earlier signal from the DSO
2017.05.22	17:30	90	90	70	100	70,00%	23	20	25 Eurcent	3 hours	Signal from the DSO	3 ours from “on”-signal, or by earlier signal from the DSO
2017.05.22	17:45	92	92	70	100	70,00%	23	22	25 Eurcent	3 hours	Signal from the DSO	3 ours from “on”-signal, or by earlier signal from the DSO
2017.05.22	18:00	93	93	70	100	70,00%	23	23	25 Eurcent	3 hours	Signal from the DSO	3 ours from “on”-signal, or by earlier signal from the DSO

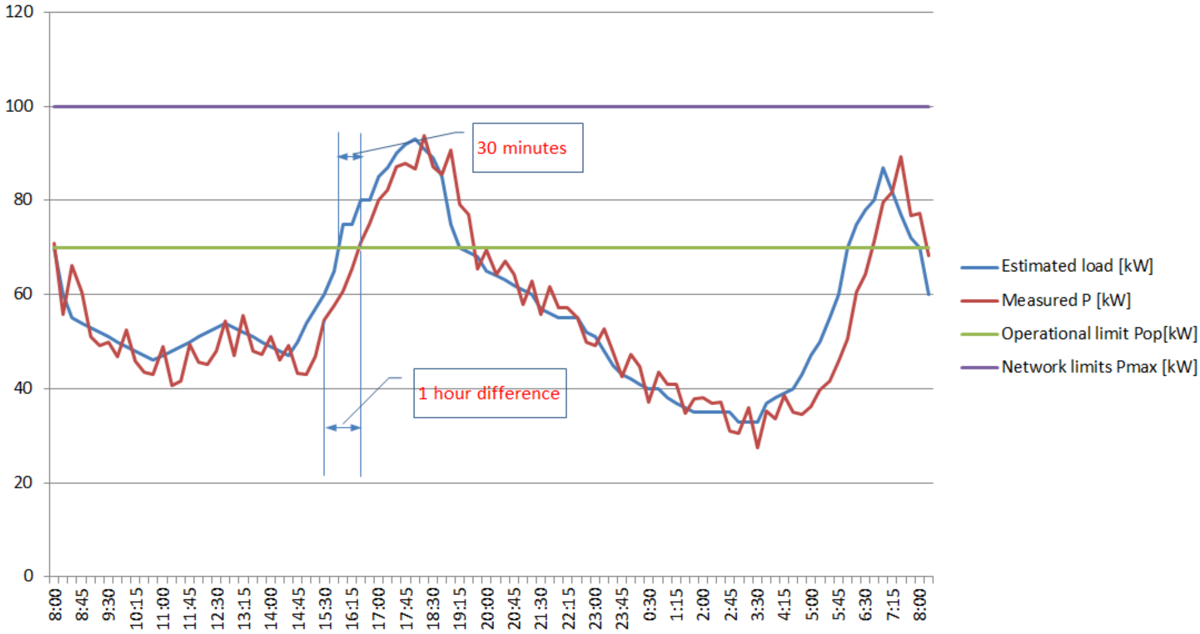
The above table presents the possible operation mode of the flexibility calculation and activation by Grid Side EMS module in case of Day-ahead Load estimation with AC power flow calculator.

The logic of the modus operandi of the both cases are very similar:

In case of day-ahead load estimation the AC power flow calculator estimates the load day-ahead, the system compares this load curve with the predefined operational limit of network. When the estimated load will exceed the operational limit then this will be the trigger to activate for the available flexibility. The calculation of amount of needed flexibility can raise some questions: in cases when there are multiple daily local maximums there will be a need for more frequent calls, this could imply more sophisticated calculation method. In reality the load curve on a pilot feeders does not show such characteristic, and we can assume that in a single day these calls will be limited to one or two. The above table shows an example (see also the embedded file) of the proposed approach.

In case of availability of real-time measurements, the method is very similar with difference of having the capability to have more precisely the activation time.

The below picture gives information about an imagined load profile which contains measurement vs. Day head AC power flow Estimated load profile:



In the above Figure, one can recognise two main differences in terms of time. The first one is the 30 minute difference between Day-ahead AC power flow estimated load curve and the Measured load curve. This information shows the importance of the real-time measurement from activation time point of view; if we have more precise information about the load pattern then we will not activate needlessly the flexibility. Of course this difference does not have to be so significant in the reality, however having both of these possibilities at disposal is likely to result in most favourable reservation and call for flexibility.

The second time difference, the 1 hour, refers to the question of the Building inertia from flexibility offering point of view, if the building is not able to react promptly or e.g in 15 minutes from receiving the activation signal from DSO, then somehow the Grid Side EMS should consider this fact and include it in the model, e.g module will contain a load forecast algorithms based on measurement and the module will be able to give information when the load curve will exceed the operational limit.

For the near real-time measurement of a feeder (MV cable line measurement with instrument transformer) an example can be found below:

POD (Point of Delivery)	Variable	Value	Status	UTC time
HU000120F11-U-000000000000	+A_LP2	0,25		2017.05.22 8:01
HU000120F11-U-000000000000	Alarm	0		2017.05.22 8:01
HU000120F11-U-000000000000	Cos_FI	1		2017.05.22 8:01
HU000120F11-U-000000000000	Frequency	49,99		2017.05.22 8:01
HU000120F11-U-000000000000	L1 voltage	236,2		2017.05.22 8:01
HU000120F11-U-000000000000	L2 voltage	234,7		2017.05.22 8:01
HU000120F11-U-000000000000	L3 voltage	234,8		2017.05.22 8:01
HU000120F11-U-000000000000	MTc	33		2017.05.22 8:01
HU000120F11-U-000000000000	+A_LP2	0,275		2017.05.22 8:02
HU000120F11-U-000000000000	Alarm	0		2017.05.22 8:02
HU000120F11-U-000000000000	Cos_FI	1		2017.05.22 8:02
HU000120F11-U-000000000000	Frequency	49,97		2017.05.22 8:02
HU000120F11-U-000000000000	L1 voltage	235,6		2017.05.22 8:02
HU000120F11-U-000000000000	L2 voltage	234,2		2017.05.22 8:02
HU000120F11-U-000000000000	L3 voltage	234,3		2017.05.22 8:02
HU000120F11-U-000000000000	MTc	33		2017.05.22 8:02

+A_LP2	Active energy (kWh)
Alarm	Alarm in case of different situations
Cos_FI	Power factor
Frequency	Hz
L1 voltage	Volt
L2 voltage	Volt
L3 voltage	Volt
MTc	Celsius

The above tables and the simple excel algorithms can be found in below embedded file:

3Smart_Data tables_DSO_v1.xlsx

Content of contract of the DSO in terms of flexibility services

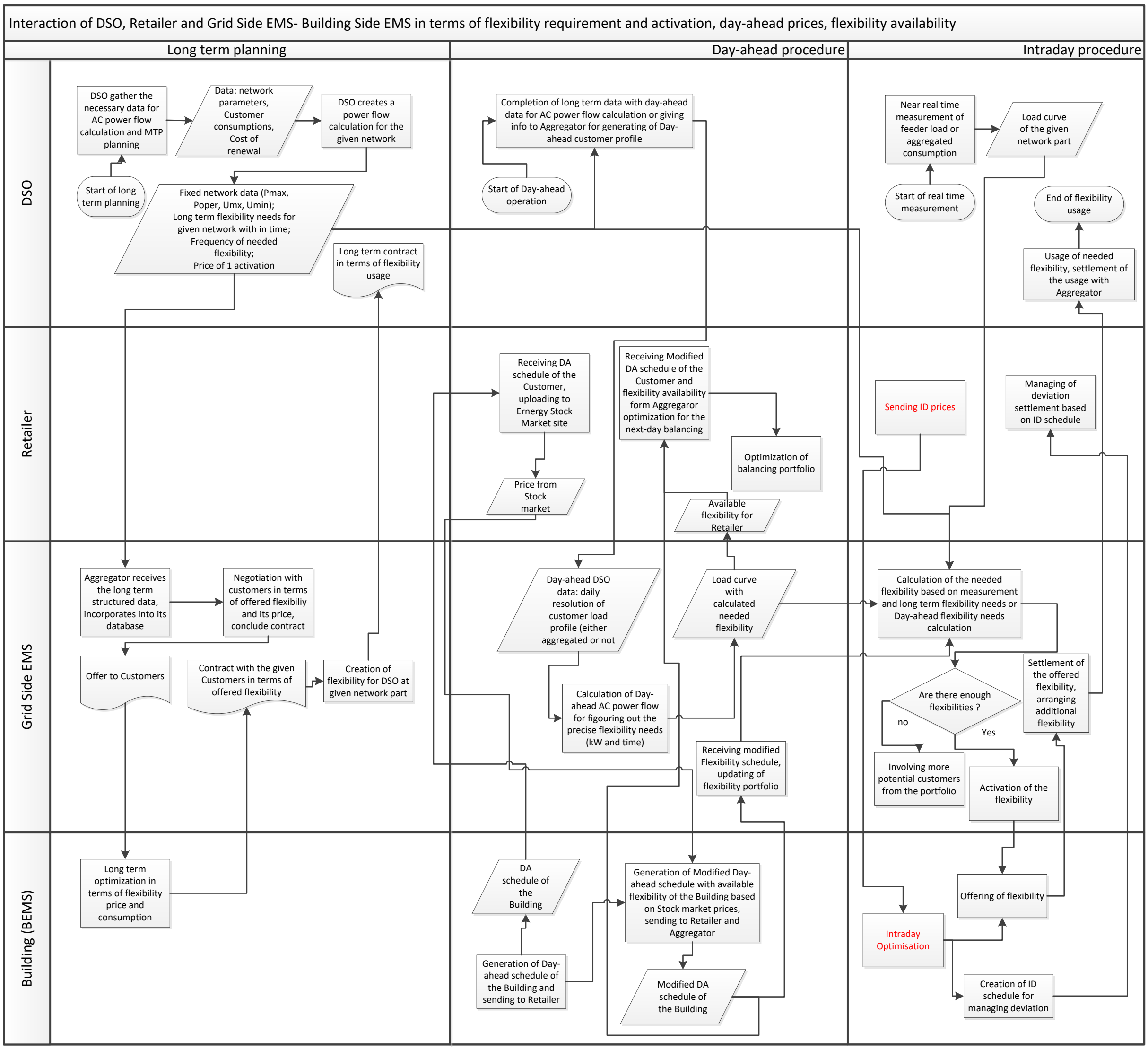
The below table proposes the content of flexibility service structure:

Service name		Flexibility service with Measurement
2)	**Contract valid from**	dd.mm.yyyy
3)	**Contract valid until**	dd.mm.yyyy
4)	**Est. no. of activations during period**	The estimated activation in the Contract period
5)	**Size of service in power (kW)**	Based on power flow calculation (e.g 50)
6)	**Size of service in energy (kWh)**	If the duration of the flexibility service is a predefined time interval then it makes sense
7)	**Max. duration of service per activation (h)**	3 hours
8)	**On - Trigger**	Signal from the DSO
9)	**Off - Trigger**	3 ours from "on"-signal, or by earlier signal from the DSO
10)	**Geography (specified by unique consumer numbers)**	e.g PoD
11)	**Maximum allowed activation time**	15 min (but it depends of the capability of the Customer process technology)
13)	**Quality in supply**	- Deviation in max. duration: +/- 5 min. - Deviation from, On - Trigger: +/- 10 min. - Deviation in size of service: Max. +/- 2 kW deviation - Acceptable no. of unsuccessful activations: 3
14)	**Pricing (DSO pays Aggregator)**	- X kEUR in reservation payment + Y kEUR per activation = estimated to Z kEUR for the entire contract period. - In total W kEUR as maximum payment for the entire contract period. - Paid at the end of the period, due to risk of alternative Aggregator (Grid Side EMS) ignorance of the contract
15)	**Estimated price per activation**	- Z kEUR
16)	**Risk issues**	Failure in supply, due to: - faulted communications or control systems between Aggregator, Grid Side EMS and Customer - Faulted communication of trigger signal between Aggregator, and DSO
17)	**Penalty if failed supply**	- X kEUR / per failed delivery within quality limits - 4 times of failed delivery → termination of the contract (Average value of life-time reduction of components etc. + administration + mobile power plants)

The above table is only an example, nevertheless it contains additional information, beside of the above mentioned Δ P and activation time, relevant for defining the communication and contracting aspects (namely the number of activations, the price of reserved capacity, the price of one activation). This information can be derived from long term power flow calculation and CBA analysis, where the DSO determines the cost of alternative network renewal/replacement and the possible number of activation numbers.

Distribution market level concept

As one can notice, one of the challenges for development of the day-ahead module lies in DSOs capability to perform estimation of missing/unmeasured demand input data. General flow chart of the interaction between DSO (Grid Side EMS) - Retailer/supplier- Aggregator - Building (BEMS) in terms of flexibility planning, and day-ahead, intraday price, schedule communication:



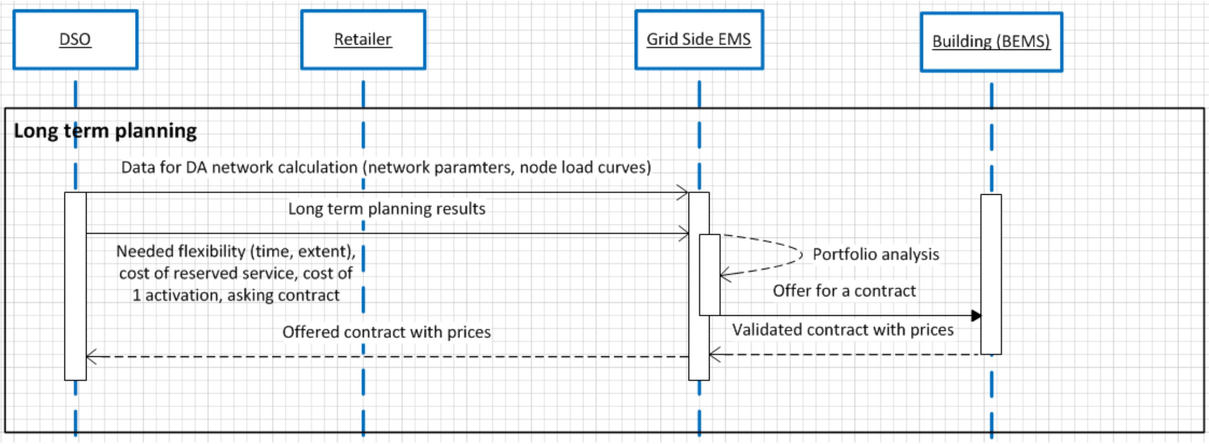
Flow chart of flexibility interaction_v Flow chart of flexibility interaction_v

Sequence Diagram of the Interactions

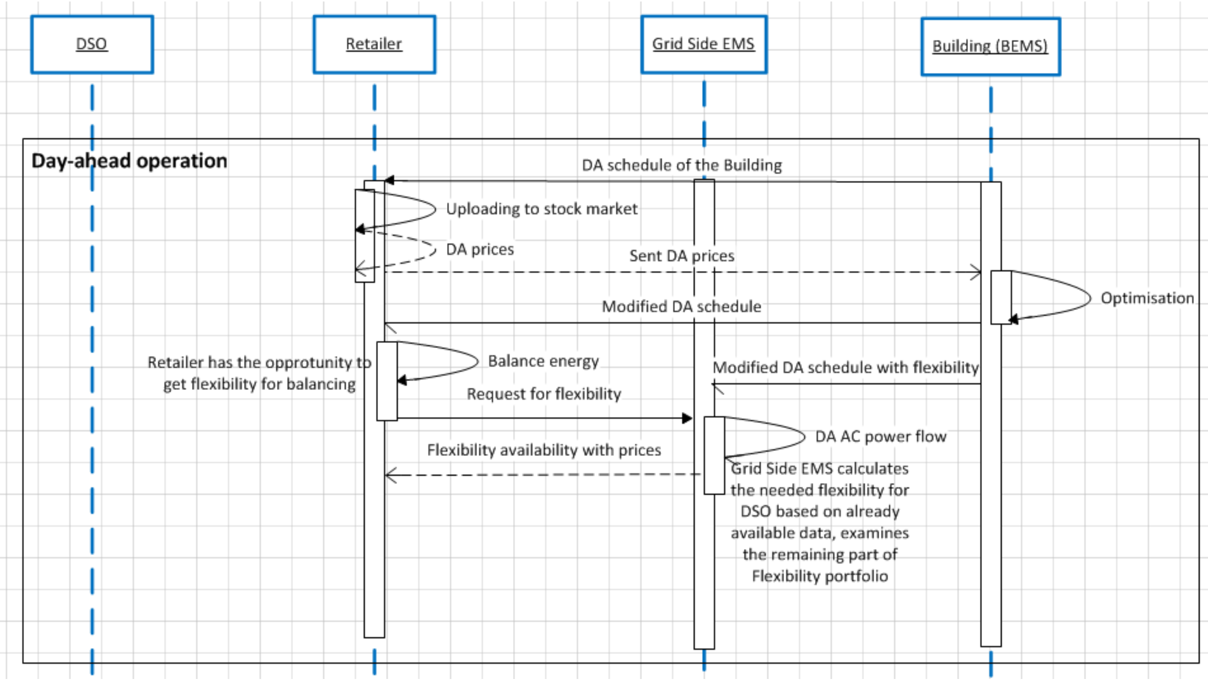
The following sequence diagrams informs us about the interaction activities between different market actors in time. The time axis starts on the top of the page and the time is moving forward as we move toward the bottom of the page.

The provision of flexibility should be based on price driven optimization (either DA, ID, BM prices or offered flexibility prices). If we imagine an ideal market environment the Aggregator will optimise only the flexibility portfolio based on plans, calculations and the information from the customer (availability, DA schedule, ID schedule, additional flexibility). The Building will optimise its consumption/generation and flexibility based on prices. These services can then be offered to other system entities (supplier, system operators etc.).

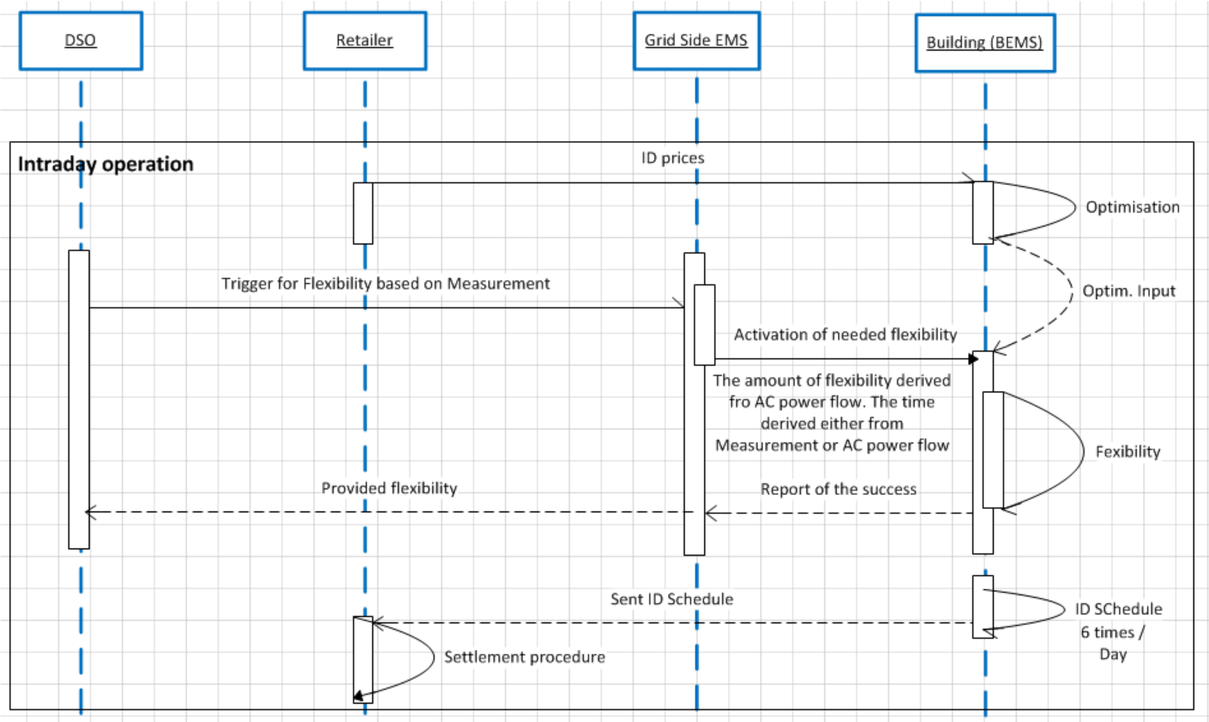
Long term planning



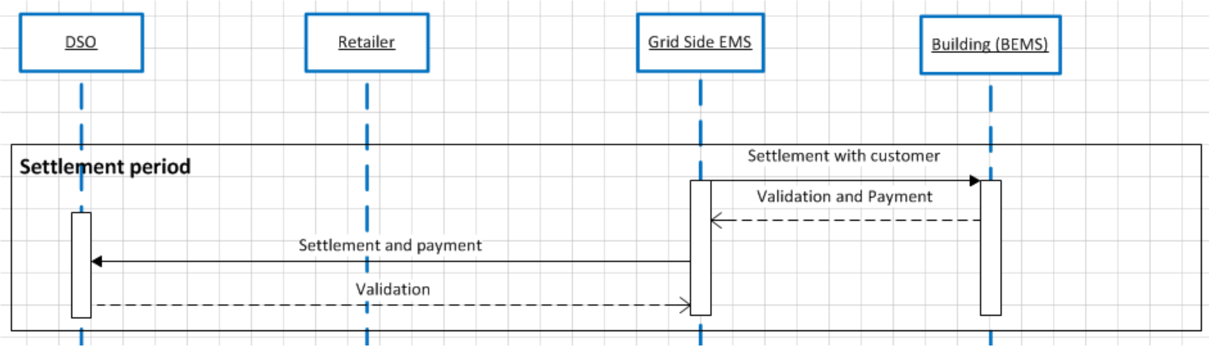
Day-ahead operation



Intraday operation



Settlement of flexibility services




3Smart Grid side EMS sequence diagram_v2


3Smart Grid side EMS sequence diagram_v2

The grid-side EMS module can have a better estimation of the DSO flexibility need in the upcoming period of the day e.g. based on meters read intra-day. The price (value) of the flexibility will be calculated from the long-range planning from the alternative cost of avoided investments or the cost of the capital in case of postponed investments. The retailer's intra-day flexibility need will come from the estimated imbalance need of the retailer.

3Smart concept

It can be concluded that flexibility of the buildings can be utilized for provision of multiple services. Which services are to be provided and which markets bring the highest profit will be discussed and analysed in details during the 3Smart project. It should be emphasized that these benefits also depend on multiple factors and vary depending on the power system energy mix, market structure, transmission and distribution networks, location of the demand response provider etc.

6. Conclusion

Current distribution network operational principles

In Croatia and Slovenia, a single DSO operates the distribution network. HEP ODS in Croatia is divided into 21 distribution control areas and the electricity distribution activities are carried out by 5 electrical distribution companies in Slovenia. There are three electric utility companies in Bosnia and Herzegovina (3 DSOs) later divided into smaller division. There are 6 DSOs in Hungary (EON represents half of them). Similar voltage levels are present among the countries (from 132 (110) kV to 0.4 kV) with small differences. All of the countries use SCADA system, except Slovenia uses GREDOS system. There are different tariffs for final consumers among the countries (detailed explanation could be found in table 1.1.3. and Appendix A). In all countries large consumers are paying for maximum power (different in every country). In Croatia, Slovenia and Hungary network losses are procured through tenders with bilateral contracts. Since Bosnia and Herzegovina has not done separation of electricity distribution, electrical energy for covering the losses cannot be purchased separately. Allowed operational range of voltage in distribution network differs among the countries. Generally speaking, it is the deviation of ±10% of the nominal value (further information in table 1.1.7.), except Hungary which has defined different range for each voltage level (table 1.1.7.). Reduction of power losses is the main aspect of optimal operational structure. Additionally, Croatia and Slovenia are aiming to increase the reliability of supply and Hungary is considering the SAIDI effect. In Bosnia and Herzegovina (EPHZHB), at the 10(20) kV voltage level, there are 50 remotely controlled and monitored switch disconnectors type ABB SECTOS NXB (D) at overhead lines, with tendency of increasing this number, and connecting them to the SCADA system. Croatia and Hungary are gradually introducing remote controlled switches however starting from higher voltage levels (35 kV network, then 20 kV).

Distribution network topology/network layouts

Distribution network in Danube region are operate as radial topology layout. Security is ensured through rings or meshed topologies where it is possible, however this is more common in urban area. The MV network has open loop structure, but is operating radially. The LV network has radial topology, with open loop structure only for important consumers. At the moment none of the DSOs not considers introducing meshed network structure in operation. Interestingly, Croatia made a few exceptions in case of large consumers in 35 kV network (ring topology). Bosnia and Herzegovina has different topological structure in urban areas: closed-loop networks, distribution network with support point and drive open spacious closed (meshed) distribution network.

All pilot buildings are connected to radially operated distribution networks. Bosnia and Herzegovina has the possibility for two side supply (on-load switching). Two pilot buildings in Croatia on are connected to different 10 kV feeders with possibility of switching and having both buildings supplied from the same feeder (however, the DSO would not favor this option).

Current operational challenges of the distribution networks

For Bosnia and Herzegovina (EPHZHB), the main challenges in operating distribution network today are as follows:

- Energy losses reduction

- Quality and reliability of supply for the final consumers
- Distributed Sources of Energy connection and network operation with integrated Distributed Sources of Energy.

Conventional drivers of reducing power losses, increasing the quality and reliability of supply for the final consumers, integration of distributed generation and possible problems with integration of electric vehicles are Croatian challenges.

Hungary puts the biggest effort in maintaining the expected quality of continuous supply. The challenge is to even further increase it despite limited resources; reduce the number of faults on the overhead line network related to external impacts and improve SAIFI and SAIDI indicators.

Slovenia's challenges are voltage fluctuations, due to presence of distributed generation, improving reliability of supply for final consumers and decreasing power losses.

SAIDI and SAIFI factors are used for determining reliability of supply in Croatia, Hungary and Slovenia (details in table 1.3.2.)

Existing/standardized distribution network planning principles

There are different long-term distribution network strategies for each country. Bosnia and Herzegovina has multiple and diverse long-term distribution network plans (refer to table 1.4.1.) Croatia aims to transform distribution system to 110 kV, 20 kV and 0.42 kV voltage level network. Similarly, Hungary wants to eliminate 35 kV network (22 kV overhead and cable and 11 kV cable). Slovenia has plans for multiple reconstructions and new 110 kV lines, as well as enlarging the percentage of cables on SN level and improving the quality of supply on LV level. Bosnia and Herzegovina does not uses GIS software, however it does have plans of introducing it during 2018 and 2019. Croatia uses DeGIS software. Hungary uses GIS software named INIS. Slovenia uses GREDOS with GIS support. Long-term development plans are made for a period of 3 to 10 years in Bosnia and Herzegovina. Croatia has a 10-year plan for development, as well as Hungary with 5-year snapshot. Slovenian DSO publishes a 30-year plan, which is revised and updated every two years. In Bosnia and Herzegovina, for EPHZHB network, load forecasts for the purpose of planning are made based on available historical load/consumption data using trend methods. Average load increases for the next five years vary depending on each distribution area, from under 0.5% to over 2% per year. However, with increasing share of renewable energy, reduction of population/consumers, introduction of power market exchange and reduction of energy losses, new and advanced methods might need to introduced soon. different than expected Croatia and Slovenia use available historical load/consumption data using trend methods. Hungary's forecast is based on time series forecasting. The distributed generation is considered for future distribution network planning only in Bosnia and Herzegovina and partly in Slovenia (Slovenia takes into account only existed distributed generation), as well as in Hungary (for LV network planning scenarios with and without DG infeed are considered). In Croatia and Slovenia additional grid investments in case of new connections are paid by the investor. For Bosnia and Herzegovina (EPHZHB), in case of new consumer connections, the new consumer always pays the requested connection power. If the new consumer is not a subject of so-called "Special Zone" (*Posebna Zona*), then the additional grid investments are being paid by DSO. Otherwise, the investment is split between DSO and new consumer; usually in 50:50 ratios. "Special Zone" is described in document "Opći uvjeti o isporuci električne energije" (General terms for electricity supply) [11]. In case of DG connections, the same principle applies as for new consumers. Exception is for DG connections with connection power between 2 kW and 23 kW (Micro-producers) which are at the same time consumers

(so called prosumers or active consumers, staying within consumers connection power). In that case, DG investors are free from paying the requested connection power [10] In Hungary payment depends on the type of customer and voltage level (Appendix A). Croatia, Hungary and Slovenia have a standardized input of new equipment costs. In Bosnia and Herzegovina EPHZHB) there is standardized input with defined prices, which are based on historical prices for equipment and current market prices. For BIH (EPHZHB), when planning new investments (e.g. new 10(20) kV substation with connection line), every distribution area uses their own estimation costs. Only Hungary considers additional planning concepts besides reinforcing the network (load and in line voltage control, PV regulation, energy storage, MV/LV automatic regulated transformers). There are no specific network plans for the pilot locations among the countries. In Bosnia and Herzegovina all of large consumers implement request connection to the network. In Croatia majority of them connect to the network, usually with significantly smaller connection power than initially requested. Slovenia has small percentage of requested connection being realized in the end. Hungary faces a drastic increase in DG connection requests, but less than 50% are realized.

Measurements, databases, historical information, grid data

In case of BIH (EPHZHB), continuous measurements are made at 35, 20, 10 and 0,4 kV voltage level and they are integrated in AMR/AMM system. Non-measured load is estimated using HEP Billing system. Voltage levels with metering spots in Croatia are 35, 20, 10 and 0.4 kV. Hungary has measurement data acquired from the SCADA system at HV and MV levels. On LV network the yearly consumption of the consumers and profile types are used. Two types of measurements are used in Slovenia: operational and electrical consumption billing measurements. In Croatia, Slovenia and Hungary there is no common database where demand/load information is stored (they all have more databases, such as SCADA, AMR, Reginfo, SAP). Bosnia and Herzegovina uses AMR and AMM database which contains measured voltages in phases and current per phase (active power, reactive power, cos phi, active energy, reactive energy are automatically calculated on the basis of measured values). SCADA system records and stores current, voltage, power and event log measurements. Different values are measured in Slovenia depending on the infrastructure. At the residential infrastructure active and reactive power, as well as event log are measured. Industrial infrastructure has additional measurements for apparent power, voltage and current. All the countries, except Hungary where additional developments are needed, have the capability of remote control for advanced/smart meter reading devices. In Slovenia, only remote connection and disconnection are possible. All of the countries have the capacity to install devices (such as AMR or smart meters) at all large consumer connection points for pilot distribution network site.

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Appendix A:

1.1.4. Explain the structure of tariffs for final consumers (domestic, small business, larger business)?

Table 1: Tariff system of Bosnia and Herzegovina EPHZHB [12]

ACCOUNTING ELEMENTS	UNIT OF MEASURE	DIFFERENTIATION		LOW VOLTAGE UNIVERSAL SERVICE						
		SEASONAL	DAILY	HOUSEHOLD		OTHER CONSUMPTION				
				I TG	II TG	I TG	II TG	III TG	IV TG	V TG
1	2	3	4	5	6	7	8	9	10	11
Metering point of customer	KM/metering point			1,90	1,90	20,00	5,20	5,20	1,90	1,90
Capacity charge	KM/kW/month	HIGHER		6,64	6,64	20,12	20,12	20,12	6,64	6,64
		LOWER		5,11	5,11	15,48	15,48	15,48	5,11	5,11
Active energy	fening/kWh	HIGHER	HIGHER	15,79	19,74	17,98	25,66	20,53	15,79	19,74
			LOWER		9,87	8,99	12,83			9,87
		LOWER	HIGHER	12,15	15,18	13,84	19,74	15,79	12,15	15,18
			LOWER		7,59	6,92	9,87			7,59
Excess reactive energy	fening/kVArh			0,00	0,00	0,00	0,00	0,00	0,00	0,00

Table 2: Tariff system of Hungary

1.		Distribution base fee	Distribution capacity fee	Distribution turnover fee	Distribution reactive power fee	Distribution loss fee
		HUF/connection point/year	HUF/kW/year	HUF/kWh	HUF/kVarh	HUF/kWh
2.	High voltage connection	206 412	1 476	0,14	2,24	0,14
3.	High / Middle voltage connection	103 212	4 656	0,56	2,71	0,22
4.	Middle voltage connection	103 212	7 968	1,36	2,71	0,75
5.	Middle / low voltage connection					
5.1	profile-settled(MV/LV I.)	3 444	-	6,18	3,75	1,44
5.2	remote mesaured (MV/LV II.)	34 404	8 088	2,36	3,75	1,44
6.	Low voltage connection					
6.1	profile-settled (LV I.)	1 446	-	9,55	3,75	2,22
6.2	periodically switched (LV II.)	474	-	3,56	-	1,66
6.3	remote mesaured (LV III.)	34 404	7 356	3,75	3,75	2,22

Table 3: Tariff system of Slovenia

Demand group				**Tariff rate**				
Voltage level	**Connection**	**Type of consumption**	**Season**	**Capacity charge (EUR/kW/month)**	**Transmitted active energy (EUR/kWh)**			
					PT	**HT**	**LT**	**UT**
HV		T≥6000 h	HS	1,05618	0,00177	0,00177	0,00139	-
			LS	0,76953	0,00125	0,00125	0,00094	-
		6000>T≥2500 h	HS	1,11795	0,00165	0,00165	0,00127	-
			LS	0,83453	0,00110	0,00110	0,00083	-
		T<2500 h	HS	1,21811	0,00171	0,00171	0,00132	-
			LS	0,88664	0,00120	0,00120	0,00092	-
MV	DTS busbar	T≥2500 h	HS	3,45210	0,00086	0,00086	0,00064	-
			LS	2,55464	0,00059	0,00059	0,00046	-
		T>2500 h	HS	3,41046	0,00109	0,00109	0,00086	-
			LS	2,52488	0,00082	0,00082	0,00060	-
		T≥2500 h	HS	3,63920	0,00910	0,00910	0,00700	-
			LS	2,68826	0,00648	0,00648	0,00500	-
		T<2500 h	HS	2,78179	0,01439	0,01439	0,01105	-
			LS	2,07582	0,01027	0,01027	0,00792	-

NN	TS busbar	T≥2500 h	HS	4,77915	-	0,00852	0,00658	-
			LS	3,74803	-	0,00658	0,00505	-
		T>2500 h	HS	3,97247	-	0,01358	0,01045	-
			LS	3,12749	-	0,01045	0,00802	-
		T≥2500 h	HS	6,33979	-	0,01891	0,01455	-
			LS	4,94851	-	0,01455	0,01117	-
		T<2500 h	HS	5,26095	-	0,02561	0,01971	-
			LS	4,11863	-	0,01971	0,01516	-
		EV charging on AC	-	2,34490	-	0,01133	0,00872	-
		Without power measurements	-	0,77710	-	0,04263	0,03278	0,03935
		Households	-	0,77710	-	0,04263	0,03278	0,03935

Legend:

T – annual operating hours
HS – high season
LS – low season

PT – peak daily tariff
HT – high daily tariff
LT – low daily tariff
UT – unique daily tariff

TS – transformer substation
DTS – distribution transformer station

Appendix B

Pricing tables supplier-end user

Table 4: Example for Day-ahead price table

Hour	Day-ahead price [€/MWh]
1	0,0449
2	0,03902
3	0,03647
4	0,03492
5	0,03625
6	0,04438
7	0,0481
8	0,06112
9	0,06571
10	0,0652
11	0,06526
12	0,06306
13	0,06526
14	0,06208
15	0,05889
16	0,05889
17	0,05577
18	0,05108
19	0,05408
20	0,06108
21	0,06921
22	0,06306
23	0,0449
24	0,03902

Table 5: Example for Intra-day price table

Quarter hour	Bid-Price [€/MWh]	Maximum bid volumen (MWh)	Ask-Price [€/MWh]	Maximum ask volumen (MWh)
1	0		0	
2	0		0	
3	0		0	
4	0		0	
5	0,0325	10	0,0325	
6	0,03		0,03	
7	0,03		0,03	
8	0,03		0,03	
9	0,03		0,03	
10	258		258	
11	0,03		0,03	
12	0,03		0,03	
13	0,742		0,742	
14	0,03		0,03	
15	0,03		0,03	
16	0,03		0,03	
17	0,0325		0,0325	
18	0,03		0,03	
19	0,03		0,03	
20	0,03		0,03	
21	0,03		0,03	
22	258		258	
23	0,03		0,03	
24	0,03		0,03	
25	0,742		0,742	
26	0,03		0,03	
27	0,03		0,03	
28	0,03		0,03	
29	0,0325		0,0325	
30	0,03		0,03	
31	0,03		0,03	
32	0,03		0,03	
33	0,03		0,03	
34	258		258	
35	0,03		0,03	
36	0,03		0,03	
37	0,742		0,742	
38	0,03		0,03	
39	0,03		0,03	
40	0,03		0,03	
41	0,0325		0,0325	
42	0,03		0,03	
43	0,03		0,03	
44	0,03		0,03	
45	0,03		0,03	
46	258		258	
47	0,03		0,03	
48	0,03		0,03	
49	0,742		0,742	
50	0,03		0,03	
51	0,03		0,03	

52	0,03		0,03	
53	0,0325		0,0325	
54	0,03		0,03	
55	0,03		0,03	
56	0,03		0,03	
57	0,03		0,03	
58	258		258	
59	0,03		0,03	
60	0,03		0,03	
61	0,742		0,742	
62	0,03		0,03	
63	0,03		0,03	
64	0,03		0,03	
65	0,0325		0,0325	
66	0,03		0,03	
67	0,03		0,03	
68	0,03		0,03	
69	0,03		0,03	
70	258		258	
71	0,03		0,03	
72	0,03		0,03	
73	0,742		0,742	
74	0,03		0,03	
75	0,03		0,03	
76	0,03		0,03	
77	0,0325		0,0325	
78	0,03		0,03	
79	0,03		0,03	
80	0,03		0,03	
81	0,03		0,03	
82	258		258	
83	0,03		0,03	
84	0,03		0,03	
85	0,742		0,742	
86	0,03		0,03	
87	0,03		0,03	
88	0,03		0,03	
89	0,0325		0,0325	
90	0,03		0,03	
91	0,03		0,03	
92	0,03		0,03	
93	0,03		0,03	
94	258		258	
95	0,03		0,03	
96	0,03		0,03	

Table 6: Example for DA Schedule sent by BEMS

Quarter hour	Schedule [MWh]	Available flexibility downwards [MWh]	Available flexibility upwards [MWh]
1	200,3312	0	0
2	197,1674	0	0
3	195,3067	0	0
4	194,0845	0	0
5	193,7057	50	0
6	191,6798	50	0
7	189,2331	50	0
8	186,2793	50	0
9	184,5782	50	0
10	183,3499	50	0
11	181,5476	50	0
12	180,3917	50	0
13	181,2773	50	0
14	201,7054	50	0
15	200,2681	50	0
16	200,0383	50	0
17	202,5564	50	0
18	228,4406	50	0
19	228,8402	50	0
20	230,9304	50	0
21	234,7491	0	0
22	274,2444	0	0
23	331,4241	0	0
24	346,6761	0	0
25	370,829	0	0
26	389,2566	0	0
27	482,541	0	0
28	494,7139	0	0
29	506,8863	0	0
30	513,0699	0	0
31	517,1902	0	0
32	517,1519	0	0
33	516,1378	0	0
34	520,5942	0	0
35	525,5421	0	0
36	528,0308	0	0
37	530,7888	0	0
38	532,094	0	0
39	537,8086	0	0
40	536,3876	0	0
41	538,2932	0	0
42	540,0219	0	0
43	542,7328	0	0
44	541,1079	0	0
45	545,0151	0	-50
46	547,3538	0	-50
47	546,6807	0	-50
48	549,2056	0	-50
49	548,8143	0	-60
50	548,1536	0	-60
51	552,0189	0	-60
52	551,8002	0	-60

53	552,5131	0	-60
54	549,553	0	-60
55	545,5757	0	-60
56	539,3767	0	-60
57	545,8844	0	-60
58	549,2516	0	-60
59	551,8857	0	-60
60	551,6798	0	-60
61	552,1232	0	0
62	550,8776	0	0
63	554,0119	0	0
64	551,3147	0	0
65	547,7498	0	0
66	456,6842	0	0
67	455,2067	0	0
68	452,9478	0	0
69	450,2548	0	0
70	447,637	0	0
71	382,0837	0	0
72	378,823	0	0
73	377,0618	0	0
74	376,9332	0	0
75	377,4792	0	0
76	352,0061	0	0
77	351,8646	0	0
78	351,3345	0	0
79	351,3319	0	0
80	310,0951	0	0
81	308,7668	0	0
82	311,0665	0	0
83	314,7137	0	0
84	319,0936	0	0
85	319,2592	0	0
86	316,7312	0	0
87	309,5338	0	0
88	302,103	0	0
89	297,2434	0	0
90	292,871	0	0
91	289,8132	0	0
92	285,9818	0	0
93	283,8081	0	0
94	281,116	0	0
95	278,6636	0	0
96	272,5619	0	0

The above schedule is sent in this form as a Day Ahead Schedule of the building to Retailer, which also includes the offering of flexibility, calculated from the previous day's prices and its own consumption (this flexibility nevertheless is not interesting for the Retailer, since the Aggregator is the actor having contracts to trade with the flexibility). BEMS will have to send the Schedule at 10:30am every day at the latest so that the Retalier can make bids in the power exchange 10:30 to 10:45 and then have time to return the DA prices by 11:00

Table 7: Example for ID Schedule sent by BEMS

Quarter hour	Schedule [MWh]	Available flexibility downwards [MWh]	Available flexibility upwards [MWh]
1	200,3312	0	0
2	197,1674	0	0
3	195,3067	0	0
4	194,0845	0	0
5	193,7057	40	0
6	191,6798	45	0
7	189,2331	50	0
8	186,2793	50	0
9	184,5782	50	0
10	183,3499	50	0
11	181,5476	35	0
12	180,3917	50	0
13	181,2773	50	0
14	201,7054	40	0
15	200,2681	50	0
16	200,0383	50	0
17	202,5564	50	0
18	228,4406	35	0
19	228,8402	35	0
20	230,9304	35	0
21	234,7491	0	0
22	274,2444	0	0
23	331,4241	0	0
24	346,6761	0	0
25	370,829	0	0
26	389,2566	0	0
27	482,541	0	0
28	494,7139	0	0
29	506,8863	0	0
30	513,0699	0	0
31	517,1902	0	0
32	517,1519	0	0
33	516,1378	0	0
34	520,5942	0	0
35	525,5421	0	0
36	528,0308	0	0
37	530,7888	0	0
38	532,094	0	0
39	537,8086	0	0
40	536,3876	0	0
41	538,2932	0	0
42	540,0219	0	0
43	542,7328	0	0
44	541,1079	0	0
45	545,0151	0	-45
46	547,3538	0	-50
47	546,6807	0	-50
48	549,2056	0	-40
49	548,8143	0	-60
50	548,1536	0	-60
51	552,0189	0	-50
52	551,8002	0	-50

53	552,5131	0	-50
54	549,553	0	-60
55	545,5757	0	-60
56	539,3767	0	-60
57	545,8844	0	-60
58	549,2516	0	-60
59	551,8857	0	-60
60	551,6798	0	-60
61	552,1232	0	0
62	550,8776	0	0
63	554,0119	0	0
64	551,3147	0	0
65	547,7498	0	0
66	456,6842	0	0
67	455,2067	0	0
68	452,9478	0	0
69	450,2548	0	0
70	447,637	0	0
71	382,0837	0	0
72	378,823	0	0
73	377,0618	0	0
74	376,9332	0	0
75	377,4792	0	0
76	352,0061	0	0
77	351,8646	0	0
78	351,3345	0	0
79	351,3319	0	0
80	310,0951	0	0
81	308,7668	0	0
82	311,0665	0	0
83	314,7137	0	0
84	319,0936	0	0
85	319,2592	0	0
86	316,7312	0	0
87	309,5338	0	0
88	302,103	0	0
89	297,2434	0	0
90	292,871	0	0
91	289,8132	0	0
92	285,9818	0	0
93	283,8081	0	0
94	281,116	0	0
95	278,6636	0	0
96	272,5619	0	0

The above schedule is sent as a Day Ahead Modified Schedule of the building to both Retailer and Aggregator together with offering of flexibility, calculated from the previous day's prices and its own consumption. This additional flexibility is relevant information for the Aggregator since the Aggregator can trade with it. Theoretically the Aggregator could send this information to Flexibility market (which does not yet exist) and could trade with the offered flexibility (e.g not only with DSO but TSO or other Balancing Responsible Parties).