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EXECUTIVE SUMMARY

This report describes in detail the design of the underlying optimization problems and use case algorithms to be tested and refined during the field testing phase in Demo 3 of Interflex.

For each use case the underlying problem is being developed and described together with the relevant regulatory framework which sets the boundaries for the actions DSOs can take today. Furthermore, a set of KPI to track and evaluate each use cases performance is being developed.

For use case 1 – Feed In Management the core issue is to reduce the amount of curtailed energy in response to grid congestion by leveraging an improved control strategy enabled by the Smart Grid Hub. During Demo 3 Interflex will demonstrate how a finer granularity in control algorithms can reduce the curtailed energy and hence increase the amount of renewable locally generated energy in a rural distribution grid.

Use case 2 – Demand Side Management focuses on how to leverage domestic flexibility in areas of high renewable generation in order to further reduce the need for DG curtailments. The concept includes a ramping up of local demand in times of high local feed in and in doing so to increase the local consumption of DG generated power temporarily and reduce stress on the grid. Furthermore, the concept also enables a controlled load shedding approach of very fine granularity to deal with peaks in power consumption expected to increase over the next years in the wake of growing numbers of electric vehicles and an accelerated switch from gas- to electric heating.

Eventually use case 3 – Ancillary Services sets out to optimize local consumption even further by leveraging domestic battery storage installations, too. Use case 3 also incorporates a forecasting component, which allows for an anticipatory charging and discharging of batteries and steering of domestic heaters.

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1. INTRODUCTION

1.1. Scope of the document

Deliverable 5.6 presents the use case algorithms and optimization problems that will be evaluated and refined by the Smart Grid Hub field tests. Each Use Case in Demo 3 is briefly recalled and put in perspective of the relevant national regulatory framework in Germany. The Use Case algorithms and optimization problems are described in detail.

1.2. Notations, abbreviations and acronyms

The table below provides an overview of the notations, abbreviations and acronyms used in the document.

AC	Alternating Current
CHP	Combined Heat and Power
DER	Distributed Energy Resources
DG	Distributed Generation
DSO	Distribution System Operator
EED	Energy Efficiency Directive
EnWG	Energiewirtschaftsgesetz (Energy Industry Act)
iMSys	Intelligent measuring system
kW	Kilo Watt
kWp	Kilo Watt peak
MsbG	Messstellenbetriebsgesetz (law for operating measuring points)
NEEAP	National Energy Efficiency Action Plan
PLC	Power Line Communication
PV-System	Photovoltaic- system
RES	Renewable Energy Sources
RSRP	Reference Signal Received Power
RSRQ	Reference Signal Received Quality
SCADA	Supervisory Control And Data Acquisition
SGH	Smart Grid Hub
SMGW	Smart Meter Gateway
LTE	Long term evolution telecommunication standard
V	Volt

Figure 1 - List of acronyms

2. USE CASE OVERVIEW

2.1. Background and targets

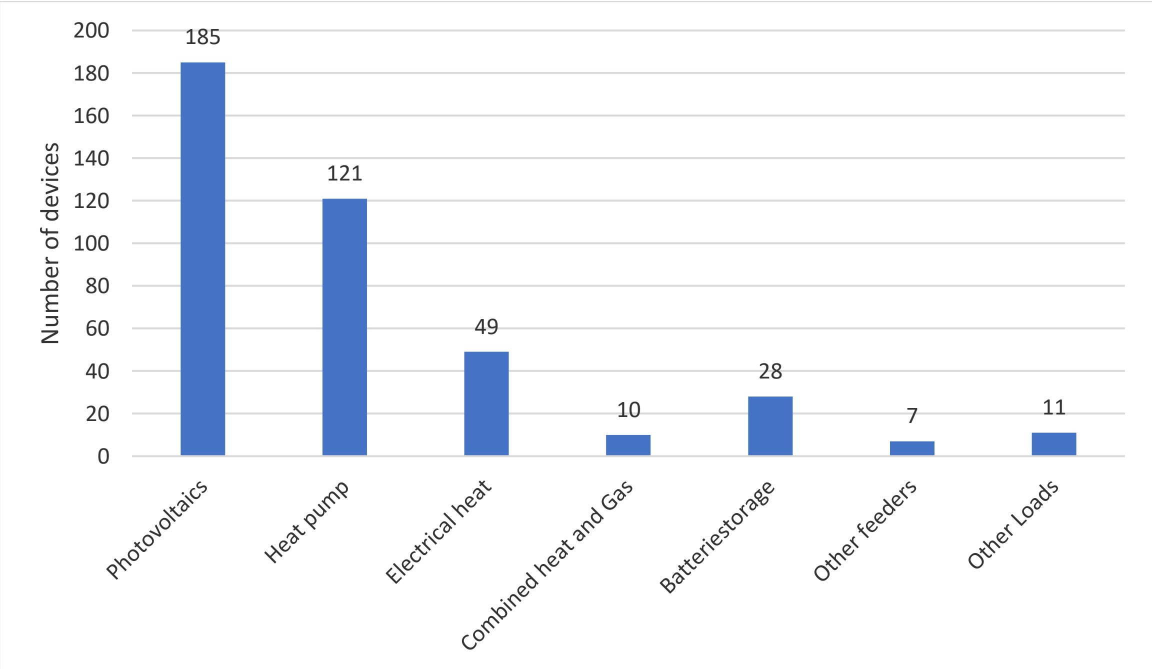
Demo 3 is motivated by the challenge to increase the hosting capacity of distribution networks for DG and the expected growth of electricity demand that will come with electric vehicles and in some regions a switch from gas-based heating to electrical heating such as heat pumps and nightstorage heaters. To keep the cost for the provision of sufficient network capacity to a minimum, Interflex explores new technologies and strategies for a smart control of DG and flexible loads. The Smart Grid Hub developed in Demo 3 enables several innovative management strategies by making customer-owned devices and their inherent flexibility accessible for the DSO. Contrary to the current power system with comparably few elements, the introduction of domestic devices as active elements is increasing the number of devices that can or even must be managed by a factor of 100 to 1000. To ensure an optimal use of these elements and minimize the interference with the customers private sphere the SGH requires precise control algorithms and optimization problems.

Each use case exemplifies a slightly different set of drivers and targets, which shall be reflected in the control logic.

2.2. Customers and available flexibility

To Avacon´s project invitation 366 customers gave a positive feedback and accepted the terms and conditions for the project participation. Together with the registration via response letter or online form, customers were invited to provide flexibilities for the project. Since some customers own more than one flexible device, the number of available devices exceeds the number of customers. The number of offered devices for each type is shown in Figure 2.

Figure 2: Flexibility portfolio offered by customers



2.2.1. Installed Capacity

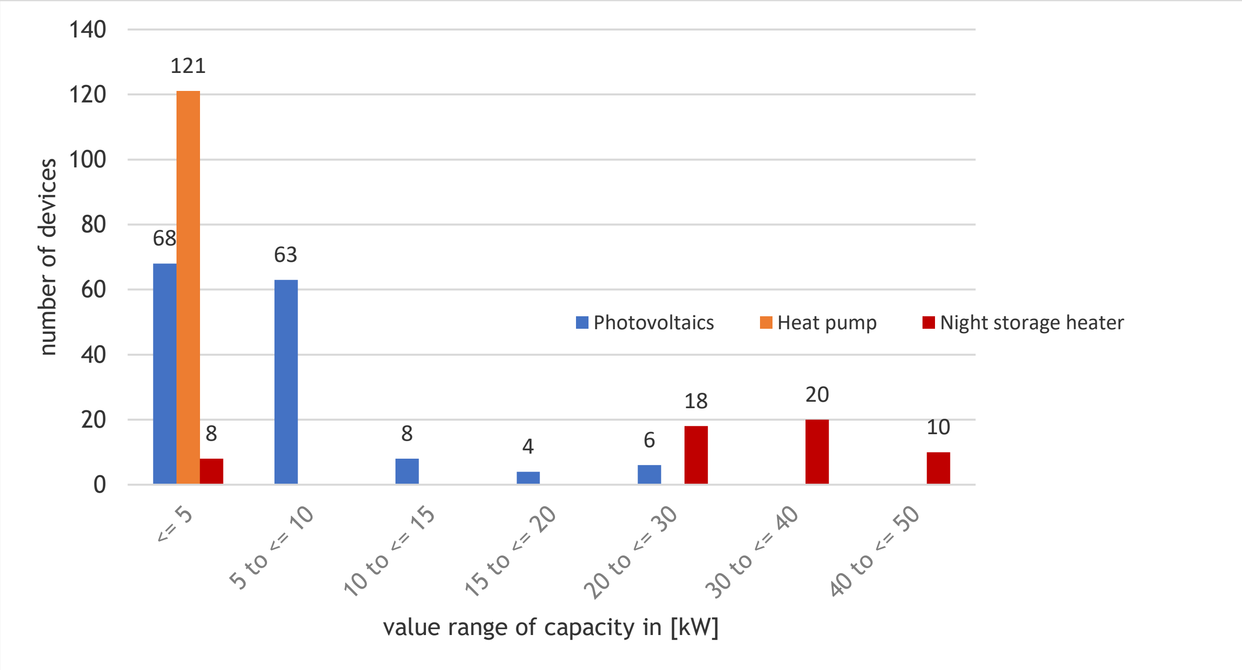
Based on the customer's address indicated at registration, information about the installed capacity of customers' devices were sourced from Avacon´s DG-database for feed-in devices (DENEA). Loads, such as heat pumps and night storage heaters, however are listed in a separate database, which does not list all devices connected to Avacons medium and low voltage grid. Since there is no legal obligation to register residential loads, the database only includes devices, that qualify for a reduced grid fee offered for interruptible loads (HT- and NT-tariffs). Table 1 lists the total number of devices registered for project participation and the total amount of installed capacity for each flexibility type, according to customers feedback and the available data listed in Avacon´s database. The missing capacity values of devices not listed in the databases will be noted from the type plates on site during the installation of the smart meter and control box.

Table 1: Total amount of installed capacity per offered flexibility type

	Number customers devices registered for project participation	**Total installed capacity**
Photovoltaic	185	890 kW
Heat pumps	121	242 kW (estimated)
Night storage	49	1,470 kW (estimated)
Battery	28	No data

In Figure 3 the number of available devices for each type is clustered into different capacity ranges.

Figure 3: Number of customer devices for different value ranges of installed capacity



2.2.2. Availability

The usability and availability of different devices for curtailment or switching requests via the metering system and control box, depends on various factors listed in Table 2.

Table 2: Influencing factors for availability of different plants types

	Usability	Availability	Requirements for availability
Photovoltaics	Curtailment of feed in	Summer: 9 am - 7 pm Winter: 10 am - 4 pm	• solar radiation • radiation angle • cloudiness • temperature
Electrical heat (night storage heaters)	Switchable load	In times out of low electricity price for electrical heaters (heating tariffs). In most cases between: • 6 am - 22 pm • 5:45 am - 21:45 pm and reload times, in most cases:	• free storage capacity • device internal control software has released external controlling

		• 14 pm - 15 pm	
Heat pump	Reducible load	always	• complete shutdown of the device is not permitted, a minimum power for heating must be available for the customer • Space for curtailment lies between the current used power and minimum power for operation: ○ $P_{currently\ used} - P_{minimum} > 0$

As stated in Table 2 the availability of each type is restricted by different factors.

Photovoltaics system can only be used for curtailment at daytime with sunny weather. The available capacity for curtailment depends on the installed capacity of each individual device, which is reduced by external environmental factors such as global radiation, radiation angle, temperature and cloudiness.

Night storage heaters will only be used as switchable load to increase local electricity demand in the grid. A curtailment of these devices in times between 22 pm and 6 am will not be carried out in the project, because in this timeframe most customers are in use of their heaters for central heating. The external control additionally must be enabled by the internal control software of the device, which is set individually for each device by customers. On top, the availability of each device requires free storage capacities for heat. If the storage of the heater is completely charged, an external control for charging will not be implemented for a few hours. Therefore, the external control of these devices will only be possible for several hours between NT-tariff times (22pm – 6 am) and reload times (14pm – 15pm).

In aspects of time, heat pumps have the highest degree of flexibility. The devices are available at any time for reduction of electricity demand in the grid. Because of technical reasons in case of most devices a complete shutdown can’t be triggered by an external control. The reduceable load therefore depends on the current load in time of triggering and the minimal reduceable load of the device.

3. USE CASE 1 – FEED-IN MANAGEMENT

3.1. Overview

Over the past decade Germany has seen a significant growth in decentralized renewable energy sources (RES). According to the renewable energy act grid operators have a legal obligation to connect all distributed generators (DG) to their network and accommodate all energy that is being produced by renewable DGs. To comply with this regulation, the challenges that German DSOs are facing are twofold: First, the DGs are often located in rural areas where the hosting capacity of the network is not traditionally designed to deal with their presence. Second, the volatility and unpredictability of RES puts additional operational burden on the DSO. If the DGs' feed-in exceed the network's nominal capacity, there exists the risk of violating voltage limits or the equipment's thermal limits. In such situations, the grid operators have the option to temporarily curtail local feed-in to maintain system stability and avoid protection tripping. Curtailment options of DG come with the obligation to increase the network's hosting capacity as soon as possible. However, grid operators had difficulties catching up with the growth of renewable energy in recent years, which resulted in a total annual cost for curtailment actions of 373 M€ in 2016. For many grid operators it is best practice to control small scale DGs via long wave radio signals. With these signals grid operators can set the generators output to 100%, 60%, 30% or 0% of its nominal power. While this technology has proven to be simple, robust and cost-effective it also comes with several drawbacks:

1) The lack of communication backchannel, making it impossible to confirm whether the signal has been received and acted upon.
2) The limitation of only four discrete setpoints.
3) The limited number of addresses, as in many areas the DGs are often connected to medium voltage and low voltage networks, where they are clustered under one radio frequency.

The motivation for this approach was that earlier SCADA could not automate the process of receiver assignment and that initially no one expected the rapid growth and overwhelming numbers of renewables. The combination of 2) and 3) means that in practice curtailment actions can only be carried out in comparably large discrete steps. As a result, it is very difficult to adjust the output precisely to the required technical limits and oftentimes DSOs are forced to curtail more energy than theoretically needed.

Hence, a novel approach for DG curtailment, which features finer granularity and dedicated bi-directional communication channels is required, leveraging on the advancements in data transmission and communication technology. The Smart Grid Hub as developed as part of Interflex is designed to address these challenges. The SGH integrates with grid control SCADA and the national smart meter framework and hence enables novel and advanced control algorithms for small scale generators to improve on todays feed in management strategies.

3.2. Regulatory Framework Feed-In Management

In Germany use case 1 is today enabled via the Renewable Energy Act (REA). §12 REA states that grid operators are obliged to optimize, reinforce and expand their network at the request of prosumers and generators to such an extent that all the energy produced by DG covered under the REA can be fed into the system. It does not leave the option of denying connection, nor does it offer the option to curtail DG feed in as a standard measure. However, the REA does acknowledge that grid reinforcements take time and cannot always keep up with the growth of new generation capacity and hence introduces a curtailment mechanism as a temporary measure until grid hosting capacity has caught up. While the general obligation to reinforce the network remains, grid operators can curtail DG feed-in under certain conditions:

- Imminent or actual grid congestion has been identified
- Feed in by DG is prioritized over other sources not covered by the REA
- The grid operator has measured the current regional power generation

The right to curtail DG's also comes with the obligation to treat all prosumers and generators equally and to ensure that a practical maximum of renewable feed in is accommodated in the network at any given moment.

The aim of use case 1 is to address the later points: Equal treatment of all customers and minimizing the amount of curtailed energy.

3.3. Detailed Description of Algorithm

As mentioned, DG capacity and generation may vastly exceed demand in a region, to the point where the capacity limits of the power lines would be exceeded. This logically leads to the situation that the grid operator is forced to curtail the regional feed-in on several occasions to avoid equipment overload and tripping of protections. The operator must determine the curtailment schedule while taking the following three criteria into account:

1) Ensuring safe operation of all equipment within technical limits at all times.
1) Limiting curtailments to a practical minimum.
2) Ensuring that all curtailment actions are carried out in a non-discriminatory manner to guarantee equal treatment of all customers.

Rural areas present themselves to be specifically challenging, as their spatial expansion allows a multitude of RES connected to a comparatively weak superordinate grid system, that is tasked with exporting excess power.

Other DGs include photovoltaics (PVs) and combined heat and power plants (CHPs), which are of a noticeably smaller scale. These are located at lower voltage levels, together with the system's loads and collectively connected to the HV system via HV/MV-substations. Accordingly, the key challenge is to develop a control scheme that takes advantage of the large number of very small generators to make the curtailments as effective as possible. The control algorithm and target function present themselves as follows below.

First, we take a look at the current best practice approach as we can find in operation at many DSOs today. Based on the regulatory framework the DSOs in Germany are fully unbundled from all generation assets, while private companies usually operate DGs. The options to control these units however are limited. Large generation plants such as windfarms (WF) are connected directly to the DSO SCADA, whereas most smaller units, like PVs and CHPs, are oftentimes only equipped with a long wave radio receiver, which are usually clustered per substation. Therefore, in best practice, control can only be exerted over the larger scale WFs. Historically, these units can accept setpoints to set their momentary output to 100%, 60%, 30% or 0% of their nominal power. When considering $i \in \mathcal{N}_{WF}$ WFs, where $\mathcal{N}_{WF}$ is the set of all WFs in the system, their curtailed power is given as

$$P_{WF,cur}^{i} = \begin{cases} 0 & no\ curtailment \\ P_{WF,act}^{i} - \alpha^{i} \cdot P_{WF,N}^{i} & curtailment \end{cases}, \quad (1)$$
$$\alpha^{i} \in \{0, 0.3, 0.6, 1\}$$

Here, $P_{WF,cur}^{i}$ is the curtailed output of WF i, $P_{WF,act}^{i}$ is its momentary uncurtailed generation, $P_{WF,N}^{i}$ is its nominal power and α^{i} defines the actual setpoint. This limits a grid operator to a few discrete steps to curtail the DG feed in. Consequently, this can result in an over-curtailment of regional DG production with the intention of avoiding equipment overload. The best practice curtailment algorithm can be stated as an optimization problem that aims to minimize the curtailed power.

$$\begin{aligned} \min \quad & \textstyle\sum_{i \in \mathcal{N}_{WF}} P_{WF,cur}^{i} \\ \text{s.t.} \quad & (1), \\ & \textstyle\sum_{i \in \mathcal{N}_{WF}} (P_{WF,act}^{i} - P_{WF,cur}^{i}) \\ & + \textstyle\sum_{j \in \mathcal{N}_{PV}} P_{PV,act}^{j} \\ & + \textstyle\sum_{k \in \mathcal{N}_{CHP}} P_{CHP,act}^{k} \\ & - P_{Load} \leq P_{Line,N}. \end{aligned} \quad (2)$$

Taking an overhead line as an exemplary piece of equipment at the risk of being overloaded, the nominal line capacity is given by $P_{Line,N}$, while $P_{PV,act}^{j}$ states the uncurtailed generation of the PV generator $j \in \mathcal{N}_{PV}$, where $\mathcal{N}_{PV}$ is the set of all connected PV generators. Similarly, $P_{CHP,act}^{k}$ is the uncurtailed generation of the CHP $k \in \mathcal{N}_{CHP}$ and $\mathcal{N}_{CHP}$ is the set of all connected CHPs. Finally, P_{Load} is the summed-up system load.

The SGH enables the DSO to leverage the smart meter infrastructure, which will become standard in Germany in the upcoming years. This enables the possibility to control small DG individually and directly, which did not exist up to now. Consequently, the DSO will have a substantial number of additional options to shape the curtailment action and track the technical limits of stressed equipment more closely. The operating engineers can control smaller units, increasing the granularity and therefore reducing the overcompensation of the curtailment.

As stated previously, small scale PV and CHP applications can only be regulated to an on or off state. Their respective curtailed powers $P_{PV,cur}^{j}$ and $P_{CHP,cur}^{k}$ are therefore given by:

$$\begin{gathered} P_{PV,cur}^{j} = \beta^{j} \cdot P_{PV,act}^{j}, \\ \beta^{j} \in \{0,1\}, \end{gathered} \quad (3)$$

$$\begin{gathered} P_{CHP,cur}^{k} = \gamma^{k} \cdot P_{CHP,act}^{k}, \\ \gamma^{k} \in \{0,1\}. \end{gathered} \quad (4)$$

The setpoints are defined by the binary indicators β^j and γ^k. Again, an optimization problem can be formulated to minimize the curtailed power:

$$\begin{aligned}
\min \quad & \textstyle\sum_{i\in\mathcal{N}_{WF}} P^i_{WF,cur} + \sum_{j\in\mathcal{N}_{PV}} P^j_{PV,cur} + \\
& \quad + \textstyle\sum_{k\in\mathcal{N}_{CHP}} P^k_{CHP,cur} \\
\text{s.t.} \quad & (1),\ (3),\ (4) \\
& \quad \textstyle\sum_{i\in\mathcal{N}_{WF}} (P^i_{WF,act} - P^i_{WF,cur}) \qquad (5) \\
& \quad + \textstyle\sum_{j\in\mathcal{N}_{PV}} (P^j_{PV,act} - P^j_{PV,cur}) \\
& \quad + \textstyle\sum_{k\in\mathcal{N}_{CHP}} (P^k_{CHP,act} - P^k_{CHP,cur}) \\
& \quad - P_{Load} \le P_{Line,N}.
\end{aligned}$$

In practice the curtailment request will be generated in the grid control SCADA once an actual or imminent equipment overload is identified. Grid control SCADA will request a certain amount of reduction in current power output in a certain grid area to the SGH via a TASE.2[1] interface. It is then up to the SGH to identify the elements to be curtailed until the target function is satisfied.

3.4. Expected results and KPI

The goal of use case 1 is to reduce the amount of curtailed energy and the number of affected elements while respecting the technical limits of the equipment involved. Hence the use case level KPI are:

1. Reduction of curtailed energy in [kWh]
2. Reduction in affected elements
3. Number of violations of technical limits
4. Number of activations per element (Max, min, mean and mode of activations)

4. USE CASE 2 – DEMAND RESPONSE

4.1. Overview

In the past, the common way of intervening in the load flow of households in German distribution grids was related to night storage heaters. These electrical heating systems were designed to charge at night-time and emit their heat during the day. To activate/deactivate the storage heaters, DSOs sent out control signals via audio-frequency ripple control according to a schedule. On one hand, this set up was economically advantageous for consumers due to cheap electricity tariffs during off peak times. On the other hand, the power supply companies offered these reduced night-tariffs with the intention to shift power consumption to the night. Thereby, there was no need to shut down base load power plants at night.

[1] TASE.2 (Telecontrol Application Service Element 2), also known as *Inter Control Center Protocol* (ICCP) is a communication standard defined in IEC-60870-6 and the state-of-art manufactuer-independent protocol for communication between grid control centers.

As many of these large (nuclear) power plants are nowadays being replaced by small, decentralized renewable energy sources (RES), influencing the load flow is taking on a new role. This transformation is stimulated by the two following developments:

1) The roll-out of smart meters offers new technical steering possibilities for DSOs:

   Starting in 2018, smart meters must be installed in many German households and commercial consumers. The roll-out will be completed by 2032. Thereby, DSOs will be able to receive more measured data of the medium and low voltage grid than today. This extra data can improve the state-estimation in the DSO's grid control system. Additionally, smart meter devices can be combined with control boxes. These allow the DSOs to individually control connected consumer devices that today can only be reached by ripple control or not at all. With these new technical opportunities smart grids can be formed in which generation, load and storages are connected, steered and balanced in an intelligent way.

2) The flexible load potential in households is increasing:

   While the number of night storage heaters in Germany is declining the share of other electrical heating systems is on the rise. Electrical heat pumps are installed in more than one third of new buildings to meet the requirements of the German Energy Saving Regulation. Furthermore, the number of charging stations for electric vehicles is growing.

Under these changing circumstances, consumer load can be used as a flexibility to balance the growing share of fluctuating RES. Up to today, balancing the grid meant to generate just enough power to satisfy the electricity demand. In the future, adjusting the load to the generated energy can also be an option. This will be necessary to integrate more decentralized renewable energies into the grid, which are only temporary available. It would not only mean reducing the load when the production of RES is low, but also locally increasing the consumer load in times with a high feed-in of renewable energies.

This use case examines if the DSO can eliminate congestions in its distribution grid and therefore reduce the curtailment of decentralized RES by regulating the consumer load. It would give the DSO a new measure to react to transmission capacity problems and further critical situations.

4.2. Regulatory Framework Demand Response

The Energy Efficiency Directive (EED) 2012/27/EU provides the framework for the development of demand response in Europe. According to Art 15 §4, all incentives that could hamper the participation of Demand Response measures shall be repealed. Furthermore, §8 promotes the non-discriminating participation of Demand Response in balancing, reserve and other system service markets and encourages the national energy regulatory authorities to define technical modalities for participation in these markets based on technical requirements. As of 2016 an amendment of the EED is in preparation.

Based on the EED, the National Energy Efficiency Action Plan (NEEAP) 2017 of the Federal Republic of Germany explains the existing measures to eliminate constraints for demand response. The NEEAP emphasizes that controllable, pooled load can participate in the German balancing energy market non-discriminatory. To control load on a low-voltage level by the DSOs, the NEEAP refers to §14a Energiewirtschaftsgesetz (EnWG, German Energy Industry Act).

According to § 14a EnWG, German low-voltage consumers are granted reduced system usage fees for fully interruptible appliances with separate metering points that can be controlled by the system operator for load relieving purposes. This regulation gives system operators the possibility to pause and steer the load of interruptible appliances. Times of charging, hold-off and maximum interruptions are stipulated by contract. Many electrical heating systems such as heat pumps or storage heating opt for ripple control receivers to benefit from reduced fees. Within the Interflex project, they can be replaced by a bidirectional connection via control boxes.

It is planned to shape and detail the contents of §14a EnWG in a separate regulation that still must be developed.

The 'Messstellenbetriebsgesetz' (MsbG, German law for operating measuring points) stipulates DSOs to roll out smart meters in Germany by 2032. Customers consuming more than 6,000 kWh per year as well as customers with interruptible appliances or feed-in are equipped with an intelligent measuring system (iMSys) which includes a smart meter gateway. Smaller residential consumers are only equipped with modern measuring devices without gateways. A nationwide roll-out of control boxes is not regulatory planned. Therefore, this use case can only be executed within the Interflex project, as project customers receive an additional control box for their iMSys. The MsbG with the regulation of smart meters sets only the basis for future possibilities to equip customers with additional steering devices that allow bidirectional communication. The implementation of control boxes would highly increase the benefits of smart meters for system operators. Without this regulation the DSO is not able to individually steer the residential demand side area-wide.

4.3. Description of algorithm

4.3.1. Feed-in caused congestions

As already described in Use Case 1 – Feed-In Management, decentralized generation can sometimes exceed the transmission capacity limits of the grid equipment, e. g. of power lines and transformers. Instead of curtailing the regional feed-in to avoid overloading, this Use Case proposes to raise the consumption on the demand side. This is supposed to reduce the share of generated energy transmitted to upstream networks.

Accordingly, the optimization problem is to maximize the load on the low voltage level to consume the generated energy of decentralized RES locally.

$$\max \sum P^i_{flexLoad}\ , \quad i \in \mathcal{N}_{CD}$$

Here, $\mathcal{N}_{CD}$ is the set of all consumer devices that are controllable by Avacon in the project area. $P^i_{flexLoad}$ is the respective flexible device's power consumption from the low voltage distribution grid. As described in 2.2, in the Interflex project $P_{flexLoad}$ includes the power of night storage heaters P_{NS}, heat pumps P_{HP} and electrical energy storages P_{EES}. Since heat pumps usually run constantly they will not be able to contribute much additional load for this use case.

$$\sum P^i_{flexLoad} = \sum P^i_{HP} + \sum P^i_{NS} + \sum P^i_{EES}$$

Triggering event for this use case is the violation of an equipment's limiting values. To detect or predict these congestions the grid is monitored in real time by Avacon's network control system eBASE. With its Distribution Management System (DMS) functions, eBASE performs an online state estimation of the grid and several network calculations, e.g. contingency analysis. These applications detect and signal ongoing limit violations in the basic case as well as predictable n-1 violations in case of an outage.

When the SGH receives the information of congestions from eBASE, the SGH needs to identify the available load that takes effect on the overloaded part of the grid. The availability of the different load types varies. Their restrictions described in chapter 2.2.2 must be considered.

Subsequently, the SGH sends out control commands to the identified devices to increase their consumption.

After the SGH has requested the currently maximum available load, the SGH needs to exchange this information with the eBASE system. Following, the control system must check if the equipment's overload persists. In this case, feed-in management as described in Use Case 1 must be applied to eliminate the congestion completely.

Optimization according to this use case supports the following two overall targets:

- Eliminating or at least reducing congestions by lowering the current of the transmission equipment below or closer to their limiting values
- Minimizing the curtailed power from RES

4.3.2. Load caused congestions

In contrast to congestions caused by high feed-in of RES there is also the possibility of a local congestions caused by high load. In practice, this is rarely a problem in Avacon's distribution grid today. Nevertheless, it could become more relevant in the future as the number of electric vehicles and electrical heating systems are on the rise. Using these appliances with a high coincidence factor will affect the low voltage grid and may cause local congestions. Conventionally, this would require the expansion of the system. As an alternative to strengthening the distribution grid, this use case proposes to reduce the demand of flexible appliances.

Accordingly, the optimization problem is to minimize the load on the low voltage level:

$$\min \sum P^{i}_{flexLoad} \;, \;\; i \in \mathcal{N}_{CD}$$

In contrast to the use case of feed-in caused congestions, heat pumps as part of $\sum P^{i}_{flexLoad}$ now play an important role in this use case. As stated in chapter 2.2.2, their load can be reduced for a couple of hours no matter of day or night time.

The controlling process in this use case is similar to the one for a feed-in caused congestion and therefore not described in detail. The trigger for this Use Case would also be a violation of an equipment's limiting values detected by the eBASE system. Afterwards, the SGH sends out a request to reduce all available load considering the restrictions of the different types of appliances.

If lowering the power of the controllable appliances is not sufficient to eliminate the congestion further DSO measures could be radical. Basically, the DSO has no other option to promptly solve the congestion than to shed more load. If the DSO has no contracts with customers for this case, this action would massively contradict principle of security of energy supply. Therefore, when deciding to apply this use case instead of expanding the system, the DSO must assure the maximum overload of the weakest equipment is always smaller than the available, reducible load in the respective part of the grid.

$$(I_{act} - I_{nom}) * U * \sqrt{3} * \cos \varphi \leq \sum P^{i}_{flexLoad}$$

I_{act} is the actual electric current on the equipment, I_{nom} is the equipment's nominal current.

4.4. Expected Results and KPI

Use Case 2 is expected to decrease occurring congestions in the distribution grid. This reduces the curtailed electrical work from RES. Reducing congestions should also lead to decreased grid expansion costs in the long term. However, as grid expansion has long planning and approval processes and the Interflex project only lasts until the end of 2019, the period will be too short to determine saved grid expansion costs.

The following KPI are used to measure and describe Use Case 2:

- Reduction of power [W]
- Increase of power [W]
- Reduction of congestions [A]
- Number of affected appliances by the reduction
- Number of affected appliances by the increase
- Number of violations of technical limits

5. USE CASE 3 – ANCILLARY SERVICES

5.1. Overview

The balance between production and consumption in a power system has long been provided by large controllable generators. However, a large share of these units are expected to be switched off and replaced by RES with lower marginal costs and emission levels. Besides the uncontrollable nature of RES, many of these units are connected to the distribution grid, causing reverse power flows and increasing the need for voltage control. The combination of increased RES-based distributed generation and decreased availability of conventional generators, creates a greater need for flexibility in the power system. This flexibility gap encourages the utilization of distributed flexibilities such as flexible loads and DGs to support the system operators in maintaining high power quality and reliable operation of the transmission and distribution system. The objective of Use-case 3 is analyzing the potential of distributed flexibilities in providing ancillary services to the DSOs.

A substantial amount of research have demonstrated the potential of distributed flexibilities in providing ancillary services, so called system flexibility services, to system operators. The flexibility services proposed so far include, but are not limited to, frequency control, congestion management, voltage control, and resource optimization. For this use case, a new ancillary service, called Local Balancing, is proposed. This service aims at optimizing the resource allocation in the distribution grid by decreasing the load-generation mismatch at the low voltage level.

While Use-case 1 and 2 focus on activating the available flexibilities when the system is in critical state, Use-case 3 adopts a preemptive approach, aiming to minimize the number of critical events. In other words, Use-case 3 demonstrates an active, bottom-up approach for the operation of the distribution system.

5.2. Regulatory Framework

Please refer to section 3.2 and 4.2.

5.3. Description of Algorithm

As described in the previous sections, the objective of Use-case 3 is minimizing the load-generation mismatch at low voltage level. The proposed algorithm consists of two steps as described below.

1. First day-ahead schedules for the flexible loads and Electrical Energy Storage (EES) devices are obtained. For this purpose, two different models are proposed and tested.

2. The system is observed at real time, to ensure that the loading of devices does not exceed their nominal power rating.

The following sections provide detailed description of the proposed algorithm.

Day-Ahead Schedule for Flexible Loads and EES, Optimization Method

To provide an optimized day-ahead schedule for the EES and flexible loads, the SGH takes the load, generation and ambient temperature forecasts as input and aims to allocate the available flexibility to those time periods when they are most needed. The general optimization problem is formulated as

$$min \sum_{t=1}^{T} (P_t^G - P_t^{Load} - P_t^{EES})^2$$

where P_t^G, P_t^{Load} and P_t^{EES} are the local generation, local load and power input of the local EES during time-step t respectively. The local load consists of an uncontrollable and a flexible part, i.e.

$$P_t^{Load} = P_t^{Load\_unc} + P_t^{flexible}$$

The only flexible loads included in this use case so far are the electrical heat pumps. Based on the thermal model used in this use case, the indoor temperature at the end of time-step t is given by

$$\theta_t = \epsilon\theta_{t-1} + (1+\epsilon)(\theta_t^A + \eta_t^{COP}\frac{P_t^{HP}}{A})$$

where

θ_t is the indoor temperature at the end of time-step t,

θ_t^A is the ambient temperature at the end of time-step t,

P_t^{HP} is the active power consumed by the heat pump during time-step t,

η_t^{COP} is the coefficient of performance of the heat pump during time-step t,

A is the overall thermal conductivity of the building, and

$\epsilon = \exp[-\tau/TC]$ is the factor of inertia, where $\tau = \Delta t$ is the duration of one time period, and TC is the time constant of the system.

Based on equation X, the power consumed by the heat pump during time-step t, is given by

$$P_t^{HP} = \frac{1}{1+\epsilon}(\theta_t - \epsilon\theta_{t-1}) - \frac{A}{\eta_t^{COP}}\theta_t^A$$

The power injected into the EES is given by

$$P_t^{EES} = \frac{1}{\Delta t\ \eta^{EES}}(E_t^{EES} - E_{t-1}^{EES})$$

where E_t^{EES} is the state of charge of the EES at the end of time-step t, and η^{EES} is the efficiency of the EES.

Using equations XYZ, the optimization problem is formulated as

$$\min \sum_{t=1}^{T} (P_t^G - P_t^{Load_{unc}} - \frac{1}{1+\epsilon}(\theta_t - \epsilon\theta_{t-1}) - \frac{A}{\eta_t^{COP}}\theta_t^A - \frac{1}{\Delta t\ \eta^{EES}}(E_t^{EES} - E_{t-1}^{EES}))^2$$

subject to

$$\theta_{min} \le \theta_t \le \theta_{max}$$

$$P_t^{HP} \ge 0$$

$$0.9\ P_{ref}^{HP} \le \sum_{t=1}^{T} P_t^{HP} \le 1.1\ P_{ref}^{HP}$$

$$0.9\ E_r^{EES} \le E_t^{EES} \le 1.1\ E_r^{EES}$$

The constraint in equation X is imposed to ensure the thermal comfort of the residents. Since the objective is modifying the local load to match the local generation, in areas where the installed DG capacity exceeds the local load, the algorithm could lead to an overall increase in the local power consumption, keeping the indoor temperature close to θ_{max}. To avoid this affect, the constraint in equation Y is imposed to ensure that the power consumption of the heat pump during a 24-hour period does not go below 90% or above 110% of a reference value P_{ref}^{HP}. The reference value is the power needed to keep the indoor temperature at a reference value corresponding to the middle of the thermal comfort zone, given by

$$\theta_{ref} = \frac{\theta_{min} + \theta_{max}}{2}$$

The constraint defined by equation Z is imposed to ensure that the energy stored in the EES is kept between the recommended lower and upper limits, corresponding to 10% and 90% of the EES rated capacity, E_r^{EES}, respectively.

The solution of this optimization is a 24-hour schedule for flexible loads and EES. In addition to the optimized flexibility resource allocation, the day-ahead schedules makes it possible for the SGH to prepare the communication channels for switching signals in advance.

Day-Ahead Schedule for Flexible Loads and EES, Numerical Method

The second method proposed here is based on an iterative numerical method. While the optimization method seeks to decrease the power exchange with upstream network throughout the span of 24 hours, the objective of the second algorithm is allocating the available flexibilities to hours with highest power mismatch. The algorithms for EES charging, EES discharging, and heat pump activation are provided in Figure 4, Figure 5, and Figure 6 respectively. This section provides a detailed description over the functionalities of each algorithm. These algorithms are described in the same order that they are implemented. The forecasted net load is in each step updated, and passed on to the next algorithm.

To increase the local load-generation balance, the algorithm seeks to charge the EES during the time periods when local net load, P^{net}, is at its lowest. Charging all EES capacity in one or two time periods could potentially create a local maximum in the load profile. In order to avoid this, an iterative method is proposed. With this method, during each iteration, the time period with lowest net load is identified and a fraction of the available storage capacity is schedule to be charged during that time period, t.The forecasted net load of that time period is updated, taking into account the scheduled EES charging, and a new minimum is identified for allocation of the next fraction of storage capacity. The number of iterations is chosen such that the EES schedule does not cause unnecessary fluctuations in the power profile.

The algorithm for EES charging consists of several nested loops. The main loop is the Iteration-accession loop, which creates two empty arrays to store the charging schedule and the indices of the modified time periods, and passes them on to the Capacity-allocation loop. This while loop starts by calculating a fraction of EES capacity, $C^{EES}_{fraction}$, to be allocated at each iteration. An array containing the local net-load

$$P^{net} = P^{Load} + P^{EES} - P^{DG}$$

is then created/updated. The time period with lowest net load, t, is then identified and stored in the array containing the modified indices, $\text{Ind}_{\text{modified}}$. If $C^{EES}_{fraction}$ is smaller than the energy generated during t, $C^{EES}_{fraction}$ is charged to the fullest, otherwise, all the generated energy is stored. The Capacity-allocation loop then updates $C^{EES}_{fraction}$, P^{DG}, and the array containing the EES charging schedule. P^{DG} is updated to make sure that the algorithm does not store more energy than is locally produced and the loop is repeated until either the unallocated part of C^{EES} or the generated power that has not been stored is smaller than a tolerance value tol_u.

Algorithm 1 Algorithm for EES charging

Input: P^{DG}, P^{Load}, C^{EES}, tol_u, tol_{ex}

Output: EES charging schedule and state of charge

Initialisation :

Define tol_{fluct}, e, $Iterate = 1$, $isgood = 0$

while $isgood = 0$ (Iteration-accession loop) **do**

Create an empty array to save the indices of the modified time-periods, $\text{Ind}_{\text{modified}}$=[ ]

Create an array to save the EES charging schedule, $E^{EES} = [0, ..., 0]$

while $min(C^{EES}, sum(P^{DG})) > tol_u$ (Capacity-allocation loop) **do**

At each iteration, allocate a fraction of the available EES capacity $C^{EES}_{fraction} = \frac{C^{EES}}{Iterate}$

$P^{EES} = E^{EES}/\Delta t$

$P^{net} = P^{Load} + P^{EES} - P^{DG}$

Find the net load for the time-periods with nonzero generation, $P^{net}_{nonzeroRES} = \{P^{net} | P^{DG} \neq 0\}$

Find the time period with lowest net load $P^{min}_t = min(P^{net}_{nonzeroRES})$

$\text{Ind}_{\text{modified}}$=[$\text{Ind}_{\text{modified}}$, t]

if $C^{EES}_{fraction} < P^{DG}_t \Delta t$ **then**

$\Delta EES = C^{EES}_{fraction}$

else

$\Delta EES = P^{DG}_t \Delta t$

end if

$E^{EES}_t = E^{EES}_t + \Delta EES$

$P^{DG}_t = P^{DG}_t - \Delta EES$

$C^{EES} = C^{EES} - \Delta EES$

end while

$P^{net} = P^{net} + E^{EES}/\Delta t$

Remove doubles from $\text{Ind}_{\text{modified}}$

Define a counter Fluct=0

for (t $\in$ $\text{Ind}_{\text{modified}}$) (Fluctuation-counting loop) **do**

if $(P^{net}_t - P^{net}_{t-1} > tol_{fluct})$ or $(P^{net}_t - P^{net}_{t+1} > tol_{fluct})$ **then**

Fluct=Fluct+1

end if

end for

if (Fluct>0) **then**

if *iterate* is too large **then**

$tol_{fluct} = tol_{fluct} + e$

end if

$Iterate = Iterate + 1$

else

$isgood = 1$

end if

end while

Figure 4: Algorithm for charging the EES

When the Capacity-allocation loop has finished running, the net load, P^{net} is updated, taking into account the EES charging schedule. The Fluctuation-counting loop is then used to count the number of fluctuations in P^{net} created during the modified time periods. To ensure that the algorithm always converges, a tolerance value, tol_{fluct}, is used, i.e. if the power fluctuation is less than tol_{fluct}, the fluctuation is neglected. If the EES charging schedule causes power fluctuations, the algorithm checks to see whether the number of iterations has exceeded a preset value, and in that case increases the tolerance for fluctuations. The number of iterations is increased and the Iteration-accession loop is repeated. If the fluctuations caused by EES charging are negligible, the algorithm exits the Iteration-accession loop.

The EES discharging algorithm, similar to the charging algorithm, seeks to increase the local load-generation balance by discharging the EES when local net load, P^{net}, is at its highest. To avoid causing additional active power fluctuations, this algorithm also adopts an iterative method, during which, a fraction of the available stored capacity is scheduled to be discharged during each iteration. The number of iterations is then successively increased until no oscillations are caused by the EES discharging schedule.

The discharging algorithm also contains an Iteration-accession loop, which calculates the EES power input, P^{EES}, the total available stored energy, E^{EES}, and creates an empty array to store the indices of the modified time-periods, $\text{Ind}_{\text{modified}}$. The second main loop is the Energy-allocation loop which starts by calculating a fraction of the stored energy, $E_{fraction}^{EES}$, to be allocated during each iteration. An array is then created, containing the net load for time-periods during which the stat of charge of the EES, SOC^{EES}, is non-zero. The time-period, t, with highest net-load is identified and saved to $\text{Ind}_{\text{modified}}$. If $E_{fraction}^{EES}$ is smaller than the net load during t, $E_{fraction}^{EES}$ is fully discharged. Otherwise, E^{EES} is discharged to balance-out P_t^{net}. The Energy-allocation loop then updates E^{stored}, P^{net}, and the array containing the EES charging schedule, and repeats until either the unallocated part of E^{stored}, or the net power is smaller than the tolerance value tol_u.

Similar to the charging algorithm, when the Energy-allocation loop has finished running, the Fluctuation-counting loop is then used to count the number of fluctuations in P^{net} created during the modified time periods. Similarly, a tolerance value, tol_{fluct}, is used to exclude the oscillations that are smaller than tol_{fluct}. If the fluctuations are negligible, the algorithm exits the Iteration-accession loop. Otherwise, the number of iterations is increased and the algorithm is repeated.

Algorithm 2 Algorithm for EES discharging

Input: SOC^{EES}, P^{net}, E^{EES}, tol_u
Output: EES discharging schedule
Initialisation :
Define $tolfluct$, e, $Iterate = 1$, $isgood = 0$
while $isgood = 0$ (Iteration-accession loop) **do**
  $\text{Ind}_{\text{modified}}$=[ ]
  $P^{EES} = E^{EES}/\Delta t$
  $E^{Stored} = sum(E^{EES})$
  while $\min(E^{Stored}, P^{net}) > tol_u$ (Energy-allocation loop) **do**
    At each iteration, allocate a fraction of the stored energy
    $E^{stored}_{fraction} = \frac{E^{stored}}{Iterate}$
    $P^{net}_{nonZeroEES} = \{P^{net} | SOC^{EES} \neq 0\}$
    Find $P^{max}_t = max(P^{net}_{nonZeroEES})$
    $\text{Ind}_{\text{modified}}$=[$\text{Ind}_{\text{modified}}$, t]
    if $E^{stored}_{fraction} < P^{net}_t \Delta t$ **then**
      $\Delta EES = E^{stored}_{fraction}$
    else
      $\Delta EES = P^{net}_t \Delta t$
    end if
    $P^{net}_t = P^{net}_t - \Delta EES/\Delta t$
    $E^{EES}_t = E^{EES}_t - \Delta EES$
    $E^{stored} = E^{stored} - \Delta EES$
  end while
  Remove doubles from $\text{Ind}_{\text{modified}}$
  Define a counter Fluct=0
  for t $\in$ $\text{Ind}_{\text{modified}}$ (Fluctuation-counting loop) **do**
    if $((P^{net}_{t-1} - P^{net}_t) > tol_{fluct})$ or $((P^{net}_{t+1} - P^{net}_t) > tol_{fluct})$ **then**
      Fluct=Fluct+1
    end if
  end for
  if Fluct>0 **then**
    if Iterate is too large **then**
      $tol_{fluct} = tol_{fluct} + e$
    end if
    $Iterate = Iterate + 1$
  else
    $isgood = 1$
  end if
end while

Figure 5: Algorithm for discharging the EES

For the scheduling of heat pumps, a simple algorithm is used. This algorithm finds the time-period with highest net-load, t_{max}, and lowest net-load, t_{min}. The initial indoor temperature is set equal to the reference temperature, θ_{ref} and is then gradually increased until it reaches the highest thermally comfortable temperature, θ_{max}, at t_{min}. The indoor temperature is then gradually decreased to reach the lowest thermally comfortable temperature, θ_{max}, at t_{max}, and then again decreased to reach θ_{ref} by the end of the scheduling period. Here, the assumption is made that P^{net} reaches its lowest value prior to reaching its highest value. The algorithm can easily be modified to include the scenario when $t_{max} < t_{min}$.

Algorithm 3 Algorithm for heat-pump activation

Input: P^{net}, θ_{ref}, θ_{max}, θ_{min}
Output: Heat pump activation schedule

$Initialisation:$
$Find\ P^{net}_{tmin} = min(P^{net})$
$Find\ P^{net}_{tmax} = max(P^{net})$

for (i=1:tmin) **do**
  $\theta_i = \theta_{ref} + \frac{(\theta_{min} - \theta_{ref})(i-1)}{tmin-1}$
end for
for (i=tmin:tmax) **do**
  $\theta_i = \theta_{max} - \frac{(\theta_{max} - \theta_{min})(i-tmin)}{tmax-tmin}$
end for
for (i=tmax:end) **do**
  $\theta_i = \theta_{min} + \frac{(\theta_{ref} - \theta_{min})(i-tmax)}{end-tmax}$
end for

Figure 6: Algorithm for activating the heat pumps

Real-Time Feed-In Management

The above-described day-ahead schedule only optimizes the flexibility utilization, but does not consider the transmission capacity of network devices such as feeders and transformers. To avoid overloading of equipment, additional control mechanisms are required. For this purpose, the system is monitored in real time, and in case network congestion is detected or predicted, the excess DG feed-in is curtailed. The algorithm applied at this step is the same as the one described in section 3.

5.4. Expected Results and KPI

Expected results of this use are a decrease in power exchange between low and medium voltage networks and subsequently decreased congestion on medium voltage and high voltage devices. It is further expected that these effects will carry over and result in decreased grid expansion costs, decreased line and transformation losses and decreased reverse power flow.

KPI to quantify the effects of this use case are active power on MV feeders, active power on MV/LV transformers, reduction of active power exchange between low and medium voltage networks, nr of congestion events, duration of congestion and active power variation.