MARKET ENABLING INTERFACE TO UNLOCK FLEXIBILITY SOLUTIONS FOR COST-EFFECTIVE MANAGEMENT OF SMARTER DISTRIBUTION GRIDS

Deliverable: D8.3

German Demonstrator — Demonstration of congestion management using market driven utilisation of flexibility options in a LV grid

Demonstration results assessment and conclusions

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List of Abbreviations

BMWK	German Ministry for Economic Affairs and Climate Action
BEMS	Business Energy Management System
BUC	Business Use Case
CC	Chance Constraint
D	Deliverable
DER	Distributed Energy Resource
DdSE	Data driven State Estimation
DN	Distribution Network
DNI	Distribution Network Incidents
DSO(s)	Distribution System Operator
EV	Electric Vehicles
FNA	Flexibility Needs Assessment
HEMS	Home Energy Management System
KPI	Key Performance Indicator
LV	Low Voltage
MNS	Mitnetz Strom
MV	Medium Voltage
MVP	Minimum Valuable Product
NRAs	National Regulatory Authorities
OBR	Optimal Bid Recommender
OPF	Optimal Power Flow
PV	Photovoltaic
REST API	RESTful application programming interface
SO(s)	System Operator
SSH	Secure Shell
SUC	System Use Case
T	Task
UMEI	Universal Market Enabling Interface
WP(s)	Work Package

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Executive Summary

This Deliverable has been drafted in the context of the EUniversal project. The EUniversal project aims to overcome existing limitations regarding the use of flexibility by DSOs for congestion and grid management. Considering the European approach as well as the need for harmonization and creation of standards, one objective of EUniversal is the establishment and integration of a Universal Market Enabling Interface (UMEI) to ensure system interoperability to facilitate access to multiple flexibility market platforms and thus access to distributed flexibility. During the project, the UMEI is tested in three locations across Europe, i.e. Portugal, Germany and Poland, examining its use for market-based flexibility procurement in various use cases.

This report concerns the German Demonstrator and follows up on the deliverable D8.2 "Demonstration of congestion management using market-based flexibility in the LV grid" for this demo.
The deliverable D8.3 assesses project results and draws conclusions from the German EUniversal Demonstration. Furthermore, this final report of WP8 describes the lessons learned within the Demonstration.
This deliverable reports the test results of the flexibility value chain within the German demonstrator (WP8), starting from congestion detection to the market-based flexibility service procurement. The tests of the German Demonstrator are divided into two parts: 1) Individual tests of each smart grid tool, the market environment and associated functions of the DSO, FSP and the Optimal Bid Recommender to ensure correct functioning and information exchange and 2) the operational testing of consecutive members of the digital flexibility value chain.
D8.2 mainly outlined the test part 1), related findings and challenges of the performed test series. This report will cover part 2) of the digital flexibility value chain. Wherever possible, the functionalities and operational processes will be measured against the Key Performance Indicators (KPIs) identified in WP6.

1 Introduction

1.1 Background

The European Union aims at transforming the energy system towards a sustainable, low-carbon and climate-friendly economy. The scope is to increase the energy share of electricity production in distribution grids to around 50% of renewable energy sources (RES) until 2030 while guaranteeing the security of supply and avoiding unnecessary grid investments. For this purpose, load generation and consumption of prosumers across all grid levels shall serve as energy and flexibility resources making them active participants in the energy system. In such a scenario, prosumers become key enablers towards a more sustainable, low-carbon and climate-friendly electricity system by adapting their consumption and production behaviour to stabilize the grid when needed. Yet, flexibility will also add complexity and create unpredictable power flows in the distribution networks. Distribution System Operators (DSOs) need to integrate smart-grid solutions to cope with the new types of load patterns of diverse small-scale assets (e.g., electric vehicles and heat pumps) and to identify the required flexibility to safely host the increasing share of RES. Therefore, innovative technologies and solutions are required to transform the challenges of the energy transition into opportunities for the sector, and ultimately for the society.

The EUniversal project aims to overcome the existing challenges for DSOs concerning the use of flexibility. The primary project goal is to overcome barriers between multiple market agents and their internal systems through the Universal Market Enabling Interface (UMEI), described in detail in the project deliverables D2.4-D2.6. The UMEI has been developed to support distribution system operators and their active system management by facilitating access to distributed flexibility via multiple market platforms at different locations while limiting the DSO system changes to a minimum. The UMEI is tested in three different demonstrations in Germany, Poland, and Portugal. This deliverable describes the results obtained from the German demonstrator.

1.2 Scope and objectives of this document

This report is part of the eighth work package of the EUniversal project. The objective of WP8 is to validate the concepts, and tools developed throughout the EUniversal project within the context of the German demonstrator. This context is the following: the German DSO is facing specific challenges with respect to the LV network. With the increasing number of renewable generation and the addition of new flexible loads, congestions and voltage problems in the grid are becoming more frequent and observability needs to be increased. As such, the main objective of the demonstrator was defined as to increase observability and to develop technical solutions for the congestion management and voltage control in the LV-Grid with the help of flexibility markets.

The German demonstrator, led by German DSO Mitnetz Strom, examines the operational and functional viability of each element that is required to fulfil the complete value chain when using market-based flexibility to solve network congestions. This value chain starts from smart grid tools to identify existing and future congestions in terms of location, volume and direction, to using an optimal bid recommender to select the optimal bid available on the local flexibility market. The full value chain, as tested in the German demo, is shown in Figure 1.1.

This report builds further on the previous reports concerning the German demo, namely D8.1, in which the demo specifications are outlined, and D8.2, showing the functional test scenarios preceding the demonstration phase. The objective of this report is to give an overview of the results achieved during the German demo. Where applicable, these results are quantitatively assessed according to the Key Performance Indicators that were previously defined in WP2/WP6 [5].

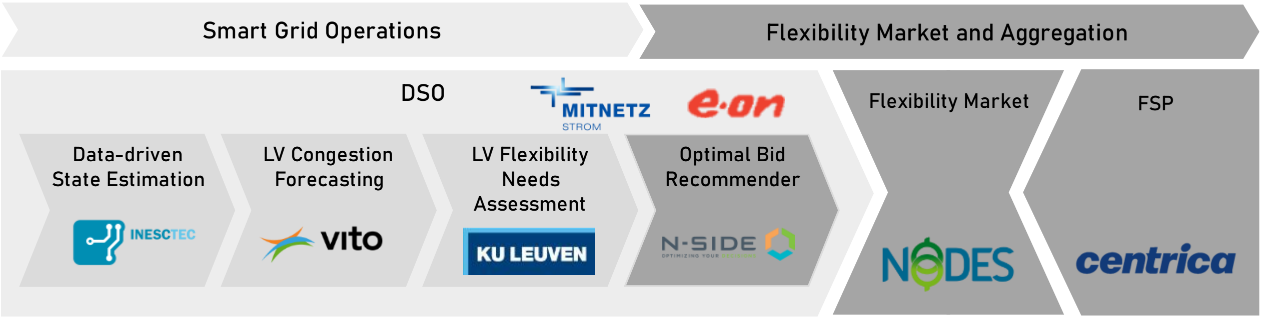

Figure 1-1: Simplified overview of the smart grid tools and market environment as tested in the German Demo.

To compile this report, valuable information from other WPs was used, namely:

- WP2, for the definition of use cases that are demonstrated, as well as the UMEI API functional specification, namely with the identification of the interactions between the DSO and Flexibility Market platforms and data exchange
- WP3, with the use of a flexibility toolbox, identifying the technologies and solutions most suitable to provide flexibility services to the distribution grid
- WP4, for the development of the DSO smart grid tools and their alignment
- WP5, the identification of relevant market mechanisms
- WP6, with a common framework to harmonise, monitor and assess the validation of the result

1.3 The integration of the UMEI

One of the core ambitions of the EUniversal project was to develop a universal approach on the use of flexibility by DSOs and their interaction with flexibility markets. This has led to the development of the concept of the Universal Market Enabling Interface (UMEI).

Deliverable D2.6 holds the description of the UMEI interface, which was specifically designed to support the interactions between the different actors.

Within the German demo, all interactions between the DSO, the FSP and the market operator happen through the UMEI. In deliverable D8.2 is explained how the communication chain was set-up, and shows the results of specific test scenarios to ensure the operational reliability between all systems via the UMEI.

As the successful completion of these tests was shown in D8.2, no further UMEI-specific results will be given in this report. This report rather will rather focus on the test results of the entire flexibility chain, where all individual tools are combined together.

1.4 Regulatory framework

Germany has implemented multiple methods of allocating flexibility. one being the mandatory Redispatch 2.0 [12], which is a cost-based method. Besides Redispatch 2.0, cost-based flexibility is mainly regulated through the paragraph §14a in the German Energy Industry Act (EnWG). The national regulatory authorities (NRAs) are currently working on an updated version to amplify the roles and resources to use the distributed flexibility while maintaining the existing redispatch measures to a large extent.

Market-based allocation of flexibility is regulated through paragraph §14c EnWG. On one hand, the use of market-based flexibility shall reduce or even prevent additional costs and bridge time delays of the grid infrastructure expansion. On another, market-based flexibility helps to use the available resources efficiently and effectively by allocating flexibility to the use where it has the highest value, e.g. to solve a local congestion. Besides, implementing flexibility markets (explicit flex) to benefit from the available distributed flexibility for grid services requires an adaption of the German regulatory framework as well as adjustments of the grid tariff and tax schemes (implicit flex) to incentivize the participation of flexibility providers. A detailed evaluation of the required adaptions has been elaborated by a forum of experts and presented to the German Ministry for Economic Affairs and Climate Action (BMWK) in June 2021. This adaptation has, however, not yet led to an alteration in the regulatory framework, and in the German Easter package (2022)[9], market flexibility was only mentioned as an alternative measure with the flexibility potential being categorized as undetermined benefits. This categorization is especially important considering the challenges and risks of integrating flexibility markets, such as the increasing need for coordination between system operators as well as the coordination of numerous new assets and asset types that contribute to the load flow and feed in conditions. Furthermore, especially in Germany the potential risk of strategic bidding to artificially increase the revenue of market participants is a major argument against the market-based approach.

Nevertheless, we remain convinced that market-based allocation of flexibility will become the dominant method in the long-term while the rules-based schemes described above are advantageous only for an interim period.

With the ongoing work on the German Demo, the goal is to showcase the digital value chain of flexibility suggesting innovative solutions to overcome the existing technical and operational challenges.

1.5 Report structure

In the following chapter 2, a summary of the pilot activities is given, including an explanation on how the different test scenarios were set up.

In chapter 3, the results of the demo tests are discussed and quantified. During the demonstration phase, a set of System Use Cases (SUC) was tested, each of them dealing with a specific functional element within the overall flexibility value chain as referred to above. In chapter 3, the demonstration results are given according to the system use cases and their associated KPI's that were previously defined within WP2 and WP6 of the project.

In the last chapter, the main conclusions concerning the German demo test results are given. Also, a reflection on the overall demonstration and flexibility value chain is given.

The knowledge gained in this demonstration will be used to support WP10 in the development of business models for the exploitation of EUniversal results and to provide recommendations for policy makers and regulatory authorities to set up a framework for flexibility markets.

2 Demonstration activities

The field tests form an integral part of the EUniversal project, serving as feasibility check to ensure real-world applicability of the smart grid tools and market solutions as well as validation of the aspired targets.

The German demonstrator of EUniversal had the following objectives:

1) Achieving enhanced observability of the chosen LV grids.
2) Provide flexibility over the UMEI to the flexibility market.
3) Integrate the flexibilities into a scheduler-based congestion management.
4) Enabling the provision of flexibilities to the LV/MV connection point.

To validate the achievement of this objectives, several tests were performed. In terms of scope, these ranged from testing individual functional components, process steps and tools (see Deliverable 8.2 [2]) up to testing the entire flexibility value chain under realistic circumstances.

For this purpose, representative days, which were particularly interesting due to the weather or feed-in conditions, in the annual course of the tests were selected to illustrate the performed steps. These selected days are February 08 as the coldest day in the MITNETZ region and August 03 as the day with the highest measured feed-in power to the TSO grid in 2023. In addition, arbitrarily selected times from the executed trading processes are used to prove compatibility with the market and the UMEI. The results found are presented later in the document based on the classification of the SUCs.

Mitigation measures had to be implemented during the tests due to the conditions on site. This included adjusting the transmission capabilities of the lines downward, as well as setting a narrower voltage band level than allowed by standardization, for the congestion detection and flexibility counter measures (see Table 3-9). This is due to the fact that MITNETZ's low-voltage grids are very stable and currently do not exhibit a great likelihood of congestion.[1]

Furthermore, due to the difficulties in acquiring and equipping customers, it was no longer possible to complement all tests just with flexibilities out of the respective network areas. To cope with this the evaluation in the demo grids tests were separated into two focus schemes:

- Part A - Test DSO Smart Grid Tools – Flex market:

  Tests are carried out within the specified LV network area, using the measurements and equipment available within that network.

- Part B - Test of FSP aggregation and activation at customer side – Flex market:

  Tests are carried out using real assets that are outside of the specified LV network in a laboratory environment.

The separation of the flexibility value chain into the two focus schemes is also indicated in Figure 1-1, where the part A is indicated by a light gray color, and part B is indicated by a darker color.

[1] However, due to the rapid growth of PVs, EVs and heat pumps, congestion are expected to become more frequent in future.

This separation made it possible to run the use case of the German demo in part A with real measurements and topologies, even if the virtual portfolio of the FSP also consisted out of off-grid assets. At the same time, the technical feasibility of flexibility activation could be demonstrated in part B. This means that the entire range of functions has been tested. No further technical steps are necessary for merging the two parts. However, higher market liquidity must be achieved, e.g. through the removal of prevailing regulatory barriers and incentive creation through appropriate tariff schemes. In the evaluation of the results, further on in this document, reference is made at appropriate points where possible limitations are resulting from the application of the mitigation measures in the tests.

3 Demonstration results

3.1 BUCs of the German Demo

In line with the prevailing business needs, the following two **BUCs were initially defined in the German demonstrator (see D2.2 [3])**

Mechanism	Service	Buyer	Auction type	Product	Timeline	Aggregation	BUC	Platform
Flexibility market (UMEI)	Corrective Congestion management and voltage control	DSO only	Continuous market	AP	Day-ahead intraday	Yes	DE AP	NODES
				RP	Day-ahead intraday	Yes	DE RP	NODES

Figure 3-1 - BUCs German Demonstration

As indicated in Deliverable 8.2 it was in the current set-up not possible to independently control reactive power and active power due to obligatory cos(phi) specifications in the technical connection conditions of the inverters. The German demonstration focusses on the more relevant case of congestion management and voltage control with market-based active power flexibility. Since the process-related procedures are analogous in reactive and active power management. In the rest of the document, we will analyze only the effects of this use case even if some of the learnings may also be relevant for aspects regarding reactive power.

3.2 BUC - Congestion Management & Voltage Control with market-based active power flexibility

The Business Use Case that defines the activities in the German demo is described as 'Congestion Management and Voltage Control with market-based active power flexibility'. An extensive description of this BUC can be found in D2.2 [3], however the main points are repeated here.

This Use Case deals with short-term grid operation and comprises both a day ahead and an intraday process. The focus is the low voltage grid and the provision of aggregated LV flexibility for the MV level. The objective of the BUC is to mitigate congestions (overloading of lines/transformers, voltage band violations) using market-based active power flexibility in a cost-efficient way, while ensuring that flexibility activation of market bids will not create (LV) grid congestions. This means that the local market design enables the trade of aggregated flexibilities, and that the DSO gets the right visibility to check that a contract will not worsen or create a congestion. The FSP can also re-optimize the dispatch of the resources while fulfilling his contract at the aggregated grid area level.

The Use Case is divided into the 3 phases, illustrated in Figure 3-2: Prequalification, Selection/Bidding, Delivery and Settlement:

1. Registration and Prequalification: Registration of assets and assignment to a grid node
2. Selection/Bidding: State estimation and prediction of congestions: Flexibility bids are offered on NODES market platform by the Flexibility Service Providers. The DSO accesses the flexibility market to activate the optimal flexibility bid in terms of location, volume and price to solve the grid congestion. The FSP is notified about the activation of its flexibility, hence his delivery obligation to the DSO for the selected period.
3. Validation and settlement: Flexibility resources are activated, and the selected flexibility is delivered. The delivery and the respective payments are validated and defined using the baseline and the meter data.

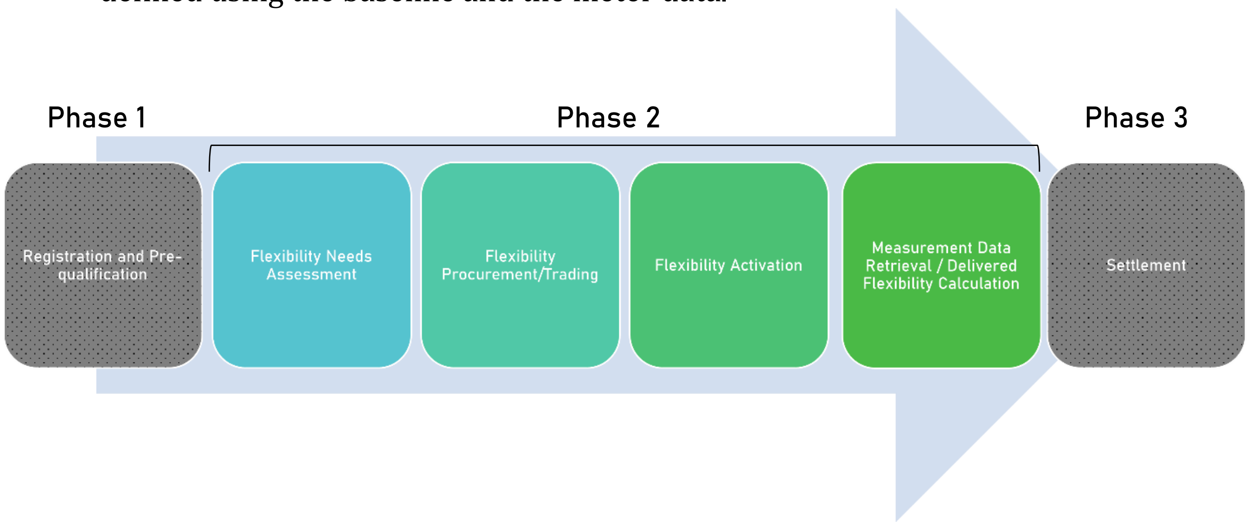

Figure 3-2: The three phases of the congestion management use case.

For every specific functionality that is required within this BUC, a SUC was defined. An extensive description of all SUCs can be found in deliverable D2.1[1]. An overview of the relevant SUCs to this BUC is shown in Table 3-1. Throughout the EUniversal project, the SUCs are classified into three domains: Smart Grid Operations, Flexibility Market and Flexibility Aggregation, these are also shown in Table 3-1.

In the following sections, a description of the results obtained during the German Demo tests for each of the relevant System Use Cases is given. Where applicable, the results are quantified according to the Key Performance Indicators (KPI's) associated to each System Use Case. These KPI's are identified and described in deliverable D6.2 [5] and are also indicated in Table 3-1.
The discussions on the results obtained by each SUC are grouped according to the SUC domains, where the Smart Grid operations domain is split into "Congestion Detection and State Estimation" and "Congestion Management and Flexibility Need Quantification".

Table 3-1: Overview of SUCs and associated KPI's relevant to the German Demo BUC.

Domain	SUC ID	SUC name	Related KPI's	Owner

Smart Grid Operations	Congestion Detection and State Estimation	SUC 5	Estimating LV voltage magnitude based on historical data and load forecasts	CM_KPI_5: Voltage Magnitude Prediction Error	INESC TEC
		SUC 6	Day-ahead congestion forecasting	DE_KPI_03: Share of correctly forecasted congestions DE_KPI_04: Share of false positive congestion forecasts	VITO
	Congestion Management and Flexibility Need Quantification	SUC 4	Day-ahead congestion management considering flexibility needs in LV and MV networks	CM_KPI_4: Avoided Restrictions CM_KPI_1: Flexible capacity vs. flexible volume offered ratio CM_KPI_2: Flex volume mobilized CM_KPI_3: Flex bids accepted by DSO vs flex volume delivered by FSP DE_KPI_02: Cycle Time DSO process	INESC TEC
		SUC 8	LV flexibility needs assessment for voltage and congestion management	DE_KPI_06: Over-/under-estimation of flexibility	KUL
		SUC 12	Minimizing costs linked to DSO flexibility requirements	DE_KPI_01: Costs of Congestion Management with flex Market vs. Curtailment	N-SIDE
Flexibility Market		SUC 13	Short-term flexibility procurement		NODES
Flexibility Aggregation		SUC 16	DER registration and configuration		CENTRICA
		SUC 17	Bidding aggregation		CENTRICA
		SUC18	Resources' dispatch and monitoring		CENTRICA
		SUC 19	Baselining	DE_KPI_05: Baseline accuracy	CENTRICA

3.3 Smart Grid Operations: Congestion Detection and State Estimation

3.3.1 Test methodology

The SUCs within the domain concerning congestion detection and state estimation were tested as part of focus part A of the German demo activities. This means that the tests were carried out within the LV network area specified for the demo activities (for details, see D8.2), using the measurements and the equipment and assets from that area.

Figure 3-3 shows the position of the SUCs considered here within the overall flexibility value chain (Figure 3-3).

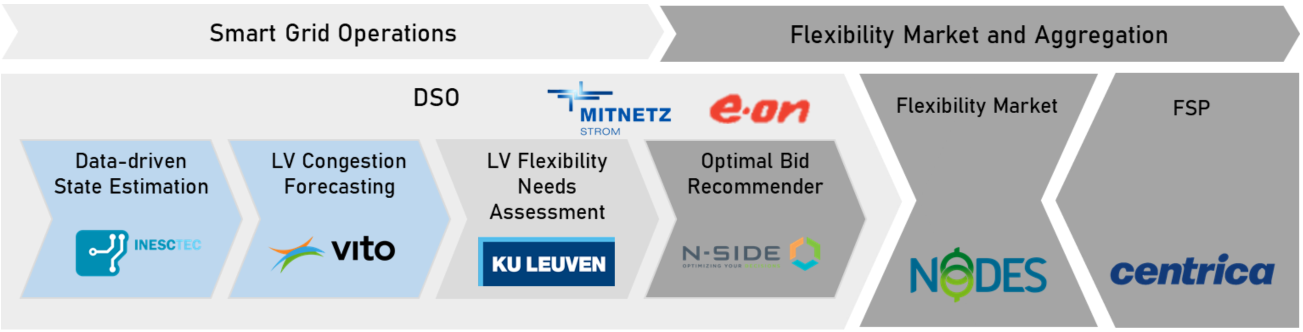

Figure 3-3: Overview of the flexibility value chain with the functional blocks concerning the SUC's on congestion detection and state estimation highlighted in blue.

3.3.2 SUC 5 – Estimating LV voltage magnitude based on historical data and load forecasts.

Numerous challenges now emerge in the lower tiers of the distribution system due to increasing renewable energy integration, storage, electric vehicles, demand-side management, microgrids, and peer-to-peer markets. Developing monitoring tools is critical to ensure operator awareness, given that real-time grid monitoring remains limited by the communications infrastructure limitations, and by the smart meter technology.

This use case primarily focuses on LV network monitoring, addressing common grid obstacles and enhancing asset control tools. The Data-driven State Estimator (DdSE) core objective is to provide real-time and short-term network state forecasts exclusively based on data measurements, without relying on grid topology or electrical characteristics.

The main steps of the estimation are the following:

1. **Data Collection**: New measurements from smart meters and other devices, including weather data, are periodically retrieved and added to a knowledge database.
2. **Data Quality Check**: The Data Manager examines the data for inconsistencies or errors, correcting missing or inaccurate values.
3. **Database Update**: Validated data is integrated into the knowledge database, preserving raw data as a backup.

4. **Performance Analysis and Optimization**:
    - If results are good, hyper-parameters are fine-tuned to align with LV consumption patterns.
    - If errors exceed a threshold due to grid changes, hyper-parameters are reset and optimized.
5. **Save Hyper-parameters**: The optimized hyper-parameters are saved in the database for future use.
6. **Real-time State Estimation**:
    - New real-time data triggers a state estimation process.
    - Inconsistent measurements are removed from the data.
7. **Database Update**: Validated real-time data is added to the knowledge database.
8. **State Estimation**: The state estimation tool determines the most likely current system state, providing information on voltage magnitude, uncertainty, and active power injection.
9. **Data Request**: The state estimation tool requests necessary data, including updated hyper-parameters, real-time measurements, historical data, and additional variables.
10. **Storage and Display**: The results of the real-time state estimation are stored and may be displayed in a user interface for visualization.
11. **Integration with Other Tools**: The updated system state can be used by other tools, such as voltage control, based on predefined criteria.

In the current implementation of this LV monitoring Demonstrator, meters are split as follows:

- 10 meters communicate voltage and active power every 15 minutes.
- 47 meters store their readings of voltage and active power and communicate them by the end of the day.

The arrival of a new set of real-time measurements (every 15 minutes) triggers the DdSE to reconstruct a new state of the system. The voltage estimations for three connection points of the Demonstrator grid over 10 days are illustrated in Figure 3-4, Figure 3-5 and Figure 3-6.

Figure 3-4: Comparison between estimated and real voltage values for one smart meter (id: L3 [67729186]) connected to phase a, over the period of 10 days

Figure 3-5: Comparison between estimated and real voltage values for one smart meter (id: L2 [37341193]) connected to phase b, over the period of 10 days.

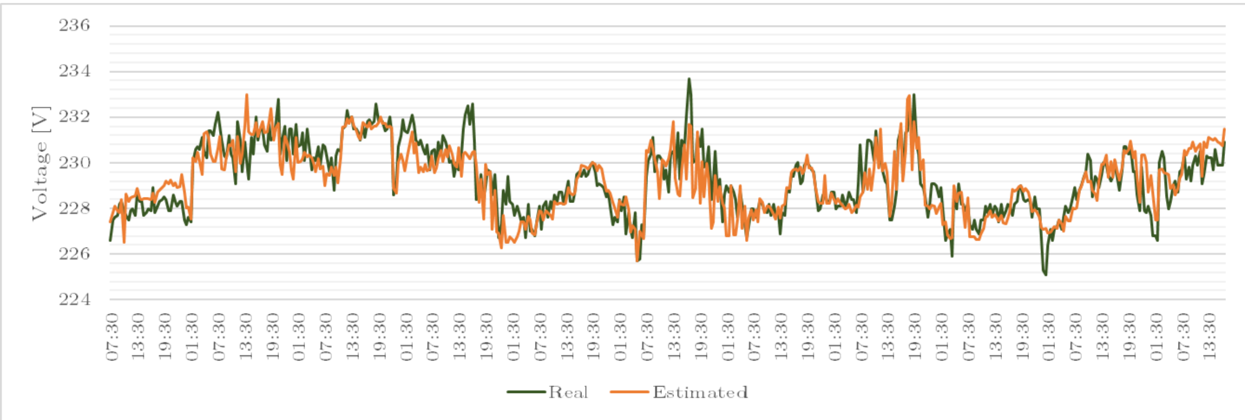

Figure 3-6: Comparison between estimated and real voltage values for one smart meter (id: L1 [37341196]) connected to phase c, over the period of 10 days.

According to the results, it is evident that the tool is highly reliable in providing estimations that closely match the actual values. Although, in some cases the tool is uncapable of following sudden changes (voltage spikes). This degree of accuracy offers significant reassurance to the system operator, as it enhances its ability to make informed decisions about the system's operations.

3.3.2.1 KPI's

The KPI "*CM_KPI_5: Voltage Magnitude Prediction Error*" assesses the ability of the tool to estimate voltage values by comparing these estimated scenarios with the actual registered voltage magnitudes. Therefore, this KPI gauge the algorithm's accuracy in performing state estimations, focusing on voltage magnitude performance and dispersion. Two primary indicators were computed (details in deliverable D6.3):

1. **MAE (Mean Absolute Error)**: This metric measures the average absolute difference between predicted and actual voltage magnitudes, providing an indication of the algorithm's overall accuracy.
2. **MAD (Maximum Absolute Deviation)**: Assesses the maximum absolute discrepancy between predicted and actual voltage magnitudes, highlighting the most significant deviations encountered during state estimations.

Two other metrics were also computed:

3. **MAPE (Mean Absolute Percentage Error)**: Quantifies the percentage difference between estimated and actual values calculating the average absolute percentage difference across all data points.
4. **MSE (Mean Squared Error)**: Evaluates the average of the squared differences between predicted and actual values.

From the same evaluation that was used to produce the plots in the subsection above (10 days), the following metric values were obtained:

- MAD: 3.1994 V
- MAE: 0.4425 V
- MAPE: 0.1915 %
- MSE: 0.3858 V

3.3.3 SUC 6 – Day-ahead congestion forecasting

This use case holds the description of the operation of the LV grid day ahead congestion forecasting tool. The output of this tool is information on the risk for congestion, per feeder and transformer, day ahead and per quarter hour time step. Next to that, the tool calculates the available capacity on the feeders and the MV/LV transformers in the form of headroom per asset, i.e., maximum total offtake and injection by the flexible devices, in order to avoid congestions.

The tool is hourly activated and executes the following steps:

1. Collect input data, which consists of:
    - the LV grid layout, including meta-specs on the connection
    - Historic and recent connection profile measurements
    - Weather forecasts, comprising of temperature, cloud coverage and solar irradiance
    - Information on the flexible assets, as available to the DSO
    - Latest measurements from the feeders/transformer's considered

2. Calculates the risk for congestions, per feeder and MV/LV transformer, per quarter hour, for the next 48h. The congestion risk is based on a predefined risk threshold and is given per grid node and time step. The risk for following congestion types is derived: overcurrent, overvoltage, undervoltage and transformer overloading. Also, the statistically aggregated risk that any congestion will occur is calculated.

The congestion risk is calculated for a base-case, i.e., no flexibility is used, and for a worst-case flexibility usage. For the latter case, it is assumed that the flexible assets are on at full power.

3. Calculates per MV/LV transformer, per quarter hour, how much headroom, in [kW], is available for use by the flexible devices, e.g., to offer flexibility for MV congestion management, ancillary services, etc.
   Headroom consists of an upper and lower limit per quarter hour. Positive is offtake, negative injection. A positive upper limit indicates up to how much flexible offtake can be activated without risk for congestions. The next tool in the chain can then freely select bids within the head room constraint.

4. Publishes the following information to be used by the DSO operators or follow up tools
   • Congestion probability report
   - Asset congestion risk report
   - Asset headroom report (as input for the Optimal bid recommender tool described in SUC12)

The accuracy and performance of the congestion forecasting tool were assessed by comparing the calculated congestion risks with measurements obtained at predefined locations in the network. These measurements are mainly located at the feeder heads (at the transformer) for every network participating in the pilot.

3.3.3.1 KPI's

Two Key Performance Indicators were defined to assess the performance of the congestion forecasting tool. These KPI's are:

- **KPI_DE-03**: The ratio of the correctly forecasted congestions versus all congestions that occurred.
- **KPI_DE-04**: The ratio of the incorrectly forecasted congestions versus the total number of congestions forecasted.

More background and the calculation methodology for these KPI's can be found in deliverable D6.2 [5].

The idea behind these KPI's is that all congestions should be correctly detected, to ensure that the DSO has adequate time to take action to avoid all congestions. False negatives should not occur. False positives are acceptable, but their share should be as small as possible.

During the German demo tests, it became clear quickly that the LV networks considered are operated quite far from any congestion limit. Even in high-load conditions, no congestions were measured. This was also indicated by the congestion forecasting tool, as no congestions risks were detected, meaning that the performance of the congestion forecasting tool proved to be very accurate.

However, to challenge the forecasting tool, the congestion detection limits were lowered so that a few congestions were measured. The results of the congestion forecasting tool, using such lower congestion limit, is shown in Figure 3-7 and Figure 3-8 for two feeders that are representative of the group of feeders in the pilot area. The congestion current limit was set to 35A for feeder 318752, and to 63A for feeder 67729185. The congestion risk threshold, i.e., the threshold above which the statistical forecast of the congestion risk identifies a congestion is for this case set to 5%. This means that if the congestion risk is higher than 5%, a congestion is detected. This limit also was chosen to be very low, to account for the low (real) congestion risks.

The accompanying assessment and calculated KPI's are shown in Table 3-2 for the same feeders and for a measurement period of roughly one month. Next to the calculated KPI's, the average Continuous Ranked Probability Score (CRPS) of the congestion forecast result is also given. The CRPS score is a generalization of the Mean Average Error when dealing with probabilistic forecasts [6], and gives an indication of the average accuracy of the probabilistic forecast.

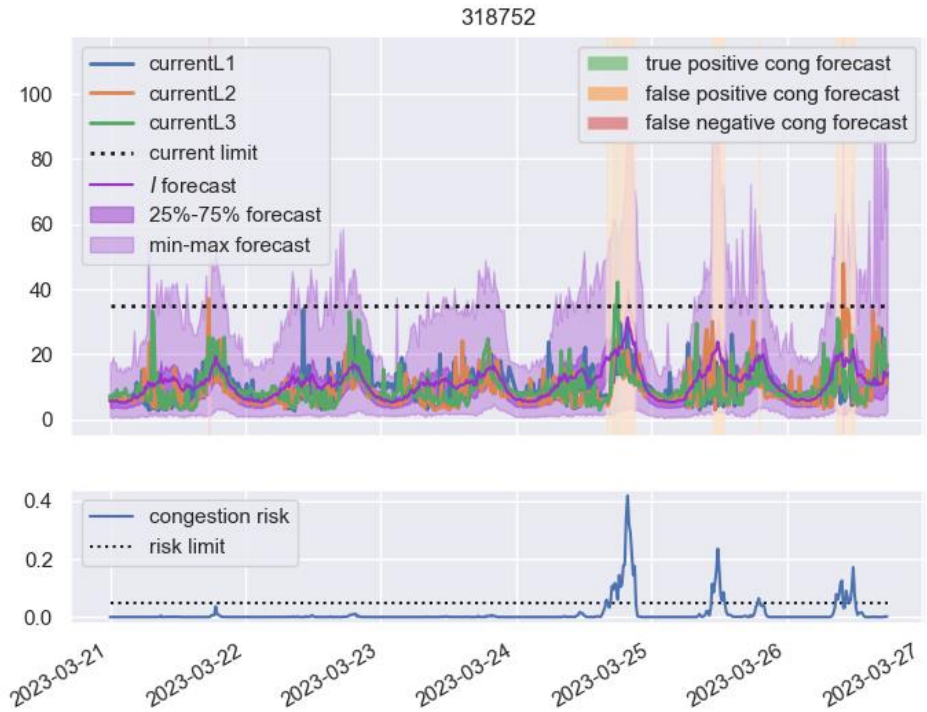

Figure 3-7: The congestion forecast result for feeder 318752. In the top plot, the measured quantities are given in blue, orange and red. The statistical forecast is shown in purple. The bottom plot shows the associated forecasted congestion risk.

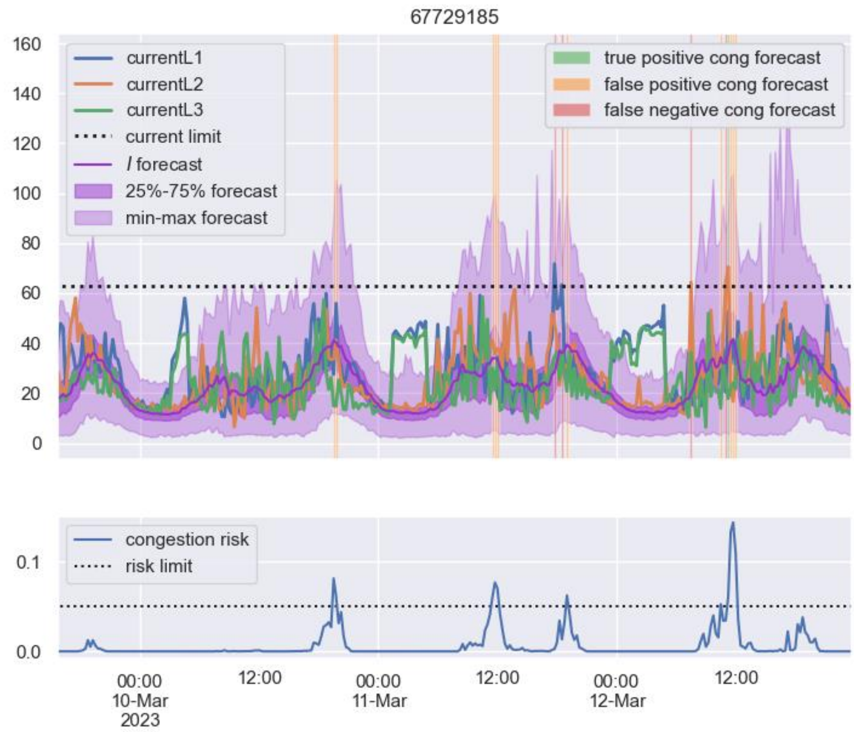

Figure 3-8: The congestion forecast result for feeder 67729185. In the top plot, the measured quantities are given in blue, orange and red. The statistical forecast is shown in purple. The bottom plot shows the associated forecasted congestion risk.

Table 3-2: Congestion forecast assessment and KPI results for feeder 318752 and 67729180.

measurement period	feeder	$\#C_0$	$\#C_{fc}$	$\#C_{fc,\,c}$	$\#C_{fc,\,f}$	$\#C_{fc,\,n}$	KPI_DE_ 03	KPI_DE_ 04	average CRPS
19/02/2023 - 24/02/2023	318752	3	21	0	21	3	0	1	2,60
25/02/2023 - 28/02/2023	318752	3	25	2	23	1	0,67	0,92	2,91
02/03/2023 - 04/03/2023	318752	2	30	1	29	1	0,5	0,97	2,85
06/03/2023 - 12/03/2023	318752	5	40	1	39	4	0,2	0,98	2,82
17/03/2023 - 20/03/2023	318752	2	38	0	36	2	0	1	3,53
21/03/2023 - 26/03/2023	318752	4	41	2	39	2	0,5	0,95	2,99
01/08/2023 - 04/08/2023	318752	0	6	0	6	0	-	1	2.70
19/02/2023 - 24/02/2023	67729185	5	10	0	10	5	0	1	6,00
25/02/2023 - 28/02/2023	67729185	7	16	1	15	6	0,14	0,95	7,47
02/03/2023 - 04/03/2023	67729185	3	6	0	6	3	0	1	7,13
06/03/2023 - 12/03/2023	67729185	7	11	1	10	6	0,14	0,91	7,88
17/03/2023 - 20/03/2023	67729185	1	10	0	10	1	0	1	6,30
21/03/2023 - 26/03/2023	67729185	3	10	0	10	3	0	1	6,00
01/08/2023 - 04/08/2023	67729185	0	0	0	0	0	-	-	4,57

$\#C_0$: number of measured congestions
$\#C_{fc}$: number of forecasted congestions
$\#C_{fc,\,c}$: number of correctly forecasted congestions
$\#C_{fc,\,f}$: number of false positive forecasted congestions
$\#C_{fc,\,n}$: number of false negative forecasted congestions

From these results several observations can be made:

- With lowered congestion limits, the congestion forecasting tool can detect some congestions. However, the number of false positive congestions quickly becomes quite large, in comparison with the actual number of congestions measured. This is because the congestion limits for this analysis had to be lowered to a level where the congestions are normal offtake peaks.
  A few congestions are also missed; however, it must be noted that false positive congestions are in most cases detected quite close to an actual measured congestion. This effect again points to consumption peaks, with lower limits identified as congestion issues, but essentially are 'normal' offtake peaks.
- The congestion forecasting is based on historic offtake profiles. The pool of profiles that was available within this project, contained about 90 yearly profiles. With this relatively low number, already a relatively low average CRPS score could be achieved. It must be noted however, that with a larger pool of historic profiles, it is expected that more accurate forecasts are achievable.
- The results of the congestion forecasting also show that not all behavior was accurately forecasted. The cause of this is that the pool of historic profiles used within this project, did not contain profiles exhibiting the specific behavior of specific (flexible) devices, such as e.g., the heat storage devices. This means that this behavior is missed in the baseline congestion forecast. This effect can be seen in the forecast result of feeder 67729185 shown in Figure 3-8. The offtake pattern caused by the heat storage devices is not accurately captured in the congestion forecast.
  To account for the possible congestion risks including these flexible assets (heat storage devices, heat pumps and electric vehicles), a worst-case congestion risk was calculated as well. This worst-case congestion forecast then assumes that such flexible devices are assumed to be always switched on. An example of the results is shown in Figure 3-9. This worst-case flexibility forecast is then further on used to calculate the headroom capacity available on the feeder (discussed further in chapter 3.4.2)

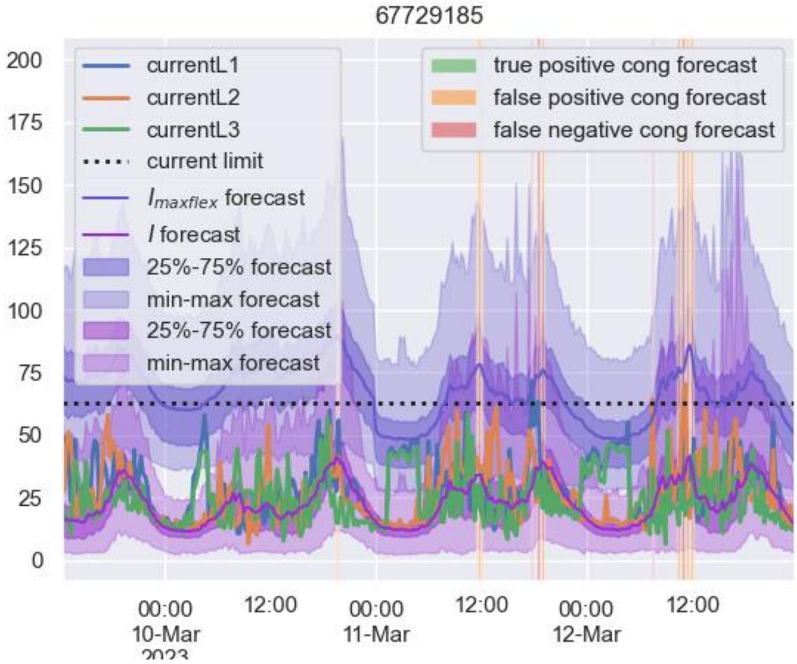

Figure 3-9: Congestion forecast result for feeder 67729185. The measured quantities are given in blue, orange and red. The statistical forecast is shown in purple. The worst-case flex forecast is shown in dark purple; the baseline congestion forecast is shown in light purple.

3.4 Smart Grid Operations: Congestion Management and Flexibility Need Quantification

3.4.1 Test methodology

The position of the SUCs concerning congestion management and flexibility need quantification within the overall flexibility value chain are shown in Figure 3-10.

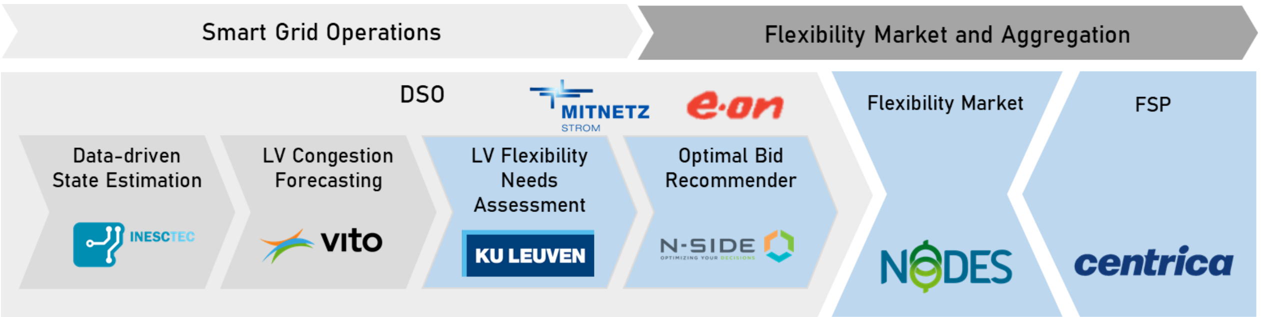

Figure 3-10: Overview of the flexibility value chain with the functional blocks concerning the SUC's on congestion management and flexibility need quantification highlighted in blue.

The tests concerning these SUCs were allocated to be tested either as part of focus part A or as part of focus part B of the German demo activities (see chapter 2).

The parts of the SUCs that deal with congestion management and the flex market are done within focus part A of the German demo activities. This means that these tests are done using the measurements and the equipment and assets from the specified demo LV network.

In contrast, the parts of the SUCs that deal with the FSP aggregation and activation at customer side area are tested within part B of the demo. This means that the tests dealing with the customer assets are demonstrated using DER assets outside of the specified demo network area. As mentioned in chapter 2, the reason for this were the difficulties in acquiring and equipping sufficient customers from within the demo network areas as well as compatibility problems with the HEMS and inverters.

The environment for the tests of FSP aggregation and activation (Part B) is shown in Figure 3-11, and can be described as follows: The FSP receives the market offers via the UMEI from the flexibility market. To control the corresponding flexibility demand, it sends the encrypted control command to the HEMS via API. The HEMS is connected over a router with the house network. When receiving a flexibility activation command, the HEMS communicates with the hybrid inverter via Modbus and thus ensures that the operating point is adjusted. In reverse, the measured values of connected grid meters, battery and inverter can be accessed over the HEMS again over the HEMS API.

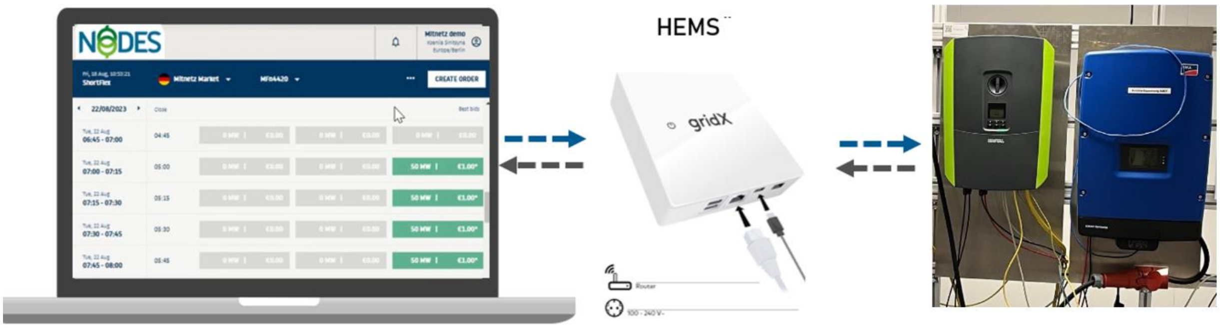

Figure 3-11 – Set-up for flexibility activation tests.

Figure 3-13 shows a screenshot of the HEMS user interface, which enables monitoring of the grid import/export power, the PV generation, the battery state of charge, the battery active power, as well as the household consumption.

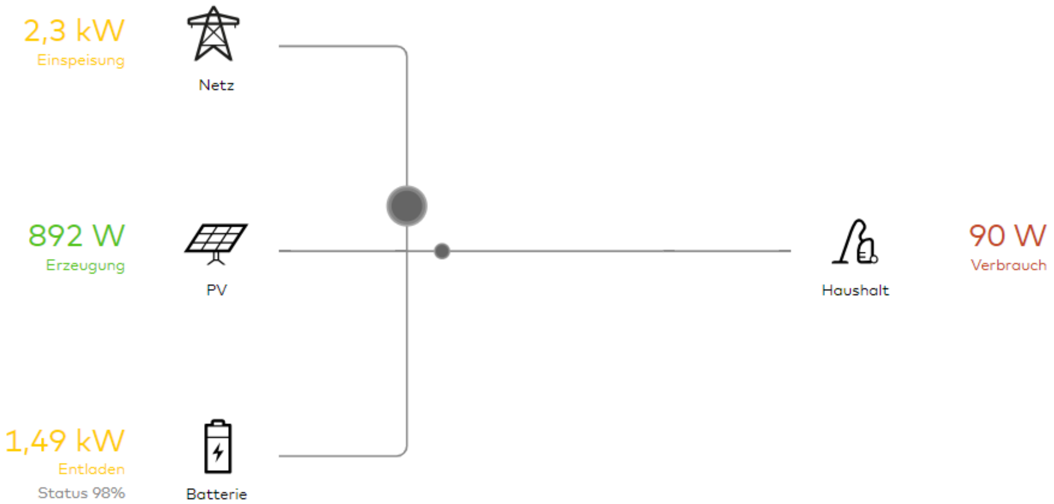

Figure 3-12: GridX system monitoring UI

In the lab test, Centrica has used the HEMS APIs developed by gridX to monitor and control the battery in the test setting. Figure 3-13 *s*hows, in blue, the measurements received from the battery active power sensors. In red, we show the control signals sent by Centrica. We see that the measurements clearly follow the control signals. This showcases the successful integration of the control API between Centrica and the HEMS of gridX.

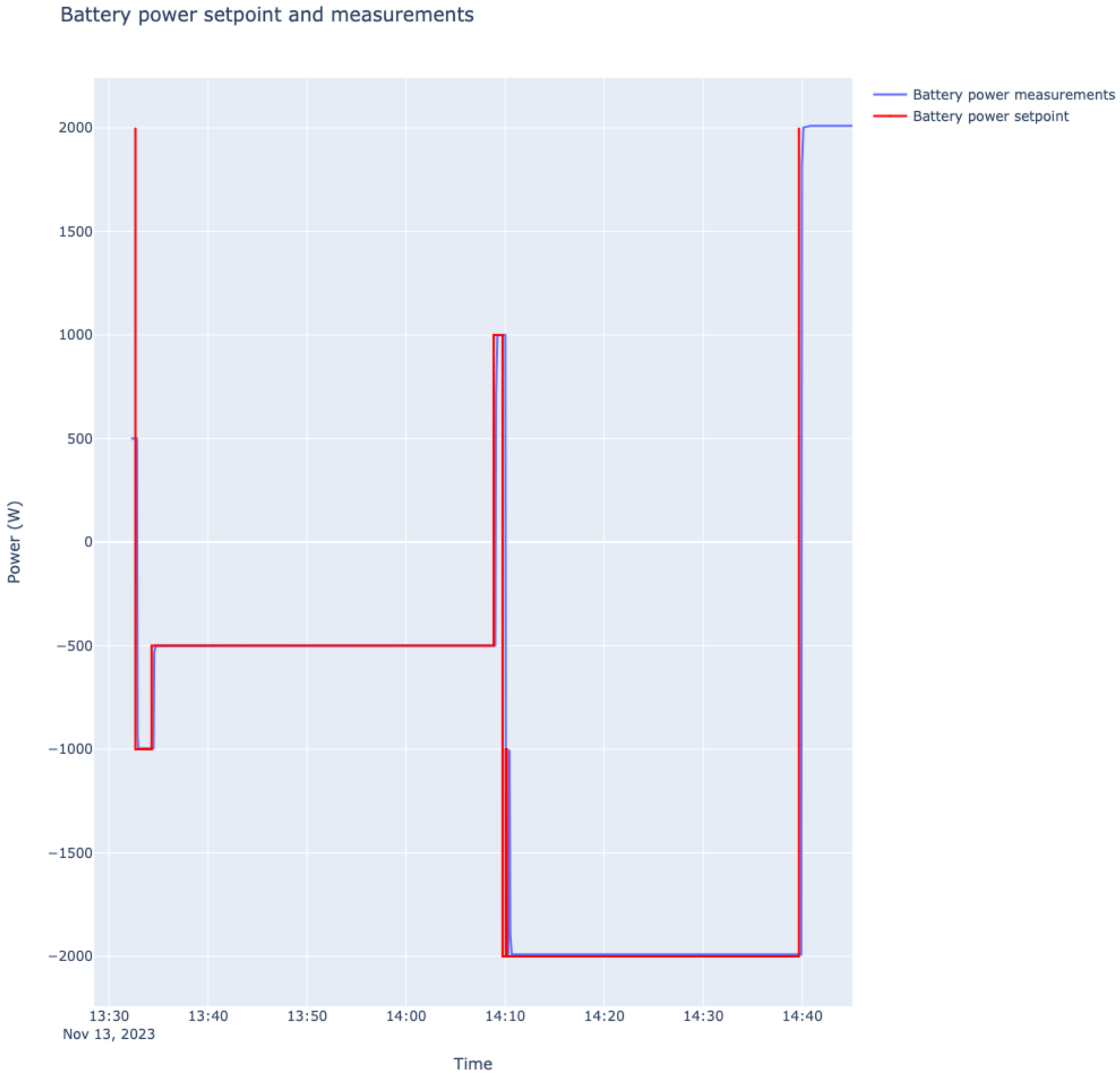

Figure 3-13: Measurements and control setpoints

3.4.2 SUC 4 – Day-ahead congestion management considering flexibility needs in the MV network.

The day ahead congestion management is based on the following principles:

1) It is ensured that there are no congestions in the low voltage or that these can be solved first.

2) The remaining potential can be used for congestion management at the next higher level, in this case medium voltage.

This use case describes the congestion management tools that allow the DSO to identify potential network restrictions for the next day, and define flexibility needs to be procured in local flexibility markets to solve technical restrictions.

The main steps of the SUC are (more details can be found in deliverable D2.3 [7]):

1. A flexibility needs to solve potential network issues at the MV network is identified.
2. The statistical congestion forecast produces maximum and minimum allowed limits of using the available flexibility at the MV/LV substation, in order to avoid that MV flexibility activation of LV flexibility creates additional problems in the LV networks connected downstream.
3. The DSO publishes the flexibility request, the FSP offers its flexibility on the market accordingly. Offers are submitted via the UMEI. Any sell or buy order on NODES market contains only the following information: location (through the grid node), the volume and the price of the flexibility while grid specific data or user data remains anonymous. As such, all data and information exchange is compliant with GDPR and general information security policies. Furthermore, the limitation of data exchange to a minimum required may prevent strategic bidding behaviour of market participants. The Flexibility bid recommender tool optimizes the bid selection for the DSO and recommends the best suitable offers in the market.
4. Finally, the according flexible assets are activated by the FSP.

The performance of this SUC is assessed showing the results on two representative days: February 08 as the coldest day in the MITNETZ region and August 03 as the day with the highest measured feed-in power to the TSO grid in 2023. In addition, a number of arbitrarily selected times from the executed trading processes are used to prove compatibility with the market and the UMEI.
As also mentioned above, the SUC is demonstrated using lower network congestion limits, as otherwise no (risk for) congestions could be identified.

3.4.2.1 KPIs

Five Key Performance Indicators were defined to assess the performance of the day-ahead congestion management. More background and the calculation methodology for these KPI's can be found in deliverable D6.2 [5]. The results of each KPI will be discussed separately.

- **CM_KPI_4: Avoided Restrictions**
  This KPI reflects the number of avoided restrictions on the LV network by the congestion management.
  Within the German demo market setup, the congestion forecast produces maximum and minimum allowed limits for the activation of flexibility on the LV network, i.e. the so-called headroom. These limits should make sure that no congestion occurs within the LV network after flexibility activation. The KPI on the avoided restrictions is calculated as the difference between the actual congestions and the forecasted congestions, expressed as a ratio versus the forecasted congestions.
  Since the set-up of the flexibility market is such that the inclusion of the headroom makes sure that all congestions on the LV network are avoided, this ratio is always 100%, i.e., all congestions on the LV network are *a priori* avoided by making sure that only grid-safe flexibility bids will result from the market clearing.

The consequence of this approach is that a portion of the available flexibility is a priori restricted from the flexibility market, i.e., imposing headroom limits implies that a part of the flexibility is assumed to be 'procured' by the DSO to avoid congestions on its network. It must be noted here that the headroom limits are not restricting any particular source of flexibility but put limits on what a group of flexible resource can maximally consume/produce. This also means that a worst-case situation is considered for the limit calculations: the worst-case flexibility activation that can happen in a grid-safe manner sets the limit.
To assess how much of the overall flexibility in one network location is restricted by the headroom limits, a second performance indicator is calculated as the ratio of the maximum available flexibility within the network versus the headroom of the flexibility. This ratio is calculated for the positive flexibility as well as for the negative flexibility.

The resulting indicators are given in Table 3-3 for the two indicative days, February 8th and August 3rd of 2023. The results are given for the avoided restrictions and procured flexibility on 2 transformers within the network area specified for the demo.

Table 3-3: Results of performance indicators for avoided restrictions.

	MLq0094			**MFn4420**		
	CM_KPI_4	**positive flex procured by DSO [%]**	**negative flex procured by DSO [%]**	**CM_KPI_4**	**positive flex procured by DSO [%]**	**negative flex procured by DSO [%]**
08-02-2023	100%	36%	0%	100%	70%	0%
03-08-2023	100%	8%	0%	100%	38%	20%

Figure 3-14 (a) shows the maximum flexibility and headroom on February 8-9 at the transformer in network 'MLq0094' (transfo id 89128458). This figure shows that most flexibility is restricted during the evening hours, i.e., when the baseline network load is highest, and there is less room for 'extra' flexibility for MV services. For network MLq0094, there are no restrictions on the negative flexibility, also not during summer, as indicated in Figure 3-14 (c).
Figure 3-14 (b) shows the maximum flexibility and headroom on February 8-9 at the transformer in network 'MFn4420' (transfo id 1020274). Quite some flexibility is restricted during the whole day, as the network is quite heavily loaded. During summer, there are only restrictions on the flexibility during the evening hours. During winter, there are no restrictions on the negative flexibility, however, during summer the negative flexibility gets restricted as well during the hours of maximum power injection, as indicated in Figure 3-14 (d).

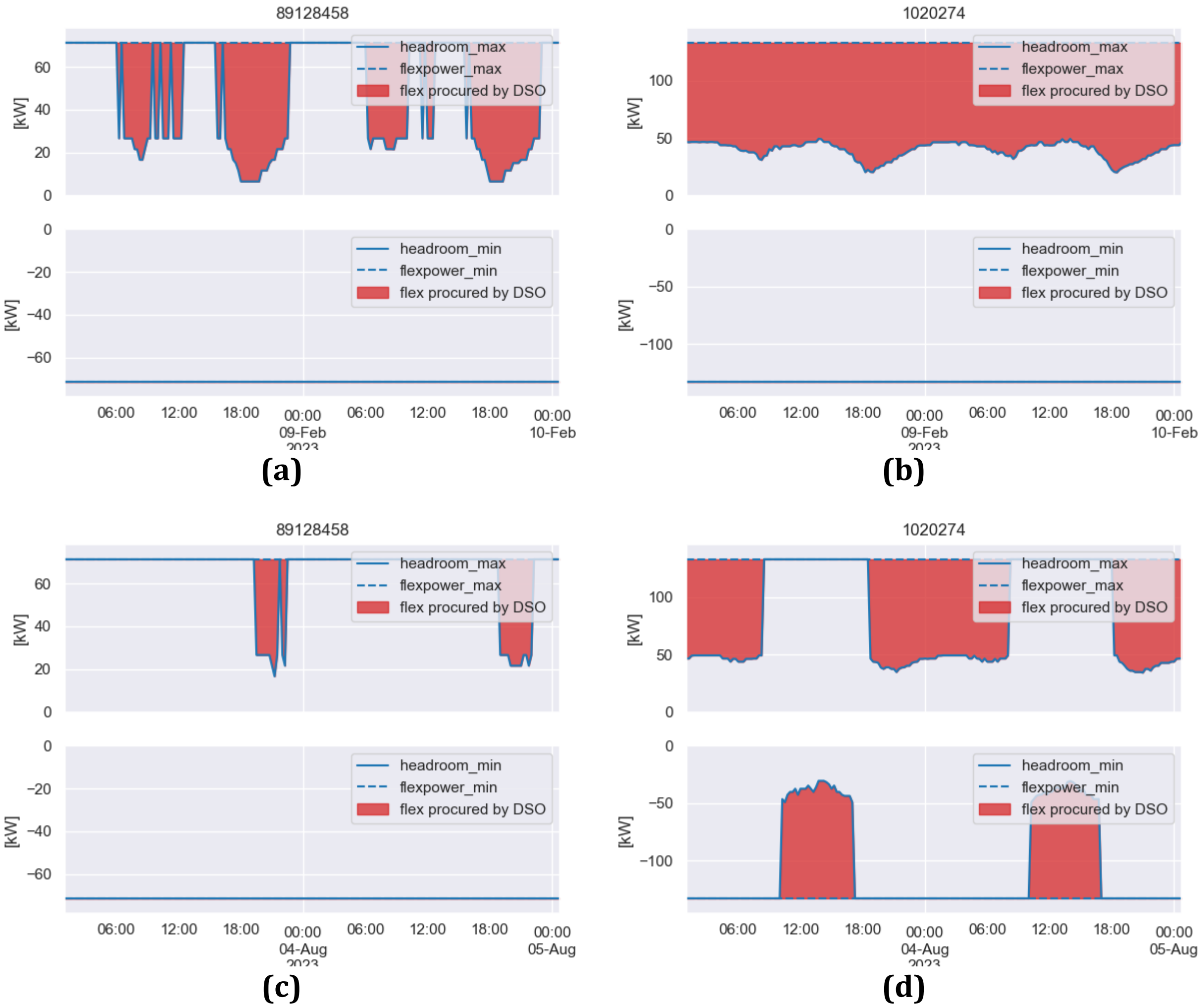

Figure 3-14: Maximum/minimum flexibility and headroom on February 8-9 and August 3-4, at the transformers in network 'MLq0094' (transfo id 89128458), and 'MFn4420' (transfo id 1020274)

- **CM_KPI_1: Flexible capacity vs. flexible volume offered ratio**:
  This KPI is used to assess how much flexibility volume the FSP has been able to expose to the market from the overall flexible capacity registered. The KPI is calculated as the ratio of the amount of flexibility offered by the FSP to the overall amount of flexibility registered.
  As previously mentioned, it proved to be quite challenging within the German demo to acquire sufficient customers within the LV network area to take part in the flexibility market, therefore this KPI is only assessed on the results from demo part B. These results are shown in Table 3-4.

Table 3-4: Results of CM_KPI_1

Demo Part A	NA
Demo Part B	100%

The high value of tests part B can be explained in particular by the demo background. Since it was not possible to find enough participants due to insufficient incentives, test times were coordinated and agreed upon beforehand. Accordingly, unlike than in a typical market environment, there were no or only very limited uncertainties for the FSP in the flexibility activation process. The result is an accurate match of the offers made.

- **CM_KPI_2: Flex volume mobilized**
  This KPI is used to assess to which extent the market has been able to mobilize flexibility from the network area. It measures the quantity of flexibility available in the market[2], and is calculated as the overall sum of flexibility available.
  The results of this KPI are given in Table 3-5.

  As repeatedly mentioned above, one of the main challenges for the German demo was to acquire sufficient customers to provide flexibility within the defined network area. Despite the numerous attempts, the response to this request was very low. This is reflected by the results of CM_KPI_2 in part A of the demo activities.
  This result also indicates that the organization of a flexibility market which involves assets owned by residential customers connected to the LV network, is not straightforward, and a major challenge is to acquire sufficient liquidity on this market. Due to the major problems with acquisition as well as problems in the installation process and compatibility with the HEMS, it was ultimately not possible to use any battery from the selected grid area. Thus, none of the 16kWh storage capacity that is theoretically available in the LV grid with transfo id 1020274 has been used in the tests. However, the results of CM_KPI_2 on part B of the demo show that it is possible to acquire flexibility from assets that are connected in a LV network. For the flex activation tests, however, it was necessary to use systems outside the network.

Table 3-5: Results of CM_KPI_2

Demo Part A	0/167 kWh
Demo Part B	33,5 kWh +- 20,9kW

- **CM_KPI_3: Flex bids accepted by DSO vs flex volume delivered by FSP**
  This KPI is used to assess if the FSP is able to deliver the amount of flexibility that was bid through the market platform. The KPI is calculated as the ratio of the delivered flexibility and flexibility bid accepted by DSO.

[2] Note that the definition and calculation of this KPI has changed with respect to the CM_KPI_2 as defined in D6.2. The decision to change this common project KPI was done in agreement with the other EUniversal demo activities. An extended explanation of this KPI will be given in the final version of D6.3.

Similarly, as with CM_KPI_1, this KPI is assessed on the results obtained from part A of the demo activities as well as from part B of the demo activities. These results are given in Table 3-6.
Again, similarly as with CM_KPI_1, the results of the KPI on demo Part A indicate the issues with the customer acquisition.
On the other hand, the results of part B display the outcomes of the laboratory test designed to manage assets and activate flexibility. It is important to note that in the controlled environment of the laboratory, all variables, including the load profile consumption of end-users, the behavior of end-users, and photovoltaic (PV) production, are known in advance, and system parameters can be pre-set. Consequently, there is no randomness or uncertainty during the lab test, allowing the Flexible Service Provider (FSP) to successfully activate all submitted flexibility values in the market. As a result, the value for CM_KPI_3 is 100% for Demo Part B.

Table 3-6: Results of CM_KPI_3

Demo Part A	NA
Demo Part B	100%

It is worth mentioning that in real-life scenarios involving actual customers, FSP may not always be capable of delivering 100% of the flexibility bids to the market due to unexpected and unpredictable user behavior or other external factors.

- **DE_KPI_02: Cycle Time DSO process**
  This KPI is used to assess whether the calculations of the congestion management cycle can be done within a certain time, as the DSO needs to be able to react adequately to the grid situation. The KPI is calculated as the amount of time between information input (Ti) and finalized output to the market.

Table 3-7: Results of DE_KPI_02

T_{cycle}	56min

3.4.2.2 Potential link to the Redispatch 2.0 scheme

Redispatch 2.0 is the predominant method in Germany for congestion management. The legal basis is the Grid Expansion Acceleration Act (dt.: Netzausbaubeschleunigungsgesetzes – NABEG [12]).

It currently only applies to units of >100kW. In addition, the regulations of Redispatch 2.0 do not cover demand side. The market-based inclusion of small-scale decentralised flexibilities in the electricity market, on the other hand, is a central and overarching goal of the European legislator in the so-called Clean Energy Package. [7]

As a result, an expansion to smaller unit sizes, which are then available in aggregate form on markets, for example, seems to be a logical step forward. In this sense, the German demonstrator was able to gain initial experience for a possible linking of the setups and to demonstrate important basic principles.

First of all, it was shown, especially by the tools of congestion detection, that suitable forecasts for congestion and flexibility demand can be developed, by using other approaches (more characterized by probabilistic than deterministic). Second, that an aggregation of flex resources for system services is possible without creating new congestion in the low voltage with the help of suitable tools. Furthermore, that an iterative calculation of these demands and thus a linkage into the established data exchange model of Redispatch 2.0 seems possible. And last but most significantly, that the incorporation of Demand Side Response is a valuable addition.

Nevertheless, one limitation that had to be taken into account during the test is the insufficient participation of customers. That excluded the evaluation of an appropriate and pragmatic baseline determination, which is one core aspect of the linkage. However, they show real difficulties in the possible extension of redispatch and flexibility markets to low-voltage connections (private households), which can only be overcome by appropriate incentive systems and regulatory changes.

It also remains to be noted that there are still important steps to be taken for a successful implementation into operation. One key aspect of it is the integration of micro-flexibilities and flexibility markets into the established data model of redispatch. In addition, a standardisation of control channels and a coordination between balancing markets. For further research or implementation projects, significantly flex resources from the medium voltage level would therefore be an important and better starting point to achieve sufficient liquidity. From there, a phased implementation can be approached, as also suggested in [7].

3.4.3 SUC 8 – LV Flexibility needs assessment for voltage and congestion management.

The Flexibility Needs Assessment (FNA) involves evaluating the level of flexibility required by the Distribution System Operator (DSO) to effectively plan and obtain flexibility from the market, minimizing the likelihood of Distribution Network Incidents (DNIs). The FNA algorithm operates without assuming the specific locations of flexible resources. It assumes that flexibility is present at nodes where there are connected loads or generation sources. To model potential DNIs, uncertainties are incorporated using a Monte Carlo approach, simulating various scenarios based on nodal load and generation forecasts and historical forecast errors. For each scenario, an FNA-Optimal Power Flow (FNA-OPF) problem is solved. However, a robust FNA, considering the worst-case scenario, might lead to excessive procurement of flexibility. To mitigate this, a risk-based index, such as a chance constraint (CC), is introduced. Higher CC values indicate a greater risk the DSO may face in dealing with unresolved DNIs [10].

The description of the LV FNA tool used in the German demo evaluation under the EUniversal project is introduced in [10], and detailed also in the prior deliverables D8.1 [8] and D8.2[2]. The key learnings form the tool implementation in the German demonstration are also detailed in [11]. For the demo implementation of the FNA tool the load profiles scenarios are now created by means of a prediction model using historical data and by employing reduced network models, see Figure 3-15.

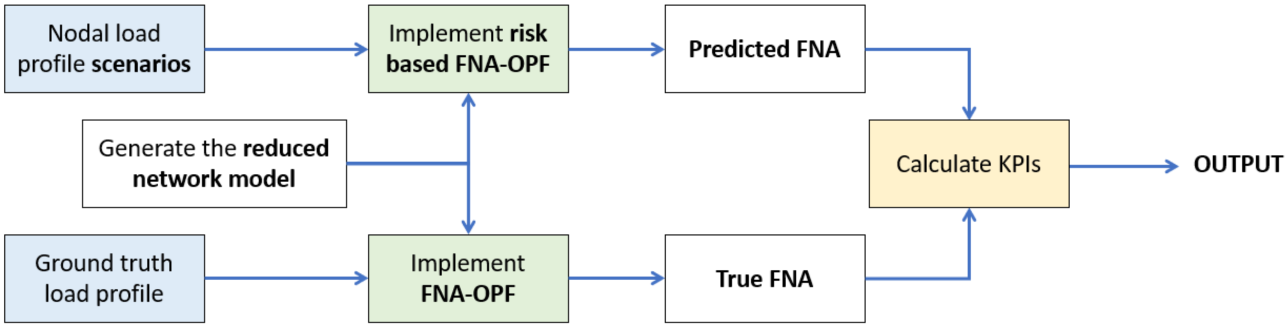

Figure 3-15: Outline of the FNA tool for EUniversal demo evaluation and KPI calculation

Figure 3-16 below showcases the timeline of execution of the FNA tool on the Mitnetz Strom server. The Flex calculation is performed one day ahead (D-1), and load scenarios are deduced based on measurements of the day before (D-2).

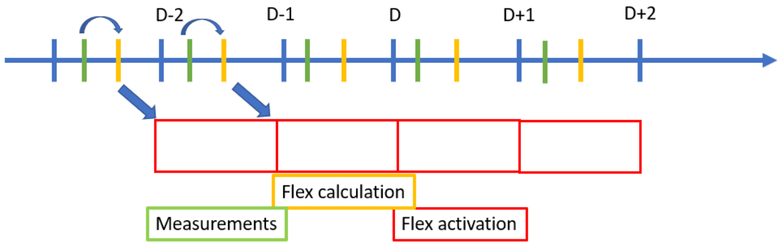

Figure 3-16:Timeline of implementing risk-based FNA in day-ahead.

Reduction network model: Using the reduced network along with the load scenarios, the FNA is calculated. Note from Table 3-8 that the number of nodes for the reduced order model is substantially lower than the original network model. Figure 3-17 and Figure 3-18 show the original and reduced versions of the MLq0094 and MFn4420 networks in more detail.

Table 3-8: Network reduction impact on the number of nodes, loads, and branches

	MFn4420		MLq0094	
	Original	Reduced	Original	Reduced
# branches	560	32	603	40
# nodes	561	38	603	40
# loads	222	25	331	30

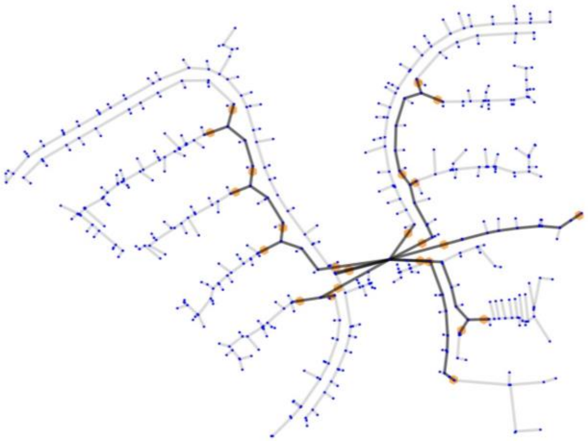

Figure 3-17: MFn4420: Original network (grey), reduced network (black), measurement locations/aggregated loads (orange), buses (blue).

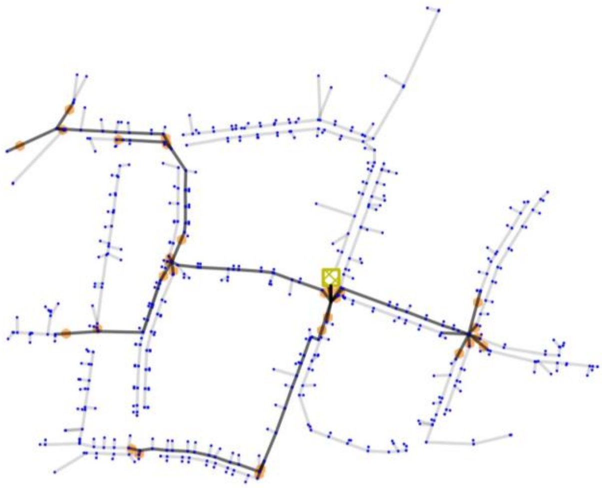

Figure 3-18: MLq0094: Original network (grey), reduced network (black), measurement locations/aggregated loads (orange), buses (blue).

Reduction of branches and nodes: The use of aggregated loads allows firstly to remove branches which are not loaded anymore, e.g., the branches downstream of $P_{2,agg}$ in Figure 3-19. Secondly, branches can be merged and intermediate buses removed, e.g. applicable for the branches and nodes between $P_{1,agg}$ and the bus at P2 in Figure 3-19. This reduction step retains the same electrical behaviour (r, x) of the network but reduces the number of branches and nodes, but also the calculation time substantially. The rating of the merged branch is taken equal to the largest rating of all merged branches.

Nodal load profile scenarios*:* Load profile forecasted scenarios are needed for identifying the flexibility needs of the distribution network for the next day. The network measurements for (D-2) are employed for this purpose to create load profile predictions. By deducing the aggregated load from the measurements, and secondly employing a persistence prediction model, load profile predicted scenarios are obtained.

Measurements: Current and power flow measurements, with a resolution of 15 minutes, are available for the MFn4420 and MLq0094 networks at the substation and switch boxes in the network. Their location in the distribution network is presented in Figure 3-17 and Figure 3-18. Although these measurements aid in determining the load in both networks, the observability of the network is limited. Firstly, only a limited number of branches are observed, thereby the measurements only capture the aggregated consumption and production of downstream prosumers. Secondly, since not all measurements in the network are available, the networks remain largely unobservable. In practice, only measurements are available at the feeders connected to the substations and at one switch in the MLq0094 network. Thirdly, the measured quantities are not uniform across measurement locations. All available measurements include current, active power and reactive power for each phase except for the measurements at the substation of the MLq0094 network. These measurements only include the absolute value of the current measured per phase. To overcome the lack of power flow measurements in the MLq0094 network, the power flow is approximated by multiplying the current measurements with the nominal voltage until power flow measurements become available[3].

Aggregated loads: The FNA tool employs a reduced order model with aggregated loads for executing FNA calculations. The reduction approach is discussed in a section below. The use of aggregated loads allows firstly to easily deduce the aggregated loads from the measured power flows and secondly reduces the number of loads in the network, thereby vastly reducing the computational load. Alternatively, a disaggregation approach could also provide load profile scenarios for the hundreds of prosumers, but this approach is not considered in the execution of the FNA tool.

The aggregated loads were placed at the first bus downstream of the measurement since in practice the power flow is the same between the measurement location and the first downstream prosumer, i.e., in the red box in Figure 3-19. By placing the aggregated load downstream, the voltage and loading limits of the corresponding branch and bus are included in the flexibility calculation[4]. In Figure 3-19, it is shown that the load between the measurement points 1 and 2, i.e., $P_{1,agg} = P_1 - P_2$, is aggregated at an upstream bus close by the measurement location. Since no downstream measurements exist for measurement point 2, the power flow measured at P2 is aggregated at it first downstream bus.

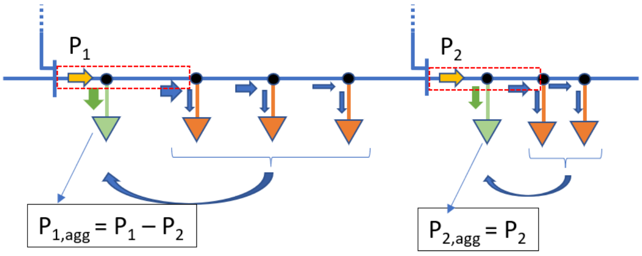

Figure 3-19: Load aggregation method and branch power flow conversion to aggregated load.

Load profile forecast scenarios: Based on the historical measurements, a persistence model is used to generate nodal load profile scenarios. This model uses the D-2 measurements as the mean expected load and builds scenarios by assuming a distribution around this mean expected load with a standard deviation of 30% of that mean expected load. This method yields the 200 load profile scenarios used in the FNA tool.

Flexibility Needs Assessment: The FNA tool uses the reduced network model and load scenarios to calculate the need for flexibility in the network to avoid probable line loading and voltage limit violations. Since procuring flexibility for the most extreme scenarios would lead to a large over procurement of flexibility, the FNA tool calculates the need of flexibility to avoid loading and voltage violations in 75% of all load scenarios. This parameter was set to this value to avoid underestimations and large overestimations of the need of flexibility.

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[3] This approximation firstly overestimates the power flow since the measured current also includes a reactive power component. Secondly, only positive power flows are obtained (loads) since the only the size of the current is measured and not its direction. Therefore, negative power flows caused by a net injection are considered as loads.

[4] This placement of the aggregated load is crucial since almost all available power measurements are located at the substation, therefore positioning the aggregated loads at the substation busbar itself would not include the loading limits of the feeders in the FNA calculation.

The functioning of the FNA tool is showcased by discussing its results on the demo days (13th and 23rd of September 2023). Since load and voltage limits are not violated in practice in the MFn4420 and MLq0094 networks, more stringent operational limits are imposed to validate the FNA tool. These limits are included in Table 3-9 below.

Table 3-9 Voltage and loading limits of the MFn4420 and MLq0094 networks during the demo days.

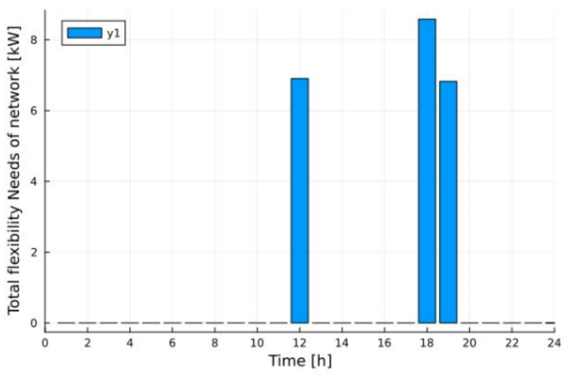
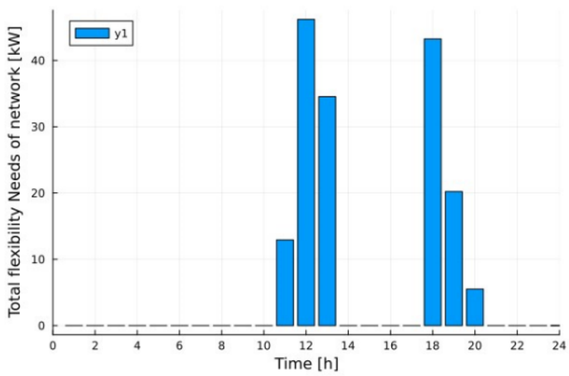
MLq0094	MFn4420
Voltage limit: 0.95-1.05 pu Current limit: **40**% of line rating Transformer limit: 50% of transformer rating	Voltage limit: 0.95-1.05 pu Current limit: **50**% of line rating Transformer limit: 50% of transformer rating

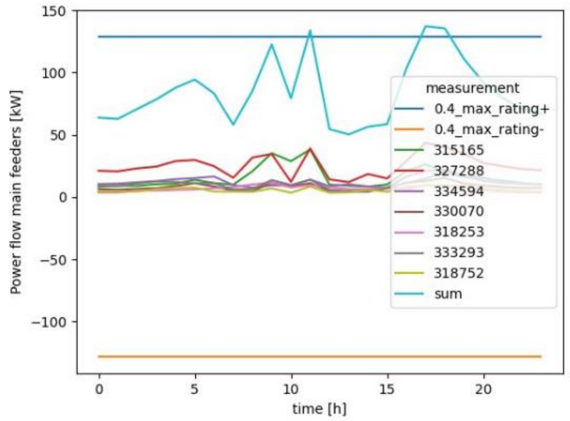
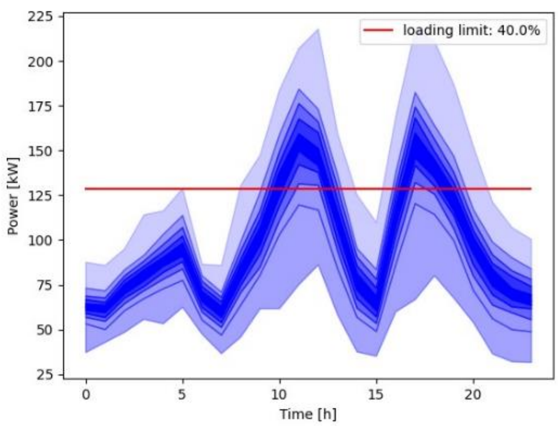
The validation of the FNA tool during the demo days is performed by comparing the predicted need of flexibility with the actual need of flexibility, by comparing the load with the loading limits in the network, and by analysing the voltage throughout the network. Both the temporal and locational aspects of the flexibility, the load and loading limits are analysed. The exact need for flexibility during a demo day is deduced after the demo day by employing the power measurements of those days to recreate the actual power flow in the test network.

MLq0094 network – 13th and 23rd of September

- The comparison of predicted FNA (Figures 3-21, 3-25, II and II) and the actual FNA (Figures 3-20, 3-24, II and II) indicates that (1) the actual location and time of the need of flexibility was predicted correctly and (2) the prediction overestimates the need of flexibility both in time, location and size. The overestimation of the need for flexibility was expected and necessary to minimize underestimations of the flexibility caused by the uncertainty in the prediction model.
- Although both loading and voltage violations can cause the need for flexibility, the FNA tool required only flexibility to avoid overloading (figures 3-22 and II25) since the voltages (figures 3-26 and II**3-26**) remained well within the predefined voltage range.
- The temporal need for flexibility can also be deduced from the loading of the most upstream branches when no flexibility is activated (figures 3-22 and II), I.e., flexibility is needed if the loading of a branch exceeds the loading limit. It was observed from these results that the branch between the substation and the transformer, which is carrying all current from the main feeders, is the bottleneck in this network.
- The uncertainty in the load scenario predictions is visualized by means of the total load in the network for all scenarios in Figure 3-23.
- *Recommendation*: Since, for both test days, the head feeder is causing the flexibility needs, uprating this cable could be more cost effective than procuring flexibility. Essentially, a trade-off between the cost of flexibility procurement and network upgrades should be made, especially if a bottleneck in the network seems to require frequent procurement of flexibility. In Figure 3-27, the rating of the branches connected to the substation is

visualized, which explains why the branch between the substation and transformer the main bottleneck is.

MLq0094 – 13th of September	
Actual temporal FNA	**Predicted temporal FNA**
 *Figure 3-20: Actual flex needs (Mlq0094, 13/09)*	 *Figure 3-21: Predicted flex needs (Mlq0094, 13/09)*

Line Loading in % of the total capacity	Total load of predicted load scenarios
 *Figure 3-22: Loading of main feeders (Mlq0094, 13/09)*	 *Figure 3-23: Total load for the predicted scenarios i.f.o time*
True Flexibility Needs [kW]	**Predicted Flexibility Needs [kW]**

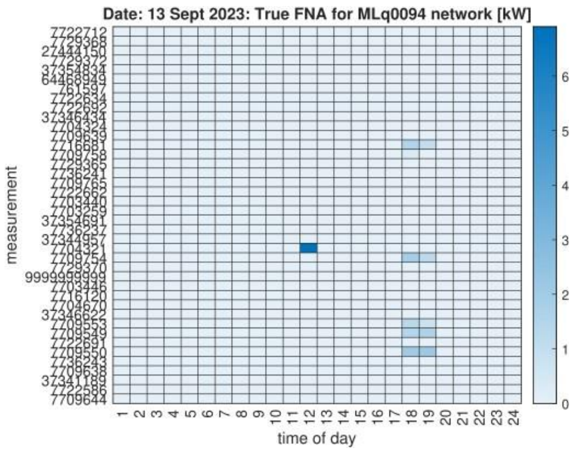


Figure 3-24: Heatmap of locational and temporal terms of actual flex needs (Mlq0094, 13/09)

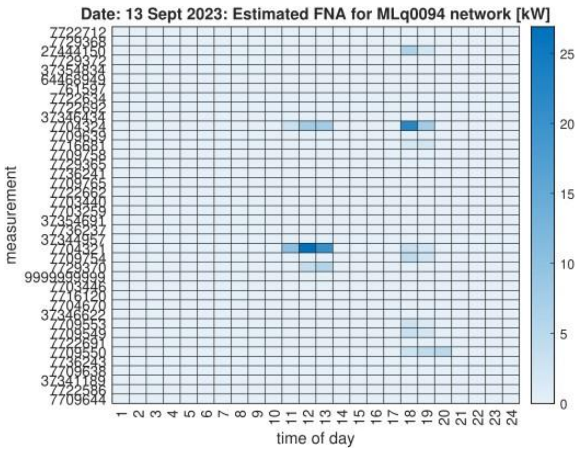


Figure 3-25: Heatmap of locational and temporal terms of the predicted flexibility needs (Mlq0094, 13/09)

Temporal distribution of bus voltages in PU

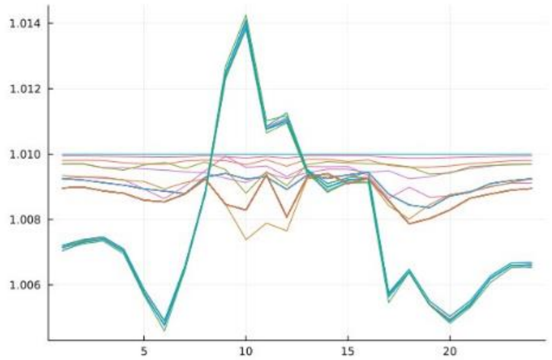


Figure 3-26: Bus voltages (Mlq0094, 13/09)

MFn4420 network – 13th and 23rd of September

- Similar to the MLq0094 network, voltage variations remain well within the limits (figures 3-32 and II) as most of the measurements are close to the substation.
- The MFn4420 network does not need any flexibility (figures 3-29 and II) for the 13th and 23rd of September since the loading (figures 3-3134 and II**Figure II**) of that network remained below the predefined loading limits.
- The predicted need of flexibility (figures 3-30 and II) was also zero for both days, thereby correctly predicting the absence of loading (figures 3-3134 and II) and voltage violations (figures 3-32 and II).
- It can be noted from the loading (figures 3-3134 and II) that the most up branch is the highest loaded line in the evening, during the load peak, while one of the main feeders is the highest loaded branch during the day, I.e., during the injection peak.
- The dashboard of the FNA tool of the MFn4420 network on the 13th of September is shown in Figure 3-28. This dashboard, developed by Mitnetz Strom shows the location, timing, feeder level and network level flexibility predictions.

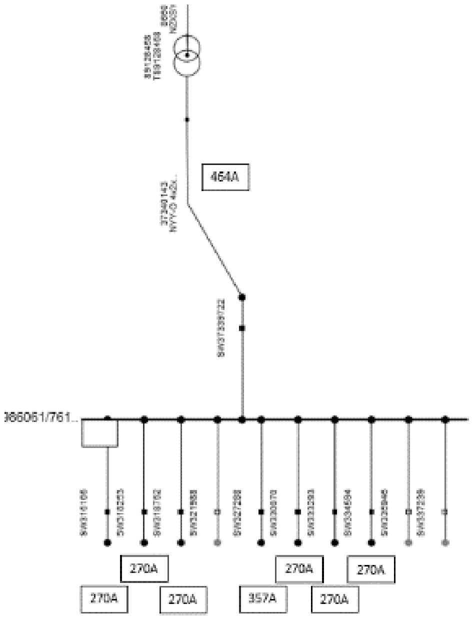


Figure 3-27: (MLq0094) Substation layout and ampacity

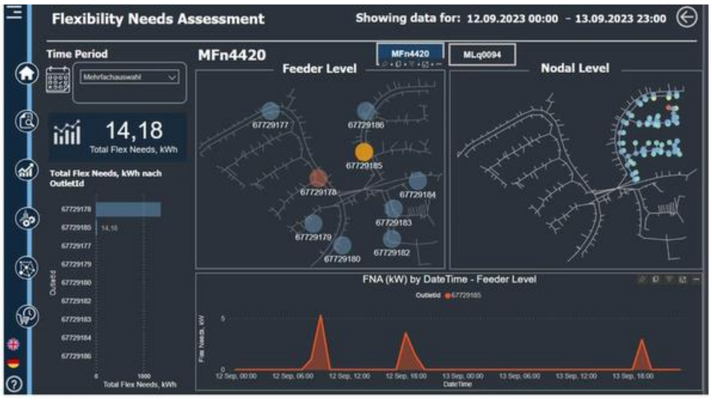


Figure 3-28: (MFn4420) Dashboard result of the FNA tool at Mitnetz Strom

MFn4420 network – 13th of September

Actual temporal FNA

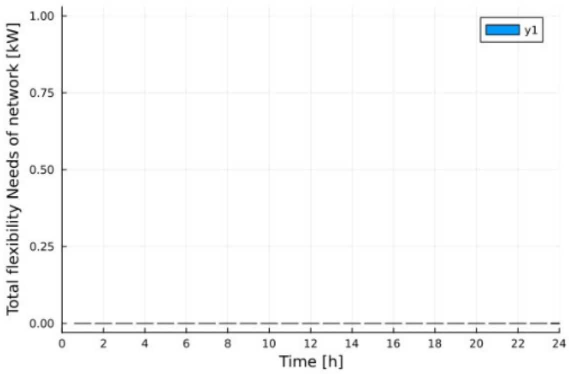


Figure 3-29: Actual flex needs (MFn4420, 13/09)

Predicted temporal FNA

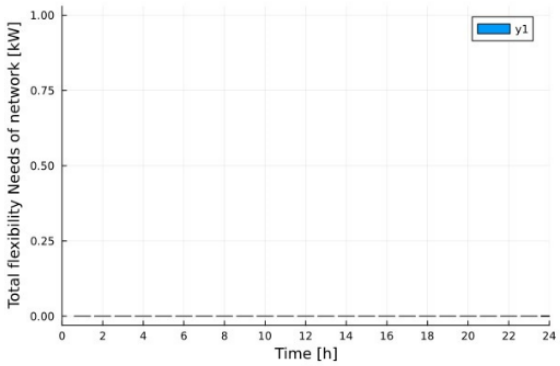


Figure 3-30: Predicted flex needs (MFn4420, 13/09)

Line Loading in % of the total capacity

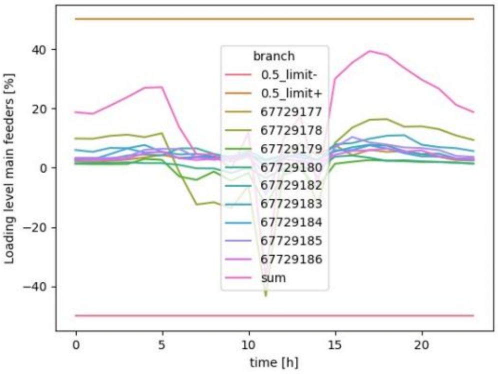


Figure 3-31: Loading of main feeders (MFn4420, 13/09)

Bus Temporal distribution of bus voltages in PU

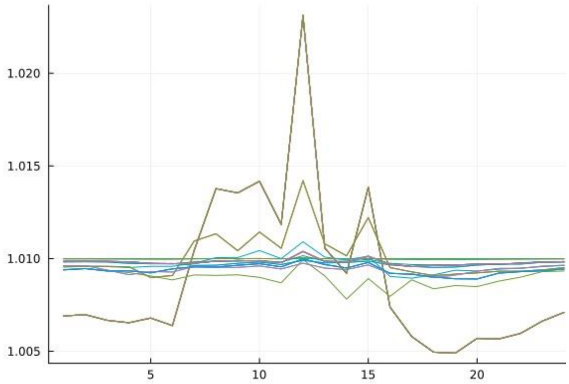


Figure 3-32: Bus voltages (MFn4420, 13/09)

True Flexibility Needs [kW]

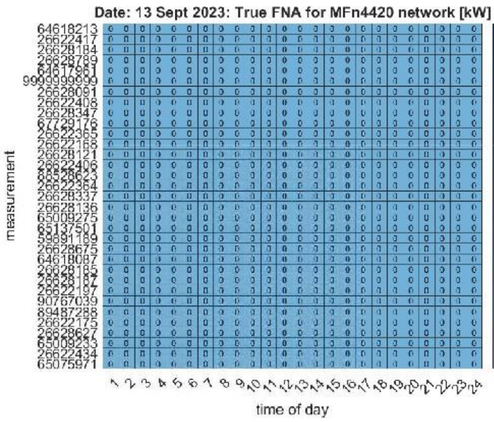


Figure 3-33: Heatmap of locational and temporal terms of actual flex needs (MFn4420, 13/09)

Predicted Flexibility Needs [kW]

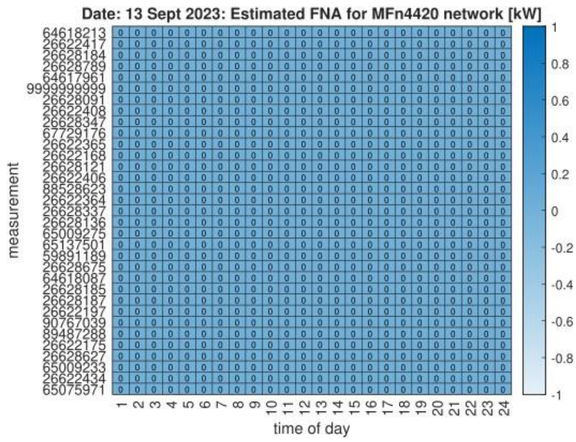


Figure 3-34: Heatmap of locational and temporal terms of the predicted flexibility needs (MFn4420, 13/09)

3.4.3.1 KPI’s

- **DE_KPI_06 Over-/under-estimation of flexibility**

This KPIs are used to assess the quality of estimation of the flexibility needs for the demo distribution networks. These KPIs provide qualitative information regarding the overestimation or underestimation of the need for flexibility. The analysis is performed by comparing the predicted need for flexibility under different levels of risk and the actual need for flexibility identified using the true measurements for the demo days.

The over-/under-estimation of flexibility is analyzed by 3 separate metrics in function of the risk level. These separate metrics are included in tables below and include the temporal and locational flexibility aspects by means of the time (t = 1, ..., 24) and bus (b = 1, ..., N) parameters. These 3 metrics are denoted as S1, S2 and S3. S1 and S2 deal with true positive congestion incidents while S3 deals with all incidents (true positive and false positive).

- **S1**: What percentage of temporal and locational predicted flexibility meets or exceeds the actual temporal and locational need for flexibility, when flexibility is required.

$$S1\ [\%] = \frac{\sum_{t,b} \mathbb{1}(|Flex_{predicted}\ (t,b)| \geq |Flex_{Actual}\ (t,b)|)}{\sum_{t,b} \mathbb{1}(|Flex_{actual}\ (t,b)| > 0)} * 100$$

- **S2**: To what extent is flexibility overestimated if the locational and temporal flexibility is required?

$$S2\ [kW] = \sum_{t,b} \mathbb{1}(Flex_{Actual}\ (t,b) > 0)\ [|Flex_{predicted}\ (t,b)| - |Flex_{Actual}\ (t,b)|]$$

- **S3**: To what extent is flexibility overestimated across locational and temporal terms?

$$S3\ [\%] = \frac{\sum_{t,b}|Flex_{predicted}\ (t,b)| - |Flex_{Actual}\ (t,b)|}{\sum_{t,b}|Flex_{Actual}(t,b)|} * 100 \qquad if\ \sum_{t,b}|Flex_{Actual}(t,b)| > 0$$

$$S3\ [kW] = \sum_{t,b}|Flex_{predicted}\ (t,b)| \qquad if\ \sum_{t,b}|Flex_{Actual}(t,b)| = 0$$

The tables below allow to deduce the over- and underestimation of the FNA tool.

Analysis KPI calculation results

- (MLq0094) The comparison of S1, the probability that the predicted flexibility meets the actual flexibility needs if an actual flexibility is needed, across different risk levels (Tables 3-10 and II-1), indicates that a high-risk level will yield low S1 values (bad accuracy of flex prediction) while using too low risk levels will yield limited improvement of the flex prediction accuracy (S1).

- (MLq0094 & MFn4420) The analysis of S2 and S3 across risk levels indicates that lowering the risk level increases the overestimation of the need of flexibility to a large extent. (Tables 3-10, 3-11, II-1 and II-2)
- A trade-off needs to be made to achieve high accuracy levels (S1) while avoiding large overestimations (S2 and S3). This reasoning was followed during the tool development, thereby setting the risk level to a static value of 0.3 for both networks.
- (MLq0094) S1 indicates that a low level of underestimation occurs, I.e., the predicted flexibility does not meet for each time and bus the actual need for flexibility in both temporal and locational terms if employing a risk level of 0.3 (Tables 3-10 and II-1). The overestimation of the predicted flexibility for the 13th and 23rd of September is 92.9% and 83.3%, vice versa, 7% and 17% of the locational and temporal predicted flexibility needs does not suffice. S2 and S3 indicate that, on average, both a large absolute and relative overestimation occurs.
- (MFn4420) Since no flexibility is needed in the MFn4420 network and the predicted need for flexibility is also zero for both demo days, no over- or underestimation is detected. Using very low risk levels would cause some predicted flex needs. (Tables 3-11 and II-2)

Table 3-10: KPI calculation for different Chance Constraint Levels or Risk levels, for the MLq0094 network on the 13th of September

	Mlq0094 Network for 13th of September										
	Risk level										
	0	**0.05**	**0.1**	**0.15**	**0.2**	**0.25**	**0.3**	**0.4**	**0.5**	**0.6**	**0.7**
S1	100	93	93	93	93	93	93	71	50	21	7
S2 [kW]	597	365	306	249	209	181	155	103	67	26	2
S3 (%)	3818	1823	1301	1003	795	630	489	256	136	45	-39

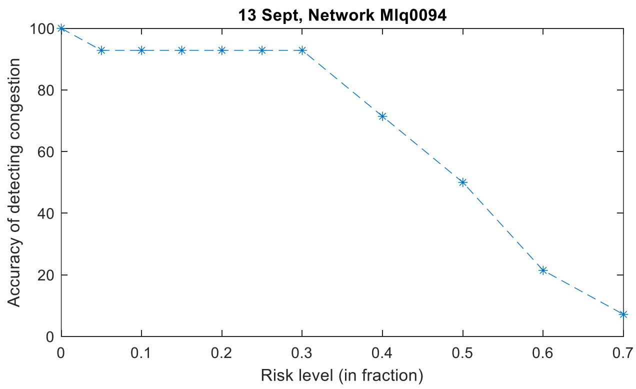


Figure 3-35: Impact of risk level on the accuracy of detecting congestions (13/09, MLq0094)

Table 3-11: KPI calculation for different Chance Constraint Levels or Risk levels, for the MFn4420 network on the 13th of September

	MFn4420 Network for 13th of September										
	Risk level										
	0	**0.05**	**0.1**	**0.15**	**0.2**	**0.25**	**0.3**	**0.4**	**0.5**	**0.6**	**0.7**
S1	100	100	100	100	100	100	100	100	100	100	100
S2 [kW]	/	/	/	/	/	/	/	/	/	/	/
S3 [kW]	164	48	22	10	3	0	0	0	0	0	0

Key takeaways

- <u>*Tool competency*</u>: The FNA tool provides the temporal and locational flexibility needs for the distribution network. The system operator can utilize this information for flexibility planning in operational timescales via flexibility procurement in the local flexibility market.
- <u>*Need for improved forecasting*</u>: the FNA tool is sensitive to the quality of forecast of nodal load profiles. In this work we utilize a persistence model for generating load profile scenarios using D-2 load profiles. We use 30% variance levels to accommodate uncertainty. Improved forecast models would allow to predict more accurately the need for flexibility thereby yielding smaller overestimations and lowering the chance of underestimations of the forecasted FNA for a distribution network.
- <u>*Setting of the risk level*</u>: We compare the forecasted FNA with the ground truth FNA of the distribution network. The ground truth FNA is calculated using the true measurements for the demo day under consideration. The risk levels assist system operators in considering future uncertainties while avoiding over-estimating the true flexibility needs of the distribution network. Using the demo networks for the selected demo days, we observe that the risk value needs to be adjusted between 10 to 30% for maximizing the accurate estimation of FNA while reducing the over-estimation of FNA.
  Since the future loading of the network is uncertain, the FNA tool is tuned to avoid underestimations and large overestimations of the need for flexibility. The risk-level should be carefully selected to increase the correct identification of FNA while minimizing the false positive congestion estimation instances.
- <u>*Assessment of the KPIs:*</u> For both demo days in the MLq0049 network, a small underestimation of the flex needs occurs in temporal and locational terms (S1) while covering the most flexibility needs. On average the need for flexibility is largely overestimated in both absolute and relative comparisons (S2, S3).
- <u>*Flexibility needs assessment vs network upgrade*</u>: For the demo network Mlq0094, we observe very high levels of predicted flexibility. This is primarily due to the bottleneck caused by the line connecting the transformer with the feeder bus bar. For this case, the efficient step to take is to upgrade the line with a higher ampacity. For such instances, avoiding infrastructural upgrades would not be recommended. A more detailed assessment needs to be performed to quantify the economic value of the line upgrade.

- *Need for more measurements*: Increased levels of the availability of the network measurements will increase the performance of the FNA tool by allowing for a less reduced network and increasing the accuracy of the load profile scenarios. Increased observability would also disaggregate the loads which otherwise is leading to underestimation of DNIs due to aggregation.

3.4.4 SUC 12 – Minimizing costs linked to DSO flexibility requirements.

Through the demonstrated Flexibility Value Chain, congestion situations can be resolved in alternative ways than curtailment. Leveraged to its full extent, this approach also provides an opportunity to supplement conventional congestion management by including the load side is included via demand-response, in parallel of the supply side.

On top of enabling a wider set of measures to help the DSO facing its challenge, this approach gives meaningful information about the value of this flexibility thanks to prices that are shared on the market.

To estimate possible cost savings allowed by this new approach, average costs were compared to those of the prevailing redispatch 2.0 scheme.

	Ramp-Down (GWh)	Ramp-Up (GWh)	Price (Mio. €)
2022	**13.047**	**11.068**	**2.689,2**
Quartal 1	4.716	4.512	926,7
Quartal 2	1.845	2.010	446,4
Quartal 3	2.456	1.353	574,1
Quartal 4	4.030	3.193	742,0

Figure 3-36 - German Redispatch 2.0 costs 2022 [13]

The cost of congestion management by flexibility market was estimated by two approaches.

- Current FCR prices, which is ~10-20 €/MWh in Belgium. [14]
- For controllable consumption devices in a critical grid state the determination procedure for the integration of controllable consumption devices and controllable grid connections in accordance with § 14a of the German Energy Industry Act of the German NRA specifies in module 2 a reduced grid fee of 40%, resulting in ≈30 €/MWh based on the 2023 price sheet. [15]

For the calculation of the KPI an estimated value of 20€ per MWh was used.

The result is shown below by DE_KPI_01.

To take the most of the flexibility market potential and to smoothen operations, Mitnetz uses the N-SIDE Optimal Bid Recommender (OBR) to minimize the costs to procure flexibility.

This algorithm works as follow:

At every call, the Optimal Bid Recommender (running on the servers of the DSO) will receive the needed inputs:

- Grid static data
- Grid state forecast (dynamic): headroom per transformer and headroom per feeder
- Market-related information: baseline of each flexible asset, flexibility bids (price and volume)

The OBR-tool then analyse and identify the combination of bids that solves as many congestions as possible and at the lowest price.

Based on the output of the Optimal Bid Recommender (OBR), the DSO will be able to submit 'buy' orders that match the recommended 'sell' orders on the market platform.

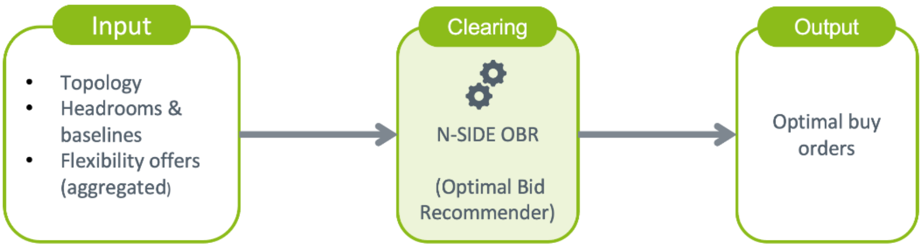


Figure 3-37 Overview of the Optimal Bid Recommender

Unfortunately, since the flexibility market could only be used to a limited extent due to a lack of regulatory incentives and role delimitations still to be defined, low market liquidity and the application of mitigation measures, the results obtained do not provide an accurate picture of the potential. In addition, any interactions with other market processes and system services, e.g., frequency control, were not considered.

3.4.4.1 KPI's

- **DE_KPI_01 Costs of Congestion Management with flex Market vs. Redispatch**

$$\text{Estimation: } \frac{c_{\text{Flex\_Market}}}{c_{\text{Redispatch}}} = \frac{2\,\frac{\text{cents}}{\text{kWh}}}{11{,}2\,\frac{\text{cents}}{\text{kWh}}} = 0{,}18$$

A theoretical comparison shows that the flexibility market approach could result in cost savings over conventional redispatch. However, the KPI does not yet represent a complete market environment and ***only allows a rough assumption*** as the practical implementation could not be fully tested in the demo and the costs of flexibility and conversional approaches like redispatch depend on many factors including regulation and market design. Grid structure and locality, margins of market suppliers, implementation costs, etc. are not sufficiently included. In addition, the cost estimate for redispatch includes compensation for balancing. This would need to be added to the flex market approach once flexibility is used on broader scale. Finally, it remains unclear whether a price of 2 cents per kWh would ensure sufficient liquidity in the market.

Although intended as a cost comparison, the experiences of the German demonstrator show that a cost-efficient market cannot be created without further adjustments. Due to missing communication standards for PV inverters, batteries and other DERs with the HEMS settings had to be made individually tailored to the inverter type, resulting in a lot of manual effort. In addition, the chosen use case for the grid connection of most private battery systems and the optimization of battery/energy management systems are designed to maximize self-consumption. A realignment can only be expected once established market products have been created and functioning incentives are in place.

3.5 Flexibility Market and Aggregation

3.5.1 Test Methodology

The allocation of the SUCs concerning the flexibility market and aggregation, i.e. concerning flexibility procurement, registration and aggregation and monitoring, within the flexibility value chain is shown in Figure 3-38.

The market-based procurement process in the German Demo is set up with the DSO MITNETZ STROM as a buyer, Centrica as Flexibility Service Provider (FSP), NODES as independent market operator and the UMEI as standard communication interface, to enable the connection of the DSOs to multiple market platforms.

Validation and settlement were not tested in the German Demonstrator because the major focus was setting up the operational flexibility value chain and the realization of market-based flexibility trading via the UMEI. The UMEI V01 covers only functions related to the trading phase, precisely the activation of flexibility on the NODES market platform. All operational steps related to registration and prequalification were conducted via the NODES UI and/or API while the flexibility procurement was done via the UMEI. All details regarding each trading phase and related operational steps are extensively documented in D8.2.

Therefore, we refer to D8.2 for the results on the following SUCs:

- SUC 13 – Short-term flexibility procurement:
- SUC 16 – DER registration and configuration
- SUC 17 – Bidding aggregation

The KPIs associated to these SUCs, i.e., CM_KPI_1, and CM_KPI_3, have been discussed above in chapter 3.4.2.1. For further assessment of these SUCs, all relevant information can be found in D8.2.

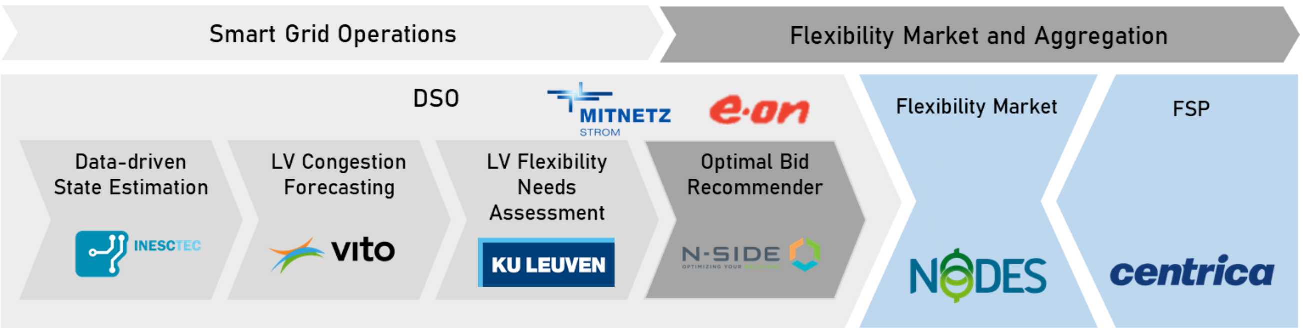


Figure 3-38 Overview of the flexibility value chain with the functional blocks concerning the SUC's on the flexibility market and aggregation highlighted in blue.

To evaluate SUC 18 - Resources dispatch and monitoring, the activation of the assets was tested as part B of the demo, i.e., within the lab environment.

In the lab test, Centrica has used the APIs developed by gridX to monitor and control the battery in the test setting. Figure 3-13 shows, in blue, the measurements received from the battery active power sensors. In red, we show the control signals sent by Centrica. We see that the measurements clearly follow the control signals. This showcases the successful integration of the control API between Centrica and the HEMS of gridX.

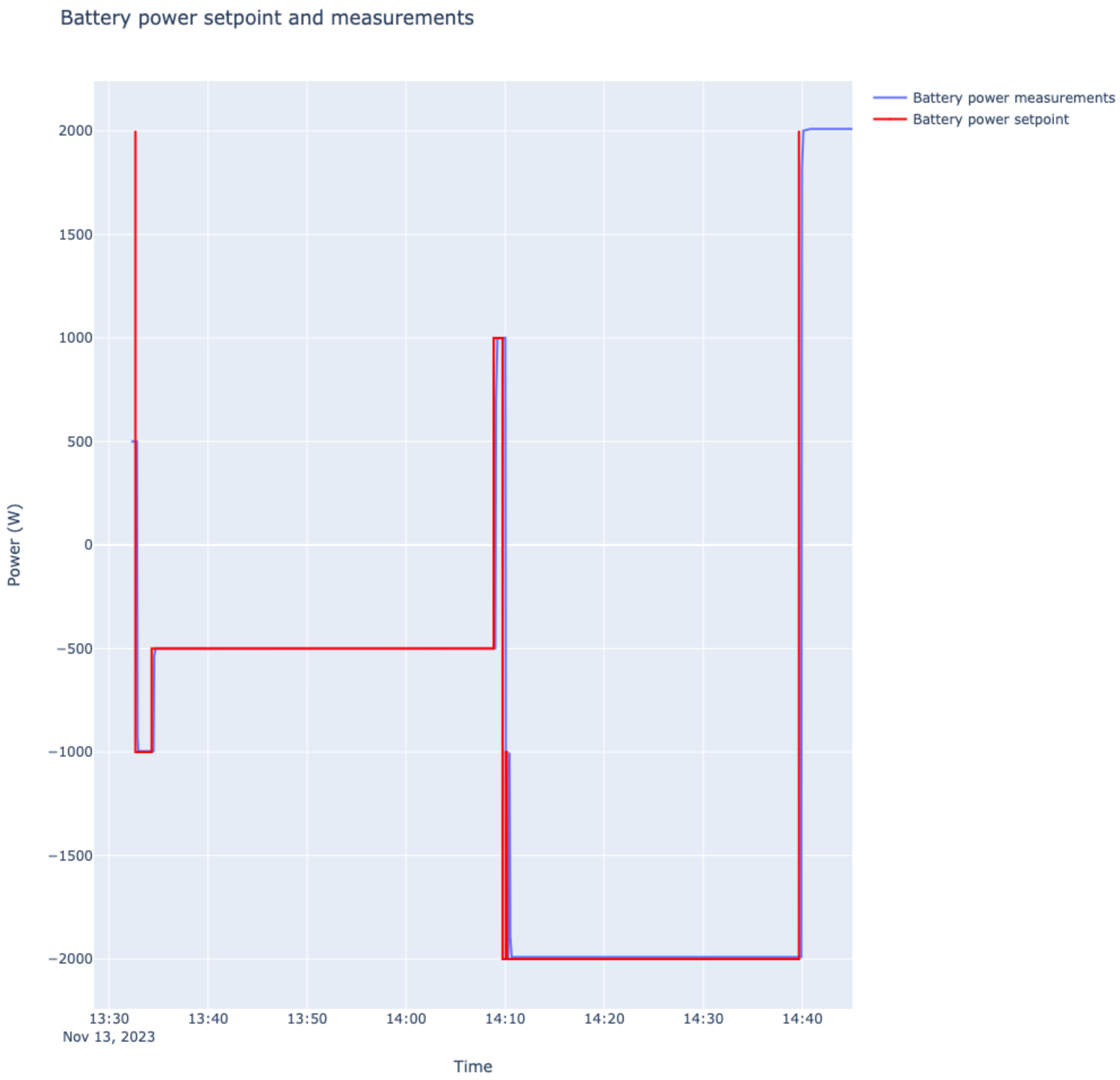


Figure 3-39: Measurements and control setpoints

3.5.2 SUC 19 – Baselining

The baseline represents a power or energy schedule that reflects an asset's typical behavior in the absence of flexibility activations. Its methodology is typically determined by the SO or FSP, depending on the specific market type, and is subject to regulatory approval. The timing of baseline submission varies depending on the grid service. The level of detail and the time window for the baseline, as well as the choice between individual or aggregated baselining, are all determined by the product's design. Different methods to calculate the baselines are discussed comprehensively in D5.1.

3.5.2.1 KPI's

- **DE_KPI_05 Baseline accuracy:**
  This KPI is used to assess the accuracy of the baselines calculated by FSO/DSO. Similar to CM_KPI_3, this KPI is assessed on the results obtained from part A of the demo activities as well as from part B of the demo activities. These results are given in Table 3 7.
  Again, similarly as with CM_KPI_3, the results of the KPI on demo Part A indicates the issues with the customer acquisition.
  On the other hand, the results of part B display the outcomes of the laboratory test designed to manage assets and activate flexibility. It is important to note that in the controlled environment of the laboratory, all variables, including the load profile consumption of end-users, the behavior of end-users, and photovoltaic (PV) production, are known in advance, and system parameters can be pre-set. Consequently, there is no error associated to baseline calculation. As a result, the value for DE_KPI_05 is 100% for Demo Part B. However, in case of real-life test, there is always an error involved in the calculation of baseline and reaching to 100% of accuracy is not possible for the case of real customers.

Table 3-12: Results of DE_KPI_05

Demo Part A	NA
Demo Part B	100%

4 Conclusions

The conclusions of the German Demonstrator within the Euniversal project can be summarized as follows:

- The demonstrator was set up to showcase and test the complete value chain when using market-based flexibility to solve network congestions. This value chain starts from congestion detection and LV state estimation, to flexibility needs assessment, followed by flexibility procurement and optimal bid selection through na optimal bid recommender coupled with a continuous flexibility market. It ends with flexibility activation. The operational and functional viability of each element that is required to fulfil the value chain was succesfully implemented and tested during the demo.
- A primary aim of the EUniversal project was to show that it is possible to set up one common interface that facilitates interactions between market platforms and different stakeholders. The German demo succeeded in using the common UMEI specifications to implement the data exchange with the NODES market platform. This shows that the UMEI facilitates DSO observability and accessibility to distributed assets in the local flexibility markets and facilitates FSPs to offer flexibility.
- Four DSO tools were developed throughout the EUniversal project specifically for the German demonstrator. These were the data-driven state estimation, the congestion forecasting tool the flexibility needs assessment tool and the optimal bid recommender. They were all successfully integrated within the environment of Mitnetz Strom, and successfully tested on the Mitnetz LV grid, using measurement data from the network. This result shows that the developed DSO tools are technically viable, and their functionality is proven within an operational environment.
- The DSO tools within the flexibility value chain should provide relevant information to flexibility markets without needing to share commercially sensitive information. Since the participation of LV consumers in system services can have a negative impact on the LV network operation, a coordinated operation between the MV and LV network was tested in the German demonstrator. To make sure that the flexibility activated at the LV network does not create additional issues, technical envelopes on the flexibility activation were imposed. This approach was succesfully implemented and tested in the demo. Promoting such a coordinated operation of MV and LV networks is of key importance for ensuring an effective use of LV flexible resources.
- End-user engagement is essential to gather end-user flexibility through local flexibility markets. This end-user engagement is required to develop the markets and test the necessary tools, and it is also necessary to ensure sufficient market liquidity beyond the testing phase. Within the German demonstrator, consumer engagement appeared to be a significant barrier. The German demonstrator had to start from scratch to engage customers, and a lack of monetary incentives lead to low interests from consumers. Furthermore, the lack of standard interfaces and lack of customers' data ownership connecting to HEMS was a considerable technical challenge as it limited the number of customers compatible with the project pilot testing. Despite the mitigation measures implemented, the rate of customer engagement remained very low.

  This result shows that various barriers, i.e. limited smartmeter roll-out, the lack of standardization of technical devices, the regulatory framework and a growing resignation among the German citizens, heavily impacts the willingness and the ability to offer flexibility services for grid management. Consequently, unless these barriers are removed, the available flexibility in the LV and MV grid remains unused, obliging DSOs to rely on the existing and costly solutions like grid expansion and mandatory redispatch for specific assets to solve grid constraints.

- Within the German demonstrator, also the combination of market and non-market-based mechanisms was done by testing the use of local available flexibility from the LV grid combined with principles of the existing German cost-based Redispatch 2.0 mechanism. The market solutions found should be able to be integrated into already established Redispatch 2.0 process, as to avoid an increased operational effort. The results of this test showed that a combination of mandatory solutions like the German Redispatch 2.0 process and market-based solutions for individual system services seems possible but is complex and requires further research.

5 External Documents

[1] Law amending the energy industry law in connection with the immediate climate protection program and adjustments to the law on supply to end customers, article 1 §13
[2] Euniversal deliverable D8.2: "Specifications of test scenarios within the German Demonstrator"
[3] Euniversal deliverable D2.2: "Business Use Cases to unlock flexibility service provision"
[4] Euniversal deliverable D2.1: "Grid flexibility services definition"
[5] Euniversal deliverable D6.2: "Definition KPI for DEMOs"
[6] Jordan A, Krüger F, Lerch S (2019). "Evaluating Probabilistic Forecasts with scoringRules." Journal of Statistical Software, 90(12), 1–37. doi:10.18637/jss.v090.i12.
[7] Euniversal D2.3: "System architecture and System Use Cases".
[8] Euniversal deliverable D8.1: "Specifications and guidelines of tools for an Active LV grid for field testing"
[9] Redispatch 3.0: Regulatorischer Rahmen, Markt- und Produktdesign. E-Bridge Consulting GmbH (2022) URL: https://www.transnetbw.de/_Resources/Persistent/c/4/6/9/c469f1b0ef6bae7e7bf7260b0b22bdcb29d83db0/221013_Bericht-Redispatch3.0_final1.pdf
[10] Hashmi, M. U., Koirala, A., Ergun, H., Van Hertem, D. (2023). Robust flexibility needs assessment with bid matching framework for distribution network operators. Sustainable Energy, Grids and Networks.
[11] Hashmi, M. U., Nagels, S., Van Hertem, D. (2023). Stochastic flexibility needs assessment: learnings from H2020 EUniversal's German demonstration.
[12] Redispatch 2.0: https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/Versorgungssicherheit/Netzengpassmanagement/Engpassmanagement/Redispatch/start.html
[13] Bundesnetzagentur. Bericht Netzengpassmanagement Gesamtjahr 2022. URL: https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/Versorgungssicherheit/Engpassmanagement/Ganzjahreszahlen2022.pdf?__blob=publicationFile&v=1 ENTSO-E. Price of Reserved Balancing Reserves. URL: https://transparency.entsoe.eu/balancing/r2/balancingVolumesReservationPrice/show?name=&defaultValue=false&viewType=TABLE&areaType=MBA&atch=false&dateTime.dateTime=18.11.2023+00:00%7CUTC%7CDAY&dateTime.endDateTime=28.11.2023+00:00%7CUTC%7CDAY&contractTypes.values=A13&contractTypes.values=A01&contractTypes.values=A02&contractTypes.values=A03&contractTypes.values=A04&contractTypes.values=A06&reserveType.values=A95&CTY%7C10YBE----------2%7CSINGLE=CTY%7C10YBE----------2%7CSINGLE&marketArea.values=CTY%7C10YBE----------2!MBA%7C10YBE----------2&reserveSource.values=A04&reserveSource.values=A05&reserveSource.values=NOT+SPECIFIED&dv-datatable_length=10
[14] ENTSO-E. Price of Reserved Balancing Reserves. URL: https://transparency.entsoe.eu/balancing/r2/balancingVolumesReservationPrice/show?name=&defaultValue=false&viewType=TABLE&areaType=MBA&atch=false&dateTime.dateTime=18.11.2023+00:00%7CUTC%7CDAY&dateTime.endDateTime=28.11.2023+00:00%7CUTC%7CDAY&contractTypes.values=A13&contractTypes.values=A01&contractTypes.values=A02&contractTypes.values=A03&contractTypes.values=A04&contractTypes.values=A06&reserveType.values=A95&CTY%7C10YBE----------2%7CSINGLE=CTY%7C10YBE----------2%7CSINGLE&marketArea.values=CTY%7C10YBE----------2!MBA%7C10YBE----------2&reserveSource.values=A04&reserveSource.values=A05&reserveSource.values=NOT+SPECIFIED&dv-datatable_length=10
[15] MITNETZ STROM. Preisblatt 2 - Netzentgelte für Entnahmen ohne Leistungsmessung https://www.mitnetz-strom.de/Media/docs/default-source/datei-

ablage/ne_2023_mns_pb2_slp.pdf?sfvrsn=158463f8_4

Annex I – German Demo dashboard illustrations.

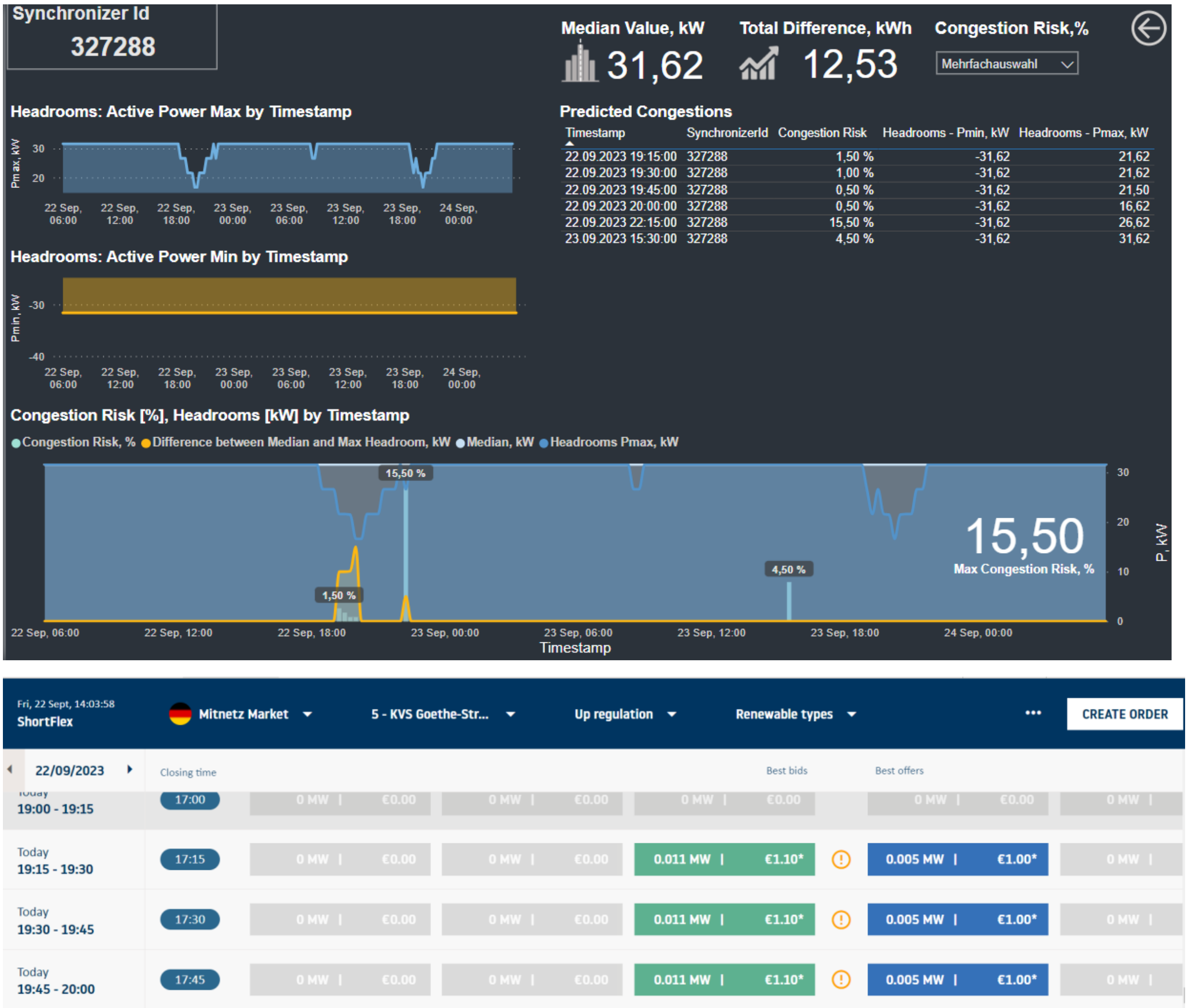


Figure I- 1 Predicted congestion September 22, 2023, and created market requests.

Annex II – SUC 8: Results of 23rd of September

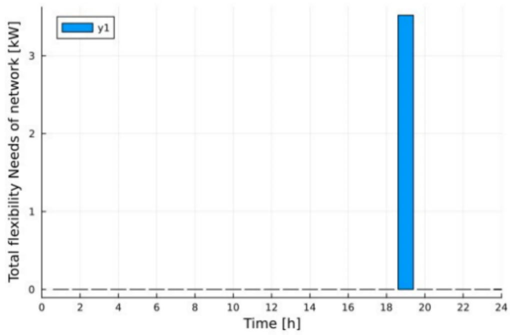
<table>
<tr><th colspan="2">MLq0094 network – 23rd of September</th></tr>
<tr><th>Actual temporal FNA</th><th>Predicted temporal FNA</th></tr>
<tr><td>

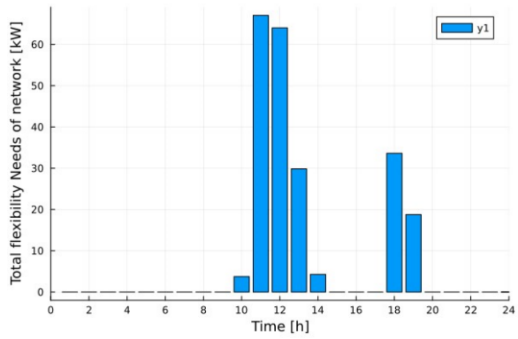
Figure II-0-1: Actual flex needs (Mlq0094, 23/09)</td>
<td>

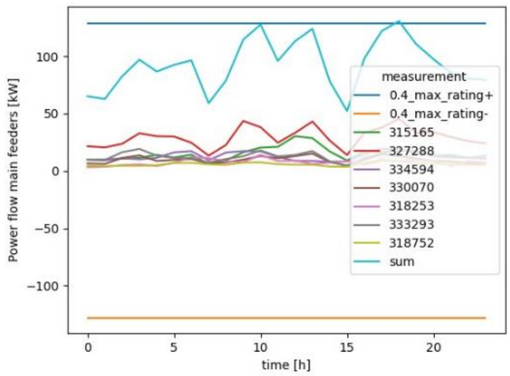
Figure II-0-2: Predicted flex needs (Mlq0094, 23/09)</td></tr>
<tr><th>Line Loading in % of the total capacity</th><th>Temporal distribution of bus voltages in PU</th></tr>
<tr><td>

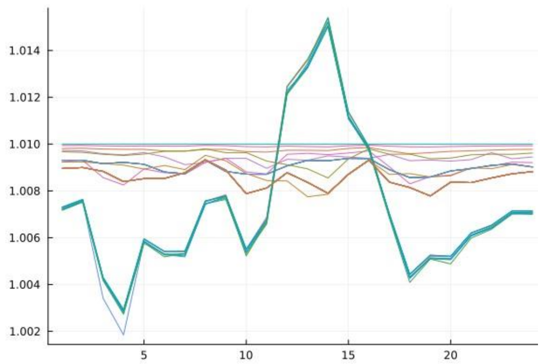
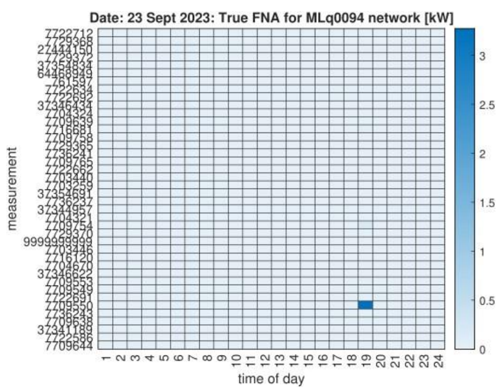
Figure II-0-3: Loading of main feeders (Mlq0094, 23/09)</td>
<td>
Figure II-0-4: Bus voltages (Mlq0094, 23/09)</td></tr>
<tr><th>True Flexibility Needs [kW]</th><th>Predicted Flexibility Needs [kW]</th></tr>
<tr><td>

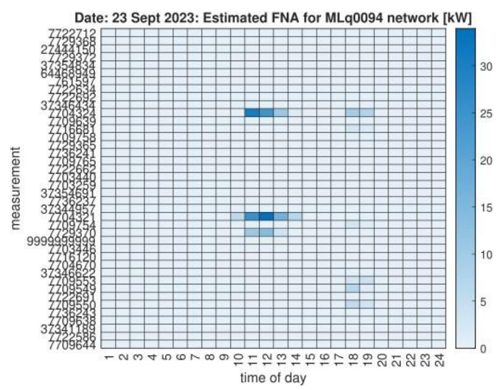
Figure II-0-5: Heatmap of locational and temporal terms of actual flex needs (Mlq0094, 23/09)</td>
<td>
</td></tr>
</table>

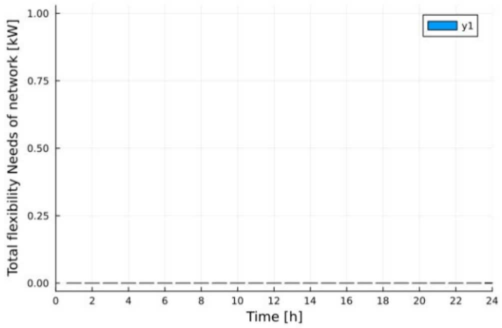
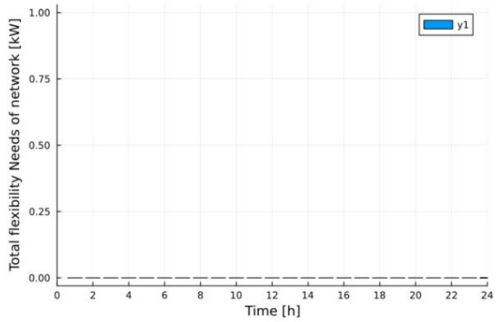
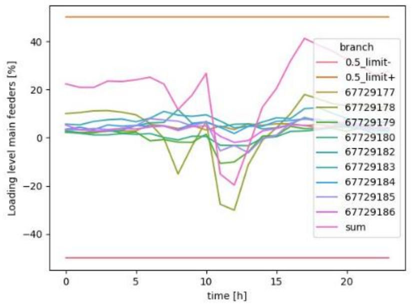
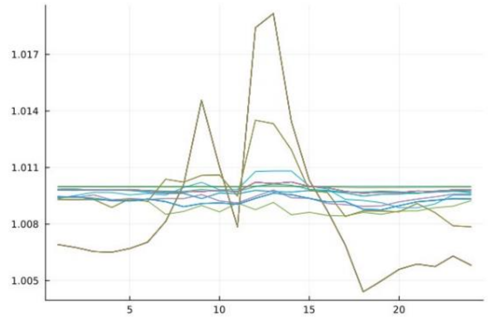
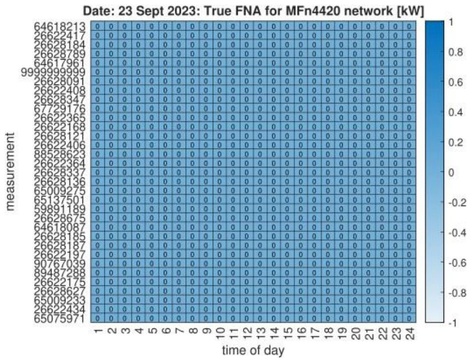
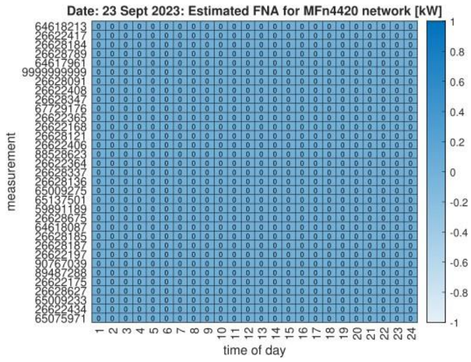
	Figure II-0-6: Heatmap of locational and temporal terms of the predicted flexibility needs (Mlq0094, 23/09)
MFn4420 – 23rd of September	
Actual temporal FNA	**Predicted temporal FNA**
 *Figure II-0-7: Actual flex needs (MFn4420, 23/09)*	 *Figure II-0-8: Predicted flex needs (MFn4420, 23/09)*
Line Loading in % of the total capacity	**Bus Temporal distribution of bus voltages in PU**
 *Figure II-0-9: Loading of main feeders (MFn4420, 23/09)*	 *Figure II-0-10: Bus voltages (MFn4420, 23/09)*
True Flexibility Needs [kW]	**Predicted Flexibility Needs [kW]**
 *Figure II-0-11: Heatmap of locational and temporal terms of actual flex needs (MFn4420, 23/09)*	 *Figure II-0-12: Heatmap of locational and temporal terms of the predicted flexibility needs (MFn4420, 23/09)*

Table II-1: KPI calculation for different Chance Constraint Levels or Risk levels, for the MLq0094 network on the 23rd of September

	Mlq0094 Network for 23rd of September										
	Risk level										
	0	**0.05**	**0.1**	**0.15**	**0.2**	**0.25**	**0.3**	**0.4**	**0.5**	**0.6**	**0.7**
S1	100	100	100	100	100	83	83	83	67	33	0
S2[kW]	704	420	347	295	250	212	180	115	52	0	0.0
S3 (%)	2.8E4	1.4E4	1.1E4	8.9E3	7.6E3	6.5E3	5.5E3	3.7E3	2.7E3	1.6E3	8.5E2

Table II-2: KPI calculation for different Chance Constraint Levels or Risk levels, for the MFn4420 network on the 23rd of September

	MFn4420 Network for 23rd of September										
	Risk level										
	0	**0.05**	**0.1**	**0.15**	**0.2**	**0.25**	**0.3**	**0.4**	**0.5**	**0.6**	**0.7**
S1	100	100	100	100	100	100	100	100	100	100	100
S2 [kW]	/	/	/	/	/	/	/	/	/	/	/
S3 [kW]	73	4	0	0	0	0	0	0	0	0	0