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Finnish demonstrator - Market based integration of distributed resources in the transmission system operation

Deliverable 6.9

EU-SysFlex

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ABBREVIATIONS AND ACRONYMS

AB	Advisory Board
AMR	Automated Meter Reading
BESS	Battery Energy Storage System
BUC	Business Use Case
CA	Consortium Agreement
CCS	Combined Charging System
CIS	Customer Information System
DER	Distributed Energy Resources
DoA	Description of Action
DB	Demonstration Board
DMZ	Demilitarized zone
DSO	Distribution System Operator
EC	European Commission
EC-GA	Grant Agreement
EV	Electric Vehicle
EU-SYSFLEX	Pan-European System with an efficient coordinated use of flexibilities for the integration of a large share of Renewable Energy Sources (RES)
GA	General Assembly
HV	High Voltage
IoT	Internet of Things
KPI	Key Performance Indicator
LV	Low Voltage
MO	Management Office
MV	Medium Voltage
NIS	Network Information System
OCPP	Open Charge Point Protocol
PC	Project Coordinator
PLC	Power Line Communication
PMB	Project Management Board
PoC	Proof of Concept
PV	Photovoltaic
RES	Renewable Energy Sources
RF	Radio Frequency
SOC	State of Charge
SUC	System Use Case
TM	Technical Manager
TSO	Transmission System Operator
UI	User Interface
WP	Work Package

EXECUTIVE SUMMARY

The EU-SysFlex H2020 project aimed at a large scale deployment of flexibility solutions, including technical options, system control and a novel market design to integrate a large share of renewable electricity, maintaining the security and reliability of the European power system. The project results will contribute to enhance system flexibility, resorting bo th to existing assets and new technologies in an integrated manner, based on seven European large scale demonstrators (WP 6, 7, 8 and 9). The overall objective of WP6 is the analysis of the exploitation of decentralized flexibility resources connected to the distribution grid for system services provision to the TSOs (Transmission System Operator), by the means of three physical demonstrators located in Germany, Italy and Finland. Following the objectives of the EU-SysFlex project and of its WP6 in particular, the three demonstrators are being set- up in order to show how resources connected to the distribution system can help to address system needs by providing ancillary services to the transmission level and, at the same time, meet the requirements of both TSO and DSO (Distribution System Operator) while, also, improving the coordination between these two actors.

This deliverable presents the Finnish demonstrator in EU-SysFlex. The objective of the Finnish demonstrator was to increase especially the use of market based concepts and virtual power plants to support the operation of the transmission and distribution networks. The innovative aspect was to integrate small, so far untapped flexible assets in medium and low voltage grid, to the aggregation processes and offer the flexibility of these assets to the TSO ancillary (frequency) services and for DSO's needs. The flexible assets in the Finnish demonstrator are an industrial-sized BESS (Battery Energy Storage System), customer and office scale batteries, EV (Electric Vehicle) charging systems and residential electricity storage heating loads. Active as well as reactive power management were applied as flexibility services.

In the demonstration of providing active power to TSO's ancillary markets, it is mandatory to enable the operation of small assets in the flexibility markets. To reach this goal forecasting and optimization, control logics as well as reliable communication systems were needed. Forecasting and optimization tools were developed specifically for each asset type of the demonstration. The tools of an aggregator to forecast the availability of assets to operate in the TSO ancillary markets, define the optimal bidding sizes and times and define the available potential in the current and future scenario. The reactive power flexibility was applied as a proof-of-concept of the demonstrated local reactive power market. In this part, an additional forecasting tool was created for the use of the DSO. Virtual power plants aggregate decentralized assets to bigger entities. The operation required development of a suitable platform/systems, interfaces between assets and different systems, and interfaces to the markets.

The Finnish demonstration reached important development steps where the industrial-sized BESS is operating in the TSO ancillary markets and multi-service provision was also demonstrated by the BESS. Remote control and control logic have been developed and tested for the PV power plant, customer-owned small batteries and the office scale battery. Several forecasting and optimization tools for the needs of an aggregator and additionally, reactive power forecasting tool for the DSO, were developed. The flexibility potential of electric heating loads has

been evaluated by simulations. A proof-of-concept of the reactive power market was demonstrated. The main focus was the operation of the DSO in the TSO/DSO interface supporting the voltage in the TSO's network. The results from the demonstration are summariserd in Table 1.

In the demonstration of resources of electricity storage heating loads via AMR meters, the demonstration's main contribution was the further developed forecast of the controllable electricity storage heating load via AMR meters. Additionally, the financial profits for the aggregator and for end-use customers from the TSO's mFRR market were simulated. For the end customers, the profits were small and this challenges the future development. The future of applying these loads via DSO owned AMR meters depends on the national statements of the roles, possibilities and obligations to various stakeholders.

In the reactive power market demonstration, a proof-of-concept of the market was presented. One aim of this entity was the DSO in the TSO/DSO connection to respect its PQ parameters without penalties when utilizing via the market the aggregator's operated, aggregated, distributed, small reactive power assets. Additionally in EU-SysFlex, a forecast was created for the DSO to be able to estimate the reactive power profile in the TSO/DSO connection. Another achievement was the aggregator's constructed ability to control the reactive power assets, here the industrial sized BESS and inverters of the PV. For the demonstrated simulation period, the DSO reached some savings. However, no other costs, like payments for the aggregator or asset owners were estimated and at this stage creating a totally new market is not seen economically viable. On the other hand, the demonstration builds upon current EU targets for the development of various market based flexibility services for the needs of the TSOs and the DSOs.

TABLE 1. THE FINNISH DEMONSTRATION KPI RESULTS

		Active power, real environment demos				Active power, simulated scenarios	Reactive power, real environment demo
	Demo	Industrial-scale BESS 1.2 MW, 600 kWh ("Suvilahti BESS")	Medium-scale BESS 120 kW ("office-scale")	EV charging stations flexibility demo & calculated cases	Customer-scale batteries flexibility demo & calculated cases	Simulated scenarios: flexibility of electric heating loads via AMR control	Reactive power market demo
KPI	**Service provision**	FCR-N (real market operation)	FCR-N (real market operation)	FCR-D (technical test)	FCR-N (technical test)	mFRR (simulation)	Q compensation (Suvilahti BESS, PV plant in Kivikko, Helsinki)
KPI-FIN1	**Increase in revenue of the flexibility service provider**	45184 € (4107 €/mo)*	7609 € (634 €/mo)*	Estimated revenue increase = 3066 €	Estimated revenue increase = 943 €	Simulated for 727 customers, 56 415 €/year ****	NA
KPI-FIN2	**Decrease in penalties for going out of the PQ window**	NA	NA	NA	NA	NA	-16 %
KPI-FIN3	**Reactive power market utilization factor**	NA	NA	NA	NA	NA	27 %
KPI-FIN4	**Flexibility service reliability**	0.174 (approx. 35 % of the offered capacity)	0.0239 (approx. 24 % of the offered capacity)	1.151	NA	NA	Complete demo period: 405.68 Excluding single BESS error: 6.28
KPI-FIN5a	**Reliability of the aggregation platform**	NA	99,23 %	Succes rate = 100 % ***	Succes rate = 39,7 %	NA	NA
KPI-FIN5b	**Usability of the asset**	Usability = 94.8%	99,47 %	NA	NA	NA	Suvilahti BESS: 99.5 % Kivikko PV-plant: 100 % Combined: 99.75 %
KPI-FIN6	**Customer acceptance**	NA	NA	NA	Customer acceptance = 100 %	NA	NA
Additional KPI:							
KPI-FIN7	**Profits of service provision**	22259 € (2024 €/mo)*	5573 € (464 €/mo)**	NA	62 €/year	Simulated for 727 customers, 23 249 €/a	NA

NA = not applicable

**High yearly variation*

***Customer profits*

****Counting only the succesfull test days*

*****From manifold simulation cases, this option presented a case with max income to an aggregator and to customers.*

Industrial-scale BESS

- Development of a set of forecasting/optimization tools to estimate the available flexibility of the LV/MV assets for TSO ancillary services
- Operated in FCR-N market successfully
- Scalable solution for future high-RES grid

Medium-scale BESS

- Successfully developed communication systems, control and optimisation logics for multi-use of the BESS
- Successfully operated in FCR-N market, peak shaving, and reactive power compensation

Customer-scale BESS

- Controlling of individual small assets was technically hard and the demo failed to fulfil the requirements for FCR-N market
- Uneconomical for customer and flexibility service provider

EV charging flexibility demo

- Successfully developed controlling logics to control charging sessions
- Strict time requirements were not met in the FCR-D market

Simulated flexibility of electric heating loads via AMR meters

- Technical tests could not meet the requirements for mFFR market
- Estimate of low profitability for single load

Reactive power market demo

- Technical proof of concept developed for a new market mechanism to manage reactive power in the TSO/DSO connection point
- Successfully controlled the assets to provide reactive power

Utilisation of distributed BESS (office and industrial scale) were proven to be efficient and reliable assets to provide ancillary services to the frequency containment reserve market operated by the Finnish TSO. The Finnish demonstration has shown a strong case for scalability and replicability for industrial scale BESS with new developed IoT platform and optimization tools. Multiuse of both industrial and office scale BESS when possible is strongly advised. Other demonstrated assets (residential BESS, EV chargers, residential electricity storage heating loads via

AMR meters) had technical and financial limitations yet to be resolved. However, in future these assets could provide active power flexibilities to the TSO. Especially as the power demand for EV charging increases this provides major possibility for flexibility service providers.

1. INTRODUCTION

1.1 INTRODUCTION TO THE EU-SYSFLEX PROJECT

The EU-SysFlex project seeks to enable the European power system to utilise efficient, coordinated flexibilities in order to integrate high levels of Renewable Energy Sources (RES). One of the primary goals of the project is to examine the European power system with at least 50% of electricity coming from RES, an increasing part of which from variable, distributed and Power Electronic Interfaced sources, i.e. wind and solar. Therefore the EU-SysFlex project aims at a large scale deployment of solutions, including technical options, system control and a novel market design to integrate a large share of renewable electricity, maintaining the security and reliability of the European power system. In order to achieve the project objectives the EU-SysFlex approach pursues the identification of technical shortfalls requiring innovative solutions, the development of a novel market design to provide incentives for these solutions, and the demonstration of a range of innovative solutions responding to the shortfalls. Other activities as data management analysis, innovative tool development and integration and testing of new system services in TSOs control centers are also included in the project approach. The project results will contribute to enhance system flexibility, resorting both to existing assets and new technologies in an integrated manner, based on seven European large scale demonstrators in Portugal, Germany, Italy, Finland, Portugal, France, and the Baltic states (WP 6, 7, 8 and 9).

The demonstrators from different countries and have common and also some specific system needs and regulations. Their set-ups and frameworks were different but as they pursued the same general objectives, they were complementary in displaying the various possibilities for addressing system needs in the distribution and transmission grid with the help of distributed flexibility resources connected to the distribution grid. The Finnish demonstrator brought in the market aspects of providing services from distributed resources from medium and low voltage distribution networks. On one hand, it aggregated small distributed resources into the transmission level markets for frequency management. On the other hand, it introduced a market based approach for a DSO to purchase reactive power control resources from a local reactive power market.

The variety of several demonstrators complementing each other demonstrated the possibility of using various flexibility resources connected to voltage levels ranging from low to high voltage in order to provide services and solve a set of scarcities such as frequency deviations, voltage violations and congestions. The demonstrators also showed different technical strategies to improve the coordination between the TSO and DSO when tackling those scarcities. When working hand-in-hand the demonstrators displayed the technical chain allowing to connect and more efficiently operate distributed assets. Furthermore, they showed how those resources can be aggregated and made available to the TSO and DSO both by coordination mechanisms and by using market based mechanisms.

In the Finnish demonstration, the flexibilities were demonstrated to provide frequency stabilization services to the TSO and help the DSO manage its reactive power exchanges with the TSO. The reactive power control assists voltage control of the TSO. These demonstrators were both developed with a market based approach.

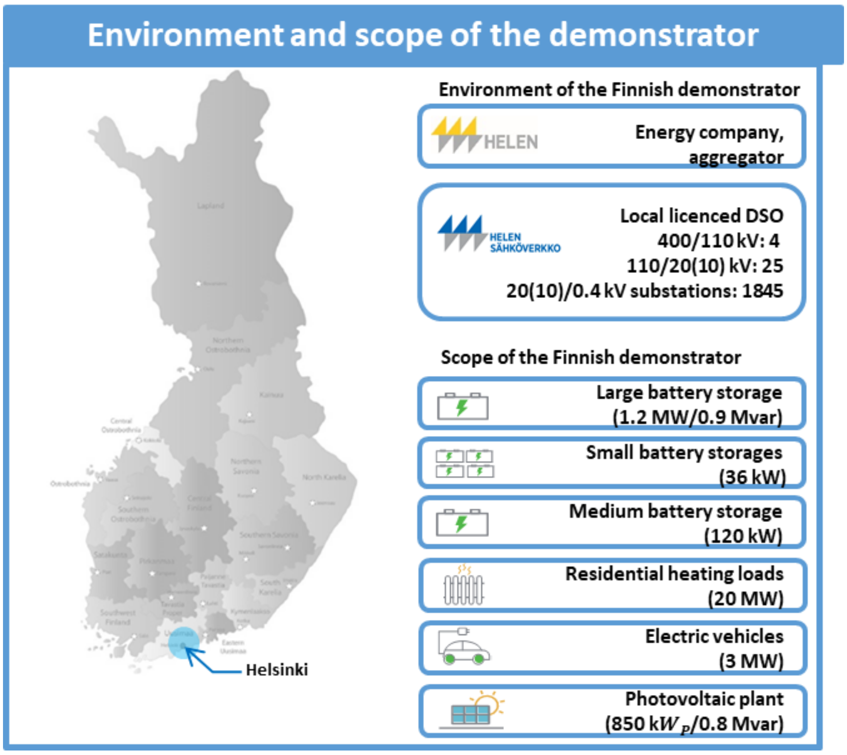


FIGURE 1. ENVIRONMENT AND SCOPE OF THE FINNISH DEMONSTRATOR

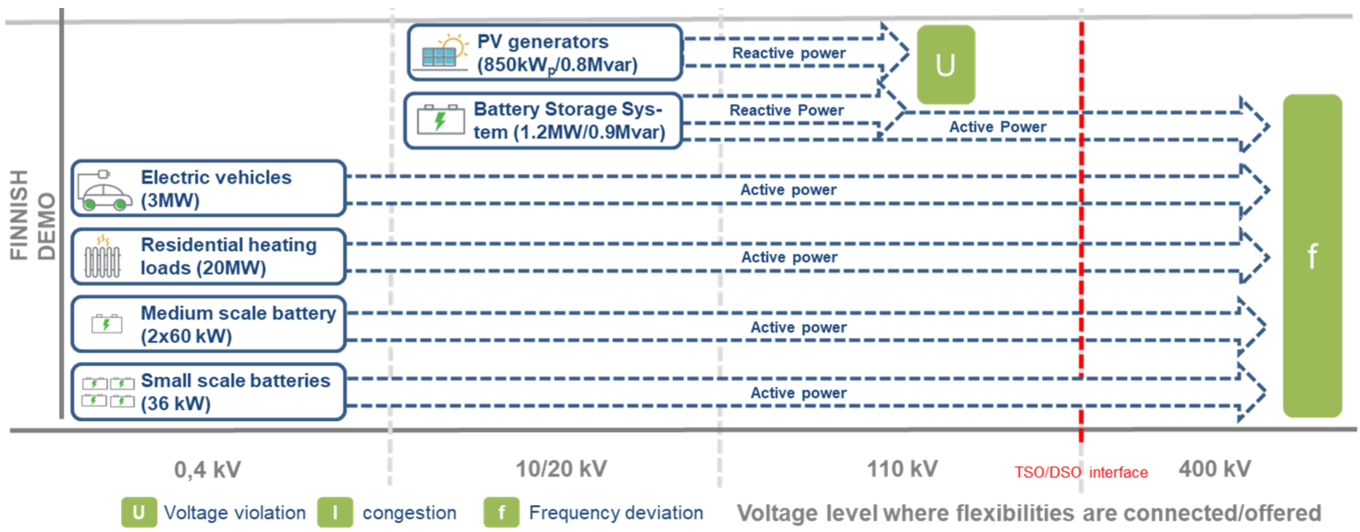


FIGURE 2. SCARCITIES SOLVED BY FLEXIBILITIES IN THE FINNISH DEMONSTRATOR

1.2 WP6 AND DEMONSTRATOR OBJECTIVES

The primary objective of WP6 is to analyse and test the exploitation of decentralized flexibility resources connected to the distribution grid, respecting to the needs of both DSOs and TSOs. Within the on-going current policies for the decarbonisation of the energy systems, RES capacities are increasing, especially in the distribution network. Originally, these networks were not designed to host large volumes of distributed RES generation capacity, when, at the same time, they have to guarantee the security and resilience of their networks. A consequence of this is their need for adequate leverage in their network operation in order to avoid congestions and constraints violations. At the same time, the amount of traditional flexibility resources, historically provided by conventional generation in the transmission level, decreases. Therefore, the use of flexibility resources in the distribution grid, to guarantee security and resilience in the transmission system operation, is increasingly asked for. This development states needs for comprehensively improving the TSO/DSO coordination. Additionally, the various flexible resources connected to the distribution network are the assets capable of providing various ancillary services to TSOs and DSOs at the same time covering their needs. The overall WP6 objectives were:

- Improve TSO/DSO coordination
- Provide ancillary services to TSOs from flexible assets connected to the distribution network
- Investigate how flexibilities connected to the distribution grid can meet the needs of both TSOs and DSOs

The general objective of the Finnish demonstrator is to show how small, distributed flexibility resources, i.e., such various size BESSes (industrial scale, office scale, customer scale), electric vehicle (EV) charging stations, residential electricity storage heating load and a PV plant connected to the low or medium voltage distribution network can be aggregated to be traded on existing TSO market places and/or for DSO's reactive power compensation needs. The specific Finnish demonstrator objectives were:

- Aggregation of small distributed assets in LV and MV network to the TSO's ancillary services and for the DSO's reactive power compensation needs
- Forming appropriate forecasting, optimization and control signals for different flexible resources
- Demonstrating the value chain of harnessing small distributed assets to the benefit of the higher voltage grid stability

1.3 SCOPE AND OBJECTIVES OF THIS DELIVERABLE

The deliverable covers the entity of the Finnish demonstrator's four years research, developments and pilots in the EU-SysFlex program. The objectives of this deliverable are to form the comprehensive presentation from the starting point of this project from the pre-SysFlex situation by building and testing the six discrete pilots up to analysing the results and finally making the summary with exploiting plan and future prospectives. The main objectives of this deliverable is to report the entity of the Finnish Demonstrator and the main part is to comprehensively present the pilot developments, set-up, results and future view with development needs.

In EU-SysFlex and WP6, the demonstrators of Germany, Italy and Finland have already together published WP6 deliverables in which they are reporting general views of demonstrators in [1], system use cases in [2], and descriptions of processes and data transfers in [3]. In addition, WP6 demonstrators' forecasting and optimization as well as grid simulations have been presented in the common deliverables [4], [5] and [6].

1.4 STRUCTURE OF THE DOCUMENT

This deliverable "Finnish demonstrator - Market based integration of distributed resources in the transmission system operation - D6.9" reports the piloted market based - active power as well reactive power - integrations of distributed resources applied in the transmission system operation . First in Chapter 2, the summary of the situation before the EU-SysFlex situation is presented following by the developments during the project in Chapter 3. Parts of these development stages, like forecasting and optimization are comprehensively reported in separate deliverables - however, these main points and achievements are summarized in this report.
The main chapter of this deliverable is the Chapter 4 where all the demonstration set-ups and results are comprehensively reported. The Finnish demonstrator had altogether six discrete pilots. The active power demonstrations included five asset types and demonstrators. Each of them is reported in a separate sub-chapter. The reactive power demonstrations covers one sub-chapter of this report.

At the end of this deliverable, the lessons learned, the scalability, replicability and the future questions are discussed.

2. SUMMARY OF THE PRE-SYSFLEX SITUATION

2.1 STATUS-QUO, DRIVERS AND CHALLENGES ADDRESSED BY THE DEMONSTRATOR

Status-quo, challenges and environment of the demonstrator

The Finnish demonstrator is focused on market based integration of flexible assets to the TSO ancillary services. As the amount of renewable, intermittent and decentralized production increases in the energy system, more flexibility is needed. Therefore, demand response and storage solutions will play a key role in the future energy system.

The prerequisites for an asset to participate in the reserves and balancing power markets include technical requirements (e.g. minimum size, activation time), market place requirements (e.g. regarding balance settlement) and the passing of a prequalification test. An aggregator can aggregate multiple assets, which do not fulfill the technical and market requirements individually, into an entity that is qualified to participate on the reserve markets. With the growing share of distributed small scale generation in the Nordic power system, flexible resources are increasingly needed for the ancillary services. Typically the assets participating in the markets are industrial-sized loads or generation capacities that are traded by the asset operator or by a retailer. In the future, it will be possible to include so far untapped small scale assets to the aggregation processes. These small scale assets can include battery energy storage systems of different sizes, EV charging stations, residential electric heating loads and loads connected to building automation (e.g. air ventilation). Assets are owned and operated by manifold owners and operators, like aggregators, retailers, service providers as well as end-use customers. For example for EV charging, there are e.g. public, company-owned and private EV charging stations and this brings various aspects to flexibility analysis, forecasting, optimization and operation [7], [8], [9].

In addition to the TSO ancillary markets, the Finnish Demonstrator studies a market based concept for local reactive power compensation needed by the DSOs. To support the TSO's operation of the national transmission grid, every DSO manages the PQ window at the TSO/DSO interface (within the Finnish demonstrator 400/110 kV). The TSO has set the PQ windows to avoid excessive reactive power input/output between the TSO and the DSOs. The reason for the PQ window is to reduce the voltage violations in the TSO grid due to reactive power inputs/outputs. If the reactive power exceeds the window limits determined by the TSO, a penalty reactive power tariff is charged from the DSO.

Currently in Helsinki, the control of the PQ window is mainly realised by 110 kV reactors and the on/off control of 110 kV capacitors. In addition, a tariff structure also exists between the DSO and power tariff customers in order to direct and guide these bigger customers in their electricity usage of reactive power. However, the benefits of the tariffs between the DSO and bigger customers have remained minor because the costs of reactive power have so far remained low. Furthermore, no major problems have been caused to the DSO. On the other hand, DSOs could use other active methods to reach more reactive power compensation to manage and control the PQ window at the TSO/DSO interface. Flexible resources regarding reactive power exist in the distribution network, but DSOs have no convenient mechanism to reach these assets. The Finnish demonstrator tackles this issue with the proof of concept for a reactive power market mechanism. It should be noted that the use of reactive power assets connected in the distribution network always needs the DSO's validation before working on the demonstrated market.

During the past decade Helen has been developing capabilities to integrate third party owned assets into the balancing markets. So far, these assets have typically been industrial-sized loads or large generation capacities. In EU-SysFlex, Helen is aiming at utilising the experience gained with the larger assets to harness small distributed assets to the markets. The main difference with small assets compared with assets that are already aggregated and traded today is the even higher uncertainty of the available capacity. This demonstration provides solutions to this challenge by developing a capacity forecasting tool of different assets for day-ahead and intraday markets.

Drivers

Different drivers, both external and internal, affect the Finnish Demonstrator: external drivers with the goal to integrate a higher share of RES in the system and internal drivers in the form of improved cost efficiency for the system overall and of increased revenue for the aggregator. Consequently, the demonstrator aims for increased use of market-driven concepts to support the operation of transmission and distribution networks.

2.2 GOALS OF THE DEMONSTRATOR AND CONTRIBUTION TO THE WP6 AND PROJECT

The general objective of the Finnish demonstrator is to show how flexibility resources, i.e. small, distributed resources, such as electric vehicle (EV) charging stations, large scale battery energy storage system (BESS), customer scale batteries, PV plant and residential heating loads, that are connected to the low or medium voltage distribution network, can be aggregated to be traded on existing TSO market places and/or for DSO's reactive power compensation needs.

Specific goals of the Finnish Demonstrator:

- Aggregation of small distributed assets in LV and MV network to the TSO's reserve markets and for the DSO's reactive power compensation needs
- Forming appropriate forecasting, optimization, communication channels as well as control logics for different flexible resources
- Demonstrating the value chain of harnessing small distributed assets to the benefit of the higher voltage grid stability
- Evaluating the business potential of the demonstrated solutions in cooperation with WP11

2.3 INNOVATION OF THE DEMONSTRATOR

The Finnish demonstrator takes a step forward by aggregating small, so far untapped distributed assets to the benefit and needs of electricity network (at both TSO and DSO levels). Active as well as reactive power of the smaller assets are utilized by the Finnish demonstrator in the EU-SysFlex research program.

Innovations in Finnish demonstrator regarding active power flexibility

The active power of the resources is applicable for TSO's frequency and balancing markets. To achieve this, a vital element of the project is to develop a tool that can forecast and optimize the availability of capacity from different resources (EV charging stations, residential heating loads, battery energy storage system) that are characterised by intermittency and variability. Another vital aspect is to demonstrate and define which kind of communication channels, systems and control logics are needed in order to aggregate and control the small assets according to the rules of the TSO ancillary markets.

As some of the distributed resources are typically owned by third parties (e.g. customer scale batteries), this demonstrator also develops new cooperation concepts between an aggregator/retailer and the asset owners.

Innovations in Finnish demonstrator regarding reactive power compensation

For reactive power, a former comprehensive research of reactive power management reported the drastically changed reactive power situation in Finland that has also been measured and observed by the DSO of the Finnish demonstrator (Helen Electricity Network, here written as "Helen DSO"), the Finnish TSO (Fingrid) and extensively in Finland. There is going on an apparent and remarkable change in the reactive power characteristic from consumption towards production of reactive power. Therefore, a new market based concept for reactive power compensation is tested in the EU-SysFlex to widen the supply and availability of new type of reactive power resources, now owned by third parties. For aggregators and asset owners this solution might offer new business opportunities.

2.4 EXPECTED RESULTS AND KPI

This chapter gives an overview of the expected results of the Finnish demonstration. The chapter also summarizes the Demonstrator specific KPIs.

Expected Results

- Aggregation of so far untapped distributed assets in the low and medium voltage network and demonstration of flexibility service provision
- Suitable interfaces to connect small distributed assets to the aggregation platform to create a virtual power plant
- Forecasting and optimization tools to estimate the availability of the distributed assets to the TSO ancillary services
- Proof of concept for a reactive power market mechanism

- Evaluation of flexibility market operation schemes and business models
- Increased use of market-driven concepts to support the operation of transmission and distribution networks

Key Performance Indicators (KPIs)

The KPIs of the Finnish demonstrator are presented in D10.1 Report on selection of KPIs for the demonstrations [10]. The Finnish demonstrator is testing the following services:

- Active power flexibility provision to TSO ancillary (frequency) services (FCR-N, FCR-D, mFRR)
- Reactive power flexibility provision to support the DSO to stay within the limits of PQ window and eventually to support the TSO in the voltage control of HV network

The KPIs of the Finnish demonstrator are presented below:

KPI n°1		
KPI name	**Increase in revenue of the flexibility service provider**	FIN
Main objective	Calculation of the total increase in revenue by providing new services with a specific set of resources compared to the BaU services and resources.	
KPI Description	The Revenue is calculated by multiplying the provided power by the price of the service summed over a set of resources and a set of markets/services.	
Unit	€	
Formula	$$R = \sum_{s \in S} \sum_{a \in A} \sum_{t=1}^{T} \boldsymbol{P}_{s,a,t} \cdot \boldsymbol{\pi}_{s,a,t}$$ where S is the set of available markets/services A is the set of available resources t is one of the T time periods considered $\boldsymbol{P}$ is the realized power exchanged π is the price	
Target value	Estimated costs of operating the flexibility	
Baseline scenario	Operating with the existing pre-SysFlex capacities	
Smart-Grid scenarios	With EU-SysFlex innovations. Horizon: demo period Operating the resources on other markets, or on a combination of markets.	

KPI n°2			
KPI name	**Decrease in penalties for going out of the PQ window**	KPI ID	
Main objective	Estimate the value of the market that is being developed in the project for the DSO		
KPI Description	Calculating the cost of being out of the PQ window with and without the market support. The costs consist of two parts which are related (when being out of the window) to the 1) reactive power, 2) reactive energy.		
Unit	%		
Formula	$\frac{C_{\text{hmarket}} - C_{\text{h}}}{C_{\text{h}}}$ The invoicing period is a month and the measurement data is hourly PQ data. Only those hours exceeding the PQ limits are taken into account, however, during a month, the 50 highest exceeding hours are free of charge and out of consideration. For those hours of interest, the costs include 1) the cost of reactive power and 2) the cost of reactive energy. $C = C_{\text{power}} + C_{\text{energy}}$ For power cost: For those *k* hours exceeding the PQ limits, the 51st highest absolute value of Q determines the cost of power. $C_{\text{power}} = c_{\text{power}} * \Delta Q_{51\text{st}\,max}$ *$\Delta Q_{51st\ max}$ is the amount of reactive power exceeding the PQ limits of the 51st highest hour [MW] (*accurated definition compared to KPI definition presented in *D10.1 Report on the selection of KPIs for the demonstrations*) For energy cost: For those (*k-50)* hours exceeding the PQ limit are taken into account, the exceeding reactive energy is the penalized energy. $C_{\text{energy}} = c_{\text{energy}} * \sum_{51}^{k} \lvert \Delta E \rvert$ where C_{h} is the cost for deviating from the allowed Q band when operating BaU [€] $C_{hmarket}$ is the cost for deviating from the allowed Q band when Q market is used [€]		

	C_{power} is the cost for reactive power [€] c_{power} is the unit price for reactive power [€/MW] C_{energy} is the cost for reactive energy [€] c_{energy} is the unit price for reactive energy [€/MWh] k is the number of hours when exceeding the PQ limits during a month $\Delta Q_{51st\ max}$ is the amount of reactive power exceeding the PQ limits of the 51st highest hour [MW] ΔE is the sum of reactive energy exceeding the PQ limits [MWh]
Target value	Less than zero
Baseline scenario	w/o EU-SysFlex (compensators)
Smart-Grid scenario	with EU-SysFlex innovations. Horizon: demo period

KPI n°3			
KPI name	**Reactive power market utilization factor**	KPI ID	
Main objective	The goal is to measure the need for such a market and estimate the value for the aggregator		
KPI Description	Calculation of the number of hours that the market is being used to compensate the reactive power during the test period		
Unit	%		
Formula	$\frac{\sum h}{T_{\text{test period}}} \cdot \mathbf{100}\ \%$ where $\sum h$ is the number of hours that the market is being used to compensate the reactive power $T_{\text{test period}}$ is the number of hours during the test period (in the demonstration one month)		
Target value	>0		
Baseline scenario	No baseline		
Smart-Grid scenario	with EU-SysFlex innovations. Horizon: demo period		

KPI n°4			
KPI name	**Flexibility service reliability**	KPI ID	
Main objective	Difference between the offered bids and the realized power exchanges.		
KPI Description	The root mean squared error (RMSE) between the bid power exchanges and the realized ones. This error includes forecasting errors, but also the other sources of errors in the system (e.g. communication failures, asset owner overriding the command, …)		
Unit	MW		
Formula	$RMSE = \sqrt{\frac{\sum_{t=1}^{T}(P_{R,t} - P_{B_v,t})^2}{T}}$ where t is the one of the T time periods considered P_R is the realized power exchanged P_{B_v} is the power accepted (or validated) from the bid on the market		
Target value	Towards 0.		
Baseline scenario	No baseline		
Smart-Grid scenario	with EU-SysFlex innovations. Horizon: demo period		

KPI n°5a			
KPI name	**Reliability of the aggregation platform**	KPI ID	
Main objective	The goal is to measure how reliably the platform delivers and receives information		
KPI Description	Calculating the hours that the communication is travelling through the platform		
Unit	%		
Formula	$AV[\%] = \frac{T_{com}}{T_{op}} \times 100\%$ where T_{com} [s] is the total duration in which all the aggregation platform is working correctly as defined in the demonstration specifications. T_{op} [s] is the total operational time of the aggregator during the tests carried out.		
Target value	$AV[\%] > x\%$, as good as possible		
Baseline scenario	No baseline		
Smart-Grid scenario	With EU-SysFlex. Horizon: demo period		

KPI n°5b			
KPI name	**Usability of the asset**	KPI ID	
Main objective	The goal is to measure asset usability		
KPI Description	Calculating the hours that the asset is available and usable for operation		
Unit	%		
Formula	$\boldsymbol{AV}[\%] = \frac{\boldsymbol{T_{com}}}{\boldsymbol{T_{op}}} \times \mathbf{100}\%$ where $\boldsymbol{T_{com}}$ [s] is the total duration in which asset is working correctly as defined in the demonstration specifications. $\boldsymbol{T_{op}}$ [s] is the total operational time of the asset during the tests carried out.		
Target value	$\boldsymbol{AV}[\%] > x\%$, as good as possible		
Baseline scenario	No baseline		
Smart-Grid scenario	With EU-SysFlex. Horizon: demo period		

KPI n°6			
KPI name	**Customer acceptance**	KPI ID	
Main objective	The goal is to have an attractive service that encourages the customers to give permission to use their resources (eg. electricity loads or battery storages) by the aggregator/utility company		
KPI Description	Measuring how well customers will engage to take part in grid stabilization. KPI can additionally be supported by conducting an interview with a defined group of customers, eg. key customers.		
Unit	%		
Formula	$\frac{\boldsymbol{accepted\ contracts}}{\boldsymbol{offered\ contracts}} \cdot \mathbf{100}\%$		
Target value	15% – 25%		
Baseline scenario	No baseline		
Smart-Grid scenario	With EU-SysFlex innovations. Horizon: demo period		

KPI n°7		
KPI name	**Profits of service provision (revenues of service provision-costs of service provision)**	FIN
Main objective	Calculation of the benefit for the customers when they are provided new services with a specific set of resources compared to the BaU services and resources.	
KPI Description	The Revenue is calculated by multiplying the provided power by the price of the service summed over a set of resources and a set of markets/services and subtracted the cost of grid service and energy retail.	
Unit	€	
Formula	$R_{net}(T) = R(T) - C(T)$ where $C(T) = C_{gridE}(T) + C_{gridP}(T) + C_{spot}(T)$ $C_{gridE}(T) = \sum_{n=1}^{T} P_{mFRR}(n)\pi_{gridE}(n)$ $C_{spot}(T) = \sum_{n=1}^{T} P_{mFRR}(n)\pi_{spot}(n)$ R_{net} is net income for the customers R is revenue from the markets (see KPI1) C is cost for the customers arisen from cost of grid tariff and energy tariff C_{gridE} is cost for the customers arisen from energy in the grid tariff C_{gridP} is cost for the customer arisen from demand in the grid tariff C_{spot} is cost for the customer arisen from spot based energy tariff $\boldsymbol{P}$ is the realized power exchanged π is the price	
Target value	Estimated costs of operating the flexibility by taking into account the grid tariff and energy tariff	
Baseline scenario	Operating with the existing pre-SysFlex capacities	
Smart-Grid scenarios	With EU-SysFlex innovations. Horizon: demo period Operating the resources on other markets, or on a combination of markets.	

3. DEVELOPMENTS DURING THE PROJECT

In this chapter, the systems (hardware and software) that were developed, purchased, installed or run during the project are described. During the four years of EU-Sysflex, many tools have been developed and assessed and multiple software solutions tested. Some of these software solutions remain in use post-SysFlex and some were only needed and evaluated during the demonstration project without direct post-SysFlex use. In general, the developments during the project are tools and software solutions that enable the use of small to medium scale assets to provide flexibility for the TSO or the DSO. This includes forecasting tools that estimate the available flexibility from different kinds of distributed small scale assets as well as a forecasting tool to estimate the need of reactive power compensation for a DSO. In addition to forecasting tools, the developments include optimization tools that create optimal bidding strategies for distributed assets. Furthermore, the whole ICT-environment had to be developed in order to use these distributed assets for providing flexibility. This included testing a new aggregation platform (pilot project) with a third party as well as expanding the abilities of an existing IoT platform that Helen uses as part of its ICT-systems.

In the next chapters, these developments are described more in detail. Chapter 3.1 presents an overview of the whole development work realized during EU-SysFlex in a visual form. Chapter 3.2 describes the developments regarding the communication systems and interfaces between different systems. Chapters 3.3 and 3.4 describe the forecasting and optimization tools developed during EU-SysFlex. Moreover, the forecasting and optimization tools have been described in depth in the dedicated deliverables D6.2: *Forecast: Data, Methods and Processing. A common description* [4] and D6.5: *Optimization tools and first applications in simulated environments* [5].

3.1 OVERVIEW OF THE DEVELOPMENT WORK REALIZED IN THE DEMONSTRATOR

The overview of the Finnish demonstration of both active and reactive power demonstrations is shown in Figure 3. The main development was done in the aggregation platforms and the integrations between the aggregation platforms, assets and other systems. All of the aggregation platforms had development or were new platforms tested during the project. All of the assets were existing before the project as were the integration platform, Helen's trading systems and TSO ancillary markets. Additionally, new development was required between Helen's trading systems and the integration platfrom which required a DMZ data intregration software in order to transfer market operation data from the IoT platform. All of the BESSes and EV chargers operated in active power demontrations and the Suvilahti BESS together with the PV plant operated in the reactive power market demonstration.

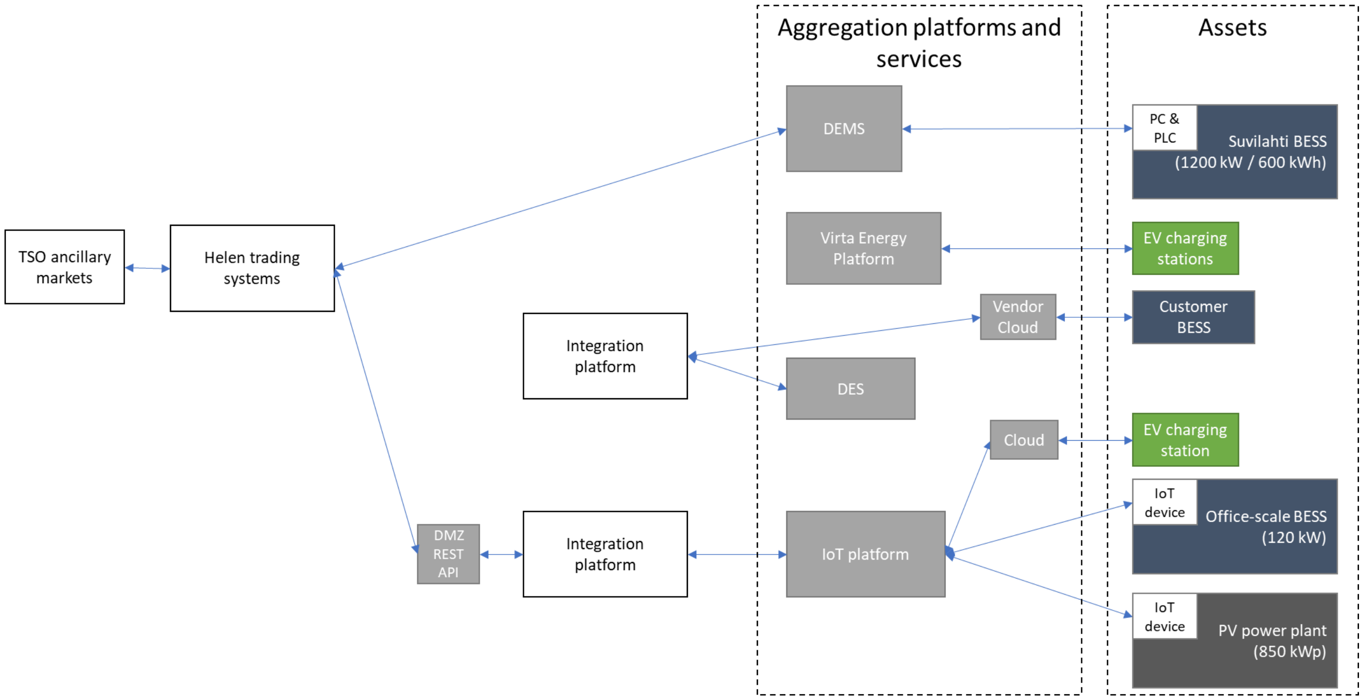


FIGURE 3. OVERVIEW OF THE DEVELPOMENTS IN SYSTEMS AND INTERFACESES IN THE FINNISH DEMONSTRATION

After the EU-SysFlex project, the work discontinued with the DES aggregation platform as it was replaced with the IoT platform. In addition, as DEMS and Virta Energy Platform were not Helen's property, upgrades and development are required by the owner.

3.2 COMMUNICATION SYSTEMS AND INTERFACES DEVELOPMENT

In this chapter, all active and reactive power communication systems and interfaces are presented. Pre-existing and new developed interfaces are described separately for every asset.

Large scale BESS

A large scale BESS was installed on-site and it was used in different studies prior to EU-SysFlex. During EU-SysFlex the large scale BESS was connected to an aggregation platform and operated through it. The aggregation platform was in use and connected to Helen's energy trading systems prior to the project. Figure 4 shows the interfaces and communication systems of the large scale BESS.

The interfaces between the Programmable Logic Controller (PLC) local control and the aggregation platform were already existing. In addition, the aggregation platform had active interfaces to Helen's Energy trading systems prior to EU-SysFlex. New development was done in the data transmission interface for the BESS to operate in the TSO's active power frequency reserve markets.

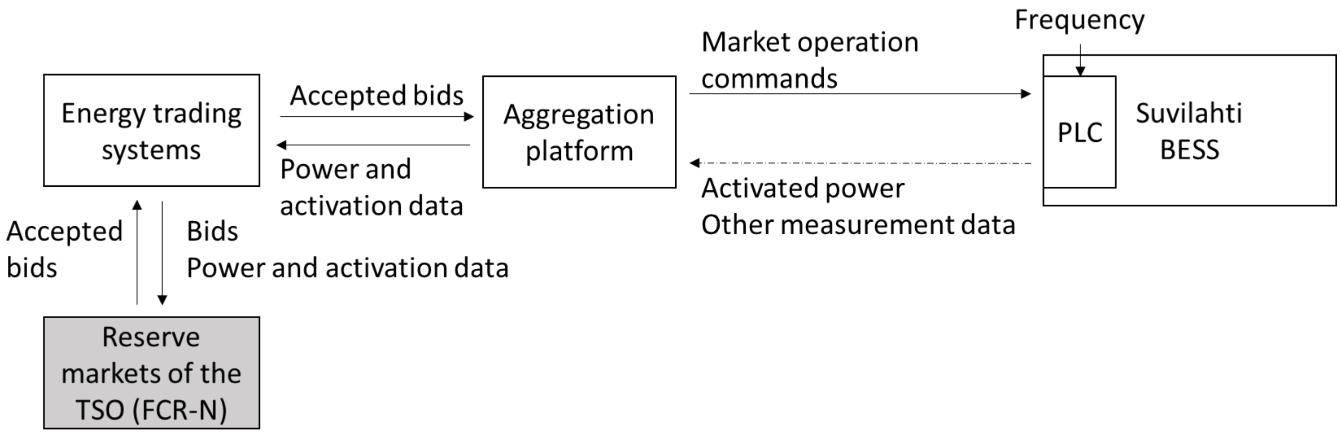


FIGURE 4. LARGE SCALE BESS

In reactive power tests, the large scale BESS operated according to manual reactive power set points saved into the BESS PLC and thus no new interfaces were developed for the reactive power tests.

Office scale BESS

The office scale BESS was a new system installed in an office building. New communication systems and interfaces were taken into use for the BESS to operate. The BESS was connected to an IoT device via Modbus TCP and the IoT device to the IoT cloud platform using mobile internet connection. The use of Modbus allowed the device to use standardised Modbus protocol for reading from and writing to Modbus registers. The IoT device had been developed to function with the specific cloud service and it was purchased from the IoT platform provider. The IoT device itself only transfered data between the BESS and the cloud and all operational logic was built into the IoT platform. In the IoT platform, there were different user interfaces where users could create dashboards and logics.

During EU-SysFlex different dashboard views were developed to enable easy use for the BESS operator. In addition to dashboard views, operational logics were developed to enable the different functions defined for the office scale BESS. These functions enabled the BESS to control the smart office power consumption with peak shaving logic and to participate in the FCR-N market operated by the Finnish TSO Fingrid as well as compensate the buildings reactive power. The logics for BESS operation were developed in house in Helen.

Other interfaces consisted of an integration platform, a new developed DMZ (demilitarized zone) of trading systems and energy trading systems as presented in Figure 5. During EU-SysFlex a DMZ of trading systems was developed in oder to transfer market and real-time data between the IoT platform and energy trading systems. The DMZ is mandatory for the IoT platform to be operated as an aggregation platform for decentralized assets. The DMZ of trading systems was developed by a subcontractor.

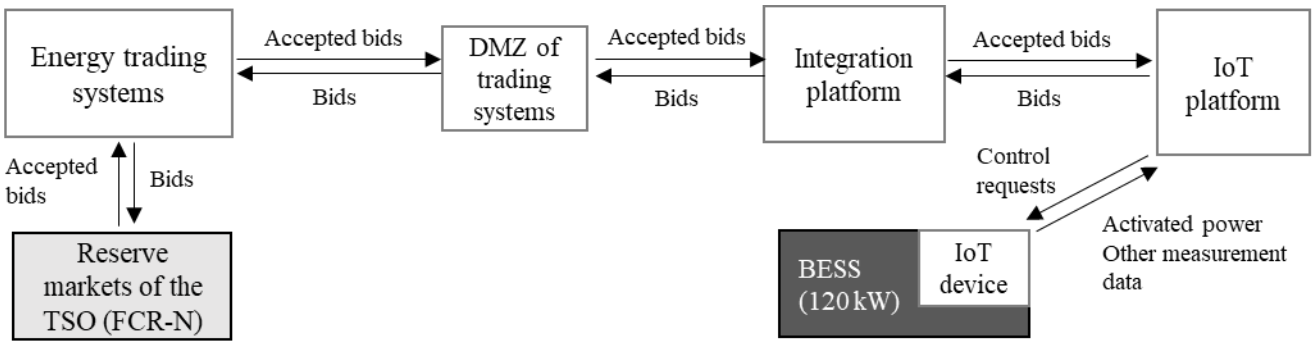


FIGURE 5. OFFICE SCALE BESS

Customer scale BESS

Small scale residential BESSes were owned by the customers. The BESSes were connected to the DES aggregation platform that was under development by Tieto a Finnish software company. Operational logics for BESS control were developed to the aggregation platform by the subcontractor. Figure 6 illustrates the interfaces between the customer scale BESSes and the used aggregation platform. This aggregation platform was a third platform developed by Tieto and used by Helen in EU-SysFlex and it was connected to Helen's integration systems.

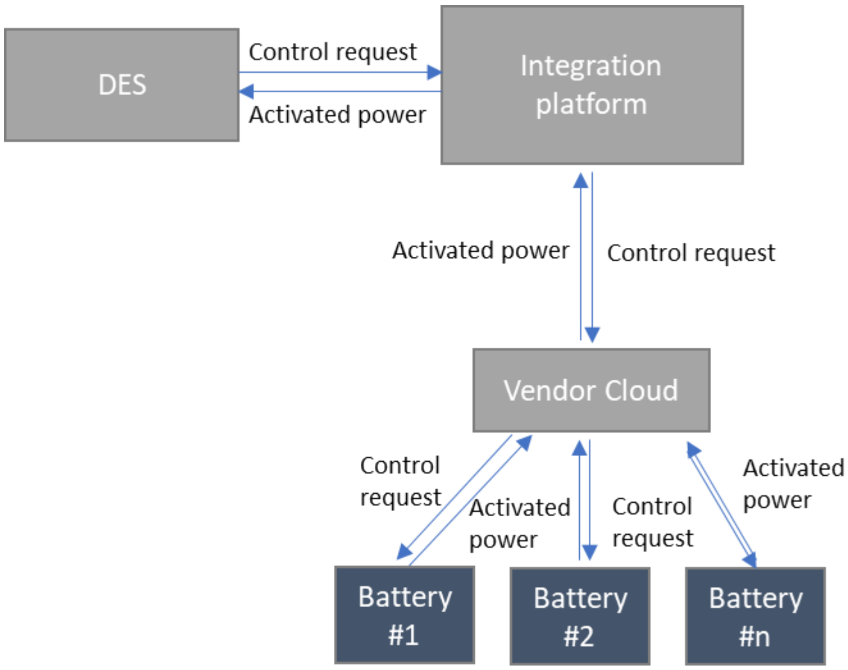


FIGURE 6. CUSTOMER SCALE BESS

Electric Vehicle (EV) charging stations (*Virta*)

An existing user interface (UI) called Virta Energy Platform and it's back-end were used for the EV charging demonstration. This platform handled communication between the UI and the charging points. Figure 7 shows the interfaces of the EV charger demonstration. The EV charging demonstration used charge points which were installed prior EU-SysFlex for the customers. In total, eight private AC chargers at a smart office environment and one Helen's public DC fast charger were used in the demonstration.

A new control logic was developed for demand response by Virta Ltd. in cooperation with Helen. The developed logic enabled to limit charging power to the connected charge point fleet. In addition, a user interface section was created for the control logic to the existing Energy Platform UI where the user could enable and disable the use of the logic and insert setpoint parameters. The developed control logic was called FCR step function. The parameters to the FCR step function were frequency activation limit, frequency deactivation limit, time delay and power limitation. The FCR step function was developed to match the Finnish TSO Fingrid's FCR-D technical requirements. In addition to user input parameters, grid frequency and charging power of charge point fleet were other input parameters for power reduction logic.

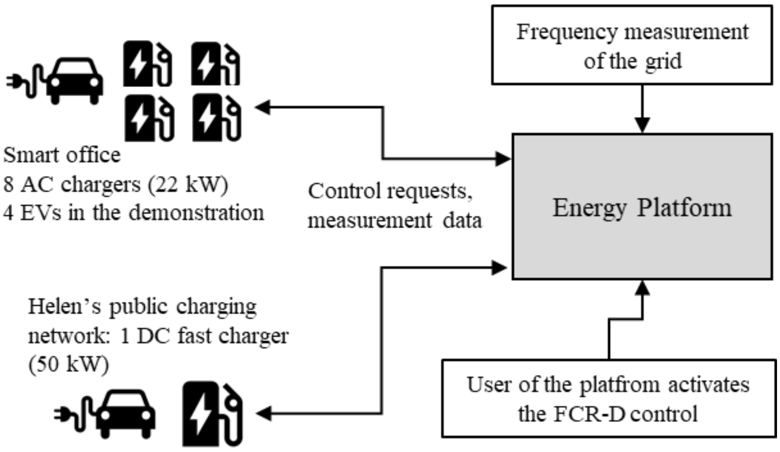


FIGURE 7. EV DEMO SET-UP

Electric Vehicle (EV) charging stations (*Wapice-3rd party*)

In addition to the EV charging control demonstration with Virta, another charge point control demonstration was done with a 3rd party. In this demonstration, the complete flow from an IoT platform UI to a single charge point was developed. The interfaces are shown in Figure 8. An OCPP (open charge point control protocol) charger was installed on a customers site and the charger was connected to an open source charge point controlling OCPP capable platform. Additionally, the charge point controlling platform was integrated with an IoT platform. To the IoT platform simple UI dashboard was created which enabled users to set desired charging current limitations.

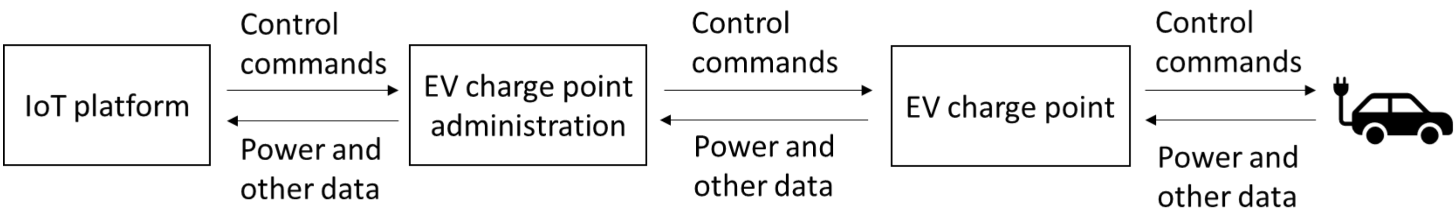


FIGURE 8. EV2 DEMO SET-UP

PV plant reactive power

The Kivikko PV power plant was used for reactive power control during the EU-SysFlex project. The PV power plant was connected to an IoT platform with an IoT device prior to the reactive power compensation demonstration. New interfaces and control logics were developed for controlling the reactive power shown in Figure 9.

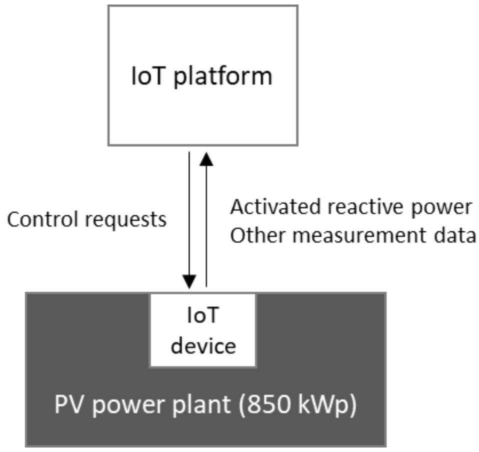


FIGURE 9. PV POWER PLANT Q-POWER

3.3 FORECASTING

Forecasting is a crucial part of any flexibility activity but it is further emphasized in the case of small scale and distributed assets. Small scale assets cannot provide enough flexibility on their own, so they have to be aggregated into a pool that is then used for flexibility provision. In order to successfully bid flexibility to e.g. a specific market place and operate the pool in response, forecasting is needed. During EU-SysFlex, different sets of forecasting tools were developed by VTT based on the data provided by Helen. These forecasting tools encompass three tools related to active power that are aimed for an aggregator's needs and one tool related to reactive power that serves the DSO needs. The different forecasting tools are described in detail in the EU-SysFlex deliverable D6.2: *Forecast: Data, Methods and Processing. A common description.* the following paragraphs give a short summary of each tool.

Forecasting tool for households with electric heating having storage (hot water tank)

The electric heating of the households can be controlled via the AMR systems (Automatic Meter Reading). The tool forecasts the heating needs for houses with a hot water storage unit used for space heating and domestic hot water. The storage is large enough so that charging once per day for a couple of hours is enough to load up enough heat for the whole day. The forecasting tool forecasts the heating needs throughout the day but can also predict how the heating system will react to changes and commands resulting from the operation of the AMR-connected switches. The tool also predicts the available times and amounts for up and down regulation, which could be bid to the TSO ancillary services (studied market mFRR). The tool has been utilized in the simulated case scenarios presented in Chapter 4.1.6 and in ANNEX I.

Electric Vehicle (EV) charging stations

The forecasting tool is used as a basis by an optimization tool in order to bid the capacity available from a set of public EV charging stations to the flexibility markets. The forecast is intended to give an estimate of how much capacity can be made available for specific markets by estimating the usage of the EV charging stations. In this case, the target markets are the frequency containment reserves (FCR) markets.

Customer-owned small scale batteries

The tool is made in the context of individual households owning PV panels and a battery, with its primary use being to store and use locally as much of the PV production as possible. The objective of the forecast is to identify how much of the batteries capacity has to be reserved for that purpose and cannot be used to be bid on other markets.

PQ window compliance tool

The tool is a preliminary step in the operation of the DSO managed reactive power market. The question that needs to be solved is to know how much additional reactive power services the DSO should procure from the demonstrated market in order to minimize the costs charged by the TSO when the exchanges between the distribution and transmission networks are out of bounds of the permitted active (P) to reactive (Q) power ratio, referred to as the PQ window.

3.4 OPTIMIZATION

In the Finnish Demonstration, optimization is closely related to forecasting and often it can be difficult or even impossible to consider them as separate functionalities. During EU-SysFlex, two optimization tools have been developed in cooperation with VTT. Both are related to the operational and bidding strategy of assets on the frequency regulation markets, and have been developed for the need of the aggregator. These two optimization tools are described in detail in the dedicated EU-SysFlex deliverable D6.5: *Optimization tools and first applications in simulated environments.* the following paragraphs give a short summary of both tools.

Battery Energy Storage System (BESS, rated 1.2 MW and 600 kWh)

As a result of tests in which the BESS was operated continuously with its maximum capacity, it has been noticed that the BESS is very often running itself completely full or completely empty. This is not efficient and hence optimization measures have to be applied. There is an incentive to stop providing the FCR services at specific times and instead charge or discharge the battery in order to bring it back closer to a SOC (State Of Charge) of 50 %. In the optimization, a balance must be found between the benefits of allowing the BESS to provide its services during more time periods on one hand and the costs of running the battery as well as imbalance costs on the other. Finding this balance is where the optimization process can take place. Therefore forecasting tool aims to minimize the impact of the times when the battery is unable to provide frequency containment reserves (FCR-N) and to find optimal bidding price/strategy to maximize the income from the FCR-N market.

EV charging stations

The optimization tool uses the forecasting tool as a basis. Its objective is to determine how much power the aggregator should bid on the markets. In order to maximize the revenues from providing the service, the optimization algorithm has to find the balance between the increased revenues due to bidding and providing higher amounts of frequency products with the cost of being charged penalties for failing to provide the promised services. As a result, the tool gives an optimal power curve that shows available flexibility for each hour of the day (i.e. bidding curve). The tool shows available capacity to be bid for FCR-N and FCR-D. FCR-D is the best market for "regular one-way" charging stations, since the market is only for up regulation.

4. DEMONSTRATION SET-UP AND RESULTS

This chapter describes the different field tests conducted during EU-SysFlex as well as their results. The chapter is divided into sub-chapters for each individual demonstration. First, demonstrations and field tests regarding active power are presented and after that the demonstrations regarding reactive power.

4.1 ACTIVE POWER DEMONSTRATION

Active power field tests include five different demonstrations: three battery demonstrations, EV charging station demonstration and the AMR control demonstrations. The set-up and results of these demonstrations are described in the following chapters.

4.1.1 SUVILAHTI LARGE SCALE BESS DEMO

Introduction

A Battery Energy Storage System (BESS, 1.2 MW and 600 kWh, ±900 kvar) located in Suvilahti, Helsinki (referred later as “Suvilahti BESS”) has provided a research platform for Helen since August 2016. The purpose of purchasing the battery was to demonstrate the multi-functionality of the battery and its technical capability to provide services for several stakeholders. To learn the best practises in the operating environment of the battery, its limitations and to identify possible needs to make changes to the regulations, also local DSO (Helen DSO) and the Finnish TSO (Fingrid) participated the “Suvilahti BESS research project”. In addition to the own research project of the battery (which started in August 2016 and ended in August 2019), the battery has operated as a research platform in two EU funded research projects, EU-SysFlex and mySMARTLife [11]. The next subchapters will describe the testing phase of the battery as well as the operation of the battery in the FCR-N market. The operation of the BESS in the FCR-N market has been one of the key objectives of the EU-SysFlex Finnish Demonstration.

FIGURE 10. BATTERY ENERGY STORAGE SYSTEM IN SUVILAHTI, HELSINKI. SOURCE: HELEN LTD.

The infrastructure of the Suvilahti BESS is in two containers: one container has the battery cells, inverters and control devices and the other has the transformers and the MV (medium voltage) switchgear. The normal operation for the BESS is to produce or consume 1.2 MVA, but it has capability to be operated with a maximum apparent power of 1.8 MVA for up to 30 seconds. The Suvilahti BESS is connected to medium voltage (10 kV) network and it is in the same grid connection point with a PV power plant (380 kWp) and two electric vehicle charging stations.

The smart grid entity of Suvilahti is supplied by a MV feeder from the Suvilahti 110/10 kV substation, which is one of the 25 primary substations of the local DSO. The substation has two main transformers with nominal rating 31.5 MVA and 47 medium voltage feeders. The loading density in this area is high and thus, the lengths of the feeders of the distribution network are short. The local power system is strong with a short circuit power of 230 MVA on the MV side.

4.1.1.1 TESTING PHASE

Helen tested different operations of the Suvilahti BESS during the testing phase and as a part of different research projects that the battery participated in. The main research questions were

1) How to provide ancillary services to TSO, such as reserve power in FCR-N market
2) How to implement peak power shaving and energy time shifting for the DSO's needs such as smoothing out PV production, shaving dynamic office electricity consumption loads and shaving the metro acceleration and braking peak powers from neighboring substation
3) How to provide voltage control and reactive power compensation services to the local DSO

During the research and testing phase, various frequency control characteristics with different power-frequency curves, SOC target values, dead bands, and recovery (charging or discharging) power values were tested. During the testing phase, operation according to FCR-N and FCR-D market rules were also tested.

Furthermore, multioperations of the battery were tested which included e.g. simultaneous use of FCR and voltage regulation and either voltage regulation or reactive power compensation depending on the time of the day in addition to the frequency control, which was active all hours. More information on the different tests of the battery can be found in [12], [13] [14].

Outcomes of the testing phase

One of the most promising applications for the Suvilahti BESS is the participation in the TSO's reserve power markets, namely FCR-N or faster markets. Advantages of a BESS for FCR operations include extremely fast reaction time. The reaction time of a BESS to achieve full power is few hundreds of milliseconds compared to traditional reserve power suppliers' tens of seconds. This is beneficial as the inertia of the power system is expected to decrease in the future as renewables replace traditional power generation. Therefore, battery energy storage systems would also be suitable assets to operate in the fastest markets, like FFR, which is targeted to handle situations of low inertia. The FFR started operations in May 2020 in Finland.

During the testing phase of the battery, if the battery operates continuously according to a control curve of the FCR-N market, it was noted that the battery is reaching its capacity limits and either being too full or too empty resulting in a failure of delivery. Therefore, there would be lost revenue from ancillary service markets if the battery is operated continuously in the market, i.e. all hours are bid and accepted. According to the tests, the availability of a BESS for market operations was higher when there was within a wider dead band an active SOC control with a recovery power. However, the SOC management should be fitted to the technical requirements of the TSO's frequency markets in order to operate successfully and avoid penalties. A need to define a suitable bidding logic was identified and one of the tools of the EU-SysFlex Finnish demonstration tackles the issue of how to operate the BESS optimally in the FCR-N market to maximize revenues.

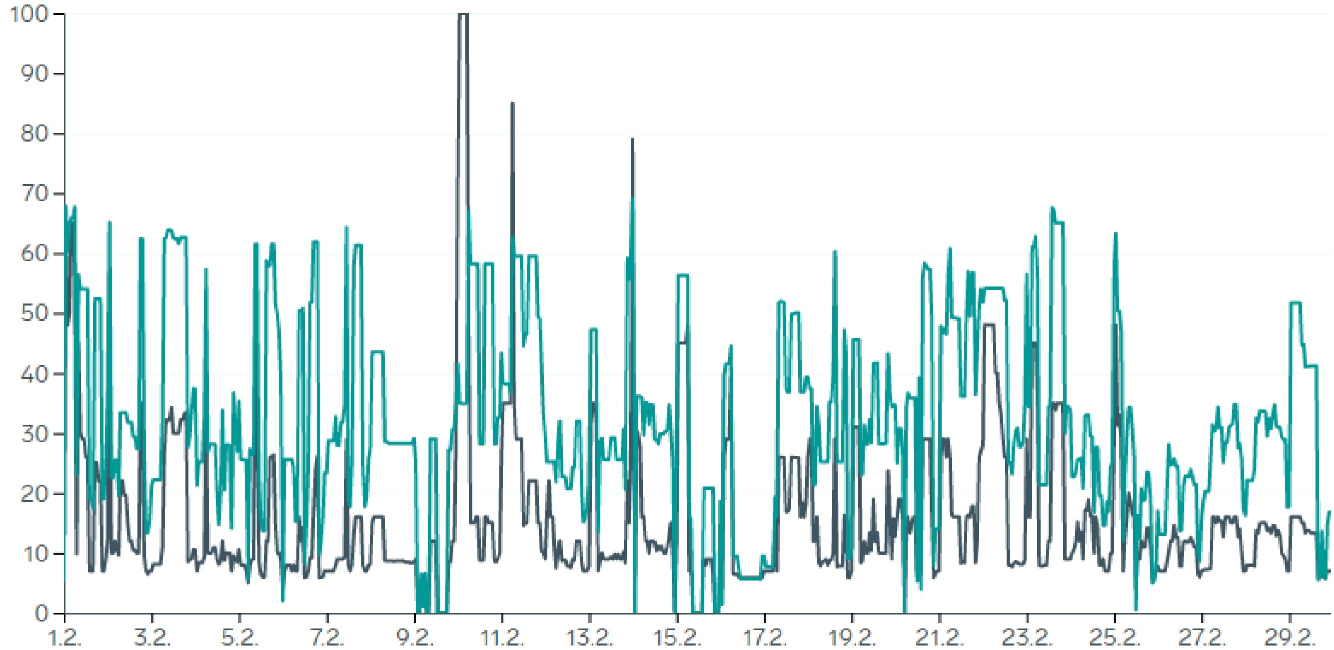
After the technical research and testing phase, the next step was to build suitable communication channels and control logics for the battery in order to start business operation in the FCR-N market. The next subchapter describes the operation of the battery in the FCR-N market.

4.1.1.2 DEMONSTRATION SET-UP

During the end of 2019 and beginning of 2020 the communication interfaces and control logic of the Suvilahti BESS were finalized. The battery has been operated in the FCR-N market since the end of January 2020. The BESS is connected to Helen's current aggregation platform via standard IEC 104 - connection. The aggregation platform communicates with Helen's trading system, which is the link to the TSO ancillary markets. In the case of Suvilahti BESS, the aggregation platform does not include any calculations or control logic regarding the frequency regulation. It merely sends an activation signal to the BESS which states, whether or not the bid for the current hour was accepted by the TSO. The actual control logic of the battery is located on the local computer of the BESS. If the bid was accepted, the BESS receives this information from the aggregation platform and follows the correct control curve defined on the local computer. If the bid was not accepted, the hour is used for the BESS to recover towards the SOC of 50 %.

4.1.1.3 RESULTS

Apart from short maintenance periods the BESS has been offered to the FCR-N market every hour. However, the revenue has fluctuated significantly between individual months because of the price volatility in the hourly market. The Finnish TSO Fingrid maintains two different markets for both FCR-N and FCR-D. There is a yearly market, where the price is set for the whole year, and an hourly market, where the prices as well as acquired volumes vary for each hour depending on the demand and supply. In Figure 11, the hourly prices and volumes for FCR-N in Febuary 2020 are depicted. In February 2020, the price has varied between 0 and 100 €/MW/h.



Name	Minimum	Maximum	Average
Price of frequency controlled normal reserve in hourly market	0	100.00	15.79 €/MW
Volume of frequency controlled normal reserve in hourly market	0	69	33 MW

FIGURE 11 FCR-N HOURLY PRICES AND VOLUMES IN FEBRUARY 2020 [15]

The amount of penalties has also fluctuated between different months. Some penalties can be explained by faults and communication errors, which have led to situations where the bids have already been sent to the TSO but the battery was unable to provide any regulation. Examples of such situations include inverter failures, which occur from time to time, failure of the communication link between the BESS and the aggregation platform or the freezing of information flow on the local computer of the BESS or aggregation platform. In addition to these events, some penalties occur every day due to the limited energy capacity of the battery. If the battery is either too full or too empty, it cannot provide enough regulation according to the frequency. These penalties are very hard to forecast and they vary more or less randomly depending on the grid-frequency. It is also important to note that the revenues and penalties go hand in hand. If a FCR-N provider fails to provide the energy promised on the market, they must pay a penalty that is equal to the revenue. Thus, if the hourly prices are high, also the penalties occuring during those hours will be higher.

4.1.1.4 KPI RESULTS

The industrial scale-demonstration is evaluated through KPI's 1, 4, 5b and 7 of the Finnish demonstrator.

KPI1 Increase in revenue of the flexibility service provider

The industrial scale BESS participated during the demonstration to the TSO's power reserve market. The increase in revenue was gained from operating in the reserve market in February to December in 2020. From the market data it was found out that the BESS could deliver appriximately 80 % of the hours during the test period. The yearly increase in revenue can be calculated as:

$$R = \sum_{s \in S} \sum_{a \in A} \sum_{t=1}^{T} P_{s,a,t} * \pi_{s,a,t}$$

where

S is the set of available markets = FCR-N

A is the set of available resources = 1 BESS

T is the amount of hours bidded to market = 8760 h (8016 test period)

P is the realized power exchanged = 0.5 MW (* 80 % delivery)

π is the price (FCR-N average hourly price on the hourly market during operation) = 22.00 €/MW,h

Thus, the theoretical maximum increase in revenue calculated is 77 088 € per year (6 424€/mo). Real operation in market and increase in revenue is shown in Table 2 and it is clearly seen that the revenue is much lower then the calculated maximum.

In the summer of 2020, the battery has operated on the FCR-N market for 5 whole months. Based on this period, the revenue that the BESS is able to create for the aggregator is roughly 100 - 200 €/day (KPI no.1) , depending on the market prices and grid-frequency fluctuations. However, on top of this, some costs incur with the reserve operation. The BESS that is owned by the aggregator represents a connection point to the grid like any other MV-customer. This means that the aggregator needs to pay a distribution fee as well as an energy fee for the charged electricity. For the electricity that is discharged from the battery, the aggregator is being remunerated, so in the end the energy fee consists of the losses that happen in the battery. Usually a customer also needs to pay the electricity tax for the energy that is consumed [16]. The Suvilahti BESS, however, is exempt from this obligation since it is a battery that is directly connected to the distribution grid, and no electricity is being discharged directly into consumption.

TABLE 2. REVENUE OF SUVILAHTI BESS IN 2020

2020	
January	-
February	2901,00 €
March	4552,28 €
April	628,48 €
May	7468,21 €
June	5596,75 €
July	7681,46 €
August	2439,34 €
September	3051,45 €
October	3743,91 €
November	6174,86 €
December	946,11 €
Total	45183,85 €
	4107,62 €/month

The revenue from Suvilahti BESS in 2020 was 45183,85 € and on average the revenue was 4107,62 € per month. The result indicates that the revenue increase is rather good. The difference between the calculated increase in revenue and actual revenue is mainly due to misbehavior of the BESS and issues with the aggregation platform. However, variation in revenue is high as Fingrid purchases flexibility services only when needed. One aspect is that frequency containment reserve purchasing is dependent on weather conditions. For example in May 2020, snow melting caused major flooding risk in the north of Finland and thus hydro power plants were not able to participate to the frequency containment reserves with high volume thus increasing the price Fingrid purchases the flexibilities from the market.

KPI4 Flexibility service reliability

The reliability of the service that the battery provides is evaluated in KPI no. 4 of the Finnish demonstrator (Flexibility service reliability). In this KPI, the RMSE (Root mean squared error) between the hourly accepted bids and the realized power exchanges is calculated. Table 3 below summarizes the results of the calculations between February and June 2020. As it can be noticed, the RMSE varies quite a lot even on a monthly basis, although most of the bigger differences are evened out. The big RMSE in April, for example, is partly explained by some trouble in the communication between the systems. In May, however, the error is simply based on the grid-frequency and unwanted situations where the battery has drifted to being either full or empty.

TABLE 3 RMSE OF THE SUVILAHTI BESS POWER EXCHANGES IN THE FIRST HALF OF 2020

2020	RMSE	Unit
January	-	
February	0.144682	MW
March	0.116094	MW
April	0.194919	MW
May	0.156629	MW
June	0.204595	MW

The Suvilahti BESS operated in the FCR-N market in the year 2020. In Table 4 below, the RMSE of the operation (KPI no. 4) is calculated again for the whole year. As it can be seen, there are no major changes in the RMSE error values between the first and the second half of the year. On average the RMSE is 0.174 MW which represents approx. 35 % of the offered capacity.

TABLE 4 RMSE OF THE SUVILAHTI BESS POWER EXCHANGES BETWEEN FEBRUARY AND DECEMBER 2020

2020	RMSE	Unit
January	-	
February	0,144682	MW
March	0,116094	MW
April	0,194919	MW
May	0,156629	MW
June	0,204595	MW
July	0,201959	MW
August	0,183107	MW
September	0,190589	MW
October	0,149168	MW
November	0,124184	MW
December	0,248676	MW
Average	0,174055	MW

In December, the BESS malfunctioned and it thus failed to provide flexibility services and because the BESS was bidded to the reserve market the RMSE increased. There were several issues in the end of December and before noticing and fixing the problems the BESS was sold to the market for sevelar days.

KPI5b: Usability of the asset

The BESS in Suvilahti sends messages of error situations (e.g. inverter failure, stop, shutdown). The usability of the asset has been calculated based on the error messages of the BESS. The usability of the asset is calculated from February 2020 to December 2020. During that time the BESS operated in the FCR-N market of the TSO. The usability is calculated from

$$\boldsymbol{AV}[\%] = \frac{\boldsymbol{T_{com}}}{\boldsymbol{T_{op}}} \times \mathbf{100}\%$$

where

$\boldsymbol{T_{com}}$ [s] is the total duration in which the asset is working correctly as defined in the demonstration specifications and $\boldsymbol{T_{op}}$ [s] is the total operational time of the asset during the tests carried out. Suvilahti BESS was operating as expected approximately 7599 h during the test period of 8016 h. Thus, the usability of the asset was

$$\boldsymbol{AV}[\%] = \frac{7599\ h}{8016\ h} \times \mathbf{100}\%$$

$$\boldsymbol{AV}[\%] = \mathbf{94.8}\ \%$$

The usability of the asset was not as high as expected as the BESS had several failure situations. This is due to poor design and programming of the BESS. However, the downtime did not significantly affect the revenue and profits gained except when the BESS malfunctioned in the end of December.

KPI7 Profits of service provision

Suvilahti BESS operated most of the year 2020 in Fingrid's FCR-N market and operation with the BESS in the market began in February. Table 5 presents the revenue from the reserve market, service provision of aggregation platform, distribution energy and power costs and the net profit from the year. The net profit is calculated from

$$R_{net}(T) = R(T) - C(T)$$

where

$$C(T) = C_{gridE}(T) + C_{gridP}(T) + C_{spot}(T)$$

$$C_{gridE}(T) = \sum_{n=1}^{T} P_{mFRR}(n)\pi_{gridE}(n)$$

$$C_{spot}(T) = \sum_{n=1}^{T} P_{mFRR}(n)\pi_{spot}(n)$$

A total net profit of 22 259 € was gained from the eleven operational months. The year 2020 was a great year for flexibility services in the FCR-N market as the hourly market prices were high from May to the end of June. Additionally, during these three months almost half of the revenue was gained.

TABLE 5. PROFIT OF SUVILAHTI BESS IN FCR-N MARKET OPERATION

2020	Revenue [€]	Service provision [€]	Distribution, energy [€]	Distribution, power [€]
January	-	-	-	-
February	2901,00	-435,15	-373,7	-1512,48
March	4552,28	-682,84	-235,73	-912,64
April	628,48	-94,27	-154,34	-916,32
May	7468,21	-1120,23	-163,18	-942,08
June	5596,75	-839,51	-169,93	-1387,36
July	7681,46	-1152,22	-169,99	-816,96
August	2439,34	-365,90	-166,74	-732,32
September	3051,45	-457,72	-246,83	-1637,6
October	3743,91	-561,59	-286,86	-1126,08
November	6174,86	-926,23	-332,24	-2005,6
December	946,11	-141,92	-445,15	-1413,12
average	4107,62	-616,14	-249,52	-1218,41
Total	45183,85	-6777,58	-2744,69	-13402,56
Profits	22259,0225	€		
	2023,55	€/month		

The earned net profit is decent. However, the net profit would have been greater if the aggregation platform would not have failed in the end of the year. Additionally, state of charge optimizing would decrease penalties in the FCR-N market avoiding situations when the BESS depleats or is fully charged and no longer can maintain reserve power and thus increase profit. Notably, the power tariff is a big cost while operating the BESS as seen in Table 5.

4.1.2 CUSTOMER SCALE BATTERIES

Introduction

Customer scale batteries were purchased by Helen’s customers to their premises. The customers have so far been forerunners as the BESS prices have been high and technology has become viable finally in the past several years. All the BESSes involved in the demonstration were combined with residential PV. In addition, the customers voluntarily participated to the demonstration. In total 13 residential BESSes were used in the demonstration. The maximum power of the BESSes varied from 1.5 kW to 5.5 kW with an average output of 3 kW charging and discharging.

4.1.2.1 DEMO SET-UP

The first field tests with the customer scale batteries were conducted in December 2019 during a two-week period. The aim of the demonstration was to connect all household batteries to an aggregation platform and control them as a pool according to the frequency regulation (FCR) rules of the Finnish TSO Fingrid. The aggregation platform used for this was the aforementioned new and piloted aggregation platform (DES, distributed energy solution) that was provided by Tieto, a Finnish IT software and service company.

The demonstration included 13 household batteries with an energy capacity ranging from 1.5 kWh to 16 kWh. The maximum power output of the batteries was on average 3 kW. Thus, the overall maximum flexibility that could be provided was around 40 kW. However, this is not enough to satisfy the minimum requirement of the TSO, which is 0.1 MW on the FCR-N market. Thus, the batteries were not actually bid to the flexibility market but only controlled according to the rules.

The demonstration set-up was as follows: All 13 batteries were connected via REST API to the piloted aggregation platform. This way the platform could send as well as receive information, such as charging/discharging power and SOC from the batteries. The platform had a built-in logic, how to control the pool of batteries according to the real-time frequency of the power system. In order to avoid causing too much inconvience to the owners of the batteries at this stage, the batteries were controlled only for a single hour each day for the duration of approx. two weeks. The control hour was chosen randomly for each day. Table 6 below presents the control hours.

TABLE 6 CONTROL TIMES OF THE CUSTOMER SCALE BATTERIES DURING THE DEMONSTRATION PERIOD

13.12.2019: **6:00 - 7:00**	20.12.2019: **15:00 - 16:00**	27.12.2019: **3:00 - 4:00**
14.12.2019: **10:00 - 11:00**	21.12.2019: **6:00 - 7:00**	28.12.2019: **6:00 - 7:00**
15.12.2019: **11:00 - 12:00**	22.12.2019: **16:00 - 17:00**	29.12.2019: **10:00 - 11:00**
16.12.2019: **4:00 - 5:00**	23.12.2019: **3:00 - 4:00**	30.12.2019: **8:00 - 9:00**
17.12.2019: **9:00 - 10:00**	24.12.2019: **4:00 - 5:00**	31.12.2019: **1:00 - 2:00**
18.12.2019: **8:00 - 9:00**	25.12.2019: **18:00 - 19:00**	
19.12.2019: **18:00 - 19:00**	26.12.2019: **15:00 - 16:00**	

The main goal of the demonstration was to observe the performance of the aggregation platform as well as the response of the customers. Customers were informed beforehand of the demonstration phase, and afterwards their feedback was collected. Most of the customers did not notice the demonstration having effect on their BESS operation and only a couple who looked more into detail notice the some of the test days. All of the customers were satisfied with the demonstration.

The control logic of the batteries was built into the aggregation platform and no changes to the local software or control logic of the batteries were required. This is important considering the scalability and feasibility of such flexibility operations in the future. If changes to the local software or hardware are required, the costs of setting up the flexibility readiness of small scale batteries rise immediately. The aggregation platform also had the ability to estimate the available flexibility of the battery pool according to the usage history.

4.1.2.2 RESULTS

In general, the demonstration phase with the customer scale batteries was successful. The batteries were successfully connected to the aggregation platform and controlled according to the pre-defined schedule and the grid-frequency. However, some challenges and shortcomings were also identified and important lessons were learned during the test period. Figure 12 below presents the state of charge of the individual batteries in the aggregated pool during one single control hour (28.12.2019: 6:00 - 7:00). This is a good example of the successful operation of the battery pool. Apart from one battery (uppermost graph), all batteries are empty at at the beginning of the control hour. During the control hour, the batteries start charging and their SOC rises (down-regulation). During this particular control hour this is well visible because the frequency remained above 50,05 Hz for a long time. The frequency of the same hour is depicted in Figure 13.

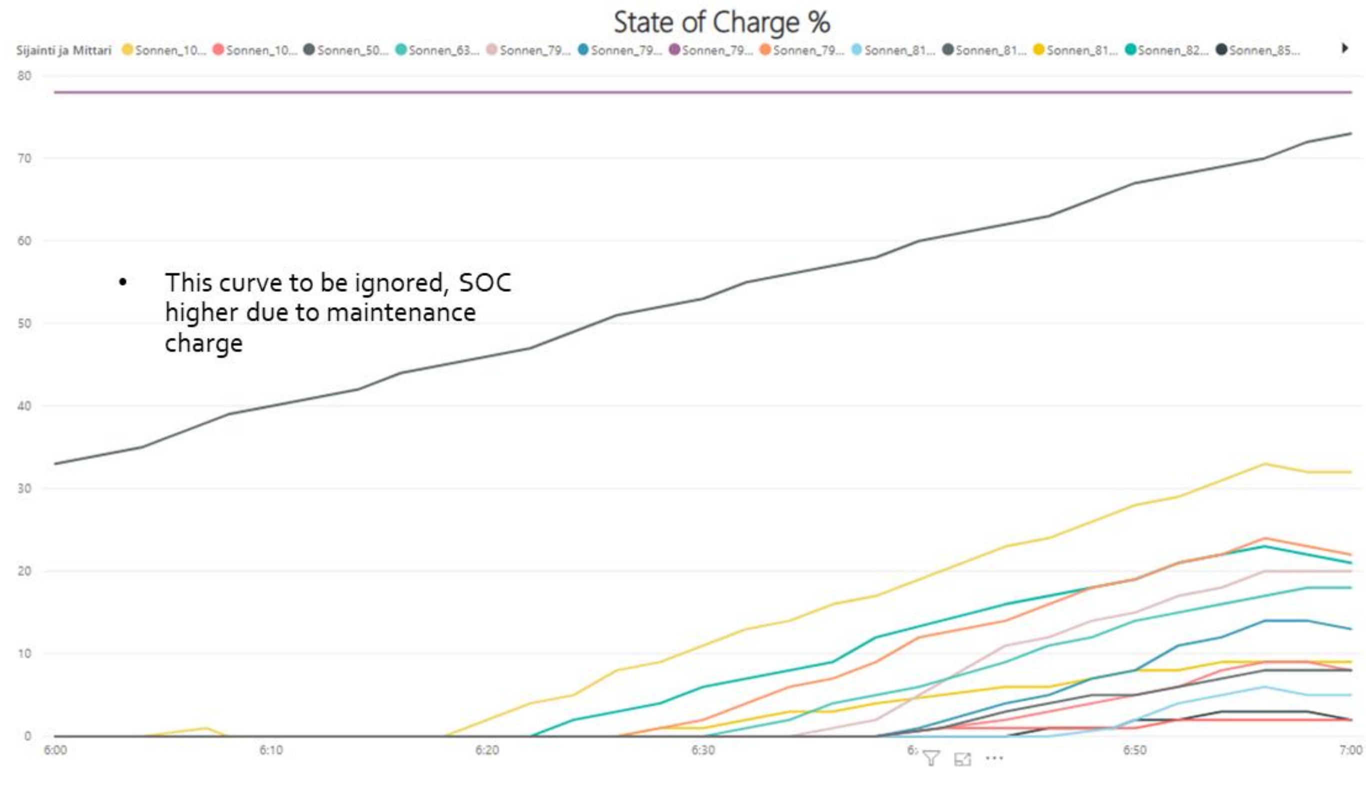


FIGURE 12 STATE OF CHARGE OF ALL PARTICIPATING BATTERIES DURING A SINGLE HOUR - 28.12.2019 06:00-07:00.

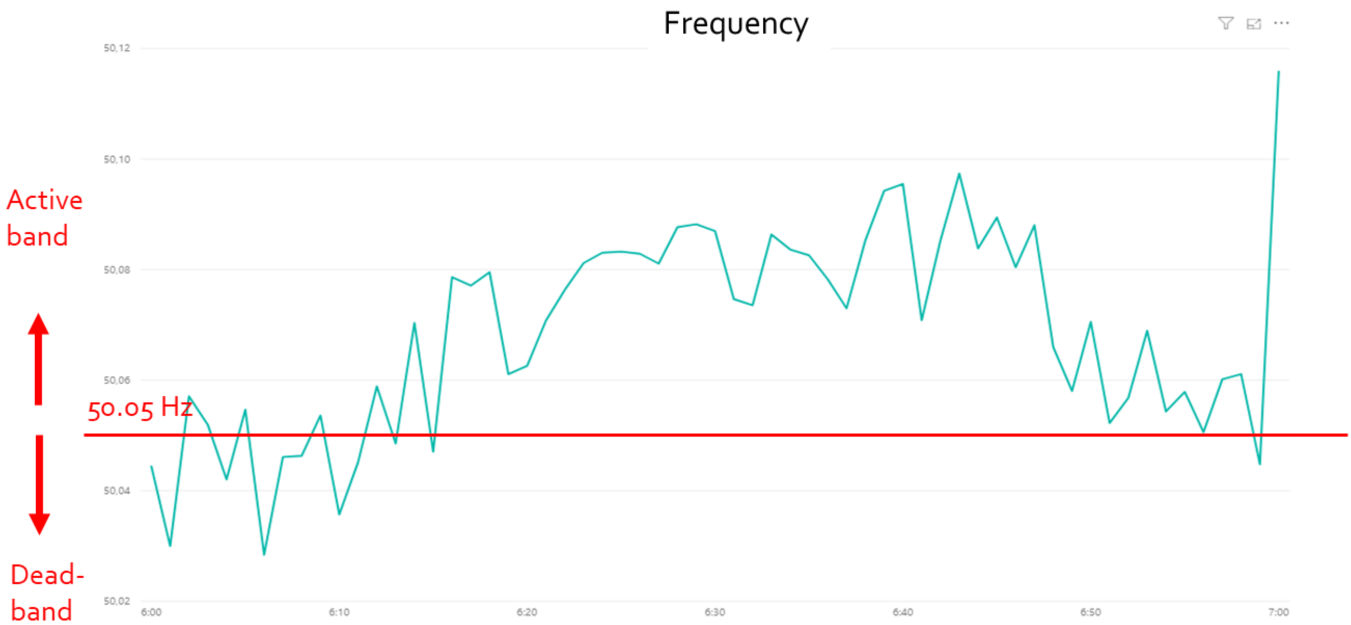


FIGURE 13 FREQUENCY OF THE GRID - 28.12.2019 06:00 - 07:00

The challenges faced in the demonstration were manifold. At the start of the demonstration phase, the control logic of the aggregation platform was under development, not yet complete and tested only fractionally. This resulted in control issues as the batteries did not receive all control commands sent by the platform. Towards the end of the first week of the demonstration period, this issue was fixed. Another issue stemmed from the symmetrical nature of the FCR-N market combined with the internal logic of the batteries. The batteries are installed in households with solar PV production and they are programmed to charge whenever there is excess solar PV production and discharge at all other times. This means that, firstly, during winter months in Finland, when there is little to no PV production, the batteries are mostly empty. This caused many control commands to fail during the demonstration period. If the aggregation platform sent a discharging signal to the battery, but the battery was empty to begin with, the command failed. Secondly, if during a control hour, the battery was released from the aggregation platform's "grip", the battery immediately started discharging, regardless of the frequency. This has been visualized in Figure 14 with a single battery.

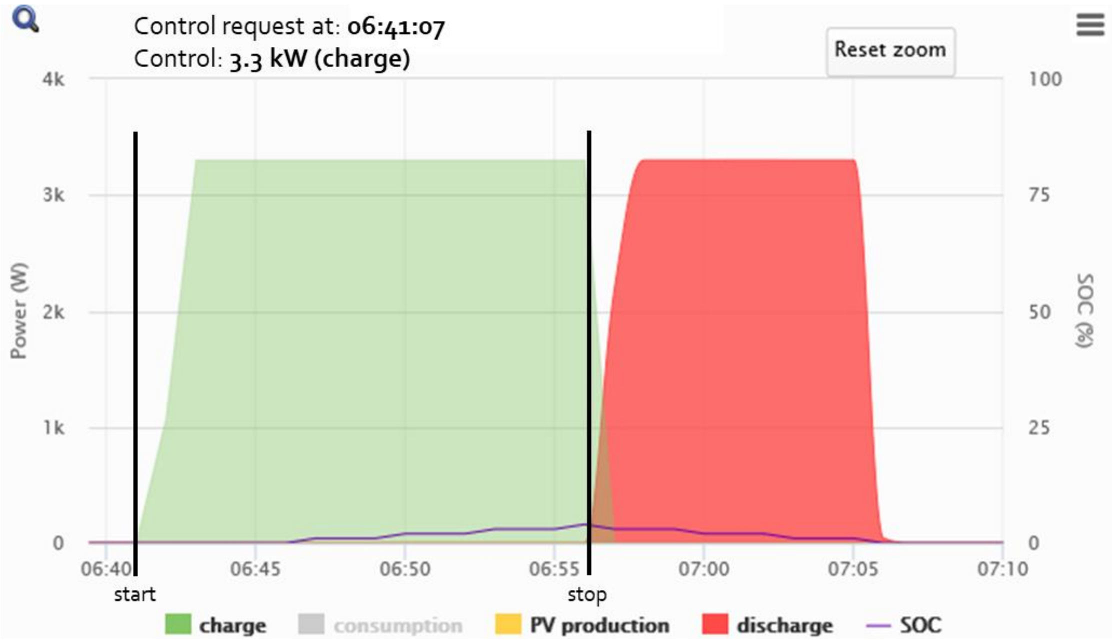


FIGURE 14 EXAMPLE OF THE CONTROL OF ONE BATTERY DURING A CONTROL HOUR

These challenges can be addressed by keeping the batteries under the control of the platform the whole time the pool is active on the market and by preparing the batteries (charging or discharging them to a suitable state of charge) before the active hour. These solutions were identified but not yet implemented during the pilot project of the aggregation platform, i.e. first demonstration period.

There were also some problems with the monitoring of the control responses as well as with meeting the desired amount of flexibility. Like mentioned above, the aggregation platform software was able to estimate the available flexibility from the battery pool according to historical data. However, the data gathered from the batteries before the demonstration period was rather scarce and took place during winter months, which made it more difficult to estimate the “bid-size”. It was noticed that the aggregation platform usually suggested a relatively small amount of flexibility for the control hours, because the share of time when the batteries are empty is really significant.

Regarding the monitoring of the control responses, the aggregation platform did not follow the control responses of the batteries with a sufficient accuracy, which made it hard to determine, which batteries had really been controlled during each hour. Furthermore, a specific feature of the batteries made the monitoring more difficult. Namely, during the times when the batteries are mostly idle, they perform full charge - discharge cycles from time to time that are controlled by the manufacturer. It is believed, that these are designed to keep the battery operational and maintain the condition and health of the cells. These full charge cycles occur more or less at random times in the pool, and this of course affects the availability of the batteries for flexibility as well as the monitoring of the responses. In Figure 15, the state of charge of all batteries is visualized over the whole duration of the demonstration. The full charge-discharge cycles are clearly visible and they are usually not in line with the control hours randomly picked for the battery pool.

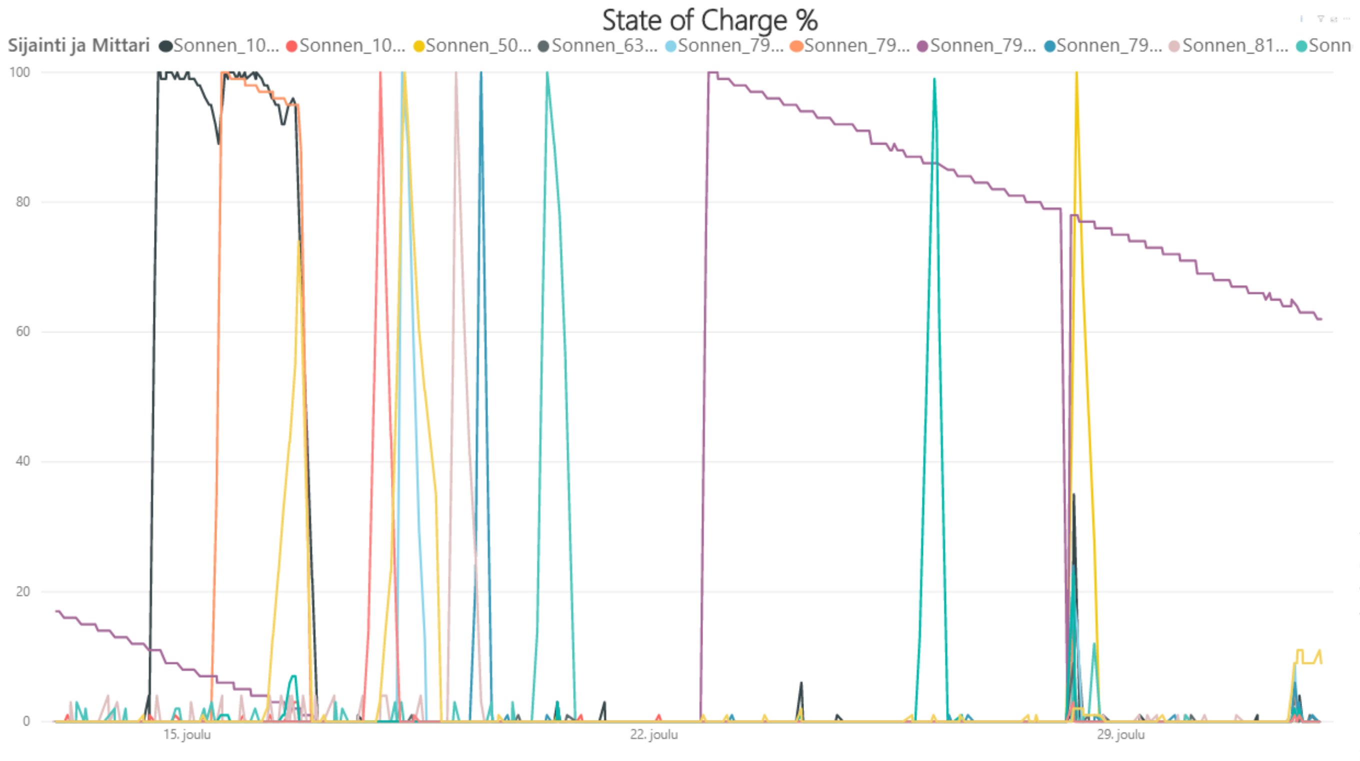


FIGURE 15 STATE OF CHARGE OF BATTERIES OVER THE DURATION OF THE DEMONSTRATION PHASE

4.1.2.3 KPI RESULTS

The customer scale-demonstration is evaluated through KPI's 1, 5a, 6 and 7 of the Finnish demonstrator.

KPI 1: Increase in revenue of the flexibility service provider

The custormer scale BESS flexibility demonstration was to show how small BESSes could be controlled and aggregated. The BESSes were not bidded to market. However, KPI no. 1 increse in revenue was calculated as if the small scale BESSes operated in the market. The increase in revenue was calculated using data from 2019 FCR-N hourly market price values and BESS capablilities of maintaining reserve volume. From the BESS data it was difficult to find out how the BESS could deliver reserve power and a assumption of 80 % was used as the reliability of the aggregation platform was poor (KPI no. 5a). The yearly increase in revenue is calculated from

$$R = \sum_{s \in S} \sum_{a \in A} \sum_{t=1}^{T} P_{s,a,t} * \pi_{s,a,t}$$

where

S is the set of available markets = FCR-N

A is the set of available resources = 13 BESS

T is the amount of hours for operation = 2160 h

P is the realized power exchanged per BESS = 3 kW (* 80 % delivery) π is the price (FCR-N average hourly price on the hourly market during operation) = 14 €/MW,h

Thus, there is an increase in revenue of 943 € per year for all 13 BESS and 73 € per BESS. The result indicates that the revenue increase is low. This is mainly due to low hourly prices in the market during winter time and a low operation time in market.

KPI 5a: Reliability of the aggregation platform

The aggregation platform used with customer scale BESSes had major issues as it was at an early development stage and therefore the platform was in continuous development during the tests. Noteably, the integration of the platform to existing systems faced several issues and therefore the tests were not a success. Table 7 presents the amount of sent commands and success rate to the different BESSes during the test period.

TABLE 7. AMOUNT OF SENT COMMANDS AND SUCCESS RATE TO SMALL-SCALE BESS

Device	Control days	Successfull controls	Unsuccessfull controls	Sum	Success rate
1	7	24	6	30	80,00 %
2	4	1	3	4	25,00 %
3	6	3	7	10	30,00 %
4	8	8	44	52	15,40 %
5	10	6	28	34	17,60 %
6	2	2	0	2	100,00 %
7	8	6	8	14	42,90 %
8	9	26	21	47	55,30 %
9	5	12	12	24	50,00 %
10	3	4	2	6	66,70 %
11	4	2	4	6	33,30 %
12	3	1	5	6	16,70 %
13	4	1	6	7	14,30 %

The reliability of the aggregation platform (KPI no. 5a) is calculated from

$$\boldsymbol{AV}[\%] = \frac{\boldsymbol{T_{com}}}{\boldsymbol{T_{op}}} * \mathbf{100\%}\,,$$

where T_{com} is the amount of successful commands (96) from the platform and T_{op} is all commands sent (242). On average the success rate was 39,7 % which is very poor. The result means that most of the sent commands did not reach the BESS and no control was performed.

KPI 6: Customer acceptance

Currently the customer scale BESS owners are forerunners as the BESS prices have been high and financial benefits are unclear. So far only a few customers have purchased a BESS with their PV system. Helen's customers were contacted and discussed a possibility to participate in the demonstration. However, the contracts made with the customers already had a term where Helen could use the BESS for demonstrating distributed assets. All of the customers accepted to participate and thus the acceptance of customer scale battery demo was 100 %.

KPI 7: Profits of service provision

Profit for customer consist of fleet revenue, aggregator provision and expences on electricity. If discharged electricity is consumend on site then additional electricity is not purchased and thus flexibility service does not increase costs. However, if electricity flows back to grid the customer is paid only for the electricity and additional costs from transmission fees and taxes weeken the profits for the customer. The net profit for the customer is calculated from

$$R_{net}(T) = R(T) - C(T) - R_{aggr}(T)$$

where

R_{net} is net income for the customers

R is revenue from the markets (see KPI1)

C is cost for the customers arisen from cost of grid and energy tariff if energy flows back to grid

R_{aggr} is the aggregators provision

Because it is not clear how much energy flows back to grid an assumption of zero is used. The result thus indicates what is the maximum profit a customer can achieve. The aggregators provision is set to 15 % and the profit for the customer is then gained from

$$R_{net}(T) = 0{,}85 * R(T)$$
$$R_{net}(T) = 0{,}85 * 73\ €$$
$$R_{net}(T) = 62\ €$$

The maximum net profit for the customer per year is rather low. The profit is much lower if any excess electricity flows back to the grid and experience shows that in most cases the net profit from the demo could be closer to 30 € per BESS per year. Additionally, use of BESSes for flexibility services might have negative impact on the expected BESS operational lifetime.

4.1.3 OFFICE SCALE BATTERY

Introduction

An office scale battery (120 kW) was installed in summer 2019 at the office of Helen DSO (Figure 16). The battery is owned by Helen and the business model is “battery as a service” i.e. the customer pays a monthly fixed fee to Helen. In addition to the battery, there are also eight smart EV charging stations located at the office building. The first priority of the battery is to operate peak shaving, but the battery could be also utilized in the TSO ancillary markets (FCR-N). In EU-SysFlex, the most intresting research questions of the office scale battery demonstration have been:

1) How to bundle peak shaving with TSO ancillary market (FCR-N) operations?
2) How much FCR-N operation increases the costs of the customer (electricity, distribution, taxes)?

The improvements and demonstrations with the office scale battery include:

- Implementation of an IoT device for remote control and data collection
- Peak shaving and definitions of the peak shaving limits, operating peak shaving via local control and implementing & testing it via remote control
- Implementation and testing of the remote control of active power in the pilot project with Tieto's aggregation platform DES.
- Prequalification tests for FCR-N with 120 kW and 100 kW charging/discharging power (as a part of the pilot project with Tieto)
- Implementation and testing of remote control via the IoT platform
- Definition, implementation and testing of control logics to operate peak shaving in certain hours and FCR-N in other hours
- Implementing communication channel developments and defining data transfer needs between the systems
- Demonstration of operation in the FCR-N market with defined bidding logic (real environment demo)

FIGURE 16. BATTERY ENERGY STORAGE SYSTEM AT THE OFFICE OF HELEN DSO. TWO BATTERY UNITS, 60 KW EACH. MODEL: TESVOLT, TS HV 70 OUTDOOR

The battery operates peak shaving as a first priority in order to reach savings in the distribution power tariff. Figure 17 shows an example of peak shaving operations. The peak shaving limit was set to 27 kW and the battery operates accordingly in order to keep the power of the office building below 27 kW. In the first phase of the demonstrations, peak shaving was operated via local control at the battery. In the second phase of the demonstration, peak shaving is controlled remotely via IoT platform used by Helen.

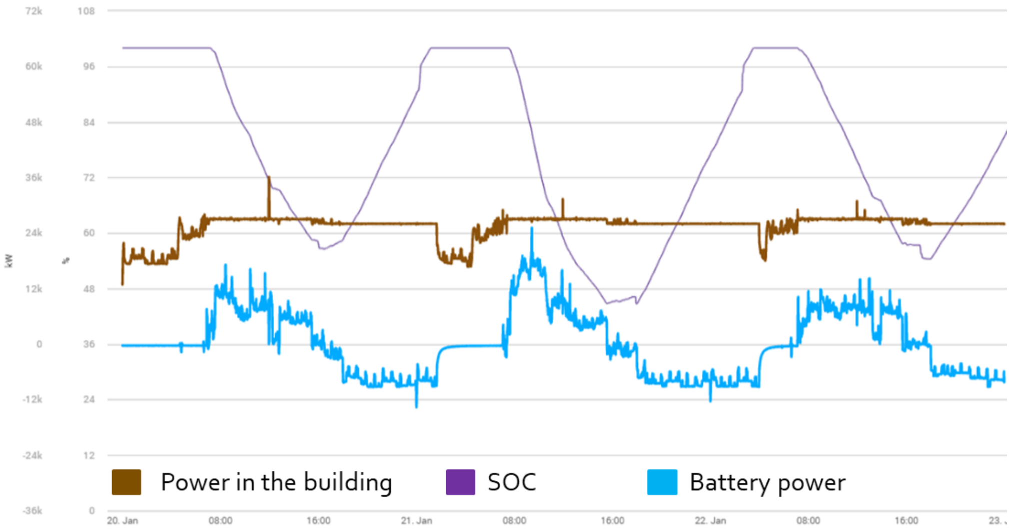


FIGURE 17.EXAMPLE OF PEAK SHAVING OPERATIONS OF THE BATTERY

Prequalification tests to operate in FCR-N

The prequalification test to operate in the FCR-N market was done in 2019. The test was implemented via the piloted aggregation platform (DES). The battery was controlled via an IoT device (a field device installed physically to the battery site, which communicates with the inverter manager of the battery). The IoT device is capable to measure the operations of the battery as well as to control the battery. The IoT device sends the measurement data to an IoT platform. The control signals were sent to the battery via the piloted aggregation platform. The aggregation platform in turn was connected to the field device via an integration platform used by Helen.

The rules followed in the prequalification test (in April 2020) are defined by the Finnish TSO (Fingrid) [17]. The prequalification test implemented with following parameters and technical specifications:

Maximum power	120 kW
Energy capacity	134 kWh
Dead band (set according to FCR-N rules)	50 ± 0.1 Hz
Recovery power in dead band	0 kW
Reactive power	0 kvar

Figure 18 shows results of a step response test where frequency deviations -0.10 Hz and +0.10 Hz are fed to the measurement branch for load-frequency control.

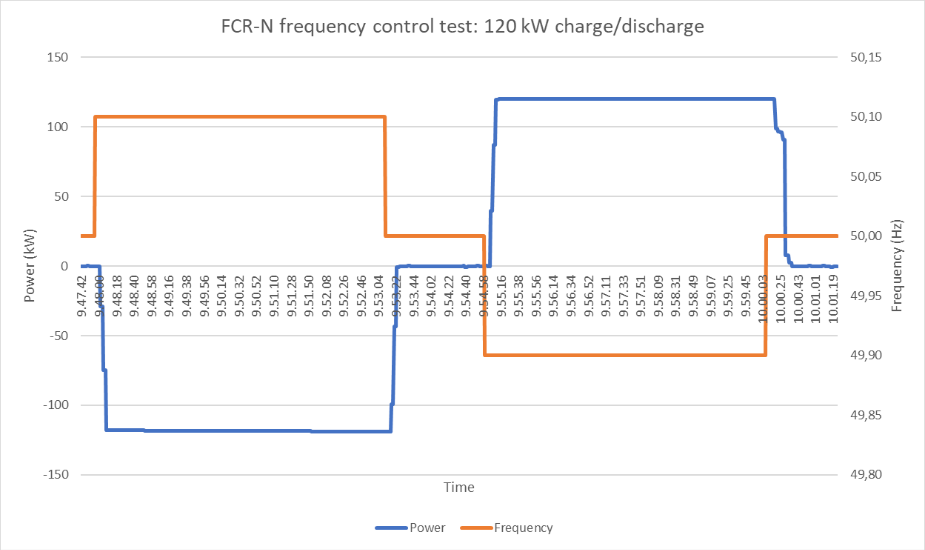


FIGURE 18. PREQUALIFICATION TEST OF THE OFFICE SCALE BATTERY: STEP RESPONSE TEST FOR FCR-N

In addition to the step response test, a sensitivity test of load frequency control needs to be performed as a part of the prequalification process. According to Fingrid, the sensitivity of load-frequency control is the smallest frequency change to which the reserve unit responds so that the activated active power can be measured. It is measured in all reserve units that participate in the maintaining of the FCR-N. The result of the test is presented in Figure 19. The frequency was set to deviate -0.02 Hz and +0.02 Hz, which is slightly bigger than the dead band. The active power activated as a result of the frequency change was measured for three minutes.

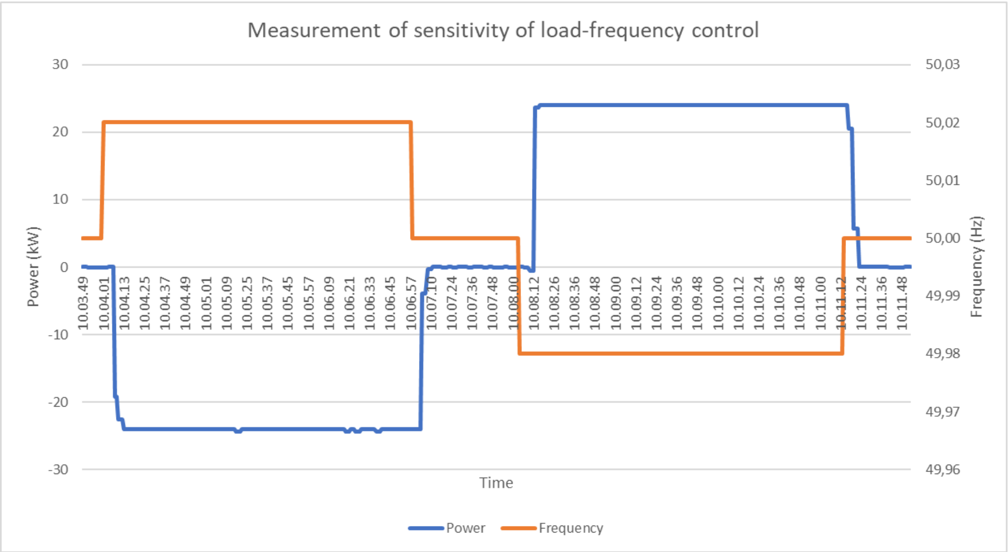


FIGURE 19. PREQUALIFICATION TEST OF THE OFFICE SCALE BATTERY: SENSITIVITY OF LOAD-FREQUENCY CONTROL

The prequalification tests were successful and the asset is qualified to participate in the FCR-N market by the TSO.

4.1.3.1 DEFINITION OF OPERATION LOGIC OF THE BATTERY

The priority of the office scale BESS is to operate peak power shaving during daytime to reach savings in the power component of the electricity distribution tariff of the customer. In this operation mode, the BESS flattens out peaks that occur due to loads of the building, e.g., EV charging, air conditioning, electric devices [7], [8]. The power component of the low-voltage power distribution tariff of the local DSO (Helen DSO in Helsinki) aims to guide the customers to shift high electricity consumption to other times of the day and thus to flatten out peak consumption times. Therefore, the peak power shaving of the BESS supports the operation of the distribution grid.
In Helsinki, the power component of the low-voltage power distribution tariff is valid between 7 AM and 9 PM from Monday to Friday [18]. The invoiced power is the highest average hourly power of the month [18]. When the BESS operates peak power shaving during these hours, economic savings can be reached for the customer in the power-based component of this distribution tariff. The amount of economic savings of the customer, however, remain low in this case.

In the demonstration, during the times that the power charge of this distribution tariff is not valid (nights, weekends), the BESS provides service in the FCR-N. Currently, in the FCR-N market, the bids can be formulated every 100 kW intervals and therefore, the bid of the BESS is 100 kW. If the BESS is operated in the FCR-N markets during the hours that the power charge of the distribution tariff is valid, this operation would increase the invoiced power and thus decrease the profitability of the FCR-N operation. In total, four operation modes of the BESS are needed to operate the peak power shaving and the FCR-N control. The operation modes used during the demonstration are presented Table 8. [8]

TABLE 8. OPERATION MODES OF THE OFFICE SCALE BESS

Time of day	Operation modes of the BESS	Reason
06-07	**Prepare for peak power shaving**	To be ready for peak shaving at 07:00. Target SOC: 100 %.
07-21	**Operate peak power shaving**	To reach savings in the power charge of the distribution tariff. (*)
21-22	**Prepare for FCR-N**	To be ready for FCR-N operation. Target SOC: 50 %.
22-06	**Operate FCR-N during accepted hours (bid: 100 kW)**	To reach additional income from the FCR-N market for the customer and the aggregator. Power charge of the distribution tariff is not valid.
Weekend 00-24	**Operate FCR-N during accepted hours (bid: 100 kW)**	
(*) Power charge of the low-voltage distribution tariff is valid between 7 am and 9 pm from Monday to Friday. The invoiced power is the highest average hourly power of the month.		

The aim of the “prepare for FCR-N” operation mode is to have as high control time in the beginning of the FCR-N operation as possible. If the SOC of the BESS is below 5 % or above 95 %, the BESS fails to deliver the FCR-N service and penalties occur [17]. In a case that some of the FCR-N bids are not accepted by the TSO, the BESS operates according to the “prepare for FCR-N” operation mode. During the “prepare for peak power shaving” operation mode the target is to fully charge the BESS.

4.1.3.2 RESULTS FROM REMOTE CONTROL: PEAK SHAVING, REACTIVE POWER COMPENSATION, FCR-N

During development and testing phase, the office scale BESS was controlled remotely from an IoT platform. The BESS was attached to the IoT platform through an IoT device with Modbus TCP. The main research questions were

1) How to implement remote control to the BESS from the IoT platform
2) How to implement peak shaving for lowering office power demand
3) How to implement office building reactive power compensation
4) How to provide ancillary services to TSO’s FCR-N active power reserve market

Development steps

The IoT platform was a new platform where decentralized assets could be aggregated, controlled and monitored. Use of this new platform required development in operational logics, dashboard views as well as integrations between the platfrom and Helen’s energy trading systems.

During the development and testing phase a peak shaving function was developed. Rules for peak shaving function were created with power output limitations if the BESS charge was under a certain threshold. In addition to peak shaving, an operation logic according to the FCR-N market rules was developed. During the testing of FCR-N market operation logic various control characteristics were tested with different SOC (charging or discharging) recovery power values and SOC optimation power values at low or high SOCs. Also functions to prepare the BESS to operate in peak shaving mode and to operate in FCR-N market were developed.

To bid the battery to the reserve markets from the IoT platfrom a DMZ (Demilitarized zone) of trading systems was developed during EU-SysFlex project. This DMZ integrates the IoT platform and Helen’s energy trading systems and allows decentralized aggregated assets controlled from the IoT platform to be bidden to the power reserve markets. A proof-of-concept integration of the DMZ was developed and taken into use and the office scale BESS could be bidden to the reserve markets.

The developed DMZ takes the bids, combines them into one bid for each market (FCR-N, FCR-D etc.) and reserve product (production, load, other) and sends the bids to the energy trading systems. From the energy trading systems the bids are directed to the Finnish TSO Fingrid’s power reserve markets. The TSO then accepts or declines the offer depending on the need for reserve power and bid price. Then the TSO sends the accepted bids to the energy trading systems from where the DMZ reads the accepted bids. The DMZ divides the accepted bids between the assets. If the bid is accepted partly than the reserve power request for each asset is divided. Additionally, the

DMZ transfers real-time data: volume of Frequency Containment Reserve reserve power and remaining activation time from assets with limited activation capabilities e.g. a BESS.

Peak power shaving

The power consumption of the office building varies through the day as the demand increases during working hours and decreases during night-time. Additionally, during summer, power demand increases significantly due to increased air-conditioning. As the office pays for peak power in the power distribution tariff, a BESS can compensate for higher power demand. In Figure 20, it is shown how the power consumption of the office varies without peak shaving and how the peak power is reduced when peak shaving is turned on. The peak shaving limit was 27 kW. This demonstration was performed in winter and the peak power of the office was approximately 35 kW. The results show that the BESS can reduce peak power by several kW.

The peak power shaving logic requires information of the office power consumption, BESS power production/consumption and the peak shaving limit value. The office buildings power as well as reactive power were read from a power meter installed on-site and the BESS power was read from the BESS Modbus register. The peak shaving logic then compared the instant power consumption of the building, the BESS power production/consumption and peak shaving limit and calculated a new active power setpoint value for the BESS every 15 s. The new set point value than was sent to the IoT device which than wrote the value to the corresponding Modbus register. The BESS changed the power output/input value in a matter of milliseconds after a new set point value was written.

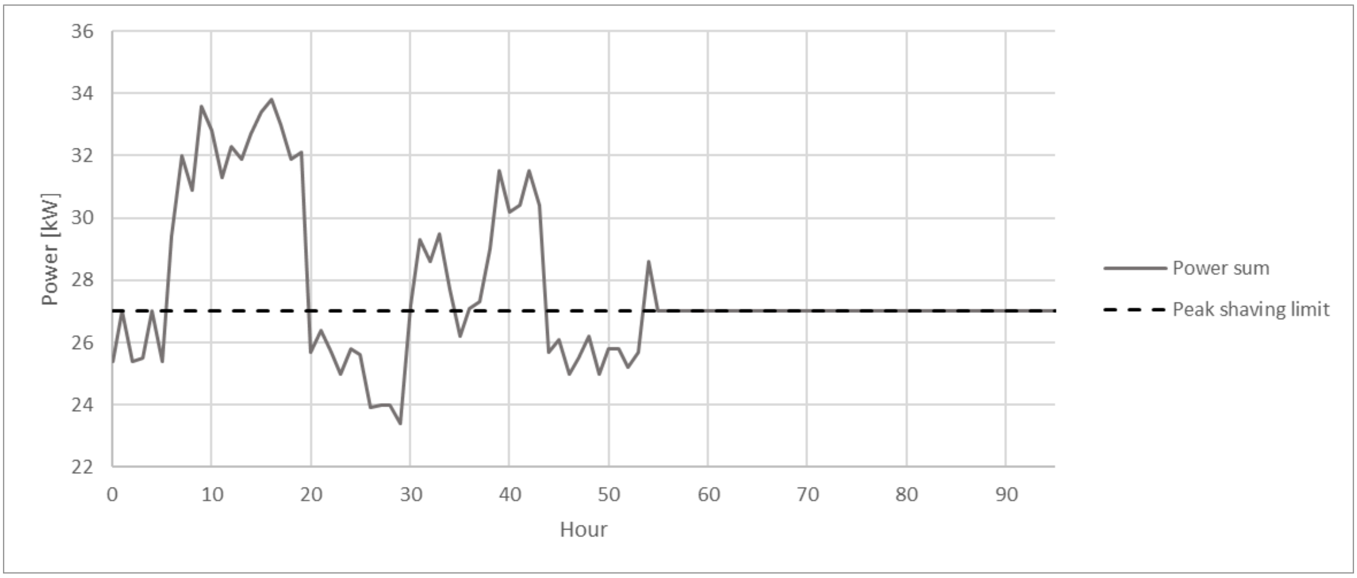


FIGURE 20. THE REALIZED ACTIVE POWER CONSUMPTION BEFORE PEAK SHAVING AND AFTER SETTING PEAK SHAVING FUNCTION ON

As a BESS has limited energy capacity during high power consumption for long periods the BESS could depleat. To prevent complete depletion and risk the peak power usage increase further a power reduction in discharging was set if the SOC fell below 36 %. Different reduction values were tested and it was found out that a reduction to 90 % of the desired power output was most beneficial. Due to power reduction the peak power was increased and the power tariff increased to the new peak power value. Therefore, a new peak power shaving limit was set if the highest hourly power was more than 0.5 kW compared to the previous peak shaving limit. The limit was rounded to the closest kW.

In the beginning of each month a new peak shaving limit was set because the power consumption varies from month to month lower in winter and higher in summer. Therefore, the limit was 92 % of previous months average hourly power consumption. As the power consumption decreases towards the winter in autumn the limit is automatically lowered. However, when power consumption increases towards summer the limit rises as explained earlier.

Reactive power compensation

Every electrical load, other than purely resistive loads, consumes or produces reactive power. For power tariff customers, this may increase the costs since these tariffs include fees of oreactive power. For instance, in the case of the demonstrated office building, there are devices with power electronics, e.g. ventilation, cooling, lighting, that cause inductive or capacitive reactive power. A BESS can compensate reactive power by changing its power output characteristics in the inverter. Figure 21 shows the reactive power of the office before the reactive power compensation and after the compensation function was enabled. The results show that the BESS reduces both reactive power consumption and production towards the electrical grid when reactive power compensation function is active.

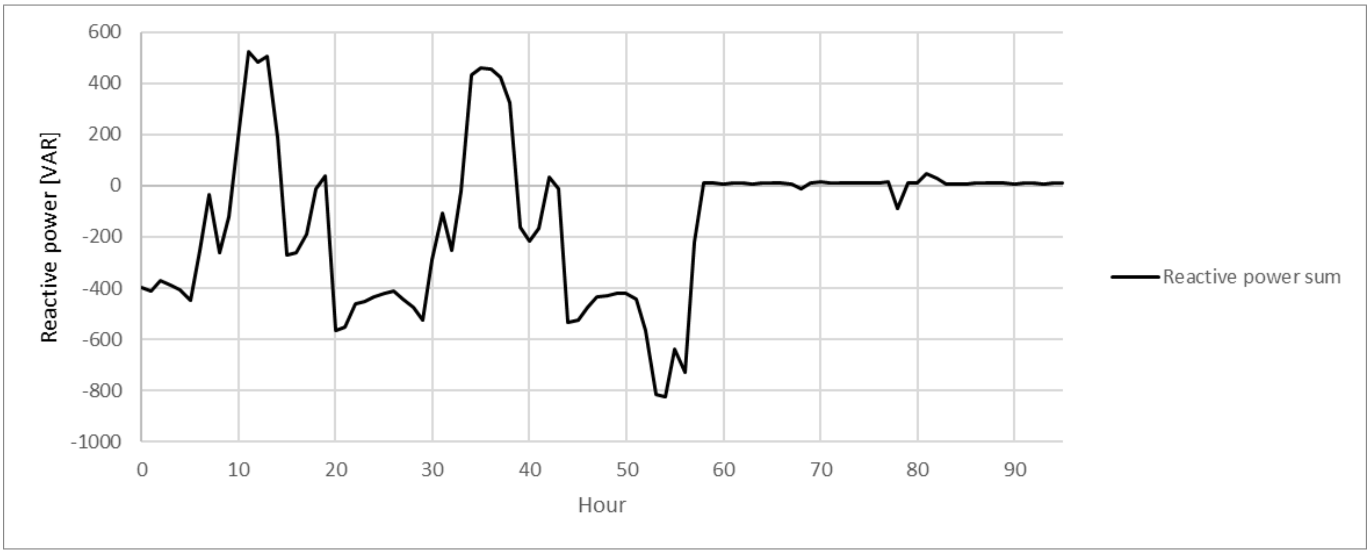


FIGURE 21. OFFICE BUILDING: REALIZED REACTIVE POWER BEFORE THE COMPENSATION AND AFTER THE COMPENSATION FUNCTION WAS ON

The reactive power compensation logic requires information of the office reactive power production/consumption and BESS reactive power production/consumption. The reactive power compensation logic then compared the instant reactive power production/consumption of the building and the BESS reactive power production/consumption and calculated a new reactive power setpoint value for the BESS every 15 s. The new set point value than was sent to the IoT device which than wrote the value to the corresponding Modbus register. The BESS changed the reactive power output/input value in a matter of milliseconds after new set point value was written.

FCR-N control

An asset, which is operated in the FCR-N market, follows the normal grid frequency (50±0.1 Hz) with a response that is linear to the frequency change. The nominal power response of the demonstrated BESS was 100 kW. During the demonstrations, the BESS was not yet bid on the FCR-N market. However, the BESS was controlled according to the FCR-N rules for a test period of two weeks during non-peak power tariff hours. When the frequency is above 50 Hz the BESS is controlled to charge and when the frequency is below 50 Hz the BESS is controlled to discharge. When the frequency is between 50±0.01 Hz the BESS is idling. Figure 22 shows a short period of the normal operation of the BESS in the FCR-N control. It is seen that as the frequency changes the control of the BESS is fast and accurate. During the FCR-N test control period, the BESS operated as expected and the control logic in the IoT platform and communication systems worked as planned.

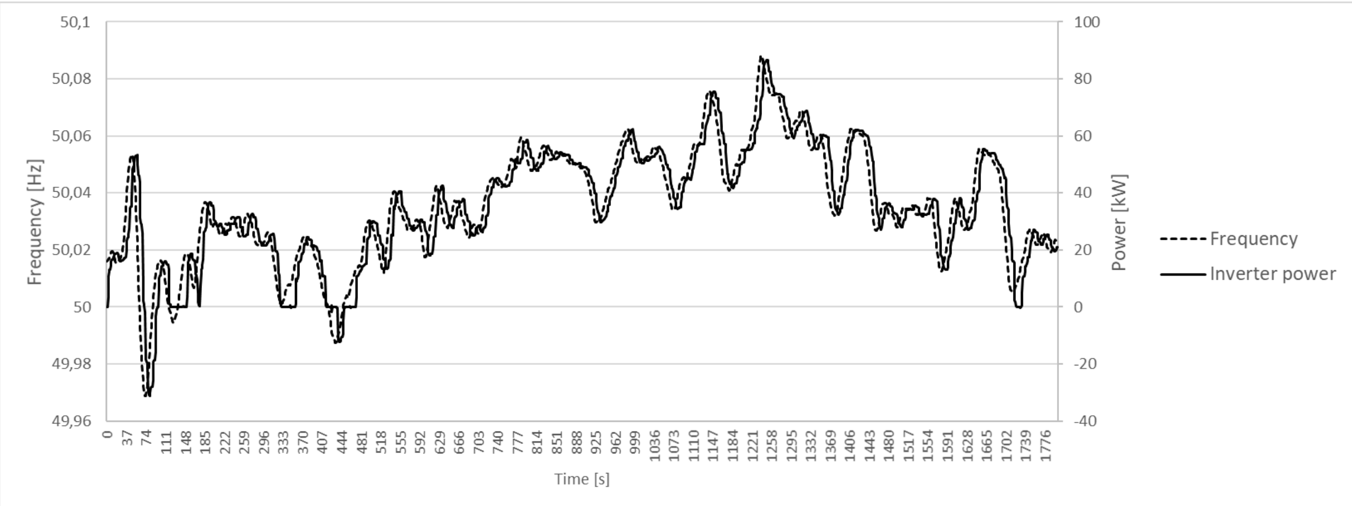


FIGURE 22. THE BESS IN THE FCR-N OPERATION

As all batteries have limited energy capacity, the demonstrated BESS was fully charged and fully depleted during the FCR-N control as the frequency was either above or below 50 Hz for a long enough period. In FCR-N, if the SOC of a battery is at 95 % or at 5 %, the battery is not able to provide FCR-N [17]. This kind of situation leads to penalties due to failure of delivery. The tests show that the BESS was more than 90 % of the time delivering full required power in the FCR-N. For the demonstrated BESS, the result can be considered adequate.

The active power of the BESS in FCR-N operation follows the normal grid frequency of 50 Hz. FCR-N operation logic was developed to the IoT platform where a general setpoint value from -1 to 1 indicated the frequency from 49.9 Hz to 50.1 Hz. If frequency is above 50 Hz the BESS is charged and if it is below 50 Hz the BESS is discharged. The technical requirements for FCR-N allow use of a dead band zone (50±0.01 Hz) where no activation is required. In addition, assets such as the BESS, with limited activation capability are allowed to use power and energy capacity that is not reserved to maintaining the reserve [17]. As the provided reserve power of the office scale BESS was 100 kW the SOC optimization power was 20 kW. This additional power was implemented with an offset value to the power output if the BESS was above 75 % SOC or under 25 % SOC. The use of SOC optimization improves the flexibility service reliability significantly. However, if the frequency remains in either direction from nominal 50 Hz for a long period, the BESS will eventually deplete or become fully charged and no longer provide service until the frequency is favourable again.

4.1.3.3 KPI RESULTS

The office scale-demonstration is evaluated through KPI's 1, 4, 5b and 7 of the Finnish demonstrator.

KPI1 Increase in revenue of the flexibility service provider
The office scale BESS was a technical demonstration which focused on remote control operation functionalities. However, one important achievement was to have the BESS accepted to Fingrid's FCR-N market. By the end of the project the BESS was accepted to the market and Helen could bid the BESS to the market. Unfortunately, from real world operation not enough data was gained and therefore the increase in revenue of the flexibility service (KPI no. 1) was calculated based on the two weeks test period in the beginning of 2021. The increase in revenue was calculated using data from 2019 FCR-N hourly market price values and BESS capablilitie of maintaining reserve volume. From the BESS data it was found out that the BESS could deliver an excellent 90 % of the hours during the test period. The yearly increase in revenue is calculated from

$$R = \sum_{s \in S} \sum_{a \in A} \sum_{t=1}^{T} P_{s,a,t} * \pi_{s,a,t}$$

where
S is the set of available markets = FCR-N
A is the set of available resources = 1 BESS
T is the amount of hours without power tarrif = 3148 h
P is the realized power exchanged = 0.1 MW (* 90 % delivery)
π is the price (FCR-N average hourly price on the hourly market during operation) = 26,86 €/MW,h

Thus, an increase in revenue of 7609 € per year (634 €/mo) is reached. The result indicates that the revenue increase is not much. The main issue is that the operational time in the reserve markets is low. If increasing the operational time the BESS should be bid during power tariff hours this would increase operational costs. Therefore, off tariff hours biding logic is more economical. The profit for the customer is presented futher in KPI no. 7.

KPI4 Flexibility service reliability
Demo period of two weeks 1.1.2021-15.1.2021

RMSE of the operation (KPI no. 4) is calculated from two weeks demo period. The BESS was operated outside of power tariff hours during night times from 1.00 am to 6.00 am and all hours on weekends. Figure 23 illustrates the maintained volume of the 0.1 MW office scale BESS for frequency containment reserve for normal operation during one day of the test period. It is seen that the BESS is able to maintain the reserve power most of the time. However, as the BESS either depleted of fully charged and the grid frequency was unflavourable the BESS failed to deliver the reserve for a couple of hours.

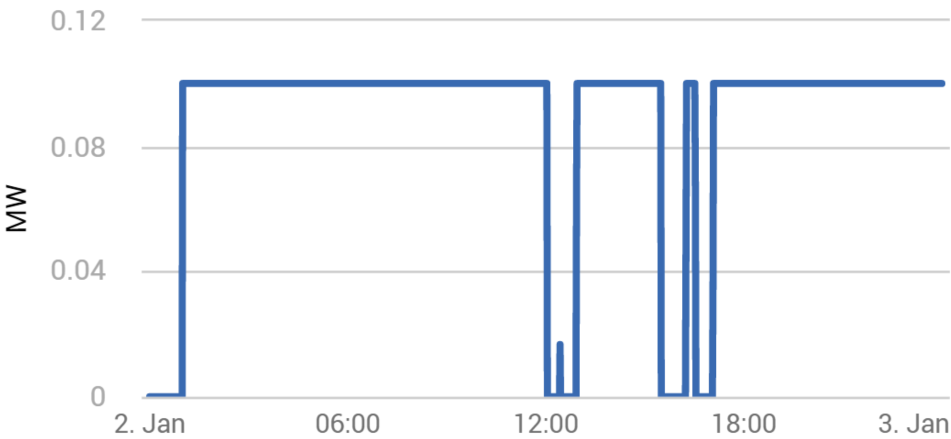


FIGURE 23. MAINTAINED VOLUME OF 0.1 MW OFFICE SCALE BESS 2.1.2021

For the two weeks test period the BESS was able to deliver reserve power adequately. Flexibility service reliability is calculated from

$$RMSE = \sqrt{\frac{\sum_{t=1}^{T}(P_{R,t} - P_{B_v,t})^2}{T}}$$

where t is one of the T time periods considered, $\boldsymbol{P_R}$ is the realized power exchanged and $\boldsymbol{P_{B_v}}$ is the power accepted (or validated) from the bid on the market. The RMSE for the test period with the office scale BESS is 0.0239 MW which represents approximately 24 % of the offered capacity. This is significantly better than with the industrial scale BESS which has an RMSE of 35 % of offered capacity. There are several factors why the office scale BESS flexibility service reliability is better. First the power capacity ratio is smaller and thus the BESS can deliver nominal power for a longer time and in addition a smart state of charge optimization function is enabled with the office scale BESS. The SOC optimization can be implemented to the industrial scale BESS with some system changes.

KPI5b Usability of the asset

During the demonstration of the office scale BESS the reliability of the asset revealed to be very high. The usability of the asset (KPI no. 5b) is calculated from the time when the asset was operational and functioning as expected. When the BESS was in an error state or not in operation this accounted for downtime of the BESS. Usability of asset was defined during a two months period beginning from January 1st to February 28th when the BESS was mainly in peak shaving operation and for two weeks (outside of power tariff hours) in FCR-N operation. Total down time during that period was 451 minutes and the total time for the period was 84960 min. Usability of the asset is calculated from

$$\boldsymbol{AV}[\%] = \frac{\boldsymbol{T_{com}}}{\boldsymbol{T_{op}}} \times \mathbf{100}\%$$

where T_{com} is time when asset was functioning as planned and T_{op} is time of the test period. Thus, it is got

$$\boldsymbol{AV}[\%] = \frac{\mathbf{84960}\ \boldsymbol{min} - \mathbf{451}\ \boldsymbol{min}}{\mathbf{84960}\ \boldsymbol{min}}\ \boldsymbol{x}\ \mathbf{100}\ \%$$

$$\boldsymbol{AV} = \mathbf{99.47}\ \%$$

As seen, the usability of the office scale BESS is high. Software improvements to the BESS could further increase the usability. However, the aggregation platform has a lower reliability and thus even though the asset usability is high the operation reliability and usability is limited to the reliability of the IoT platform when operated as demonstrated.

KPI7 Profits of service provision

Profits for the BESS owner depends on the contract with the aggregator and the operational costs of the BESS. In this demonstration a 15 % share of revenue is the profit for the aggregator. The operational costs consist of excess electricity that the office building does not consume when the BESS is operating in the FCR-N market and it is discharging due to low frequency. If the BESS is discharging with higher power than the building is consuming the electricity flows to the grid and the electricity utility can pay for the excess energy. However, as the purchased electricity has transmission and tax costs and only the energy is compensated the excess energy to grid increases the operational cost. Table 9 shows the profit for the BESS owner.

TABLE 9. PROFIT FOR BESS OWNER

Revenue	7608,79 €
Operation cost	894,03 €
Aggregators share	1141,32 €
Profit (customer)	5573 €

The operational cost for BESS owner is estimated from test data where approximately 41 kWh of excess energy flows to the grid. The yearly profit of 5573 € for the customer with a 0.1 MW BESS is not high. The current BESS prices does not support this solution as a scalable soltution for customers. However, once the BESS prices decrease and the need for grid flexibilities increase due to growing RES share in the grid the revenues and profits rise. In addition, combining different flexibilities greater profit or lower operational costs can be obtained.

4.1.4 EV CHARGERS DEMO WITH VIRTA LTD.

The EV charging network is expanding rapidly in Finland and thus presents an interesting opportunity to provide flexibility to the power system. In EU-SysFlex, an optimization tool and a forecasting tool have been developed in cooperation with Helen and VTT. The tool estimates the available flexibility from a set of EV chargers and determines an optimal bidding strategy to offer this flexibility to the TSO ancillary services.

In addition to the tool, an EV charger flexibility demonstration was performed during the project. In this flexibility demonstration, a frequency regulation ability (FCR-D) was developed and implemented for dedicated chargers that included eight AC chargers located at the office of Helen DSO (same site as the office scale battery) and one DC public fast charger (max power output 50 kW). This demonstration was performed together with Virta Ltd., the charging platform service provider for Helen. Figure 24 illustrated the EV charging flexibility demonstration set-up.

The eight chargers located at the DSO's office are owned by Helen DSO, and the public fast charger is owned by Helen. All chargers are part of Virta's charging station network and can be controlled through Virta's systems. Virta has developed a so called Energy Platform that has the ability to send control signals to all EV chargers that are connected to Virta. The FCR-D control logic was implemented into this Energy Platform, and through the user interface of the platform, Helen is able to manually send activation signals to the charging stations. Used interface for the FCR-D control logic is shown in Figure 25. This demonstration did not include setting up scheduled/automatic activation signals or any real market operations. The main goal of the demonstration was to evaluate the readiness of the EV chargers to provide flexibility by controlling them according to the FCR-D rules and to follow their response and performance. Important questions to be answered included:

- How fast is the response of the EV chargers and can they fulfill the market requirements set by the TSO?
- How should the requested power decrease be allocated to different chargers that charge with different powers?
- How reliable is the communication between EV chargers and the Energy Platform?

In oder to measure the control responses of the EV charging stations properly, some configuration changes were made and one additional measuring device was installed on the demo site. The AC chargers normally send current, voltage and power measurements to the host platform every minute. This is quite slow and thus this sampling rate was changed to 5 seconds from the technical configurations of the chargers. In addition, a metering device was installed to the switchboard where all the chargers are connected. This device measures the total voltage, current and power of the 8 AC chargers. The measurements are sent to the host platform approx. every 5 seconds. Moreover, the IoT device that is installed to the battery system located at the same site measures the overall power consumption at the office, including the EV charging stations. This measuring device takes measurements every second, further improving the measuremet accuracy. Of course this measurement includes other loads as well so it can only be used as a supportive element. The DC fast charger can be configured to send measurement data to the host platform every second. In the figure below, the demo set-up is visualized. The reason why only 4 AC chargers are depicted is that currently only 4 EVs are using the charging stations at the office of Helen DSO.

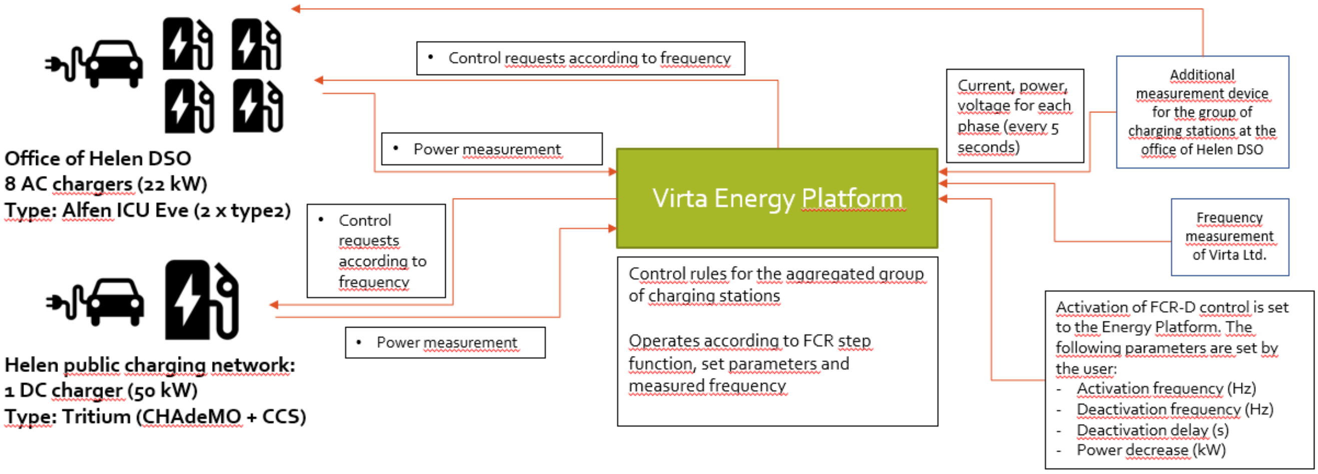


FIGURE 24. THE EV CHARGING STATIONS DEMONSTRATION SET-UP

Results of the first demo period

The first demonstration period of the EV chargers was performed in September 2020. During these tests, four EVs (two full electric vehicles and two plug-in-hybrid vehicles) were charging at the office of Helen DSO. In addition, one full electric vehicle was charging at the fast charger in a different location. In the first phase of the demo, the four AC chargers were aggregated into one pool and several control requests were given to them through Virta Energy Platform. In the second phase, the fast charger located elsewhere was added to the aggregated pool and control requests were given to all five chargers. The control requests in the first two phases of the demo were performed with exaggerated frequency limits, so that an immediate response could be observed as seen in Figure 26. In the third and final phase of the demo, only a single AC charger was controlled and the frequency limits were set to more realistic values, so that a real life situation could be demonstrated. The duration of the last control phase was 120 minutes and during this time, 11 activations were observed.

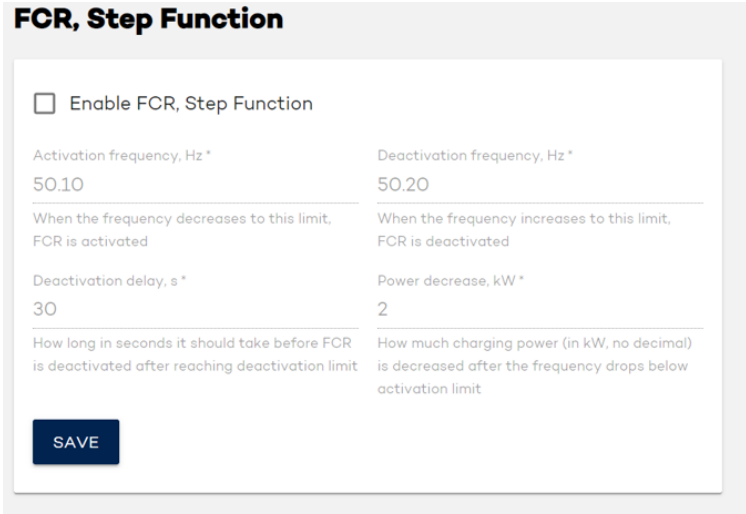


FIGURE 25. FCR FUNCTIONALITY IN VIRTA ENERGY PLATFORM USER INTERFACE

During the first two phases of the demonstration the activation limit of the FCR step function was set to 50.10 Hz and the deactivation frequency to 50.20 Hz. Since the frequency of the grid is usually around 50 Hz, this way it could be observed an immediate activation of the step function. Since the deactivation frequency was even higher than the activation frequency, deactivation was achieved manually by disabling the step function entirely.

During the first phase of the demo, all control signals were delivered and executed successfully by the Virta Energy Platform. The results of a single control request are depicted in below. During this test, four EVs were connected to AC chargers. Out of the four EVs, only a single EV was charging from all three phases. The power reduction request of the first test was 5 kW and the observed reaction was 5.6 kW. Figure 26 shows the power limitation in all three phases. The difference results from the fundamental functionality of the chargers: The EV charger can only limit the maximum charging current, whereas the minimum change in amperage is 1 A. This results in small inaccuracies depending on the requested power reduction.

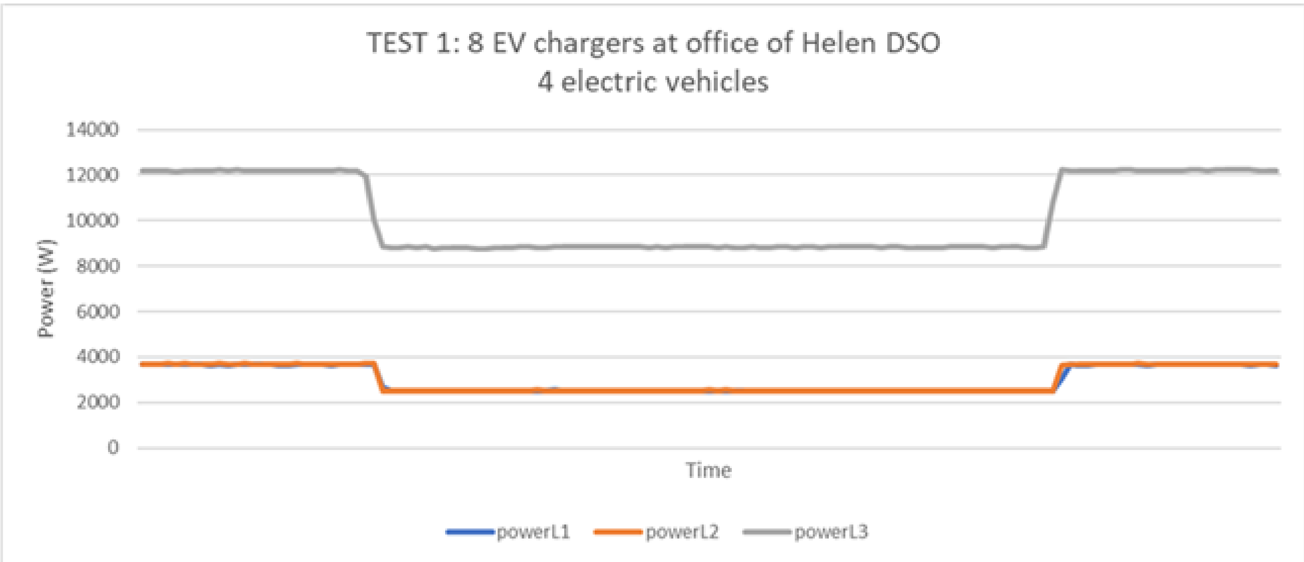


FIGURE 26. REACTION OF FOUR CHARGERS TO A SINGLE MANUAL CONTROL REQUEST

TABLE 10. REDUCTION OF CHARGING POWER FOR A SINGLE MANUAL CONRTOL REQUEST

EV	Charging power in normal situation (kW)	Charging power after FCR-D control (kW)	Reduction of charging power (kW)
EV1	3.5	2.5	1.0
EV2	3.5	2.5	1.0
EV3	1.4	1.4	0.0
EV4	10.9	7.4	3.5
TOTAL	**19.3**	**13.7**	**5.5**

The response times of the AC chargers in this test set-up varied between 13 and 25 seconds. This time was measured with the help of log-files from the chargers. The time was measured between the configuration change that limited the maximum current allowed for charging (*max current (A)* in figure above) and the moment when the full power decrease was realized in the log-files. Thus, this response time excludes the latency between the activation of the step function manually in the Virta Energy platform and the above mentioned log-file. After several tests, it can be concluded that this latency is in the range of maximum few seconds. The response times include an uncertainty of roughly 5 seconds, since the AC chargers write log-files with a minumun interval of 5 seconds.

In phase two of the demo, the fast DC charger was added to the pool of controllable chargers. Similarly to the first phase, control requests were delivered and fulfilled successfully. This time the requested power reduction was bigger (30 kW), since the fast charger was initially charging with approx. 30 kW. The control response is presented in Table 11.

TABLE 11. REACTION OF 4 AC CHARGERS AND ONE DC FAST CHARGER TO A MANUAL CONTROL REQUEST

EV	Charging power in normal situation (kW)	Charging power after FCR-D control (kW)	Reduction of charging power (kW)
EV1	3.5	1.4	2.1
EV2	3.5	1.4	2.1
EV3	1.4	1.4	0.0
EV4	10.9	4.0	6.9
EV5	33.0	13.1	19.9
TOTAL	**19.3**	**13.7**	**31.0**

The activation response times were similar to the ones in the first phase with the exception of the DC fast charger. With the fast charger a noticeably longer response time was observed as seen in Figure 27. The fast charger only gradually reduced the charging power of the car which resulted in a total response time of over one minute.

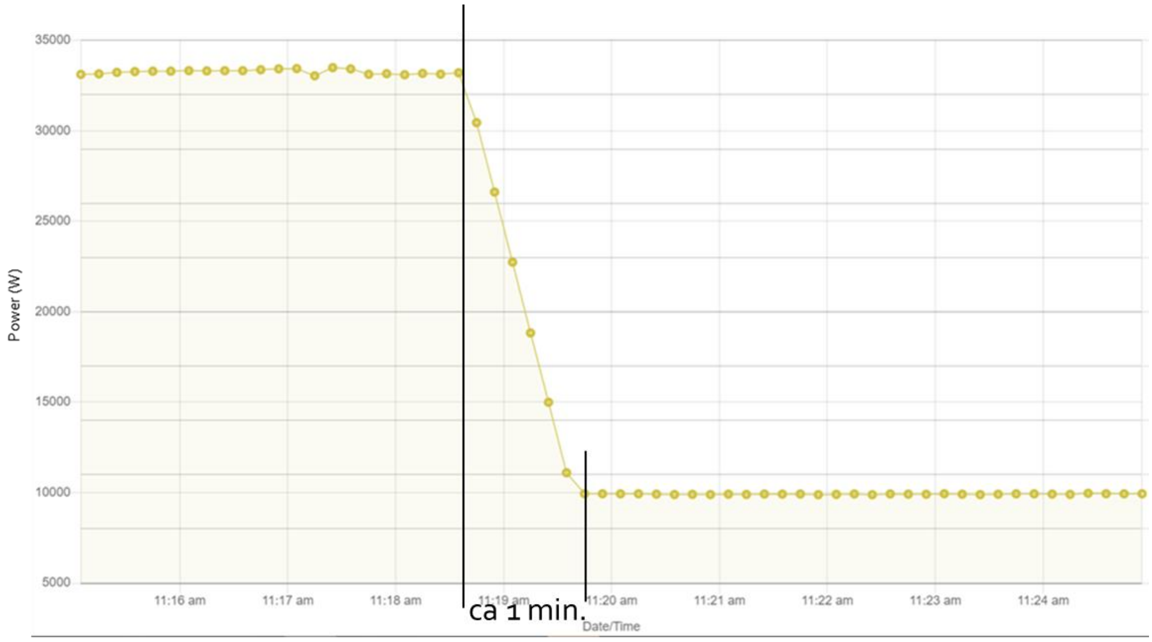


FIGURE 27. POWER DECREASE RESPONCE OF NISSAN LEAF AT FAST CHARGER

Results of the second demo period

After the first demonstration period, a second demo period was performed in November 2020 which included separate testing for the DC fast charger and a renewed sequence of tests for the aggregated pool of AC chargers and a fast charger. The fast charger was tested individually to examine the long response time observed during the first demo period.

In the first tests in September, the car that was charged at the fast charger was a Nissan Leaf (CHAdeMO plug). This next test was perfomed with an Audi e-tron which uses the CCS (Combined Charging System) standard. In the test, the car started charging with a SOC around 40 % with a charging power of approx. 48 kW. Three separate control requests of 50 kW, 25 kW and 10 kW were sent to the charger. The reaction of the charger is depicted below in Figure 28 and Figure 29. It was noticed that the control response was immediate with a maximum latency of 1 - 3 seconds. Thus, it is clear that the used charging plug standard affects the speed of the response.

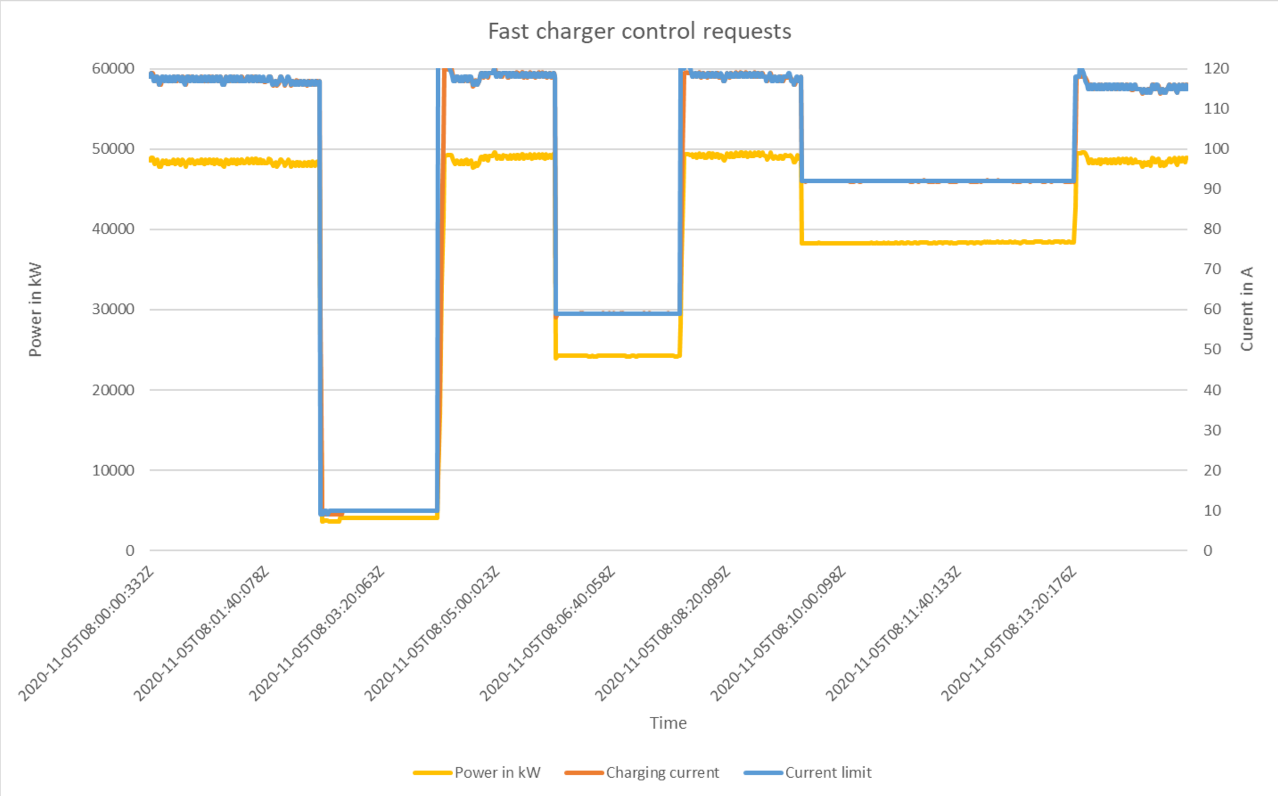


FIGURE 28. CHARGING REACTION TO CONTROL REQUEST WITH AUDI E-TRON (CCS)

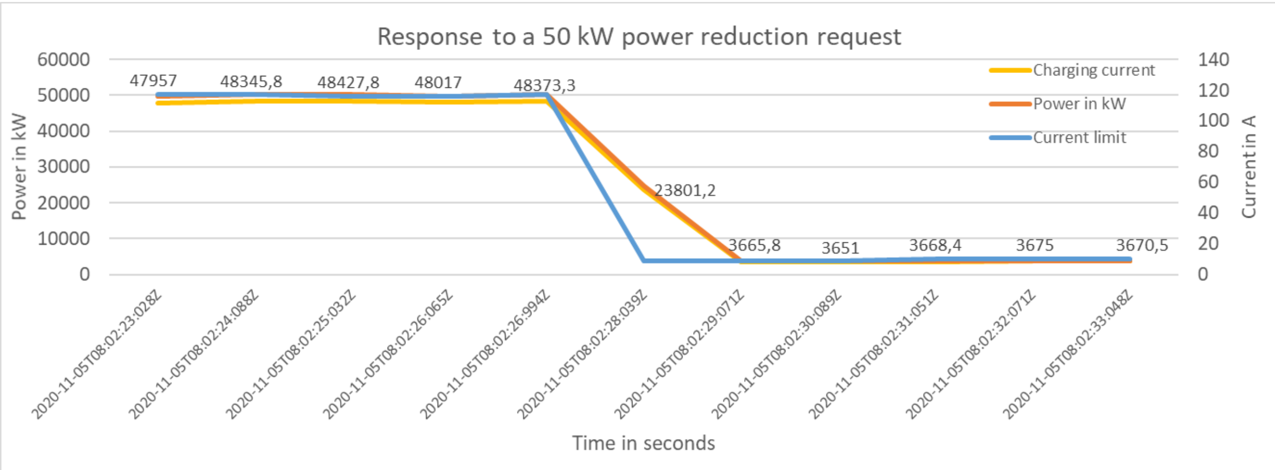


FIGURE 29. CHARGING REACTION TO CONTROL REQUEST WITH NISSAN LEAF (CHADEMO)

During the other tests of the second demonstration period the fast charger was tested with yet another EV model, an e-Golf, using the CCS standard. The results of several control requests and responses based on the grid frequency are presented in the Figure 30 below.

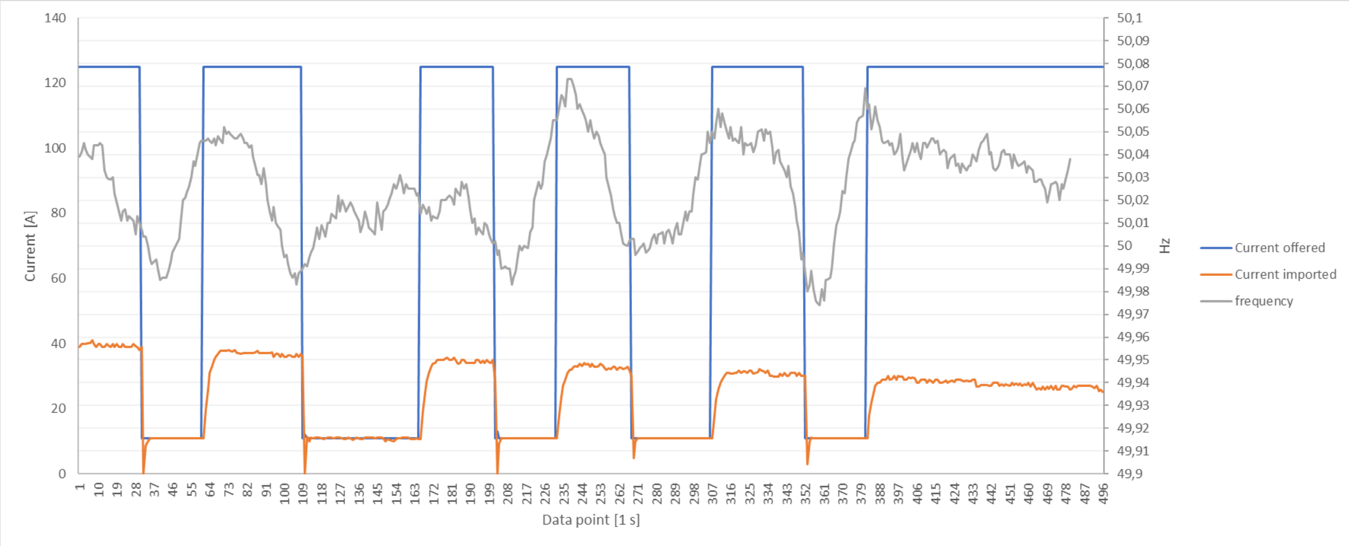


FIGURE 30. FREQUENCY RESPONSE OF E-GOLF AT A DC FAST CHARGER

The initial charging power was 40 kW. However, the charging power was reduced towards the end of the test period as battery SOC rose. The tests show that the charger was fast to realize demanded charge current limits. Additionally, like in the previous test with the Audi e-Tron, the used car and charging standard seem to have a major role in realizing the limited charging current. Using CCS standard, the cars reduced charging current in less than 2 s. However, the used controlling platform added a lot of delay when responding to the frequency. On average, it took 9.4 s to realize the power decrease once the frequency had gone under a specified threshold. Noteably, there was a large dispersion in response times as the fastest response happened in 5 s and the slowest took up to 15 s.

The second demonstration period also included combined tests with both AC and DC chargers, similarly to the first demonstration period. However, some issues were faced with these tests as the log-files of the aggregation platform appeared to be erronous. Due to the problems, some of the tests that were initially planned, were not performed. One set of control requests was successful and the results from these tests is taken into account in the KPI calculations in the next chapter.

To address the issues faced during the demonstration, the AC chargers concerned were checked for firmware updates and communication protocol updates. Some measures were taken to ensure that any future tests will be successful.

TABLE 12. DC FAST CHARGER

EV	Test	Reduction of charging power (kW)	Time from received control command to fulfilled control (seconds)	Sample interval (seconds)
Nissan Leaf	1	20	60	10
	2	23	70	
Audi e-tron	1	44	3	1
	2	25	1	
	3	10	1	
Volkswagen e-Golf	1	35	3	1
	2	25	2	
	3	10	1	

Delays of the DC fast charger control tests are presented in Table 12. It is seen that either the EV model or the charging standard has an effect on reaction time. The Nissan Leaf used CHAdeMO and the Audi e-Tron and the Volkswagen e-Golf used CCS standard. On average the EVs using CCS standard had a reaction time of 1.83 s to a power decrease command and the CHAdeMO had one of 65 s.

4.1.4.1 KPI RESULTS

The EV demonstration is evaluated through KPI's 1, 4 and 5a of the Finnish demonstrator.

KPI no1: Increase in revenue of the flexibility service provider

The EV demontration itself focuses on the technical capabilities of the chargers to participate on the TSO's ancillary markets. However, the expected revenue that the aggregator could achieve by using the public charging station network for providing ancillary services (KPI no.1) can be evaluated with the help of some assumptions and calculations. Figure 31 below, the average total hourly charging power of the whole public charging network is depicted on four different days in November 2020. The figure also contains the average charging power calculated for the whole day (red line). This is the amount of flexibility that could theoretically be offered on average to the TSO's flexibility market place every hour of the year. The market place considered in this case is the frequency containment reserve for disturbances (FCR-D), which is only activated in situations, where the frequency is below 49.9 Hz. This market place is most suitable for EV chargers since activations occur quite seldom and no symmetrical control (increasing charging power) is required. The yearly increase in revenue for the aggregator can be calculated as:

$$R = \sum_{s \in S} \sum_{a \in A} \sum_{t=1}^{T} P_{s,a,t} * \pi_{s,a,t}$$

where

S is the set of available markets = FCR-D

A is the set of available resources = approx. 200 public EV charging station

T is the amount of hours in a year = 8760

P is the realized power exchanged = average value of the four different red lines = 70 kW

π is the price (FCR-D average hourly price on the hourly market 2019) = 5 €/MW/h

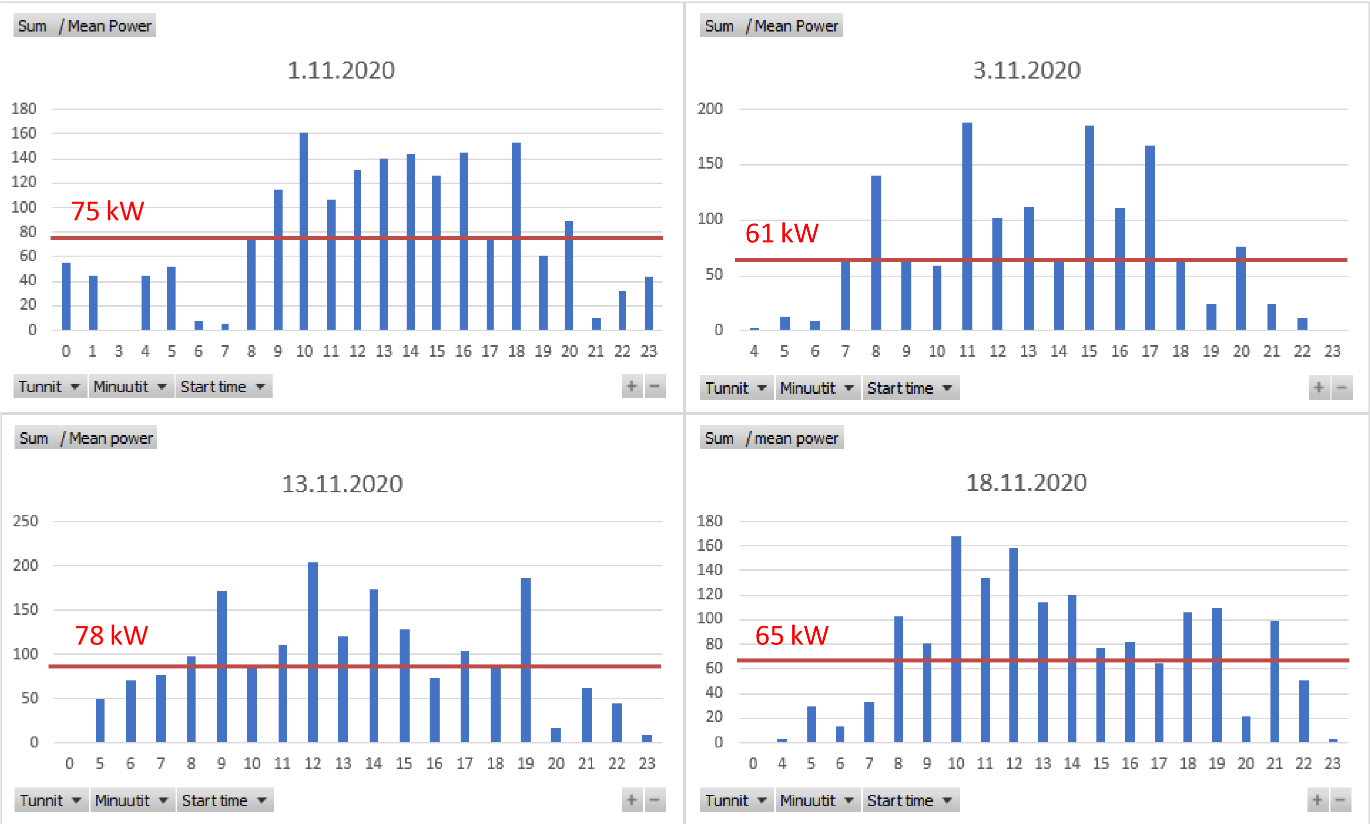


FIGURE 31. MEAN HOURLY TOTAL CHARGING POWER WITHIN HELEN'S PUBLIC EV CHARGING NETWORK

Thus, the result is:

$$R = 8760\ h * \ 70\ kW * 5\frac{€}{MWh} = 3066\ €$$

The results indicate that the achievable revenue by offering the EV charging stations to the FCR-D market is nowadays very low. This is because the chargers are still mostly underutilized and most of the EV's charging only use a fraction of the maximum charging power. This is e.g. explained by the fact that in Finland, plug-in electric vehicles are more common than full electric vehicles at the moment. The charging powers of a plug-in electric vehicle are much lower than those of full electric vehicles.

The increase of revenue from flexibility operations has also been evaluated earlier parallel to the forecasting work done in task 6.3 of EU-SysFlex. During that task, VTT created an optimal flexibility curve that could be offered to the TSO's ancillary markets and also calculated the daily profit from flexibility provision that could be achieved. The result was that the increase in revenue from the public charging station network in Helsinki area is approx. 9,5 €/day. This estimate is also in line with the other calculation method described above.

KPI no4: Flexibility service reliability

The results for the flexibility service reliability (KPI no. 4) for the first demonstration period (September) are presented in Table 13. below and the results for the second demonstration period (November) in Table 14. The root mean squared error (RMSE) between the requested power reduction and the actual power reduction is calculated for each activation during the demo.

TABLE 13. EV CHARGING CONTROL TESTING IN SEPTEMBER

10.9.2020	**Requested reduction (kW)**	**Realized reduction (kW)**	**Squared error**	**MSE**	**RMSE**
test 1	5	5.5200	0.2704	2.1907	1.4801
test 2	14	11.8900	4.4521		
test 3	30	31.3600	1.8496		
Autonomous operation of one charger (AC) for one hour				**MSE**	**RMSE**
test 4	2	1.9136	0.00746496	0.022293	0.149307
test 5	2	2.1344	0.01806336		
test 6	2	2.1712	0.02930944		
test 7	2	2.1528	0.02334784		
test 8	2	1.9688	0.00097344		
test 9	2	1.8584	0.02005056		
test 10	2	2.2264	0.05125696		
test 11	2	2.1896	0.03594816		
test 12	2	2.1896	0.03594816		
test 13	2	1.8952	0.01098304		
test 14	2	2.1528	0.02334784		
test 15	2	2.1344	0.01806336		
test 16	2	2.1528	0.02334784		
test 17	2	1.8768	0.01517824		
test 18	2	2.1528	0.02334784		
test 19	2	1.8584	0.02005056		

The upper RMSE is the total error for all tests (1 - 19), including control requests of different sizes. The lower number is the RMSE for tests 4-19 where the asked power reduction was always 2 kW. As it can be seen, the accuracy of the control request is quite good, between 7 % and 14 % relative to the average requested power reduction.

TABLE 14. EV CHARGING CONTROL TESTING IN NOVEMBER

11.11.2020	Requested reduction (kW)	Realized reduction (kW)	Squared error	MSE	RMSE
test 1	1	1.4200	0.1764	5.8858	2.4261
test 2	2	5.1100	9.6721		
test 3	3	3.6100	0.3721		
test 4	10	6.3500	13.3225		

As mentioned in the previous chapter, during the second demonstration period, only one set of tests (including four individual power control requests) was performed successfully. Thus, the RMSE-values could also be reliably calculated only for these control requests. Compared to the first demonstration period, the error value is significantly higher, which further underlines the problems faced with the system during that day.

The RMSE taking all tests into account is 1.151.

KPI no5a: Reliability of the aggregation platform

The aggregation platform used with EV charging demonstration worked as intended. However, some minor issues were encountered during the tests with the developed FCR-step function logic for power reduction. The issues were mainly due to configuration errors with a few EV charging points and with the function itself and all of these issues were resolved during the complete testing period. Unfortunately, the aggregation platform had major issues on the third testing day and therefore all data obtained that day was unreliable. The issues faced with the third test day could not be traced and thus the reliability of the platform was derived from the two test days. This caused to cancel the test day before resonable testing had begun. In total four hours of testing was done during the two test days and as the platform functioned the whole time the reliabilities of the aggregation platform is gained from

$$\boldsymbol{AV}[\%] = \frac{\boldsymbol{T_{com}}}{\boldsymbol{T_{op}}} * \mathbf{100\%} = \frac{\boldsymbol{4\,h}}{\boldsymbol{4\,h}} * \ \mathbf{100}\ \% = \mathbf{100}\ \%\ ,$$

where T_{com} is the time the platform operated correctly and T_{op} is the total operation time. If the third testing day is taken into account the T_{op} could have been 2 h at least and thus the AV would be 67 %.

4.1.5 EV DEMO 2 WITH WAPICE LTD.

Electric vehicle charging can be performed with multiple different system architectures. Because the tests performed with Virta Energy platform had rather long delays in communication and the platform was not Helen's property a new demonstration with EV charging was done with other systems. The work was subcontracted from Wapice Ltd. and the results are presented in this chapter. In this demonstration, no KPIs were calculated. The research focused on AC charging active power control.

New EV charge point controlling systems were implemented and developed. The new systems consisted of a charge point using OCPP1.6 communication which was connected to a charge point administration that was controlled by the IoT platform as seen in Figure 32. First the EV charge point administration was set up into a secure cloud service and all required configurations were made. The administration used as base an open source platform SteVe which was modified for secure use by Wapice Ltd. Then an EV charge point was configured to the administration with required certificates provided by the charger manufacturer Alfen. After establishing the connection between the charge point and the administration the link was tested and validated to function as expected.

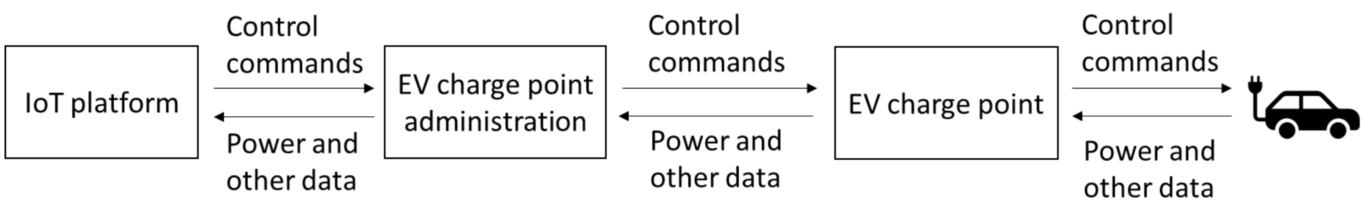


FIGURE 32. DEMO SET-UP OF EV CHARGING

Basic functionalities were implemented to the administration. These functionalities were user indentification with a RFID tag, starting and stopping a charging session and controlling the charging current. After successful implementation of the charger to the administration the administration was attached to the IoT platform. Integration to Helen's other systems was decided not to be done as this demo was a proof of concept of controlling EV charging.

Enabling and stopping a charging session was relatively straight forward by using dedicated commands to the charge point administration. Increasing or decreasing charging power required preconfigured charging profiles with charging ProfieleD parameters. For each charging profile the allowed charging current was defined. This increased the complexity slitghtly. However, the profiles are simple to copy to new charge points and thus the initial configuration can be done only once. As a couple of charging profiles were created it was tested with the charge point and an EV. In Figure 33 shows how a charging session is started and how by changing the charging profile the charging power is controlled.

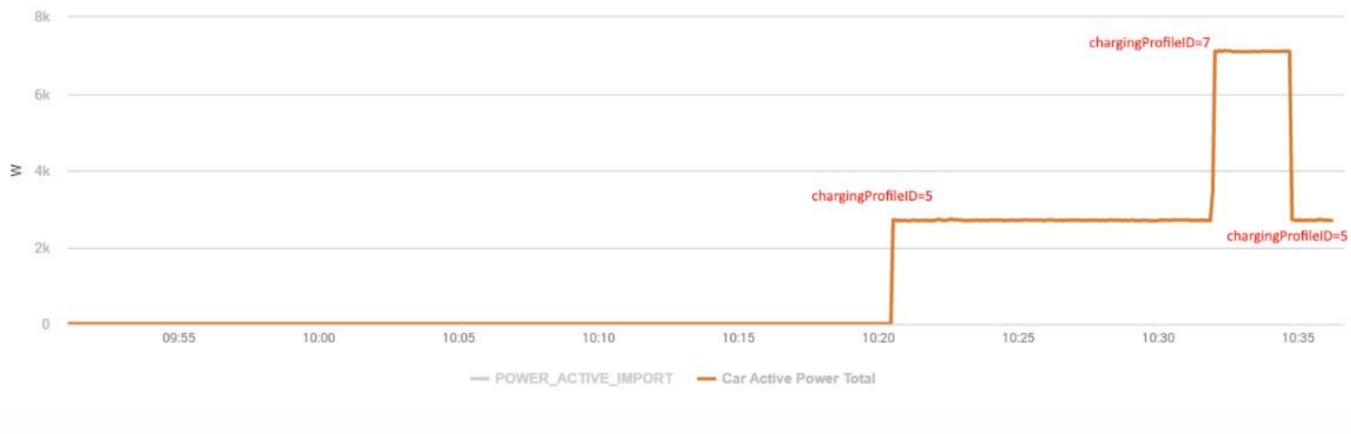


FIGURE 33. CHANGING THE CHARGING POWER

The latency of the system was tested after successful controlling of the charging session and power control. The latency was tested with two charging amperage limits 6 A and 16 A were tested. Table 15 presents the latency between the charge point administration and charge point in ms. On average the commands from the charge point administration had a 141.75 ms latency. Table 15 presents also the total latency for a power change monitored by the power meter. On average the power change took 2.4 s which is a suprisingly good result compared to the EV charging tests performed with the other platform.

TABLE 15. COMMUNICATION DELAY BETWEEN CHARGE POINT ADMINISTRATION AND CHARGE POINT AND THE TOTAL DELAY MEASURED BY EXTERNAL POWER METER

	A	ms	s
Test 1	6	143	2,5
Test 2	16	143	3
Test 3	6	141	1,5
Test 4	16	140	2,5
average		141,75	2,375

As only one charging point was attached to the charge point administration the capabilities of the administration was unclear. Thus, stress tests were performed on the administration. The stress tests were performed by simulating 255 virtual charge points and controlling the administration from the IoT platform. The IoT platform sent charging commands to all of the virtual charge points at the same time. When establishing the first command the delay was 976 ms. The value was written into a database. When giving another command the database was first emptied and the new value written taking in total of 1805 ms. The tests were also performed with virtual chargers that had a preset 5 s delay in response. The results showed that the added 5 s delay for single or several virtual charge points did not add up and the total delay grew only with the 5 s delay. If the delays from the simulation and the actual communication latency test are combined a maximum of 4.3 s is achieved. This delay would meet the strict requirements of FCR-D market where the delay is allowed to be maximum of 5 s.

4.1.6 ELECTRIC HEATING LOADS VIA AMR CONTROL: TECHNICAL ISSUE AND SIMULATION RESULTS

In this chapter, it is described how electric heating loads could be controlled in order to enable service and further aggregate to the TSO’s mFRR market.. Additionally, simulations of the potential benefits from the mFRR market with the electric heating loads located in Helsinki are reported. The loads of the demonstration are electric storage heating (i.e. hot water tank as a storage) of residental single houses controlled by AMR meters. A single load is ca. 10 - 30 kW and the total amount of this load type in the Helsinki area is evaluated to be 20 MW. This type of a heating load can be separately controlled via a specific load relay without affecting the other electricity usage of the customer. In Finland, every customer has in its metering point a remotely read AMR meter and the metering is under local DSO’s responsibility.

DSOs could utilize the controlling of electric heating loads for their local load controlling needs of the distribution networks. However, in the urban distribution network of Helsinki, Helen DSO does not have any need for this control. Actually in distribution areas having mainly residential electric heating, simultaneous controls of heating loads may cause maximum loadings thus possibly affecting rating demands of distribution networks [19]. DSOs are not allowed to take part into electricity market operations. However, in the demonstration of EU-SysFlex, the control of the electric storage heating loads is planned to take place through DSO’s AMR meters and applied to market operations via aggregators.

Generally, electric heating loads are an appealing load type to be operated in the TSO’s markets. In this demonstration, the assets (electric storage heating) are owned by customers of single houses. Aggregators operating in the TSO’s markets aggregate the assets to fulfill minimum bidding size requirements of the markets. Balancing capacity market mFRR was originally seen as a potential market for assets of electric storage heating. In this market, up regulation (i.e. more production, less load) and down regulation (i.e. less production, more load) are performed. In Finland, a minimum bid size in the mFRR market is 5 MW if the assets are electronically controlled, like planned in this demonstration case. Further, in a case of electronically controlled assets, an aggregator can additionally offer one electronically controlled assed of min size 1 MW. The activation time of assets is 15 minutes and measurements of successful control actions are demanded.

In the next subchapters, the results of the research and tests on whether the present AMR meters and metering systems are able to fulfill the market requirements or not. Additionally, the simulation results of possible income from market participation of the electric heating loads to TSO’s mFRR market is presented.

AMR metering

In Finland, the AMR metering is under the responsibility of the DSO. Finland has been a forerunner in the large scale AMR roll-out, not only in coverage of installations but also in functionality and utilization of the AMR system in various business processes. The Finnish Electricity Market law and its act from 2009 [20] stated that every customer (some exceptions included) should have a remotely read AMR meter (first generation AMR meters) by the end of 2013. Additionally, the law determined the minimum characteristics of the meters. It was stated that the AMR meters should, among others features, 1) meter the hourly average electricity consumption, 2) be remotely read once a day, 3) register starting and ending times of interruptions longer than 3 minutes. Additionally, the meters should be able to receive and perform controlling demands of loads. In Helsinki, the roll out of new meters was finished at the beginning of 2013 after having various trial development stages during the former ten years. Helen DSO has ca. 400 000 customers and AMR meters (year 2020). Earlier e.g. for smaller customers, like households, the main task of the old meters was only metering the yearly consumption of electricity for invoicing purposes and the reading was performed manually. Now, these new remotely read and operated AMR meters enabled totally new metering and controlling characteristics.

The hourly time series of electricity usage from AMR meters are remotely read once a day, typically during night time by automatic meter reading system. Various communication methods, like PLC (Power Line Communication), RF (Radio Frequency), point-to-point connection over mobile networks are used depending on the meter manufacturer, model and physical location. The meter reading system is specific for the meter manufacturer in question. Measurements are stored into DSO's measurement database and from there the data is distributed to other DSOs' relevant systems, like Customer Information System (CIS) or Network Information System (NIS) (FIGURE 34). DSOs utlize the meters in various operating and customer services.

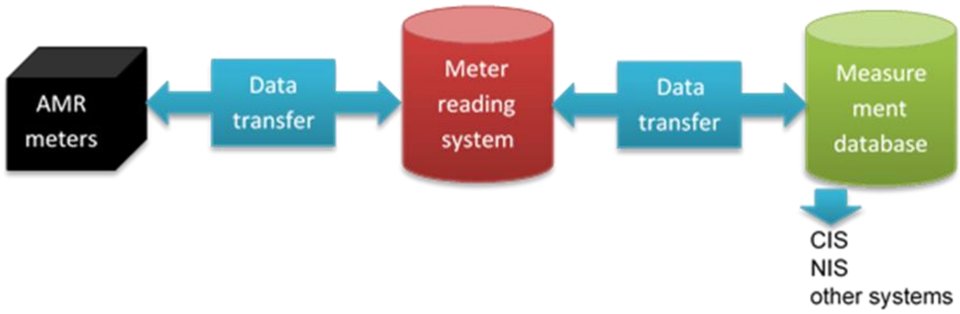


FIGURE 34. DATA TRANSFER IN THE AMR SYSTEM

The AMR meters are DSOs' property and under their responsibility. Only the DSOs have legal and technical access to the AMR meters to fulfill tasks of reading, switching and various controlling operations. Customers have access to their own consumption data. The customers own their AMR data and DSOs can utilize the data for their internal purposes. The DSOs also have the responsibility of forwarding the measured AMR data to associated market participants, e.g. energy retailers.

Load controlling via AMR meters

For controlling purposes, the AMR meters may have a disconnection relay which connects or disconnects the metering point. It is used for example when a customer's electricity contract begins or ends. The meters of customers having specific larger loads may also include a load control relay to which a part of the load can be connected. In households, this load type typically means electric heating. At such metering points, the electric heating can be separately controlled without affecting the other electricity usage of the houses. The energy consumption is not separately measured from these relays. The hourly series of energy consumption is the total electricity usage of the metering point. Relays can be controlled either by a direct (ad hoc) command or by a time based (calendar) control. The direct control is performed always separately and it requires an active data connection between the system and the meter. On the contrary, calendar controls are prescheduled in the meters and they do not require any connection once the schedule has been uploaded.

In Finland, the time based controls have been widely used with customers having time-of-use distribution tariffs where the energy price is lower during night times than during day times. Historically, the aim has been to guide customers to schedule more electricity usage during nights when generally the demand in the power system is minor. The load relay is switched on every day around at 10 p.m. and turned off at 7 a.m. If the connected load is e.g. electric heating the heater's own thermostat typically cuts the heating at some point during the night. This characteristic of a separate load relay and calendar based controls were already in use before electronic AMR meters during old times with electromechanical meters.

Helen DSO has performed research to develop the control characteristics of the AMR meters and introduced dynamic load control scheme in 2010 [21]. This control combines daily heating requirement and typically cheapest energy spot price hours of the day to create a heating pattern for the electric heating customers. The market based dynamic load control was implemented for some Helen DSO's electric storage heating customers. The heating loads of residential customers were no more controlled during fixed hours. On the contrary, the heating hours of the next day were chosen according to the selection based on electricity market spot price and temperature. Based on the outside temperature, the needed amount of heating hours for the next day was determined. For the next day, the hours were listed in an order according to the spot price from the cheapest hour to the most expensive hour. The cheapest hours were chosen for the heating. Once a day an hourly time schedule was sent by Helen DSO to the metering points in question and the electric storage heating was energized during the required, cheapest hours. The control schedule was formed in the measurement database, then sent first to the automatic meter reading system and from there to the specific AMR meters. There were plenty of time to send the control schedule to the meters and thus, no major time limitations for that existed. No particular measurements for verification of the successful operation were made. If sending the control schedule failed the AMR meters included a backup control schedule which would be used instead. This way customers would never be left without heating.

Dynamic load control was adjusted and simplified in 2016 based on the experience gained from the use. After alteration, dynamic load control's heating hours are now prioritized in a fixed order. The order was selected based on the typically cheapest hours of the night. Although at some nights the cheapest hours are different from the prioritized ones, the effect on the customers' electricity price was estimated to be minimal. The advantage of the new control model was that the heating hours were more likely to be arranged consecutively and therefore less relay switches were needed.

AMR load control for mFRR market

The ultimate goal of the Finnish demonstration is to bring small scale loads and generation assets connected to the low or medium voltage level to the TSO's reserve and frequency markets. Generally, the size of these smaller assets cover a range of some dozen to hundreds of kilowatts. By aggregating small resources the minimum market sizes can be reached. The electric storage heating loads of single houses are typically between 15 and 30 kW. The customers' heating demand is always priorized and quaranteed when controlling electric storate heating. Additionally, the market participations typically last only limited time periods, like for the mFRR market e.g. one hour / night. The customers' heating comfort is assured. Thus, concerning the TSO's markets and the nature of the electric heating load these assets are in this context appealing and so far an untapped resource for ancillary services. DSOs do not operate in the TSO's reserve or frequency markets but retailers and aggregators do. Now, in this demonstration case, the interesting loads are electric storage heating loads connected to the DSO's owned and operated AMR meters. Thus, the market based controls arisen from the retailers' and aggregators' needs should be passed via DSO's systems to the AMR relays. The goal of this demonstration was to test the technical solution. The following channel description was formed during the research by combining inputs from different actors. Parties involved in the load control channel are a marketplace operator, an energy retailer operating as an aggregator, an interface operator, a DSO and an AMR measurement reading service provider.

Figure 35 presents the studied load control channel structure. This is one view and proposal to be studied. This kind of a channel does not exist at the moment. Starting from the left, an aggregator bids its proposal to the marketplace mFRR using its Distributed Energy Management System (DEMS). The bid can include multiple kind of loads. DEMS is connected to an integration platform which handles connections to aggregated resources. When the proposal made by the aggregator is approved in the market, the aggregator has to complete the load control in the time frame determined by the marketplace. The aggregator sends a load control request to DSO's AMR loads corresponding the approved offer through necessary interfaces.

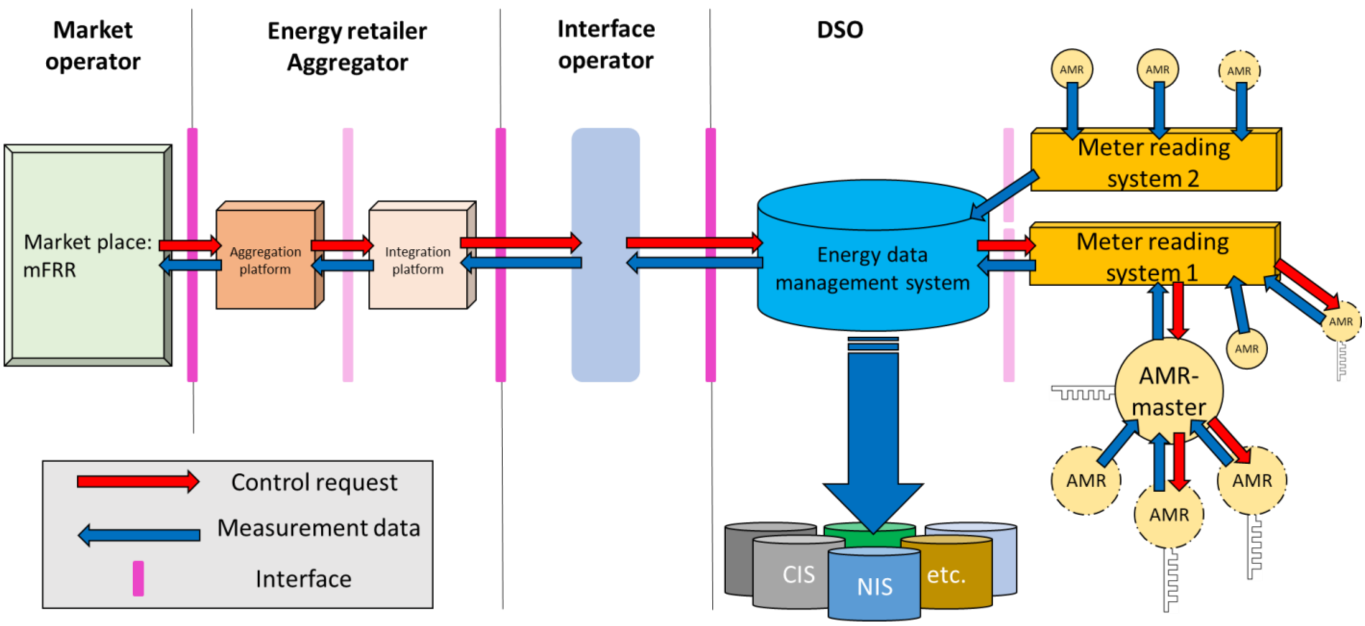


FIGURE 35. LOAD CONTROL CHANNEL SCHEME

An Interface operator between the aggregator and the DSO takes care of the coordination of fitting interfaces on both sides. Energy retailers and aggregators have customers and their controllable assets all over the country locating in many DSOs' areas. When having an Interface operator, the aggregator does not have to connect to every DSO separately and vice versa. The Interface operator's role is to build the necessary infrastructure to connect all the market players and DSOs to enable effective and structurized data exchange. The Interface operator's role in the middle is based on a proposal made by the Smart Grid Working Group actively working in Finland in 2016 - 2018 [22]. These operators do not exist in the market at the moment.

The DSO receives the control request into its energy data management system which forwards the customer and metering point specific commands to the Meter Reading System. The meter reading system then passes the control command to the specific AMR meters. Generally, one DSO can have AMR meters and Meter Reading Systems from several manufacturers. In Helsinki, all of the controllable heating load is connected to one manufacturer's AMRs and to one Meter Reading System. Electricity measurements are transferred back to markets in reversed order. Meter reading system requests the AMR meter for measurement. Once the meter reading system receives the measured values, it passes the data to the DSO's energy data management system. The data is then forwarded back to the aggregator which uses the data to verify control actions for the market place.

Load control test

In order to evaluate the performance of the AMR system a control test was carried out [19]. Instead of a complete control channel, first a preliminary test was carried out. This test was made with the aim to determine the times for the three commands (measurement, control signal, measurement). The commands are to be sent from the measurement database to the automatic reading system and from there to the meters and back. The AMR meter manufacturer provides a dashboard view for displaying meter information. The dashboard is a simple web browser user interface which also allows sending control commands to the specific AMR meter. The test included commands from the automatic reading system to a meter:

- asking the load measurement before the actual control signal,
- sending the actual control signal and
- asking the measurement of the load after the control signal.

With these three commands it could be possible to validate the control signal. Comparing the current measurements before and after the control signal the market operator can confirm that the load was actually turned on or off (Figure 36) .

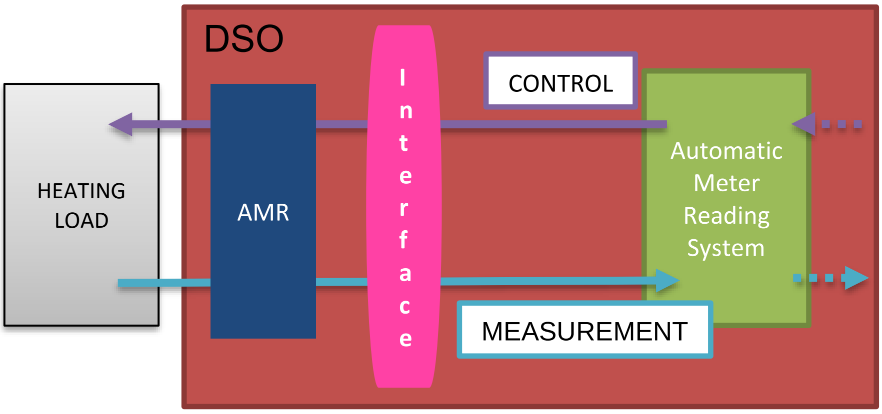


FIGURE 36. CONTROL SIGNAL AND APPLIED MEASUREMENT TEST.

The response time of a measurement command varied around some minutes. The connection to the meter has to be waken up again every time and this causes additional delays. For a single load, this procedure took an average of four minutes. This test did not include the times from the measurement database to the automatic meter reading system or back which would need to be included in the estimate of the response time.

The tests revealed that present first generation AMR meters and their reading systems have not at all been optimized for ad hoc measurements or controls. Sometime a decade ago, during the planning and installation time of first generation AMR meters, fast simultaneous market actions for high number of meters were seen as unrealistic. Now, hundreds or thousands of control commands would have to be performed in a small time frame. Challenges related to the mass control cannot be studied based on these tests. The mass control is further discussed in the following.

Based on tests and prior experience from the data exchange between the automatic meter reading system and the measurement database, the mFRR market requirement of 15 minutes can be fulfilled for a single load but not simultaneously for hundreds or thousands of metering points.

Interviews of manufacturers of AMR meters and Automatic Meter Reading Systems

AMR controlled heating loads are small in size. Therefore, aggregation of loads will be needed and all the aggregated loads should be controlled at the same time. Controlling hundreds or thousands of AMR meters through the same automatic meter reading system was discussed with market operator interviews. The operators reported that it will not be possible to send some hundreds of commands within the needed 15 minutes requirement of the mFRR market. They evaluated that possibly some dozens of commands could end to a successful operation. The bottleneck of the control channel is the data transfer capacity between AMR meters and the automatic meter reading system. The data transfer capacity was designed for tasks where time demands were much slower than the time requirements of the planned reserve markets. For the Automatic Meter Reading Systems one of the main task has been collecting measurement data in coordinated time periods, typically during the night when the data traffic is slower anyway and there was plenty of time for the reading. The solution has been cost-effective and suited well into its purpose.

With the present AMR meters, automatic meter reading system, measurement databases and communication applications, the time requirements of the mFRR market cannot be achieved when aiming to control hundreds of loads at the same time.

AMR meters in future, other controlling alternatives

The second generation AMR meters are to be installed during the 2020s [23]. Some DSOs have already begun their projects. Also in the future meters, one aim is not to loose the controlling ability of the present separately controllable electricity heating loads. However, generally, challenges arise having several actors around this application. DSOs make the investments for their AMR meter technology. Demanding additional features for AMR technology arisen from markets benefits at least the TSO, aggregators and certain customers but it is not seen equitable for all actors, e.g. those customers not having these kind of controllable loads. However, discussion and piloting is going on. E.g. when in the tests performed in the EU-SysFlex research and reported here, the slowness of the controls were found to be one of the problematic issues, e.g. the paper [24] reports a new research pilot of a Finnish DSO with second generation AMR meters, load controls of 76 customers and performed controls during some minutes.

Alternate methods of controlling the heating loads was discussed with an energy retailer. From the energy retailers or aggregators point of view, it is not reasonable to install separate expensive control devices to customer’s heating load just for the demand response market purposes. Demand response functionalities usually come as an extra feature to the main purpose of these heating optimization devices. Only once the control channel is built to the target customer point, it is reasonable to use it in every available way.

A simulation analysis of the potential benefits from demand response in the mFRR market

Above it was reported that technically the demonstration of AMR heating loads participating to the mFRR market in the demanded time frames was not applicable. A barrier was the slowness in the communication systems that occured with a higher number of AMR meters. Therefore, the rules of TSO ancillary service markets cannot be met with the AMR meters and metering systems. Despite these results, however, in the EU-SysFlex project, an already developed forecasting model of the electricity storage heating loads (developed in a previous project) was further developed by VTT by applying new data from Helen DSO. The forecasting tool and the results of the forecast are presented in [4] and [25]. The real environment demonstration was replaced with simulated case scenarios to get knowledge on the theoretical benefits of the participation of electric heating loads to the mFRR market. The results of the forecasting tool were used in the simulated case scenarios. The simulation cases were decided by Helen and Helen DSO and the simulation model was developed by VTT. An overview of the forecasting tool, its relation to the simulation cases as well as the results of the case scenarios are presented in the next subchapters.

Houses with electiricity storage heating and AMR-data

The real life AMR data related to the forecasting model and optimization included AMR measurements from single houses having electricity storage heating in Helsinki. These 727 houses have heat storage tanks heated by electricity using remote control. The heating power is not separately measured. The data covered five years 1.1.2015 –

31.12.2019. The houses were divided in two groups. The group 1 included 350 houses and 377 houses were in the group 2. The grouping is due to the fact that the houses have used different values in order to dimension their heat storage. The modelled daily heat demand in the houses of group 2 needed one hour more heating time than the group 1. The difference in this respect is so small that it was rather irrelevant for this study. The simulation models were identified utilizing data from a previous research project and its' test data from a period in June 2012 – June 2013.

Forecasting

A forecasting model of the heating needs, the expected load curves without any dynamic signals being sent and the load variations in response to dynamic control signals was developed by VTT and it has been reported in [4]. In the research, first a physically based model was presented. Further, the forecasting accuracy was improved by adding a machine-learning model to forecast the residual of the physically based model. The use of a hybrid model combined the strengths of the different approaches and ends up more accurate than its component models applied separately. In [26], an explanation of the modelling concepts and analyses with two real short-term load forecasting cases that include active demand is given. In EU-SysFlex, the machine learning model used (a Hierarchical Deep Neural Network, HDNN) is different from the ones used previously (Multi Layer Perceptron MLP and Support Vector Regression (SVR)). The machine-learning model is an application of a rather generic model for short-term forecasting of electrical and heating load of buildings that was previously developed and applied in an internal project of VTT. Figure 37 presents the aggregated physically based forecasts of Group 1 compared to the corresponding aggregated AMR measurements. It also shows the forecasted SOC of the heat storage (normalised to 100 kWh/house + bias for readability) and the control signal, because they indicate how much the load can be changed by new control actions such as provision for frequency restoration reserve (FRR). [4]

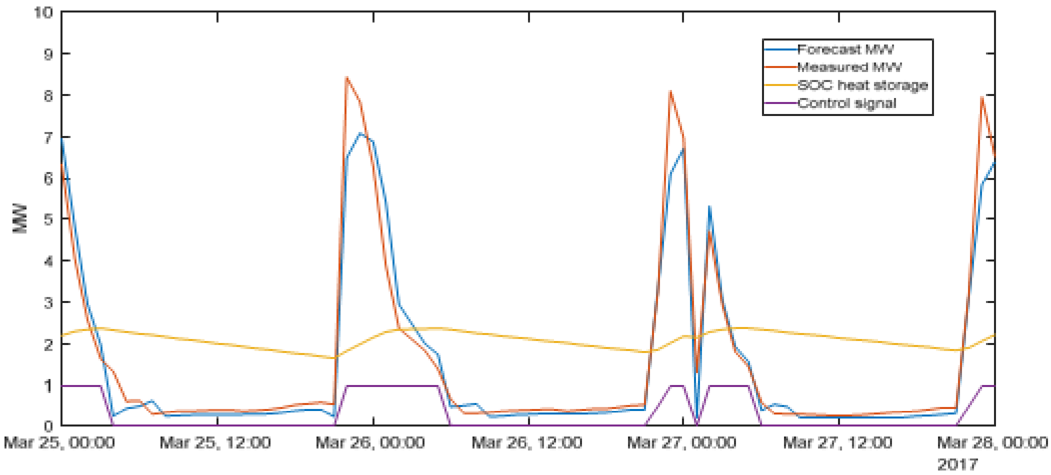


FIGURE 37. PHYSICALLY BASED LOAD FORECAST OVER A 3-DAY LONG PERIOD

Further, there was a need to know how much the load can change by following new control actions targetted for the mFRR market. This is one basic starting point from the perspective of the heating load characteristics and behaviour. The load increase potential of this load type only exists when in the initial situation the heating load is turned off. Respectively, there is a potential for the load decrease only when the load is having a state of on. The load can be increased only to the extent that the state of charge of the heat storage does not exceed its maximum allowed value. At that point, the temperature in the water tank has reached its maximum and the local control system turns off the heating regardless of the control signal state. In normal operation mode, the heating is taking place during every night. Now, market based control signals should be scheduled in a way that there is a possibility to decrease (turn off) or increase (turn on) the load. Figure 38 presents a situation where the loads are controlled so that every night the heat storage reaches its maximum temperature. Thus, the load increase potential is mainly in the afternoons and evenings. If it is expected that load increases will be required in the morning, it is possible to reduce the heating during the night in order not to have a full storage when a load increase would be required. Because the temperatures of the heat storages are not monitored it is necessary to regularly, once or twice a week, allow the heat storage of every house to reach its maximum temperature in order to ensure that the charging state in any house is not reduced too much. Figure 38 also shows the potential for load reductions during one hour, but actually nearly always much longer load reductions of the same size can be applied without causing any customer's loss of comfort, because the outdoor temperature is much higher than the heat storage dimensioning temperature. At extremely cold temperatures (below -27 °C) the possibilities to control the heating are small because the operational margins become smaller with respect to providing adequate heating for every participating customer.

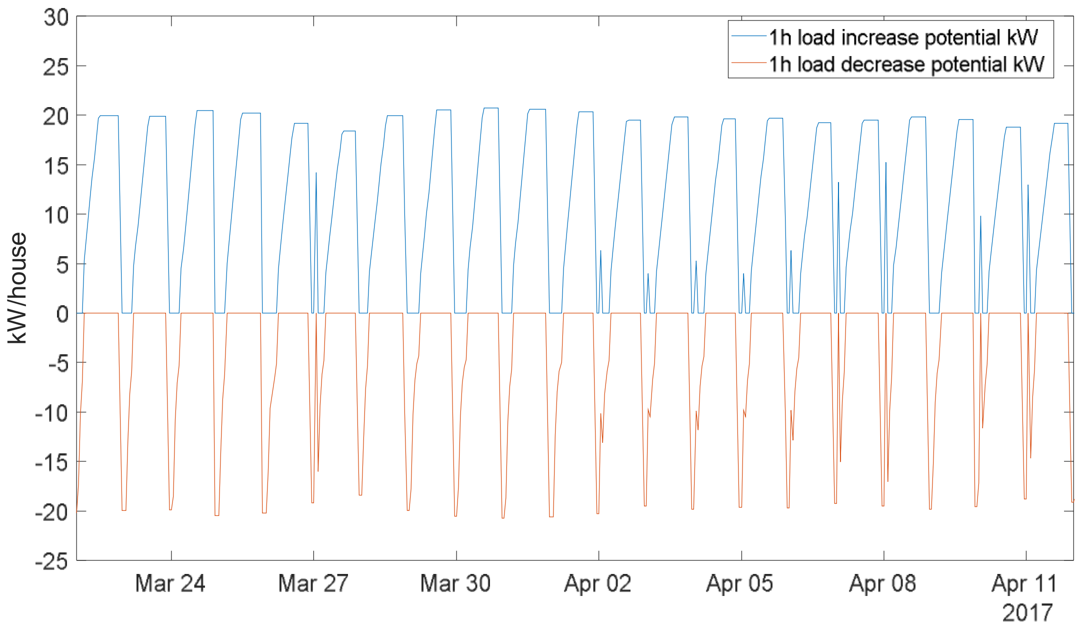


FIGURE 38. POTENTIAL FOR AN HOUR-LONG LOAD INCREASE OR DECREASE OVER A 3-WEEK PERIOD

Optimization by simulations

The forecast of AMR electric heating loads was applied in the AMR simulation cases. Within EU-SysFlex, the forecasting was further developed to support and enable the dynamic load control and thus, a hybrid forecasting model using physical aspects and machine learning methods was realised, tested and simulated. The objective was to analyse the demand response profitability with a few case scenarios. The balancing capacity market mFRR was originally seen as a potential market for assets of electric storage heating. The balancing capacity market is used to secure that Fingrid, the TSO, has a sufficient amount of Manual Frequency Restoration Reserve (mFRR) to cover the dimensioning fault [27]. The market rules valid in 2019 were applied. Balancing energy bids may be given for all resources that can carry out a 10 MW change of power in 15 minutes (5 MW if using electronic activation). The bids are given to Fingrid no later than 45 minutes before the hour of use. Balancing energy bids are either upregulating or downregulating bids. In case of upregulation, the resource owner either increases production or decreases consumptions and therefore sells energy to Fingrid. In case of downregulation, the resource owner decreases production or increases consumption and buys energy from Fingrid. An offering resource owner does not know the bids by the others.

The upper balancing energy price is the price of the most expensive upper balancing energy bid used, however at least the price in the Finnish price area in Nord Pool (Elspot FIN). The lower balancing energy price is the price of the cheapest upper balancing energy bid used, however no more than the price in the Finnish price area in Nord Pool (Elspot FIN).

Everyone from whom Fingrid has ordered upper balancing during the hour receives payment for the energy agreed based on the upper balancing energy price. Everyone from whom Fingrid has ordered lower balancing during an hour pays the lower balancing energy price for the agreed energy.
In the following analysis, the minimum power limit is ignored, because it is assumed that the electricity aggregator retailer has also other flexibilities to offer to the mFRR market and the minimum power change required is applied to the aggregated flexibility of the various resources. If the minimum power limit is applied to the studied groups alone, the rewards would be very much smaller.

The 727 houses were devided in two controllable groups of 350 and 377 houses. Seven different control strategies were created (Table 16). For example, Case 1a included a control to the group 1 during the hour 12 a.m. - 1 p.m. and to the group 2 during the hour 1 p.m. - 2 p.m. During afternoon hours only down regulation (increasing heating load) is possible while at that time of the day the heating via the specific relay is having off state. The amount of the load to be controlled during that time of the day depends on the SOC level of the water tank. During afternoon hours no up regulation (decreasing heating load) is possible. However, Case 4 presented a control strategy during the early morning hours, the group 1 during 3 a.m. - 4 a.m. and the group 2 during 4 a.m. - 5 a.m. Because the water tank has mainly been warmed up during around noon and early night hours there have existed capacity for up regulation for the group 1 and down regulation for the group 2.

Data (temperature, AMR, mFRR market data [28] from years 2015 - 2019 were applied. In the first simulations, the controls were to be performed if the market price was higher than zero and the market volume was at least 10 MW. The volume of the response depends on the out temperature. When the temperature is high the down regulation is small. When the temperature is below zero the single hour load increase is at the least 5 MW per group. Much lower temperature is needed to maintain the 5 MW load increase per group for two hours.

TABLE 16 SIMULATED CASES WITH ZERO BID PRICE

Case	Hour offered	Group	Down regulation MW [min, max] (=load increase)	Up regulation MW [min, max] (= load decrease)
1a	12-13	1	[1.1838 6.9960]	—
	13-14	2	[0.1539 6.6186]	—
1b	14-15	1	[1.3672 7.0618]	—
	15-16	2	[0.1625 6.5834]	—
2a	12-14	1	[0.7460 6.9960]	—
	12-14	2	[0.5564 6.6143]	—
2b	12-14	1	[0.7460 6.9960]	—
	14-16	2	[0.5580 6.5997]	—
3a	12-13	1	[1.3424 13.6102]	—
	12-13	2		—
3b	13-14	1	[1.4225 13.6764]	—
	13-14	2		—
4	03-04	1 and 2	—	[-0.001 -10.057]
	04-05	1 and 2	[0.3013 9.8228]	—

The objective of the simulation part was to calculate the rewards. The estimated rewards assume perfect forecasts. Taking the response forecast uncertainty into account will reduce the rewards. The RMSE (root mean square error) of the group load forecasts was about 1.4 MW when using the HDNN-physical-hybrid load forecasting model and about 1.2 MW for our most accurate ML-physical hybrid forecasting model so far. It was not modelled what is the uncertainty of the physically based sub-model alone and how it depends on the situation. Thus, it was only roughly estimated that the reduction of the rewards due to forecast uncertainties may be about 15 %, because that much more controllable load may need to be reserved in order to manage this uncertainty.

Simulations were performed for the whole five years period 2015 - 2019. A special attention was addressed to the last simulated year 2019. Like mentioned earlier, in the first simulations, the controls were to be performed if the market price was higher than zero and the market volume was at least 10 MW. Further studies included simulations where also rough optimization of the bid price was applied. The idea was that increasing the bid price from zero may first increase the net income as some non-profitable actions are removed. Increasing the bid price further will remove also profitable actions and the net revenue starts to decrease. This latter approach of non zero bid prices was chosen as the main reported result of these simulations.

The increase in revenue and profits of service were calculated. These values act also as the key performance indicators (KPI) of this demonstration. In these calculations, the real mFRR market data was included. For the grid tariff, the customers were assumed to have the time-of-day distribution tariff. It includes an energy based component and a power based component. In this grid tariff, the price of the energy is lower during the night time

(10 p.m. - 7 a.m.). The power cost is based on the third largest hourly value during the invoicing month - additionally, however, the power values from the night time are regarded by an amount of 80 %. During the night time, both the retail and the grid tariff have lower energy prices. This means that when moving heating by active market actions from the cheaper night time to the more expensive day time the cost for the customer increases. To aim to have a profitable service and products to the customers the income from the mFRR markets should be higher than the increased cost arisen from the retail and the grid tariff. It should be noticed that no other costs were included in these simulation results. For the time-of-day grid tariff, the tariff valid since 1.7.2018 was applied (the time-of-day tariff: fixed cost 14,11 €/month, power cost 1,28 €/month, day time energy 0,0209 €/kWh, night time energy 0,0109 €/kWh, prices announced tax 0%). The customers were assumed to have for the retail tariff the spot based tariff. This was calculated using the assumption that the variable price component is the same as the day ahead spot market price. It was supposed that all the customers buy electricity from their electricity retailers using a contract where the variable cost component is directly according to the day ahead spot market price. The electricity retailer's margin is typically small and here it was assumed to be included in the fixed fees that do not depend on the consumption.

4.1.6.1 KPI RESULTS

The Electric Heating Loads via AMR Control-demonstration was evaluated through KPI's 1 and 7 of the Finnish demonstrator.

Increase in the revenue of the flexibility service provider (KPI no1) is calculated by multiplying the provided power by the price of the service summed over a set of resources and a set of markets/services. This KPI is like the gross benefit R_{gross} for the aggregator.

$$R = R_{gross} = \sum_{s \in S} \sum_{a \in A} \sum_{t=1}^{T} P_{s,a,t} \cdot \pi_{s,a,t}$$

where
S is the set of available markets/services
A is the set of available resources
t is one of the T time periods considered
P the realized power exchanged [MW]
π is the price [€/MW]

An additional FIN - KPI7 was calculated describing the profits to the customers taking into account - in addition to above mentioned revenues in service provision - also the cost of service provision. This cost of service provision included the operational cost from purchasing electric energy (according to the retail tariff) and the grid tariff costs. It is the operational net revenue R_{net} from the participation to the manual Frequency Restoration Reserve (mFRR). It was calculated as follows:

1) The gross benefit $R = R_{gross}$ from the mFRR market is calculated by multiplying the response $P_{s,\alpha,t} = P_{mFRR}$ sold to the market by the mFRR market price $\pi_{s,\alpha,t} = \pi_{mFRR}$. Only the response in the hours for which the response offer was accepted was taken into account. Up regulation and down regulation have different prices and volumes in the mFRR market. Only the hours when the purchased volume was at least 10 MW were included.
2) The increase in the operational costs that the responses cause to the customers, *C*, was calculated. It comprises cost arisen from the grid tariff and from the retail tariff.
   2.1) The grid tariff costs *C* consist of an energy based component C_{gridE} and a power based component C_{gridP}.
   2.2) The retail tariff, the energy purchase cost C_{spot} was calculated using the assumption that the variable price component is the same as the day ahead spot market price.
3) Finally, the net revenue R_{net} is got by subtracting the cost increases from the gross benefit.

FIN - KPI1: The gross benefit R_{gross}

$$R = R_{gross}(T) = \sum_{n=1}^{T} P_{mFRR}(n)\pi_{mFRR}(n)$$

FIN - KPI7: The net benefit R_{net}

$$C_{gridE}(T) = \sum_{n=1}^{T} P_{mFRR}(n)\pi_{gridE}(n)$$

$$C_{spot}(T) = \sum_{n=1}^{T} P_{mFRR}(n)\pi_{spot}(n)$$

$$C(T) = C_{gridE}(T) + C_{gridP}(T) + C_{spot}$$

$$R_{net}(T) = R_{gross}(T) - C(T)$$

For the whole simulation period the grid tariff that came to effect in 1 July 2018 was applied. If the actual tariffs during the simulated years 2015 - 2019 where to be applied the comparison of different years would be much more difficult. The above KPI formulae are first calculated for the response of and average house model (Table 17). Multiplying the average house revenues by the number of controlled customers (727) the KPI for the whole demonstration group is received.

The resulting KPIs were **TABLE 18**

FIN - KPI1 = 56 415 €

FIN - KPI7 = 23 249 €

TABLE 17 SIMULATED AVERAGE 2015 - 2019 GROSS AND NET REWARDS PER HOUSE WITH OPTIMIZED BID PRICE

Case	Hour offered	Group	Mean annual gross reward €/ house	Mean annual grid energy fee change	Mean annual grid power fee change	Mean annual spot market fee change	Mean annual net reward €/house without power fee	Mean annual net reward €/house	Bid Price €/MW
1a	12-13	1	37.90	13.38	2.87	12.27	12.24	9.37	25
	13-14	2							
1b	14-15	1	42.30	15.41	7.33	10.20	16.69	9.36	24
	15-16	2							
2a	12-14	1	70.58	25.11	-1.02	17.48	27.99	29.01	0
	12-14	2							
2b	12-14	1	77.60	29.04	0.37	16.21	32.35	31.98	4
	14-16	2							
3a	12-13	1	34.21	11.81	2.40	11.50	10.91	8.50	26
	12-13	2							
3b	13-14	1	37.58	12.94	4.85	11.41	13.24	8.39	26
	13-14	2							
4	03-04	1 and 2	17.06	1.22	-2.53	1.13	14.71	17.24	0
	04-05	1 and 2							

TABLE 18 KPI - FIN1 AND KPI - FIN7 FOR THE SIMULATION CASE 2B.

	amount of customers	Reward per customer €/year	Total reward €/year
KPI - FIN1	727	77.60	56 415
KPI - FIN7	727	31.98	23 249

In all the cases, the profitability of participating to the mFRR-markets was low. At the end of the analysed period 2019, the profitability was roughly the same as the average of the whole 5 year period. The gross benefit increased towards the end but the costs to the consumer increased almost with an equal amount. Especially, the DSO power tariff costs increase towards the end. Some of the studied cases can bring some added value to investments that mainly serve some other market or purpose. It is unlikely that they can alone pay back the investments in ICT that are needed to make it possible to use the flexibility for mFRR that requires rather small control latencies with high reliability.

The aggregate model is not suitable for analysing the impacts of power-based tariffs. An average customer load model likely underestimated the aggregated impacts and is completely unable to reflect the impacts on individual houses. For that purpose in the modelling, there is a need to develop and add modelling of the highly stochastic behaviour of individual consumers as a probability distribution, for example.

General conclusions regarding the poor profitability of demand response cannot be drawn from these results, because of the following reasons

1) Some other ancillary service markets than mFRR or multiservices provision may be better for these resources.
2) Participation to some other ancillary service market does not necessarily exclude participation to mFRR.

3) The existing ancillary service markets are small, fractionalised and inefficient for small distributed resources. The ancillary service markets are being improved which will also increase the profitability of engaging distributed flexible resources to the ancillary services although it will also reduce the prices of flexibility in the wholesale ancillary service markets.

4) It is expected that the ongoing changes in the power generation (such as the move towards renewables and starting the operation of very big nuclear units in Finland) increase the need for demand-side flexibility in the electricity grids. This most likely will increase the prices in the ancillary service markets.

4.2 REACTIVE POWER MARKET DEMO

In Finland, the reactive power characteristics of the electricity power system have dramatically changed during the last decade from inductive reactive power towards capacitive reactive power [29], [30]. In Helsinki, Finland, the main causes for this development are:

1) the widening of underground cable network with growing city and replacing of 110 kV overhead lines with underground cables and thus increasing reactive power production of 110 kV and medium voltage (20 kV or 10 kV) underground cables
2) the changes in electrical characteristics of customer devices having nowadays more and more electronics meaning decreased reactive power consumption of customers. During the last decade this development has been drastic and so far, no slowdown of these changes in reactive power characteristics has been observed.

DSOs in Finland are connected to the national TSO's network through their connection points, in the Helsinki area from Helen DSO's 110 kV network to TSO's 400 kV network. In these TSO/DSO connection points, the allowed reactive power change is determined by a PQ window set by the TSO (Figure 39). The reactive power control of a DSO assists the TSO to control the reactive power and maintain the voltage quality in the 400 kV transmission network. If exceeding the window limits, the reactive power tariff becomes into force meaning considerably high costs of reactive power demand and reactive power energy for the DSO. These costs act like penalty payments. In general, this tariff structure does not include any active TSO/DSO coordination. Thus, to keep the reactive power flow inside the window and further to avoid the penalty costs, DSOs should have means to control the reactive power flow through their PQ windows. Costs of reactive power has considerably increased during the past years. The TSO launched tariff development steps of the excessive reactive power flow in the PQ window (Table 19).

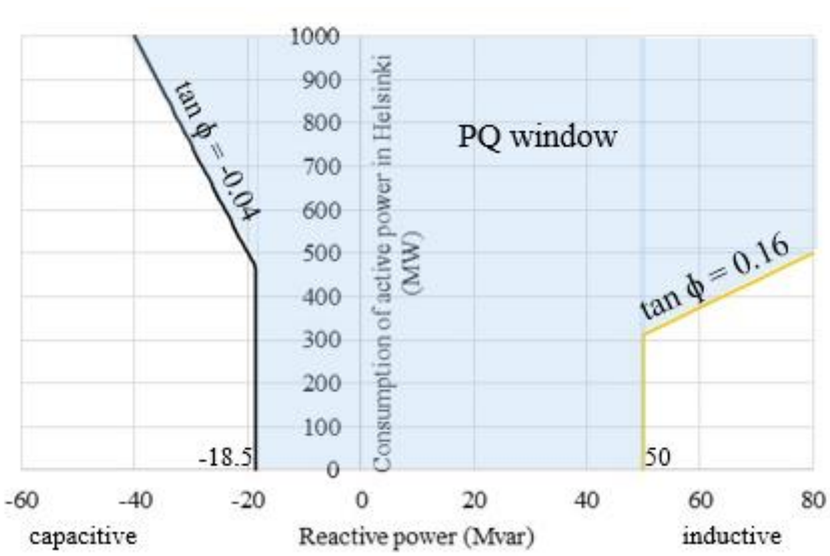


FIGURE 39. PQ WINDOW IN THE FINNISH ELECTRICITY SYSTEM, CASE HELSINKI SEPT 2019.

TABLE 19 REACTIVE POWER TARIFF ELEMENTS [31]

	Years			
	≤2016	2017	2018	2019≥
Price for reactive power (€/Mvar)	0	333	666	1000
Price for reactive energy (€/Mvarh)	0	5	5	5

Nowadays in Helsinki, the challenges arise from feeding too much capacitive reactive power to the TSO's network. The inductive reactive power limits are not exceeded. In the context of reactive power flow, the most critical times are when the consumption of active power is lowest, typically spring, summer and early autumn nights and weekends.

During 2010's, within the drastic changes of reactive power and the situation in the PQ window, Helen DSO decided to invest to its' own reactive power control capability. As a result in 2015, Helen DSO had 110 kV compensation devices: one 30 Mvar reactor and two 30 Mvar capacitors. The compensation demand was focused on the reactor, and the two capacitors were rarely used. After 2015, it was quickly observed, that still new inductive reactive power capacity would be needed and Helen DSO invested into a new 56 Mvar reactor in 2020. The characteristics of reactive power had changed considerably and major actions were urgently needed. Additionally, before having the newest 56 Mvar reactor, Helen DSO had other additional means to have more reactive power resources. The utility had a bilateral agreement with one large customer about controls of reactive power. This agreement was designed for long term and regularly repeated compensation. For the DSO, this was an efficient and straightforward solution. The DSO predetermined a compensation schedule that included time frames and amounts of compensation. The DSO payed to the customer if the compensation was done successfully. The agreement helped the DSO to control reactive power in the network and concurrently to stay within the PQ window limits. Furthermore, in recent years, one additional solution for a DSO to decrease the capacitive reactive power has been, whenever reliability is not endangered, to disconnect in the meshed network structure some 110 kV cables.

When there has been this drastic change of reactive power characteristics also DSO's own customers have been informed and guided. In the past, decades ago, the power tariff customers may have installed own compensation devices (earlier especially capacitors). Now it would be important the power tariff customers to notice and react to the changed characteristics. Here is an aim the power tariff customers to reestimate the need of their own compensation devices and possibly disconnecting these additional capacitors out of operation. Furthermore in the power tariffs, the cost of capacitive reactive power has been raised. To strengthen the guidance with tariffs, since 1.11.2020 for medium voltage power tariff customers, the cost of inductive reactive power was totally removed.

One future solution to have more controllable reactive power assets could be a reactive power market. Also in Finland, when decentralized production and the use of renewable energy gradually increases, DSOs could have markets to improve the control of the distribution network and at the same time, DSOs could support the operation of the TSO. The DSO markets could operate through the same aggregators that are currently aggregating active power resources to the ancillary markets of the TSO. The solution to widen and increase the controllable reactive power capacity available to DSOs could be a local ancillary reactive power market. In EU-SysFlex, it has been demonstrated as a technical proof of concept [32], [30], [33]. For the DSO, the aim is to operate successfully in the TSO/DSO connection point and it's PQ window and avoid or minimize the penalty costs caused by excessive reactive power flow to/from the TSO's network. For the aggregator, the objective is to gain profit from the market operations, and devide the income together with their customers in question.

An ancillary reactive power market would utilize the customer resources, that are connected to the distribution network and capable of producing and/or consuming reactive power, through aggregators. The DSO's acceptance of the reactive power resources and their planned compensation is needed in order the DSO to check that the compensation in question is appropriate to the local characteristics of the power distribution network. Assets providing reactive power compensation must meet the technical requirements defined by the DSO. Aggregators make forecast of the availability of the reactive power resources, formulate the bids and send them to the Q market. On the other side of the Q market, the DSO forecasts the active and reactive power of the PQ window and formulates - along the DSO's reactive power controlling strategies - the reactive power needs to the market. After the market clearing, the market parties are informed about the market results. Further, aggregators inform the Asset Operators. The bidding and delivery phases are presented in Figure .

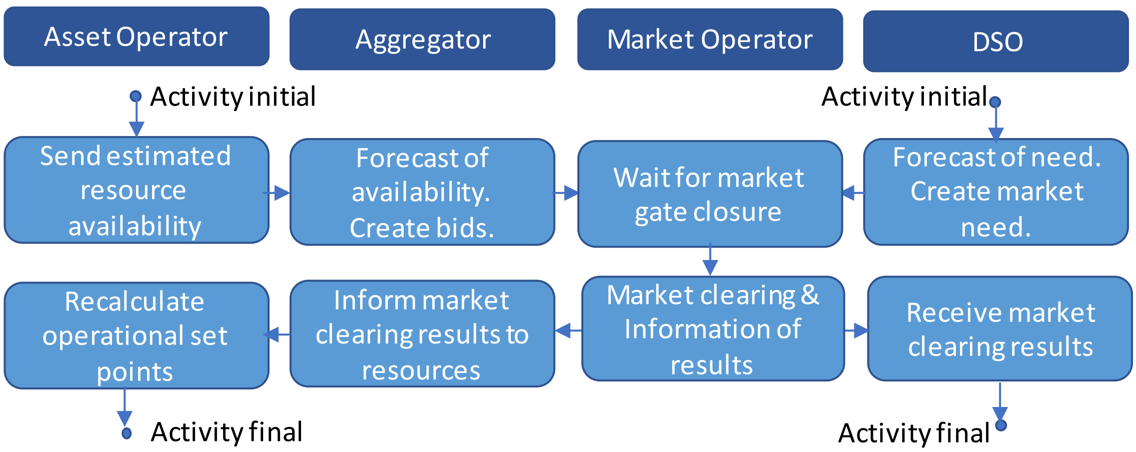


FIGURE 40. THE BIDDING AND DELIVERY PHASE OF THE ANCILLARY REACTIVE POWER MARKET.

In the EU-SysFlex demonstration, the

- Asset Operator is Helen
- Aggregator is Helen
- Market Operator is Helen DSO
- DSO is Helen DSO

The controllable reactive power resources of the demonstration are owned by Helen and they are a Battery Energy Storage System in Suvilahti, Helsinki ("Suvilahti BESS") and a PV plant in Kivikko, Helsinki ("Kivikko PV"). The assets and the testing phases are described below.

Suvilahti BESS: testing phase

Helen commissioned in August 2016 at that time the largest BESS in Nordic countries. During the first three years, this BESS was used as a research platform by Helen, Fingrid (the TSO in Finland), and Helen DSO (the DSO in Helsinki) [12] [13] [14] In EU-SysFlex, the capability of Suvilahti BESS (1.2 MW, 900 kvar, 600 kWh) is demonstrated for both, FCR-N provision as well as for reactive power compensation. Due to the rating of the BESS, it can operate in the FCR-N (bid size: 500 kW) and provide reactive power compensation (at maximum 900 kvar) at the same time without limiting each other [12]. A calendar-based reactive power compensation schedule was tested during the research phase of the battery. The calendar-based schedule can be set locally to the computer of the battery. An example of a reactive power compensation test based on a calendar schedule is presented in Figure . During the test, the BESS assisted the DSO's reactive power management according to three modes [14]

- Mode 1: Balance the reactive power flow in the TSO/DSO connection point (set point -900 kvar, night-time)
- Mode 2: Decrease the reactive power losses in the supplying primary 110/10 kV transformer (set point + 900 kvar, day-time)
- Mode 3: Minimize the losses of the BESS itself (no Q compensation, set point value 0 kvar)

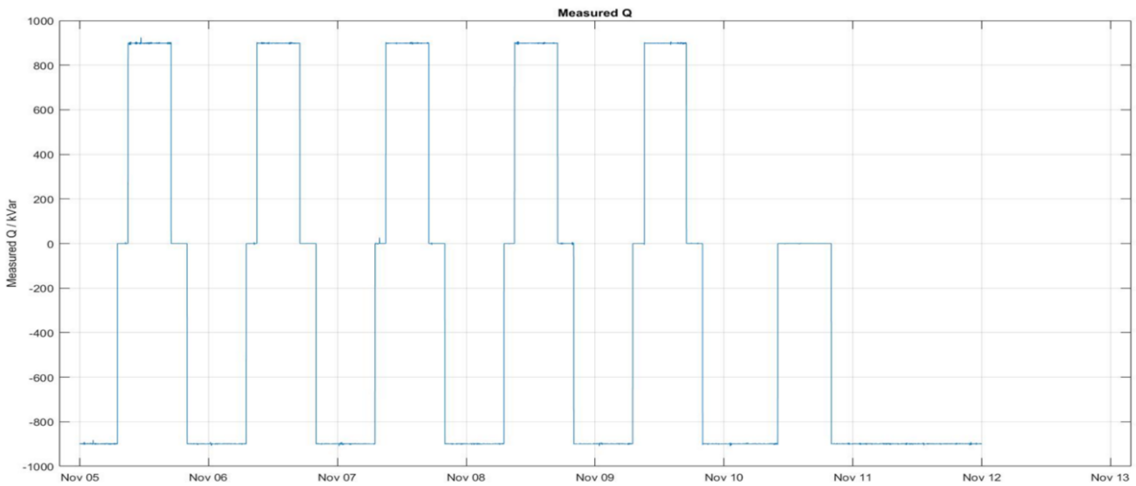


FIGURE 41. REACTIVE POWER COMPENSATION TESTS OF SUVILAHTI BESS IN 2018

In EU-SysFlex, the further studies are done according to the Mode 1 of the tests, i.e. reactive power compensation according to the need of the DSO. The savings (€) reacheable with mode 2 for the DSO are neglible small. The reactive power compensation increases the losses of the battery for the battery owner (Helen) and therefore, the battery owner should receive remuneration from the DSO if it provides reactive power compensation according to the need of the DSO.

The reactive power market demonstration phase was done at the same time when the battery was working on the FCR-N market, which means that it was in the IEC104 interface mode instead of a local control mode. During the reactive power market demonstration, the control of the battery was done manually as a set-point value (on-off control). When the BESS is in the IEC104 mode, it is not possible to use the calendar-based compensation schedule that was used in the testing phase with the local control mode.

Kivikko PV: testing phase

The remote control of the PV plant and remote control system of reactive power compensation was developed and implemented to the Kivikko PV plant during the EU-SysFlex project. The aim of the implementation and control logic was to remotely control the inverters of the PV power plant with the defined control curve. The inverters of the Kivikko PV plant were already connected to the IoT platform used by Helen via an IoT device. Therefore, the communication channel via Modbus TCP was already available and measurement data was collected to the IoT platform. However, remote control via the IoT platform was not previously tested.

A calendar-based compensation logic and schedule was developed to the IoT platform. The control of the inverters was established as follows:

- Hourly values for reactive power compensation (calendar in a csv file)
- The IoT platform visualizes the hourly values as a control curve
- IoT platform sends reactive power commands to the inverter every hour
- IoT device installed at Kivikko PV plant sends measurement data back to the IoT platform

The remote control of reactive power as well as on/off control of the inverters were tested together with the IoT platform service provider in two workshops. A compensation schedule of few days was also tested before the actual reactive power market demonstration phase.

During the tests it was decided that the maximum value of reactive power compensation would be +/- 100 kvar (while the real maximum reactive power capacity of one inverter is 450 kvar). Figure presents the results of the testing phase. The control of the inverter worked as planned. Sometimes a delay of 2 to 8 minutes was detected before the command was realized, but the control and communication channel was fast enough for the demonstration purposes.

FIGURE 42. REACTIVE POWER COMPENSATION TESTS ACCORDING TO A CALENDAR-BASED SCHEDULE WITH ONE OF THE INVERTERS OF KIVIKKO PV PLANT, APRIL 2020. MINUS: REACTIVE POWER CONSUMPTION. PLUS: REACTIVE POWER PRODUCTION.

Forecast of additional reactive power compensation

On the DSO's side, the reactive power market procedure starts by forecasting the reactive power and identifying whether additional reactive power resources are needed and announced to the market. The need of additional reactive power is formulated based on the forecast of the PQ window and the strategic use of other DSO's controllable resources, like DSO's own 110 kV reactors and capacitors. In this EU-SysFlex project, the forecast of the PQ window was done by VTT and it has been reported in Deliverable D 6.2 [4]. The realization and integration of the forecast into Helen DSO's systems was done manually for the purpose of the demonstration period due to the hypothetical nature of the reactive power market. VTT acts as the forecast provider. In the demonstration, Helen DSO asks for the forecast for the next week from VTT . The forecast was sent as a csv-file to Helen DSO, which had the responsibility of formulating the reactive power requirements according to its compensation strategy: primarily operating their own 110 kV compensation devices and in case of insufficient capacity, specifying the requested resources from the market.

Reactive power market demonstration period

September 2019 was the demonstration period. The steps of the demonstration were as follows:

- Helen DSO asked for Q forecast from VTT. Q forecast was sent from VTT to Helen DSO.
- Helen DSO determined its hourly need for Q flexibilities (PQ window: -18.5 Mvar limit during the demo)
- Helen offered Q resources to the market: All market hours: -1 Mvar (PV: -0.1 Mvar, BESS -0.9 Mvar)
- The offers were accepted according to the needs of the DSO
- Helen operated the Q resources according to the accepted offers
- The fullfilled controls were compared to the agreed amount of reactive power control.

September 2019 was chosen as a demonstration period, since it was a month when Helen DSO would have needed additional reactive power compensation.FIGURE 43 shows that in September 2019 the window limits were repeatedly exceeded. This occurred during hours when the consumption of active power is lowest, typically during nights and weekends. PQ window data of September 2019 presented the market demonstration period. However, in real life, the market play and resulted market based real life controls of the assets were performed in May 2020. Thus, the PQ data of September 2019 was applied as simulated data for the demonstration. The reason for this was that the situation with Helen DSO's own controllable reactive power assets drastically improved in the beginning of 2020 when a new reactor (56 Mvar) was installed to the 110 kV network. Since then Helen DSO's compensation device were able to take care of the PQ window situation and as a result, additional reactive power compensation was no longer needed from the demonstrated assets. Therefore, the data and PQ window status of September was used in the demonstration although the assets were controlled in real life in May, 2020. The assets were controlled according to the market result, i.e. the compensation need of the DSO. The technical real life demonstration period lasted one week and in the results and KPI calculations, a time period of one month is considered.

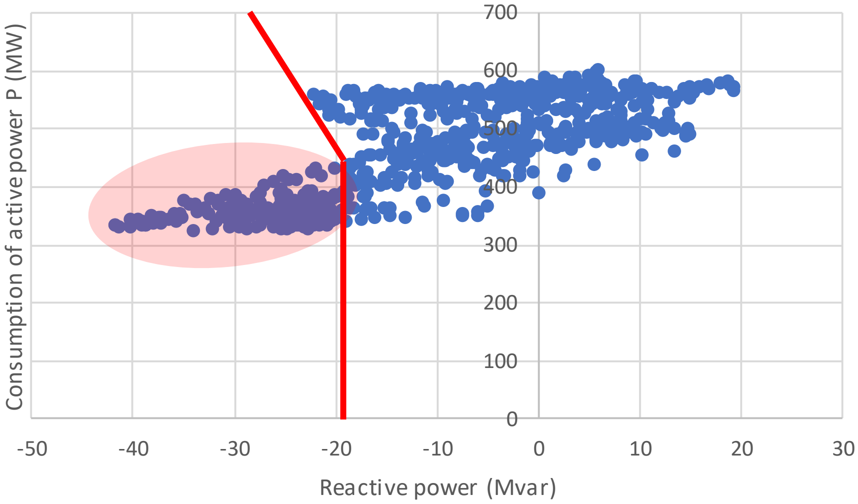


FIGURE 43. MEASUREMENT DATA OF THE PQ WINDOW IN SEPTEMBER 2019.

VTT made weekly forecasts applying Gradient Boosting Model utilizing as training data measurements from January 2016 to August 2019. VTT made first four weekly forecasts for September 2019 starting 1. - 7.9.2019, etc. ending to the fifth forecast including three days 28. - 30.9.2019. This procedure took into consideration that there would have been access to the real measurements to input them in the forecast model every week to obtain the next week's values. The weekly forecasts as an output as csv-files were sent to Helen DSO. Helen DSO formulated the reactive power demand need according to its strategy: first operating their own 110 kV compensation devices and after that formulating the need to be asked from the market. In September, there were altogether 194 such hours that Helen DSO's own controllable reactive power resources would not be adequate to stay inside the PQ window. September is typically one of the most challenging months in the context of reactive power flow in the PQ window. Generally, the need for additional reactive power resources exists when the consumption of active power is lowest, meaning spring, summer and early autumn nights, especially weekend nights.

Table 20 presents the reactive power forecast in the PQ window for 7.9.2019 added by the operation of DSO's own 30 Mvar reactor. If in the presented case, the Q forecast values were lower than the PQ window limit (here, due to low active power values during the considered hours, the capacitive window limit was the vertical line -18.5 Mvar), the capacitive side of the PQ window was exceeded (FIGURE 43). For these hours, the DSO indicates an interest and a need in the reactive power market. The aggregator was interested and able to offer inductive reactive power with its' assets of PV with 0.1 Mvar and of BESS with 0.9 Mvar. The bidding size during the demonstration was therefore 1 Mvar. The controls were successful.

TABLE 20. OVERVIEW OF THE DEMONSTRATION PERIOD AND ORDERED AND DELIVERED AMOUNTS AS WELL AS FORECASTED NEED

	Q forecast +30 Mvar	PV		BESS	
		order	delivery	order	delivery
	Mvar	Mvar	Mvar	Mvar	Mvar
7.9.2019 0:00	-17.6		0.00		0.90
7.9.2019 1:00	-19.3		0.00	0.90	0.90
7.9.2019 2:00	-22.7	0.10	0.10	0.90	0.90
7.9.2019 3:00	-24.4	0.10	0.10	0.90	0.90
7.9.2019 4:00	-24.8	0.10	0.10	0.90	0.90
7.9.2019 5:00	-25.5	0.10	0.10	0.90	0.90
7.9.2019 6:00	-23.9	0.10	0.10	0.90	0.90
7.9.2019 7:00	-17.6		0.01		0.90
7.9.2019 8:00	-15.6		0.00		0.90
7.9.2019 9:00	-10.9		0.01		0.44
7.9.2019 10:00	-5.8		0.01		0.00
7.9.2019 11:00	2.5		0.02		0.00
7.9.2019 12:00	7.6		0.03		0.00
7.9.2019 13:00	10.5		0.03		0.00
7.9.2019 14:00	11.6		0.03		0.00
7.9.2019 15:00	11.4		0.03		0.00
7.9.2019 16:00	11.1		0.02		0.00
7.9.2019 17:00	10.2		0.02		0.00
7.9.2019 18:00	6.7		0.01		0.00
7.9.2019 19:00	3.5		0.01		0.00
7.9.2019 20:00	6.2		0.00		0.00
7.9.2019 21:00	6.1		0.00		0.00
7.9.2019 22:00	-1.9		0.00		0.00
7.9.2019 23:00	-5.6		0.00		0.00

The demonstration was performed for one month. The aim was to choose a challenging month when real interest for the reactive power market would exist. FIGURE 43 shows the PQ window data in September 2019. The window limit of capacitive reactive power was repeatedly exceeded.

However, there was no need for the market for every month. Additionally, arisen from the variation of active power P and reactive power Q, P and Q considerably vary during different months, days, daytimes. During the past couple years, for most of the days and for all the late autumn and winter time, there have not been any excessive reactive power flows from the DSO to the TSO and no reactive power penalty payments have been payed. FIGURE 44FIGURE below presents the invoiced monthly capacitive reactive energy and demand of months January 2018 - September 2019. The possible activation of the market depended strongly on the season, week day and time of the day.

In this specific Helsinki case, Helen DSO was obliged to respond to the dramatic development of the reactive power characteristics and as a result, Helen DSO supplied the first 110 kV reactor of 30 Mvar in 2015. When the situation with the PQ window and reactive power continued to worsen, Helen DSO invested and took into operation a second reactor, now 56 Mvar in January 2020. After these investments, the DSO solved the gradually, but rapidly developed problematic and costly condition at the PQ window. The reaseach of the DSO markets is topical and interesting. However, during this EU-SysFlex project, the reactive power market was worth of demonstration but with unmatured nature and limited controllable reactive power resources of customers did not offer a adequate solution for the DSO in its' challenging situation in the PQ window.

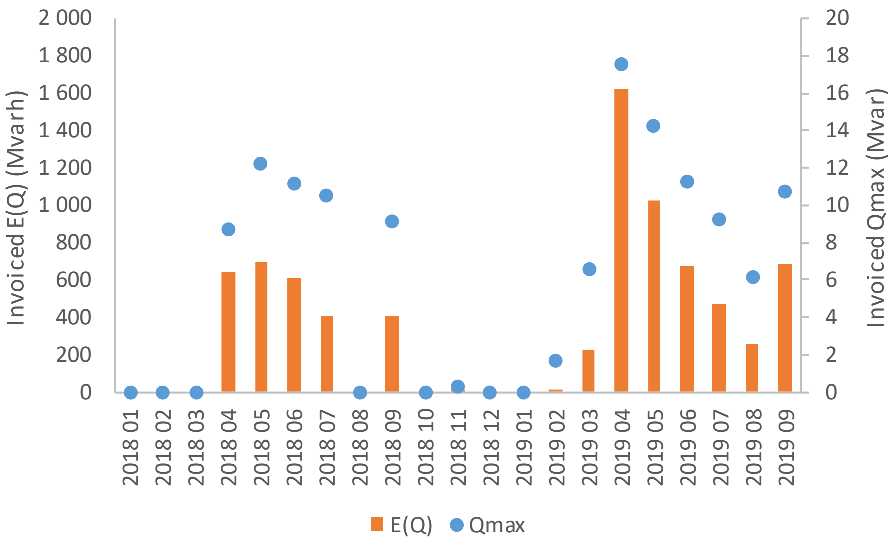


FIGURE 44. INVOICED MONTHLY CAPACITIVE REACTIVE POWER ENERGY AND DEMAND REACTIVE POWER JAN 2018 - SEPT 2019.

4.2.1.1 KPI RESULTS

The reactive power market demonstration is evaluated through the KPIs 2 and 3 and the with KPIs 4 and 5b .

KPI no2: Decrease in penalties for going out of the PQ window

For the DSO, the aim of the reactive power market is to have more controllable reactive power assets and to lower the costs from DSO to TSO caused by going out of the PQ window and the reactive power tariff to come into force. The costs arise from the reactive power tariff and are like penalty payments. The KPI - Decrease in penalties for going out of the PQ window - is determined as:

$$\frac{C_{\mathrm{hmarket}} - C_{\mathrm{h}}}{C_{\mathrm{h}}}$$

where

C_{h} is the cost for deviating from the allowed Q band when operating BaU [€]

$C_{hmarket}$ is the cost for deviating from the allowed Q band when Q market is used [€]

Here, it is reminded the accurated definition of the cost of power presented in *D10.1 Report on the selection of KPIs for the demonstrations* [10]. For the costs of energy and power, only the amount of energy and power exceeding PQ window limits affects the costs.

The PQ window is between the TSO and the DSO. The reactive power tariff comes into force if excessive reactive power is transferred in the TSO/DSO connection point. The invoicing period is a month. Hourly average values are applied in the tariff. Only those hours exceeding the PQ limits are taken into account, however, during a month, the 50 highest exceeding hours are free of charge and out of consideration. For those hours to be taken into consideration in invoicing, the costs include 1) the cost of reactive power and 2) the cost of reactive energy. By successfully utilizing the controllable assets e.g. from the market the DSO can minimize the costs. However, this KPI only evaluates the costs from the DSO to the TSO without taking into account the costs arisen operations in the market. There was no reactive power penalty payments before year 2016. However, caused by the drastic development of the reactive power characteristics all over Finland, Fingrid, the TSO applied the tariff into force with three years stepwise increases of the prices (Table 19). During the demonstration period September 2019 the tariff prices of the three years annual price development were already the maximum values of 1000 €/Mvar and 5 €/Mvarh.

During the specific demonstration period of September 2019, the KPI of "Decrease in penalties for going out of the PQ window" resulted to a value of -16 % (TABLE 21).

TABLE 21. KPI NO2: Q MARKET - DECREASE IN PENALTIES

KPI no2	Number of hours when Q market was active	Total number of hours during the period	**KPI no2: Q market decrease in penalties**
Q market demo period (1 month, Sep. 2019)	194	720	**-16 %**

The demonstration period was September 2019. **FIGURE 44FIGURE** shows that the potential need for a Q market varies remarkably between months. E.g. during winter months 2018 and 2019, there would not have been any market activities. On the opposite during spring and summer months 2018 and 2019, the market place with Q resources would have been attempting. The demonstrated market size was limited. The KPI2 would reach a value of -100 % if there would be an extensive market size with enough Q resources (Mvars) with successful market and operational actions resulting the DSO to stay inside the PQ window and to avoid the monthly penalty payments.

Above, only the DSO's savings in tariff costs were reported. However, also the expenses should be regarded and this decreases the DSO's profit received from the saved tariff costs. The DSO should pay remuneration to the market participants. Additionally, when no reactive power market exists at the moment creating a new market would need major developments of market design, IT, controls, etc. Later on, the operation of the DSO market also means additional costs for the DSO to be covered. In January 2020, Helen DSO installed and took into operation a new 56 Mvar reactor and this investment solved at that time and at least for the next years the Helen DSO's challenges in the PQ window. However further in the future, e.g. at the EU-level, the interest for development of various local markets may considerably influence also the reactive power market development. To have a live, appealing market, it should be profitable for all market participants including the DSO, aggregators and asset owners. Above, the possible savings for the DSO was discussed. Additionally, aggregators' and asset owners' income from the market should be temptingly higher than the costs arisen from the market payments and the investment and operational costs of the assets due to reactive power compensation

KPI no 3: Reactive power market utilization factor

The KPI3 - Reactive power market utilization factor - calculates the number of hours that the market is being used to compensate the reactive power during the test period as an aim to measure the need for a reactive power market and estimate the value for the aggregator. This KPI is determined as:

$$\frac{\sum h}{T_{\text{test period}}} \cdot \mathbf{100}\ \%,$$

where

$\sum h$ is the number of hours that the market is being used to compensate the reactive power

$T_{\text{test period}}$ is the number of hours during the test period (in the demonstration one month)

During the demonstration period of September with 720 hours, the market was to be used for 194 tuntia resulting to a KPI value of 27 % (Table 22).

TABLE 22. KPI NO3: Q MARKET UTILIZATION FACTOR

KPI no3	Number of hours when Q market was active	Total number of hours during the period	**KPI no3: Q market utilization factor**
Q market demo period (1 month, Sep. 2019)	194	720	**27 %**

For the demonstration period of September 2019, the KPI3 - Q marker utilization factor - reached a value of 27 % reporting the share of the hours when there was a real need for the supplementary Q resources from the market and the aggregator's successful operation of the Q assets according the Q market procedure. However, the potential need for the Q market considerably fluctuates between months arisen from the variation of active power P and reactive power Q. E.g. FIGURE 44FIGURE shows that during January 2018 - September 2019 there would have been also months without any activation of the Q market.

It can be noticed the difference nature of the KPI2 and KPI3. The demonstration period was September 2019. The KPI2 remained at a level of -16 % because the demonstrated Q resources (altogether 1 Mvar) were small compared to the queried amount of reactive power (during some hours in September 2019 even 25 Mvar). Simultaneously, the KPI3 reports a value 27 % meaning during the specific month, ca. one fourth of the hours in September the Q market resulted to successful and active Q market actions.

Like the discussion of the KPI2, Helen DSO invested in January 2020 to a new 56 Mvar reactor. Since then, at least for the next years, the potential local Q market is not topical. However, the EU level plans to strengthen the creation of local markets and the use of different local flexibilities through market procedures will most probably encourage and push to the direction of the market development.

KPI no 4: Reactive power service reliability

In the reactive power market demonstration, two measurements of the assets are available:

1) AMR measurement (hourly values) at the metering point (measures exchanges between the asset and the grid)
2) Measurement devices of the asset (in this case, measurement of the battery system and a measurement of both inverters of the PV plant)

In a market procedure, either one of the measurements could be used the determine the realized reactive power compensation. The asset owner and the aggregator have access to its measurement data of the assets and the DSO collects the measurements of the AMR meters as a business as usual process.

In comparison, in the reserve markets of the TSO, the billing of the realized flexibility service provision is based on the measurements of the asset owner/aggregator and this measurement data is provided by the aggregator for the TSO if requested. In the case of a DSO reactive power market, there is also an option to use the data of the DSO, since it measures the actual exchanges between the metering point and the electricity grid. However, the data of the DSO is the average of one hour (hourly time series) and it does not tell how the reactive power compensation has possibly fluctuated during the operating hour.

In the demonstration case, there is following difference in the data of AMR measurements compared to the measurements of the asset owner:

1) Suvilahti BESS: During the reactive power compensation, the AMR measurement was approximately 2.1 kvar higher than the hourly measurement of the battery system
2) Kivikko PV: During the reactive power compensation, the hourly AMR measurement was approximately 2.1 kvar higher than the hourly average values of the inverter 1 which was controlled during the demo.

Since the need of the reactive power compensation of the DSO is in the Mvar scale, the effect of few kvars difference remains small.

The root mean square error is calculated from equation

$$RMSE = \sqrt{\frac{\sum_{t=1}^{T}(P_{R,t}-P_{B_v,t})^2}{T}},$$

where

t = number of hours when the market was active

P_R = realized reactive power compensation of assets [kvar]

P_{B_v} = ordered compensation according to the needs of the Helen DSO [kvar]

TABLE 23. RESULTS OF THE REACTIVE POWER COMPENSATION (CONSUMPTION) DEMONSTRATION

TIME, hours when the Q market was active	$P_{R,BESS}$ Realized compensation, BESS (kvar)	$P_{R,PV}$ Realized compensation, PV (kvar)	$P_{R,total}$ Realized compensation, total (kvar)	P_B Ordered compensation (kvar)	$P_{R,total}$-P_B Difference (kvar)	Penalties due to failure of delivery
3.9.2019 2:00	901.92	101.01	1002.93	1000	2.93	-
3.9.2019 3:00	902.38	104.29	1006.67	1000	6.67	-
3.9.2019 4:00	902.15	104.11	1006.26	1000	6.26	-
3.9.2019 5:00	901.02	104.03	1005.05	1000	5.05	-
4.9.2019 1:00	901.78	101.3	1003.08	1000	3.08	-
4.9.2019 2:00	902.96	103.97	1006.93	1000	6.93	-
4.9.2019 3:00	902.32	103.95	1006.27	1000	6.27	-
4.9.2019 4:00	902.37	103.67	1006.04	1000	6.04	-
4.9.2019 5:00	901.35	103.62	1004.97	1000	4.97	-
5.9.2019 1:00	902.4	88.9	991.3	1000	-8.7	yes
5.9.2019 2:00	902.23	104.21	1006.44	1000	6.44	-
5.9.2019 3:00	902.81	104.21	1007.02	1000	7.02	-
5.9.2019 4:00	902.89	104.13	1007.02	1000	7.02	-
5.9.2019 5:00	902.31	103.92	1006.23	1000	6.23	-
6.9.2019 1:00	902.36	88.58	990.94	1000	-9.06	yes
6.9.2019 2:00	901.93	104.05	1005.98	1000	5.98	-
6.9.2019 3:00	901.96	104.21	1006.17	1000	6.17	-
6.9.2019 4:00	902.53	103.67	1006.2	1000	6.2	-
6.9.2019 5:00	902.2	103.24	1005.44	1000	5.44	-
6.9.2019 6:00	901.96	103.27	1005.23	1000	5.23	-
7.9.2019 1:00	902.13	1.31	903.44	900	3.44	-

7.9.2019 2:00	902.11	103.7	1005.81	1000	5.81	-
7.9.2019 3:00	901.25	103.75	1005	1000	5	-
7.9.2019 4:00	901.95	103.54	1005.49	1000	5.49	-
7.9.2019 5:00	902.17	103.41	1005.58	1000	5.58	-
7.9.2019 6:00	902.85	103.78	1006.63	1000	6.63	-
8.9.2019 2:00	0	98.11	98.11	1000	-901.89	yes
8.9.2019 3:00	0	104.26	104.26	1000	-895.74	yes
8.9.2019 4:00	0	104.1	104.1	1000	-895.9	yes
8.9.2019 5:00	0	104	104	1000	-896	yes
8.9.2019 6:00	0	103.81	103.81	1000	-896.19	yes
8.9.2019 7:00	0	104.46	104.46	1000	-895.54	yes
8.9.2019 8:00	0	106.73	106.73	1000	-893.27	yes
8.9.2019 9:00	0	9.62	9.62	900	-890.38	yes
9.9.2019 1:00	902.33	87.54	989.87	1000	-10.13	yes
9.9.2019 2:00	902.33	104.2	1006.53	1000	6.53	-
9.9.2019 3:00	902.38	104.15	1006.53	1000	6.53	-
9.9.2019 4:00	902.29	103.95	1006.24	1000	6.24	-
9.9.2019 5:00	902.27	103.77	1006.04	1000	6.04	-

TABLE 23 presents the KPI no4 Reliability of reactive power compensation service (RMSE) as well as an additional calculation that gives relevant information on the reliability of the service (percentage of hours of full delivery).

In the calculation of RMSE, the realized compensation is compared to the targeted compensation value. The RMSE does not take into account whether the realized compensation was above or below the target value. In the case of the reactive power market, it does not cause any issues if the realized reactive power compensation is above the target value (for a few kvars) since that still results in 100 % successful delivery. If the realized reactive power compensation is smaller than the target value, then penalties would occur for the aggregator and asset owner. The penalties would be calculated according to the amount of the failure of delivery and the aggregator/asset owner would pay that amount. Therefore, the RMSE as such does not tell about the success of the service provision. An additional KPI (hours of full delivery) is added to the TABLE 24 to show how many of the hours were 100 % successfully delivered. The effect of the error caused by a fault situation of the BESS is clearly visible in both, the RMSE and in the hours of full delivery. For comparison, the service reliability is calculated also for a situation that excludes the 31th of May.

Overall, if the one error situation of the BESS is excluded, the compensation service provision of both assets was reliable.

TABLE 24. KPI 4: REACTIVE POWER SERVICE RELIABILITY

Reactive power service reliability	KPI no 4: RMSE	Nuber of hours when some penalties occured	Number of hours when Q market was active	Total number of hours during the demo period	Hours of full delivery (%)
Reactive power market demonstration period	**405.68**	11	37	168	**70.3 %**
Excluding 31.5.2020 (BESS error)	**6.28**	2	31	144	**93.5 %**

Reasons of errors of the delivery

- Kivikko PV plant: There was a delay of few minutes in the activation of the reactive power compensation that would have resulted in some penalties. However, this results only in a minor error in the delivery (less than 10 kvar during the whole hour).
- Suvilahti BESS: During the demo period, the compensation of reactive power was manually set at the BESS local computer. The battery was manually set to control reactive power -900 kvar for the whole weekend. However, on Saturday morning the battery had a short fault situation and it went to shut down for 5 minutes. Due to the short fault situation, the set value of reactive power automatically reset to zero. This resulted in a failure to reactive power compensation during the Sunday night, since the set value was zero instead of -900 kvar. On Sunday evening, the set value of reactive power was manually set again to -900 kvar. The battery continued frequency control normally after the fault situations but the manual set point of reactive power resets to zero. This error could be avoided in a case that reactive power compensation would become business operation. If there was a business case, the software of the battery would be updated to allow a calendar-based compensation of reactive power when the battery is in the IEC104 interface control mode.

KPI 5b Usability of the asset

An additional KPI5b *Usability of the asset* was calculated. This KPI 5b is determined by calculating the hours that the asset is available and usable for the reactive power demonstration period expressed separately for the Suvilahti BESS and Kivikko PV. For Suvilahti BESS the KPI 5b was 99,5 % and for Kivikko PV 100 % (TABLE 25)

TABLE 25. KPI 5: USABILITY OF THE ASSETS IN THE REACTIVE POWER DEMONSTRATION PERIOD

	KPI5b
Suvilahti BESS	99,5 %
Kivikko PV	100 %

4.3 CUSTOMERS' PROSPECTS ON DEMAND RESPONSE

Customers' decision-making plays a key role when aiming harnessing customer-owned assets for demand response. Customers, as the owners or users of a distributed energy resource or flexible load, see the entire subject from their own perspectives while the DER usually has a main function (EV, heating, …) that is not power flexibility. The customers make choices that affect the feasibility and economic benefits of the participation to implicit and explicit demand response. Thus, customer's decision making and acceptance in the implementation of the demand response is an important and critical issue. In EU-SysFlex, a comprehensive demand-side management survey and research of customer's decision-making related to their flexibility potentials was performed. Manifold cases and views of the demand response in residential detached houses, housing associations (e.g. apartment houses), offices, and service buildings and industry were researched and analysed. Many technically easiest decisions related to demand-side management are already done in various planning phases, of e.g. buildings. Thus, in addition to enhancing the customers' knowledge, these professionals play a key role in promoting the increase of flexibilities. The interviews and surveys of customers' prospects on demand response was done in Helsinki city, representing prospects in an urban city environment. This work has been widely reported in [34] and [35].

Methodology

The customer information such as the customer knowledge base, customer decisions and flexibility resources that are relevant to each customer segment was gathered through interviews, surveys, and literature sources. In addition, representatives of electrical contractors and designers, EV charging and ground source heat pump providers, representatives of constructing companies, and trustees of large electricity users and real estate owners were interviewed. The interviews were held in autumn 2020 as conference calls, in which the interview frameworks were shared with the interviewees. The customer surveys were aimed at residents of electrically heated detached houses. An invitation to the survey on a web-based form was sent by e-mail to the selected recipients from the Helen DSO's customer register. A total of 523 customers responded to the survey. Customers were asked more specific questions based on their previous answers. From the customer's perspective, flexibility can be divided into different use cases: flexibility due to the technical limitations in the grid connection or in the property's electrification, or implicit and explicit demand response. Implicit demand-side response refers to the price-driven utilization of flexibility such as power peak shaving or day-ahead market based demand response. Explicit demand response, such as the ancillary market, is based on external demand and compensation for the use of the flexibility resource. The choices made by the customer often affect the implementation of different use cases

Results

Residential detached houses

The prospects of residential detached houses include the initial decisions related to the dimensioning of the grid connection, the network service product, and retail tariff. The heating is typically seen as an asset suitable to demand-side management. Use cases of heat pumps are also discussed. As new flexible assets, PVs, EV charging and BESSes are here reported in the sense of demand-side management in residential detached houses.

A network connection is dimensioned for the first time when a house is built. At that time, the future power demand and electricity usage is estimated. Typically, these expectations are too high and as a result, the connections are mainly oversized. In Helsinki, this overcapacity results partly from history and the DSO not having fuse-based DSO tariff alternatives guiding the more careful dimensioning. From the viewpoint of an electrical contractor or designer, it is often most cost-effective to use such overrating that guarantees that the network connection is sufficient for the entire life cycle of the building. This oversizing has only little cost impact on the builder or designer and does not affect the end customer's network service charges. Thus nowadays, load management solutions are typically not considered as an alternative to a larger grid connection.

The network service product is usually taken as given, and the replacement of the product is often not considered when the consumption profile changes, or consumption decreases or increases. The network service product is typically general tariff for non-electricity heated detached houses and time-of-day tariff for houses with electricity storage heating. In 2017, Helen DSO introduced a power charge for a time-of-day distribution tariff. Since then, it has been possible for these customers to get savings from flexibility by cutting the monthly power peak. According to the survey, customers do not consider that peak cutting is possible without a reduction in the living comfort. Thus, the demand-side is not typically recognized as an option.

According to the survey, a large proportion of customers having electric storage heating identify their heating as a flexible resource. However, some concern arose from possible deviations in the indoor temperature due to external controls. A heating as a service was seen as an option. Only less than 10% of detached house customers had chosen a day-ahead market based priced electricity sales product. One reason for this is that consumers are most actively offered fixed price contracts. Consumers who have chosen a market based contract are typically more motivated to offer their resources for demand response. Thus, from demand-side management perspective, customers of market based contracts are preferred, but however, they are not massively present.

During the lifetime of the detached houses, which might be decades, the heating type may be changed, for instance so that direct or storage electric heating is replaced by a ground source heat pump. As a result of these specific cases, the need of power capacity decreases, but grid connections will usually remain oversized. Heat pumps dimensioned for satisfying 60-80 % of the calculated peak heat consumption is quite common. They can result in an increased capacity need of 40-50% from the grid connection. From a demand response perspective, the dimensioning of a heat pump for partial power results in a higher marginal cost of demand response. The reason for this is that the rebound effect (extra power need after limited power during a demand-side operation) is more likely to lead to the use of the additional resistance to heat the electric boiler with a lower heat coefficient. When possibly aiming to offer power to the ancillary markets the higher marginal cost further reduces the hours of the participation in these markets as well as the economic benefits. This significantly reduces the feasibility of demand response. When considering demand-side management, a ground source heat pump dimensioning for full heating capacity is preferred over the partial dimensioning of a heat pump.

EVs are becoming more common and charging at residential detached houses is one appealing option. Based on the customer survey, for EV charging at residential detached houses with electric heating, fast and immediate charging is preferred for home charging. Only 8 % responded that they charge an electric car during the cheapest hours of the day-ahead market. A share of 5 % also consider the optimization of the monthly peak-power fee. The prevalence of the fast and immediate charging is based on relatively faint knowledge of day-ahead priced electricity sales products. In addition, for plug-in hybrid EVs and their relatively small batteries, the cars need to be charged whenever possible. As many as 73 % of respondents charge their electric car from a normal electrical socket, resulting in a charging power of about 1.8 – 3.7 kW. Charging is often controlled by the car's internal charger timing or calendar-based control. This type of a load control does not allow any participation in the explicit demand response such as ancillary service markets. A manual scheduling or a calendar control is also sensitive to a stratification with other loads, such as electric heating. This reduces the profitability of demand response as the power charge increases.

PV systems at residential houses are popular and their amount is expected to increase. These customers are more familiar with flexibility. The dimensioning of the system is not very accurate, and it is often done based on customer’s annual energy demand. Because emotion-based choices are very common, the customer's choice is often also based on the highest possible rated power or the PV system price. This results in a relatively low self-consumption rate and high overproduction of energy. About 20 % of customers utilize flexible relay-controlled loads to increase the self-utilization rate of the self-generated energy. If flexible resources such as water heaters or electric car charging are used for increasing the self-utilization rate, the marginal cost of explicit daytime up-regulation or night-time down-regulation will become very high.

A BESS is primarily acquired for the optimization of small scale production. Thus, in Finland, a BESS would be needed to optimize production about 180 days a year. During this time, the use of the BESS in the ancillary markets, such as FCR-N is limited by the time required to prepare for solar production optimization and the FCR-N operation. The SOC of the BESS should be ca. 50 % at the start of the FCR-N operation and ca. 0 % at the start of the storage of the excess energy from the PV system. Power discharge capacity is typically relatively low compared to energy storage capacity, as small scale BESS’s are acquired primarily for energy storage rather than power-intensive uses. As a result, the preparation phase takes at least ca. 3 hours a day, depending on the battery model and the dimensioning of the PV system, which impairs the profitability of demand response. Some of existing small scale BESSes may require retrofit matching for the external control and to meet ancillary market’s conditions and thus, worsens the profitability. From the customer's point of view, utilizing a BESS in the day-ahead market is typically not profitable. This is because the efficiency of the AC-AC cycle (which is about 80 % for small scale BESSes) increases the marginal cost of the flexibility operation to a very high level. The customers profiling as early adopters recognize the potential of a BESS in the explicit demand response and may not require financial compensation for its use however supposing not affecting the warranty, shorten the life cycle, or prevent the primary use. Customers not profiling as early adopters consider financial gain to be the most important motivation. Half of detached house customers do not know the concept of demand response, so the effects on the balance of the power system and to the environment are not familiar.

Apartment house housing associations

Compared to electricity usage of residential detached houses, apartment houses have naturally at their connection points higher power demands and annual electricity usages. Typically for an apartment house, behind the connection point of the property, the common electricity (ventilation, cooling, lift, heating and lighting of common places) of the building is one metering point and each apartment has its' own metering point. The common electricity has the highest power demand and it is supplying potential loads for demand-side operations. The ownership of the building may vary. However, the hosting is typically done by a service provider who is in a key position in promoting e.g. demand-side management issues.

Like at residential detached houses, also within the apartment houses and the housing company decision makers, there are challenges of the general understanding of demand-side management. Again, the quantity and the concept of power is most often not familiar and therefore, implementing load management solutions related to the feasibility of demand-side response is challenging.

Overdimensioning of connections has been typical. Concerning the larger low-voltage connections in residential buildings, measured peak powers were compared to connection fuse sizes in 2018. Based on this analysis, connections are clearly oversized. Almost 95 % of the customers with a 400 A connection would have succeeded with a 100 A connection and half with a 50 A connection [36]. Based on the interviews, load management solutions are not considered as an alternative to a larger grid connection, because the cost impact of oversizing is minor. However, building automation systems suitable for a load control have become more common in recent years. Depending on the builder and the customer, the integration of the selected automation system for external control signals varies widely. System requirements are usually defined for easy maintenance, remote management, and monitoring of energy consumption. As a result, even new residential buildings do not have power measurements suitable for verifying explicit demand-side response and this weakens the economic viability of demand-side management.

In a housing company, the suitability of the network service product is very rarely considered because it adds additional costs such as the property manager's additional fees. In addition, residents are not aware of the cost implications of switching the network service product. Also, the impact of load management solutions on power charges is not usually considered. On the opposite, the decision of high-performance equipment, such as charging points for electric cars or ground source heat pumps, is made mostly on other basis.

The electricity sales product is often a fixed price contract that is rarely compared or changed. In district-heated buildings, electricity forms a very small part of the maintenance costs, which means that the potential increase in management costs may be more significant for the customer. As a result, it is often not possible for a housing association to implement demand response based on the day-ahead market.

Heating system vendors also have challenges in general knowledge of demand response and to make the customer understand the flexibility potential, so the capabilities suitable for the demand response control are usually only implemented when the system is implemented as a service, i.e. the housing company only buys heat from a service provider. In this case, the costs during the use of flexibility are usually lower due to lower management and aggregation costs.

In housing associations, the largest and partially identified flexibility potential was the charging of electric cars. Although a load management solution can often be used to implement demand response, the savings from electrification costs are often more significant for the customer. Therefore, the load control required to demand-side management is usually not implemented unless there are technical reasons for this due to limited capacity. The challenge to the implementation of implicit demand response is that the benefits are evened out for all shareholders in the housing association. If the implementation of explicit demand response requires the approval of the end user, the electric mobility service provider will in most cases have to pay a fee for participating in the ancillary markets. Explicit demand response can lead to higher monthly peak power, increasing electricity distribution costs. If the housing association has the day-ahead market based electricity contract, prioritizing implicit flexibility may lead to a reduction in the hours offered to the ancillary market or increase the marginal cost. The amount of EVs will increase and thus, this load type is interesting in the sense of demand response. [7]

For PV systems, housing associations in Finland have three alternative models of implementing: the dimensioning and installation for the common parts of the building, the back-end metering model and the Citizen Energy Community. In the back-end metering model, the housing company has only one AMR metering point and thus, only one electricity sales and distribution contract. As a result, the model provides most down-regulation potential in addition to the savings in the basic charges of distribution tariffs and electricity sales. In other hand, the potential for day-ahead markets decreases due to the large random variation of uncontrolled apartment electricity loads. The Citizen Energy Community allows the excess energy to be shared inside the property grid without taxes or distribution fees . [37] The apartments have their own electricity contracts, so the profitability of demand response in the day-ahead market will improve at the housing company's common electricity metering point, as the electricity consumption profile will focus even more on the cheapest hours of the market.

Office and service buildings

Power demands at the connection points of office and service buildings are obviously higher than in the case of residential buildings. Again, the flexibility issues should be taken care of during the planning of the building. In demand-side management, various reserve market products with down- and up-regulation are to be considered. In service and office buildings, loads suitable for flexibility include ventilation, cooling, secondary heating, EV charging, and possible backup power generators.

Energy efficiency typically strongly guides the design of office and service buildings. This leads to the optimization of the use of equipment, such as ventilators, whose frequency converters are precisely controlled based on carbon dioxide and carbon monoxide measurements. This significantly reduces the potential for frequency up-regulation. The investment cost of implementing fast and short-term demand response without disturbing the indoor climate will be significantly reduced when indoor air measurements and related control logic are already a part of the building automation. The down-regulation potential offered by ventilation and electric car charging is available only during the active use of a building, i.e. typically about 27 % of hours of the year in office buildings and 40-62 % in service buildings, which limits the economic potential.

For investors owning several office or service buildings, it is a typical procedure to centralize the procurement of electricity. This is mainly done in order to minimize customer’s management costs. If a customer has transferred the profile risk to the electricity sales company, it is not possible to implement day-ahead market based demand response, even if the customer has potential flexibility resources in some properties. Centralizing the supply of electricity can also often lead to its separation from the management of electricity use and the construction planning.

Industrial scale customers

Among industrial scale customers from the city environment and having loads suitable for demand response are for instance ports and electric public transportation. For these customers, the capacity of the network connection has a strong impact on other operating costs.

For example, for depot charging of electric buses, decreasing the network connection capacity or the available charging power, or longer-term demand response actions would require an increase in the bus fleet, in order for the operator to be able to maintain the services under its contracts. In addition to a large initial investment, the expansion of the bus fleet would increase maintenance costs, which limits the use of flexibility mainly for longer-term up-regulation. An obstacle to the symmetrical regulation (FCR-N) is that charging of electric buses should be performed at partial power to allow for the down-regulation potential.

The demand response potential of backup power generators depends on their starting delay, which defines possible ancillary marketplaces. The market participation of generators starting in less than 30 seconds is possible in the FCR-D market if it is supported with Uninterruptible Power Supplies activated in less than 5 seconds. UPS devices are not primarily designed for the ancillary markets and therefore the firmware of the rectifier would have to be modified to enable a faster activation.

Conclusions from customers’ prospects of demand response

Technologies for demand-side include manifold variety of assets and systems from small to big and from simple to complex. This huge variety brings challenges in penetration of demand-side. Customers or their representatives are the decision makers of demand-side concerning their flexible assets. Thus, they should have understanding, knowledge, know-how, acceptance and economical interest on demand-side. The knowledge base of the customers involved in proactive guiding the design is of great importance for how the different use cases of flexibility are taken into account in old or new applications. It is highly important to provide all electricity users with more information regarding the opportunities and prerequisites of demand response. Generally, the more proactive the decision-making, the more profitable the implementation of demand response typically is. Discussion and communication with professional customers or their representatives may be more straightforward, however without forgetting the importance of having flexible resources harnessed from all customers with their controllable loads.

5. INTERPRETATION OF THE FIELD TEST RESULTS

In the Finnish demonstration, small distributed assets in LV and MV networks were aggregated and operated to the TSO's reserve markets and for the DSO's reactive power compensation needs. The TSO's reserve market operations included forming forecasting and optimization of the assets, constructing communication channels as well as control logics from the aggregation platform to the different flexibility assets and similarly communication from the aggregation platform to TSO's markets. The proof-of-concept reactive power market included constructing communication and control logis to reactive power assets.

Aggregation platforms

In the demonstration, four different commercial aggregation platforms were tested. One of the platforms (DEMS) was already in use prior to EU-SysFlex and one of them (Virta Energy platform) was in use by Virta Ltd. The two other platforms (DES and IoT platform) were pre-existing prior to the project and taken into further development during the project. The DES platform was an early version from a 3rd party and it required quite a lot of development during the project. The IoT platform was pre-existing from a 3rd party and all of the logics and dashboards were developed during the project.

Main objectives for an aggregation platform were the ability to add new assets to the platform and to control the attached assets according to the use cases. All of the tested platforms tried to fulfill specific tasks with most of the tasks succeeding. Most of the platforms had limitations regarding what type of control could be performed and how the attached assets could be controlled from other systems e.g. market operation control. The study showed that these limitations affect negatively the perfomance and usability of the assets. In addition to the platform operability, the demonstrated assets had different characteristics which formed a challenge when constructing the control logics and communication. Thus, standardized interfaces and communication protocols should be promoted. Also, only essential and imperative data is to be measured, transferred and used to reduce the complexity and at the same time, to ensure data security.

The IoT platform showed most potential in all field tests for a single platform to be used for many type of distributed energy resources. During the study it became clear that the development to the IoT platform was agile. It was possible to aggregate small distributed assets to the IoT platform and demonstrate flexibility service provision to the TSO's power reserve markets as well as demonstrate reactive power market asset control. The IoT platform was most successful and the aggregated assets connected to the platform could be operated as a virtual power plant (VPP). Further development will be done to the IoT platform and expand the use.

Forecasting and optimization

Forecasting and optimization of BESSes were created in this demonstration. For battery energy storages the optimization of the SOC is crucial especially when operating in FCR-N markets as the BESSes respond to the power system frequency. When power system frequency is deviating a long time from the dead band to only one direction this may cause the BESS state of charge out of bound either fully charged or depleted. As a result, the BESS might be unable to continue the operation and penalty payments are arisen. The forecasting of the power system frequency was not a part of the demonstration. The FCR-N market operations with BESSes are a multidimensional forecasting and optimization task where e.g. machine learning, forecasting and optimization could bring improvements in bidding strategies thus preventing state of charge out of bound situations.

Forecasting of EV charging power was studied in this demonstration. In order to provide ancillary services to the TSO's reserve markets the amount of reserve power is crucial to know and thus forecasting the potential reserve power was investigated. It was found out that currently not enough reserve power from EV charging is possible. However, it is seen that EV charging power will increase when more EVs are purchased and the power flexibility potential will increase significantly.

Forecasting of electricity usage of residential detached houses having electric storage heating controlled via AMR was further developed in this project. This tool forecasts the heating needs throughout the day but it can also predict how the heating system will react to changes and commands resulting from the operation of the AMR connected switches. The tool also predicts the available times and amounts for up and down regulation which could be bid to the TSO ancillary services (studied market mFRR). The development work done in this project continued a previous research by testing and improving forecasting methods.

Forecasting of reactive power profile in the TSO/DSO interface was created for the DSO to be needed in the reactive power market demonstration. The forecast supports the decision making how much additional reactive power services the DSO should procure from the demonstrated market. The DSO's aim was to minimize the costs charged by the TSO when the exchanges in the TSO/DSO interface are out of bounds of the permitted active (P) to reactive (Q) power ratio, referred to as the PQ window. The forecasting development included several alternative forecasting methods and the most promising one was chosen to be used during the demonstration period of one month. The forecasting was not embedded in the DSO's ICT systems but it was performed separately. However, this implementation is seen technically applicable when decided.

Value chain, market driven concepts and business potential

Aggregation of distributed assets were tested and developed in the Finnish demonstration considering market and business potential. Each demonstrated asset had a different value chain depending on the asset type and operation of the asset. The study showed that the industrial scale BESS had the best business potential with highest revenue in the FCR-N market. In addition, providing flexibility services to other markets could increase the business potential for industrial scale BESSes. For the office scale BESS the value chain consisted of multiple use cases for the BESS. With the current electricity and distribution prices the study showed that when using the BESS in peak power shaving and FCR-N operation it was not exactly clear what type of operation could bring the best business potential. However, the demonstrated operation showed decent revenue growth from FCR-N operation and cost savings from peak power shaving. The business potential for customer scale BESS is currently only from selling hardware. However, the value chain shows that other flexibility services could be in interest such as spot optimization if electricity prises get more volatile with growing amount of RES in the electric grid.

Value chain of aggregating EV charging points for control consists of providing power to the reserve markets. Regarding the business potential one important aspect is to understand is the EV owner willing to charge at a charger were the charging power is decreased. At least two possible solutions are how the customer is engaged to EV charging flexibility. Either the EV owner accepts the terms of conditions where the charger is used for flexibility or the customer can charge with a lower fee. The study showed that if the EV chargers are operating in the FCR-D market the income per charger is very low and thus a lower fee is insignificant.

The case of residential detached houses heated by electric storage represented a value chain where the end-use customers' electric heating loads are aggregated by the aggregator and offered to the TSO's mFRR market. The communication and controls from the aggregator to loads were to be passed via DSO's AMR systems and meters. In EU-SysFlex, the economical benefits were simulated by only taking into account the aggregator's income from the mFRR market and the increased costs for the households realized by the grid tariff (because of higher demands of electricity usage and simultaneously a grid tariff including a power component). The simulated mFRR market results indicated only modest economical benefits from the market operations. The income from the market should have been higher, first to cover the increased costs and then benefit the aggregators as well as customers. On the other hand, the electric heating loads controlled via DSOs' AMR meters are tempting flexibilities already connected to the existing AMR meters via a separate relay. The communication channel and the AMR meter interface are not at the moment determined by e.g. authorities. However, the simulations revealed small income from the mFRR market thus decrasing the interest for this case.

The reactive power market, demonstrated as a technical proof-of-concept, had a value chain including DSO, the aggregator and asset owners. The aim was to result in cost reduction for the DSO and to bring new business opportunities and economic benefits for aggregators and asset owners. However, a comprehensive economical analysis was not made while the demonstration was mainly technical. The DSO's potential benefits resulting from TSO's reactive power tariff was determined but no other economical analyses were performed. The DSO would have interest in the market if it can achieve a techno-economically attractive and reliable reactive power flexibilities from the market compared to the e.g. traditional solutions of reactive power management. The aggregator and asset owners estimate the business benefits by taking into account the income/penalties from the market and the costs caused by investments of assets, extra losses and shortened lifetimes of assets. However, possibly no new asset investments are needed if the assets (active power) already participate in the TSO's markets. The reactive power market would mean an additional and more efficient use of the assets. The price of creating or operating a totally new market e.g. with all the ICT was not estimated in EU-SysFlex. As no such market exists the possible business possibilities were only described and no economical calculations were performed.

Interpretation from field tests by asset type

All BESS - Active power

The study has shown that BESSes are a novel solution for fast and reliable flexibility services in all scales. Industrial and office scale BESSes have shown greater possibilities as the power output is large enough to fullfill the minimum requirements for participating into the FCR markets. In addition, customer scale BESSes could provide ancillary services in future as more robust control systems and greater value for service is realised. The study showed that multitasking BESSes could bring additional benefits. In the Finnish demonstration, the office scale BESS was used for FCR-N, peak shaving and reactive power compensation. This multitasking brings additional aspects to the optimization task. This was also the case when the benefits were devided between several stakeholders like the aggregator, the end-use customer and DSO. In real-life solutions, this multi-use also means agreements between the stakeholders. The agreements were not in the scope of this research.

EV charging - Active power

In the Finnish demonstration aggregated EV charging was found to be a very promising opportunity to provide flexibility services. The results show that using the EV charges for reducing power load can be done efficiently and precisely. Combining the power reduction capabilities and the forecast showed that excess power with the charges is required to fullfill the forecast errors. In addition, the results show that the current system that is in use is not enough capable to meet the strict requirements of the FCR market. While the communication delays were found to be to long in the existing system, in the different EV charging controlling tests these dalays were found to be neglectable and thus encourage to further develop the systems.

AMR - Active power

In the Finnish demonstration, electric storage heating loads via DSO's owned AMR meters (automatic meter reading) were tested to be controlled by an aggregator through DSO enabled service and further aggregated to the TSO's mFRR market. The tests performed with the first generation AMR meters and systems revealed that the time limits of the mFRR market were not reachable for a high amount of simultaneously operated AMR meters. The second generation AMR meters and systems could bring a solution for this requirement. However, there are also other issues to be solved. The control chain includes several stakeholders and interfaces (TSO's mFRR market - aggregator - DSOs' AMR meters - customers' heating loads) and this brings questions about division of benefits and costs and additionally issues of responsibilities and agreements. In the demonstration, the economical benefits for aggregators and customers were simulated showing only modest benefits from the mFRR market. The costs for the DSO were not included in those calculations.

Reactive power (PV + BESS)

Reactive power market was demonstrated as a technical proof-of-concept. In the demonstration, the reactive power assets were a BESS and a PV plant and they are owned by the aggregator. Generally, in this presented market model, the assets could be owned by an aggregator, other asset owners or e.g. end-use customers. The assets are not owned or operated by the DSO. In the demonstration, for the aggregator, the reactive power market operation meant - similarly with the operation of the flexible assets in the TSO's markets - demand to construct the control communication and logics to the various assets. Again, having different types of assets possibly means various tailored communication and control solutions according to the characteristics of the resource. In the demonstration, the distributed assets of BESS and PV plant were operated according to the reactive power market needs and this operational part was successful. Compared to the operation of the assets in the established TSO's markets with business opportunities the economical benefits from the reactive power markets were seen unmatured and thus at least in the near future, unrealistic. For the asset owners, the additional losses of the assets caused by the reactive power production/consumption most probably means lower life time and this created some suspicion of the realization. The price of the reactive power was not in the scope of the demonstration. Additionally, creating a totally new local market means costs. In the future, DSOs need more resources and tools for reactive power management. DSOs will develop reactive power management through tariff design, customer guidance and special mutual agreements in addition to the traditional investments of reactive power devices of reactors and capacitors. The realization of local reactive power market is not seen to be realized in the near future.

Customer acceptance

Customers play a key role in promoting demand-side management. In the research, the customer's decision making and acceptance in the implementation of demand response was analyzed through interviews and a comprehensive survey of various customer groups. As a result, generally, the more proactive the decision-making, the more profitable the implementation of demand response typically is. Many technically easiest decisions related to demand-side management are already done in various planning phases, of e.g. buildings. Additionally, one major challenge is to improve the customers' knowledge related to demand-side management. The need and amount of flexible resources is increasing. Thus, to promote demand-side management within various customers is in the future even more important. It is highly important to provide all electricity users with more information regarding the opportunities and prerequisites of demand response.

6. EXPLOITATION PLAN, OUTLOOK AND FURTHER RESEARCH QUESTIONS

In the Finnish demonstration a set of forecasting/optimization tools were developed to estimate the available flexibility of the LV/MV assets for TSO ancillary services. Technical proof of concepts were accomplished for distributed flexibility resources BESSes (residential, office and industrial scale), PV and EV charging points. These assets were controlled according to market actions. In addition, two BESSes (industrial and office scale) were operated in real-life TSO market. Also, a technical proof of concept was developed for a new market mechanism to manage the reactive power in the TSO/DSO connection point.

Utilisation of distributed BESSes (office and industrial scale) were proven to be efficient and reliable assets to provide ancillary services to the frequency containment reserve market operated by the Finnish TSO. The Finnish demonstration has shown a strong case for scalability and replicability for industrial scale BESS with newly developed IoT platfrom and optimization tools. Multiuse of both industrial and office scale BESS when possible is strongly advised. The main drivers for scalability consist of cheaper BESS and other hardware as well as lower operational costs and high use rate. In addition, the study showed that office scale BESS can be scaled up as BESS unit price per kilowatthour decrease. In the future, it is expected that BESS prices decline as battery production increases manifold due to exponential increase in EV production driving battery production costs down.

Other demonstrated assets (residential BESS, EV chargers, residential electricity storage heating loads via AMR meters) had technical and financial limitations yet to be resolved. However, in the future these assets could provide active power flexibilities to the TSO. Especially as the power demand for EV charging increases this provides major possibility for flexibility services. In the future, new type vehicle to grid (V2G) could provide a major possibility for flexibility service provision either locally to a building or to the grid.

The demonstrated reactive power market, as a proof of concept, proved a benefit for an aggregator to utilize the flexibility assets of reactive power in a market based manner in principle similarly to active power assets. For the DSO and the TSO additional controllable reactive power assets will in the future be needed when the changing of reactive power profiles is expected to continue. A market based approach could represent an appealing option to strengthen to have more controllable assets in the power system. Technically, the reactive power demonstration was successful. However, when no such market exists at the moment, the creation and maintenance of such a market with all the ICT etc. would need considerable efforts and is not seen economically viable at the moment.

For future research topics, the forecasting and optimization are to be further developed to utilize various probabilistic and machine learning approaches. There will be improved methods to be applied based on excessive amount of data while the penetration of EVs, BESSes as distributed assets is accelerating and more data and deeper understanding will be available. All the demonstrated cases need economic analyses where benefits for all the stakeholders - asset owners, aggregators, DSO, TSO - should be included and studied. The multiuse of assets - like BESSes for different frequency markets, for peak shaving, for reactive power compensation - is one example of multidimensional optimization task to be further investigated. For reactive power management, all the DSO's tools

- market based approach, own compensation devices, tariff design, customer guidance, mutual agreements - are to be researched as an entity to techno-economically manage the reactive power. The smallest resources can only be reached if the customer is strongly engaged to this development. Thus, the customers earn their support and research to deepen the engagement. Additionally, all the stakeholders in this chain of assets through aggregation to the TSO's markets and for DSO's needs should benefit for this development to take place in the near future. This is worth of further research.

7. CONCLUSIONS AND RECOMMENDATIONS

In the Finnish demonstration flexibility services in both active power and reactive power was demonstrated by aggregating small scale assets. The active power assets consisted of industrial, office and residential scale BESSes as well as aggregated EV charging points and a simulation with residential electric storage heating loads. For the reactive power market demonstration, proof-of-concept, an industrial scale BESS and a PV-plant was used. The demonstration also included forecasting and optimization.

The demonstration showed that small distributed energy resources require a reliable and agile aggregation platform. The study has shown the importance of the aggregation platform as several different platforms were tested and evaluated during the project. Especially integrability to different services was shown to be a key element where the aggregation platform can be implemented into the existing systems and communications built with general interfaces. The tested IoT platform showed the best opportunity for operating distributed energy resources of all size.

Forecasting the availability of distributed energy resources is important for operating assets with limited usage for market operation. The study showed that the forecasting of the available flexibility varies depending on the asset type and how it is operated. In addition, the optimization of the flexible resources was shown to have benefits for the operation. As the amount of attached distributed energy resources to the IoT platform increases, enhanced forecasting and automatic market operation will become a major advantage for efficient operation of the virtual power plant.

The active power demonstration revealed that industrial scale and office scale BESSes provide a reliable, fast and accurate service for the TSO’s FCR-N reserve market. Other active power assets should be developed further and possibly combine with other flexibility resources to fullfill the technical requirements for the reserve markets. Overall, the active power demonstrations showed that the distributed energy resource can provide a reliable and accurate solution for flexibility services.

The reactive power market for the TSO/DSO interface was demonstrated as a proof-of-concept. In Finland so far, there are no local flexibility markets. If having in the future such a market, for the aggregator, this kind of a market has similarities to the present TSO’s markets and the operation with the assets with forecasting, aggregation, communication and controlling abilities. For the DSO, generally, DSO’s reactive power management is a comprehensive task including various means, e.g. operation of own compensation devices, mutual agreements with specific customers, guidance of customers and developing tariff structures. The EU-SysFlex demonstration revealed that in the specific Helsinki case and the demonstration period, the amount of additional reactive power from the market depends strongly on the time (season, weekday, hour). For example, in Helsinki, the market would have been in operation during a few months of the year. Further, it was seen that the market saturation (excessive high amount of assets) is possible thus creating uncertainty to the future prospects of such a market. At least, for the near future in the Helsinki case, partly arisen from the characteristics of the local city distribution network, a local reactive power market is not realistic. In reactive power management, various flexibility products through mutual agreements could be interesting. This can be seen like being on a way to local flexibility markets when having a longer view of future. Also, the regulation could contribute to a development towards local flexibility markets when, at least regarding the present regulation model, investments are preferred instead of buying services.

This study recommends that aggregators should be allowed to use all kinds of distributed flexibility resources while being technology free. The applied rules should be defined by technical parameters only thus making it possible to use conventional as well as new appliances and solutions. The solutions to situations to be solved in the power systems, such as frequency or voltage deviations, are defined by technical parameters only. Therefore, all the resources able to fulfill the technical requirements should be allowed to contribute, regardless of their underlying technology. According to this approach, the following types of resources should be considered in order to solve system operation needs and system scarcities

- all renewable energy resources
- conventional loads
- new consumers such as electric vehicles and heat humps
- batteries and other energy storage systems

The cost minimization principle must be applied when selecting flexibilities so that all technologies are treated in a neutral way, being solely selected based on their price and technical characteristics

The study also recommends that the FCR markets could have the same minimum bid size by lowering the bid size in the FCR-D market from 1 MW to 0.1 MW as in the FCR-N market. This would help new technologies and early stage projects better to be aggregated and to participate to the power reserve markets as the required power capacity is achieved with smaller assets.

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ANNEX I. SIMULATION CASES FOR HEATING LOADS VIA AMR

SIMULATION CASES

Summary of the forecasting tool

The forecasting tool estimates the heating needs and reactions to control signals based on the weather information, a physical model of the households and machine learning algorithms that reduce the forecasting errors. An aggregated group of about 750 households in Helsinki equipped with electric heating and a hot water heat storage have been considered for the provision of reserves requiring a slower response (within 15 minutes). The hybrid forecasting model is explained in the EU-SysFlex deliverable D6.2 [2] chapter 3.3. AMR Controlled Electric Heating Houses Forecast. The hybrid approach is explained in [3]. So far three different machine learning (ML) models have been applied: Multi-Layer Perceptron (MLP), Support Vector Regression (SVR), Hierarchical Deep Neural Network (HDNN). The input delay structure for the MLP and SVR were optimised using a genetic algorithm (GA) and sensitivity functions [4]. The initial HDNN was transferred from a short term heating load forecasting case. SVR and MLP were slightly more accurate than the HDNN but identification of the HDNN was easier and more straightforward. SVR identification had poor scalability to higher time resolution forecasting and MLP identification required much manual iterative tuning of the learning parameters. Thus, all the applied machine learning methods had somewhat different strengths and weaknesses and it depends on the case which one of them is the best.

The models applied in the simulations

The physically based forecasting model

The main component of the physically based model is a simple first order model of the heat storage tank. The state variable of the model corresponds to the state of charge (SOC) of the heat storage tank. The model inputs comprise
1) the control signal that defines when the electrical heating power is on and
2) the forecast heat demand of the building that in the model depends on the measured and forecast outdoor temperature according to an empirically identified relation.
The electrical heating power in the model is subject to minimum and maximum constraints that are defined as explained in the following. The heating power in the model is always positive and smaller than the maximum hourly power variation range identified during about three previous weeks. In addition to the heating power, the model includes also a time dependent load profile model for non-heating loads (It is roughly speaking a day length dependent weekly load profile).

The residual hybrid model
The physically based model of the aggregated demand response is applied as a component in a hybrid model. The other component is a data driven model that forecasts the residual of the physically based mode. See Figure 1. The sum of these component models forecasts the aggregated load accurately. The model forecasts the aggregated

load subject to different the control signals. For the mFRR-market the changes in the load caused by the mFRR control signals are of interest. That is why it was simulated the model in the studied case and subtracted from the model output the base case model output.

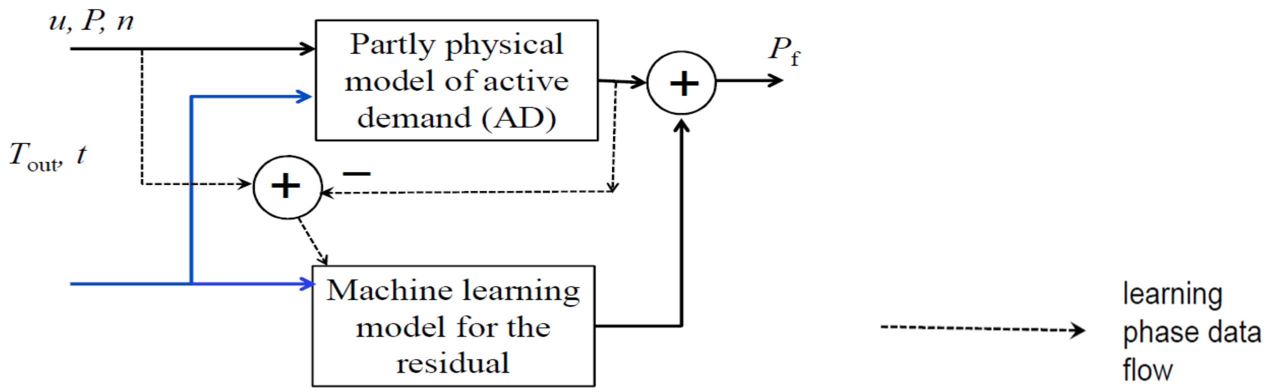


Figure 1. The main structure of residual hybrids.

The mFRR market prices and volumes

The mFRR market prices are meaningful only when there are orders from the market. The following Figure 2. shows with magenta those down regulation market prices when the orders to regulate demand down (i.e. increase load) have been at least 10 MW. On the background the down regulation prices are shown and at the bottom the orders (with negative sign) are presented. There high prices and large orders are not shown, because the scale is based on the magenta curve that shows prices only when there were at least 10 MW orders.

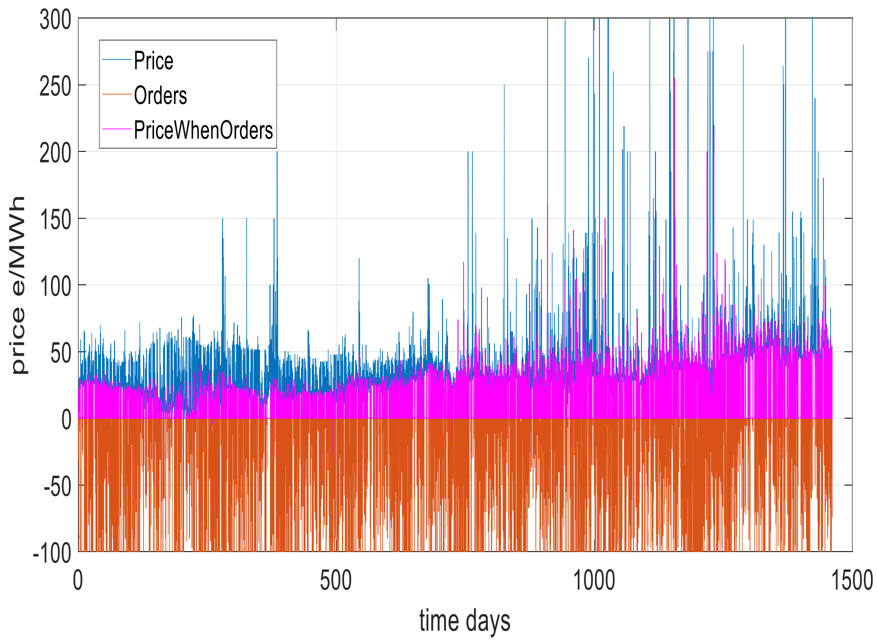


Figure 2. *The mFRR market prices and orders; the orders are in MWh/h.*

The Key Performance Indicator (KPI)

The Key Performance Indicator (KPI) in this demonstration is the operational net revenue *R* from the participation to the manual Frequency Restoration Reserve (mFRR). The corresponding KPI of the Finnish Demonstration is the KPI no 1: *Increase in revenue of the flexibility service provider*. However the equation of the KPI no1 has been modified from the original in order to take into account the costs of the market operations. Therefore, net revenue is measured instead of revenue.

The KPI for the simulated cases is calculated as follows:

4) The gross benefit R_{gross} from the mFRR market is calculated by multiplying the response $P_{response}$ sold to the market with the mFRR market price π_{FRR} . Only the response in the hours for which the response offer was accepted are taken into account. Up regulation and down regulation have different prices and volumes in the mFRR market. They are selected based on the direction of the offer. Only the hours when the purchased volume was at least 10 MW are included.
5) Calculation of the increase in operational costs that the responses cause to the customers, *C*. It comprises cost from purchasing electric energy and the grid tariff costs.
    - The grid tariff costs consist of an energy based component and a power based component (in Helsinki).
    - The energy purchase cost is calculated using the assumption that the variable price component is the same as the day ahead spot market price. It is assumed that all the customers buy electricity from their electricity retailers using a contract where the variable cost component is directly according to the day ahead spot market price. The electricity retailer's margin is typically small and it is assumed that is included in the fixed fees that do not depend on the amount of consumption.
6) Finally, the net revenue *R* is get by subtracting the cost increases from the gross benefit.

$$R_{gross}(T) = \sum_{n=1}^{T} P_{mFRR}(n)\pi_{mFRR}(n)$$

$$C_{gridE}(T) = \sum_{n=1}^{T} P_{mFRR}(n)\pi_{gridE}(n)$$

$$C_{spot}(T) = \sum_{n=1}^{T} P_{mFRR}(n)\pi_{spot}(n)$$

$$C(T) = C_{gridE}(T) + C_{gridP}(T) + C_{spot}(T)$$

$$R(T) = R_{gross}(T) - C(T)$$

where the grid power fee cost $C_{gridP}(T)$ is calculated according to the rules of the grids power fee tariff.

In this study, the grid tariff that came to effect in 1 July 2018 was applied for the whole simulation period. It has energy and a power components. If the actual tariffs where applied for the beginning of the simulation period the comparison of different years would be much more difficult. The above KPI formulas are first calculated for the response of and average house model. Multiplying the average house revenues by the number of controlled customers (727) the KPI for the whole demonstration group is got, when needed.

<u>The studied demand response cases</u>

Several cases for demand response were simulated. The following Table 26. summarises the simulated cases and some of the simulation results. This is an overview. Here only the gross rewards are shown and the impacts of the load changes to the grid and retail fees are ignored. More detailed results are shown later. There also the grid and retail fees are taken into account when the mFRR bid price is varied to maximise the net rewards. The flexible resource studied comprises 727 houses that are divided in two groups. The houses have heat storage tanks heated by electricity using remote control by the aggregator. In group 1 there were 350 houses and in the group 2 there were 377 houses. Earlier the grouping was based on the heat storage capacity normalised to the heating need, but that may not be the case anymore. The modelled daily heat demand in the houses of group 2 needed 1 hour more heating time each night than group 1. The difference in this respect is so small that it is rather irrelevant for this study. The hourly interval power time series of each house is measured. The heating power is not separately measured. The 5 year simulation period was 1.1.2015 – 31.12.2019. The simulation models were identified from a test period in June 2012 – June 2013.

TABLE 26. GROSS REVENUE SIMULATIONS SUMMARY, ZERO BID PRICE.

Case	Hour offered	Group	Down regulation MW [min, max] (=load increase)	Up regulation MW [min, max] (=load decrease)	Annual gross revenue €, 5 year mean and the 2019	Annual gross revenue / house, € 5 year mean and 2019	Notes
1a	12-13	1	[1.1838 6.9960]	—	34196	47.07	
	13-14	2	[0.1539 6.6186]	—	42630	58.64	
1b	14-15	1	[1.3672 7.0618]	—	38032	52.31	
	15-16	2	[0.1625 6.5834]	—	49114	67.56	
2a	12-14	1	[0.7460 6.9960]	—	51311	70.58	
	12-14	2	[0.5564 6.6143]	—	63862	87.84	
2b	12-14	1	[0.7460 6.9960]	—	56446	77.64	
	14-16	2	[0.5580 6.5997]	—	71061	97.75	
3a	12-13	1	[1.3424 13.6102]	—	32477	44.67	
	12-13	2		—	41009	56.41	

3b	13-14	1	[1.4225 13.6764]	—	36538	50.26	
	13-14	2		—	45083	62.01	
4	03-04	1 and 2	—	[-0.001 -10.057]	12402	17.06	1)
	04-05	1 and 2	[0.3013 9.8228]	—	11758	16.17	

TABLE 27

Notes:

1) The cases 1a – 3b are mutually exclusive, but case 4 can be applied together with any other case.
2) In cases 1a-3b only down regulation revenue is included.

The volume of the response depends on the out temperature. When the temperature is high the down regulation is small. When the temperature is below zero the single hour load increase is at the least 5 MW per group. Much lower temperature is needed to maintain the 5 MW load increase per group for two hours. The estimated rewards assume perfect forecasts. Taking the response forecast uncertainty into account will reduce the rewards. The RMSE (root mean square error) of the group load forecasts was about 1.4 MW when using the HDNN-physical-hybrid load forecasting model and about 1.2 MW for our most accurate ML-physical hybrid forecasting model so far. It has not yet been modelled what is the uncertainty of the physically based sub-model alone and how it depends on the situation. Thus, it can now only roughly estimated that the reduction of the rewards due to forecast uncertainties may be about 15 %, because that much more controllable load may need to be reserved in order to manage this uncertainty.

Simulations

All the simulations start from 1 Jan 2015 and end at the end 2019 Thus, the duration is 5 years.

<u>Base case forecasts with the physically based aggregated load model</u>

The following figures 2-5 show aggregated physically based forecasts of Group 1 compared to the corresponding measurement aggregated from hourly interval billing meters. The figures show also the forecast SOC of the heat storage and the control signal, because they indicate how much the load can be changed by new control actions such as provision for frequency controlled reserve (FCR) or manual frequency restoration reserve (mFRR). (In the figures the SOC is normalised to 100kWh/house + 50kWh/house bias for readability, 0.5 means SOC =0 and 2.5 means SOC = 0.2MWh_{heat}/house = 60 MWh_{heat} for the whole group 1) that comprises 300 houses. The model represents an average house and some houses have less heat storage capacity. Such houses reach zero SOC sooner than the model.)

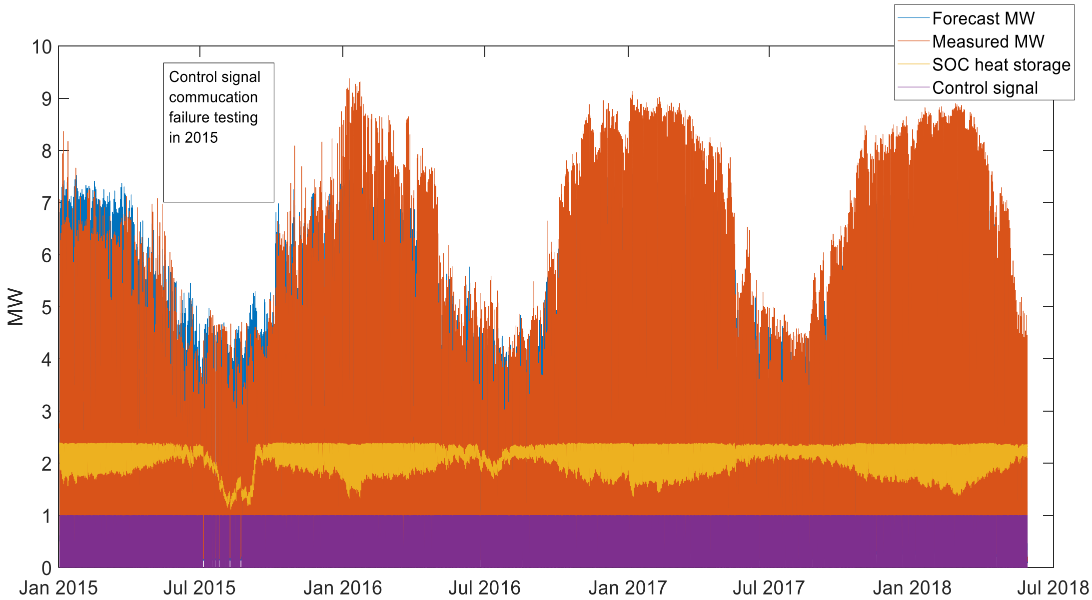


Figure 3. Physically based load forecast overview

Figure 3 shows a zoomed view of the Figure 2.

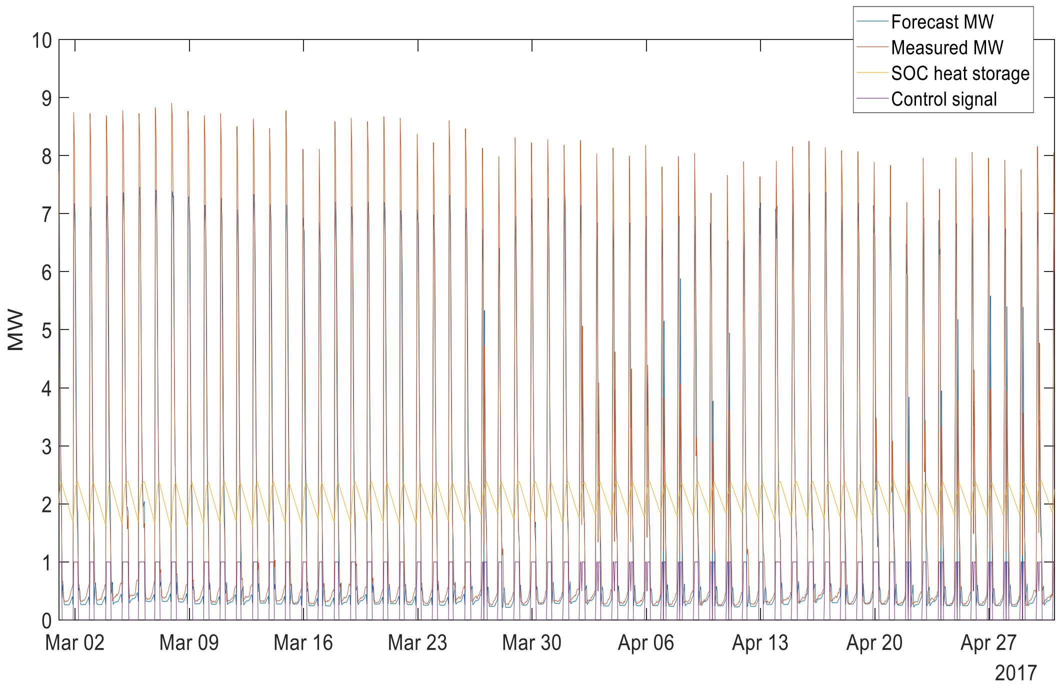


Figure 3. Physically based load forecast, a two months long period.

Figure 4 shows a zoomed view of the Figure 3.

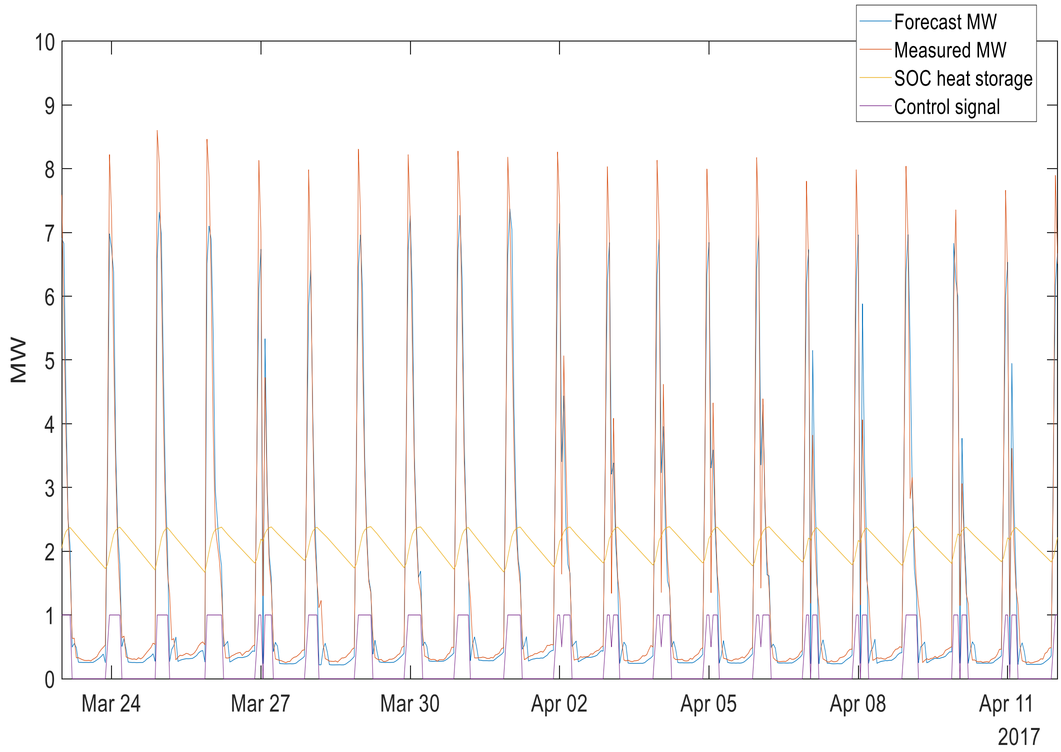


Figure 4. Physically based load forecast, a 20 days long period.

Figure 5 shows a zoomed view of the Figure 4. In the Figure 5, the time changes from winter time to summer time (daylight saving time) on 26th March 2017 at 3:00.

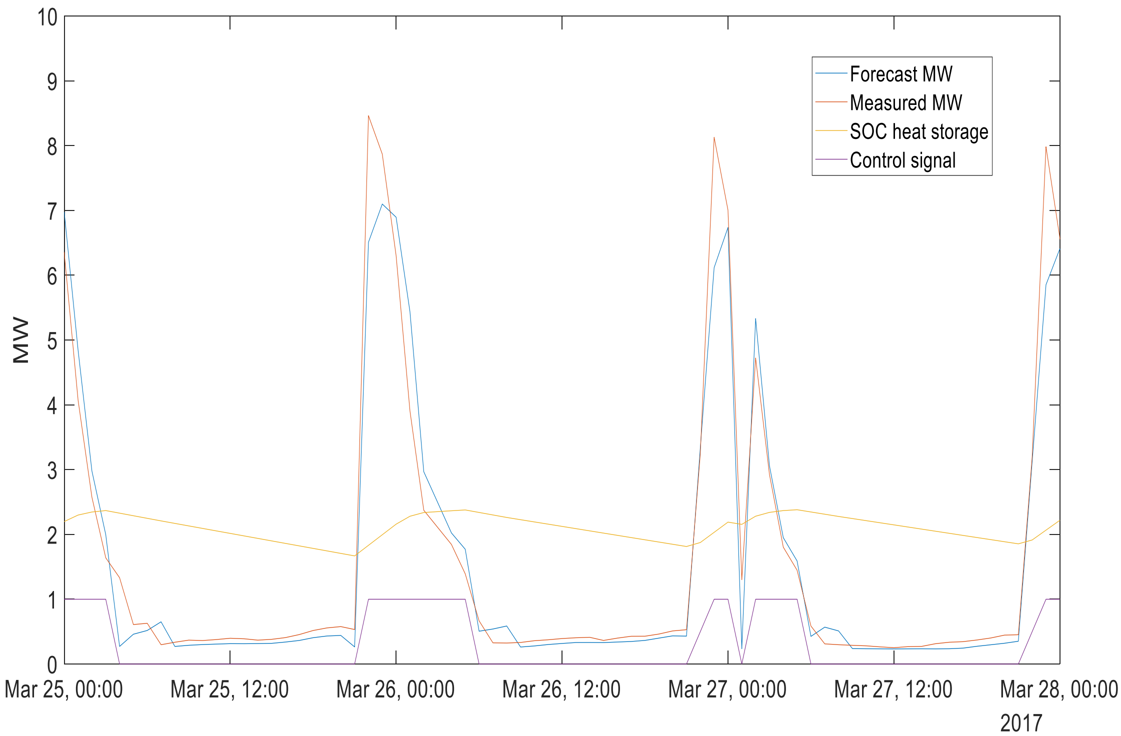


Figure 5. Physically based load forecast, a three days long period.

Case1a: Load increase group1 at 12:00 to 13:00 and group 2 13:00 to 14:00

The electrical storage heating is turned on for the group 1 at 12:00-13:00 and for the group 2 at 13:00-14:00, if the market price was higher than zero and the market volume was at least 10 MW. The down response volume of the offered hours multiplied by the down regulation price of the same hour was summed over the whole 5 year simulation period. That gave 171098 €, which makes 34196 € annually.

Year	2015	2016	2017	2018	2019	sum	average
Gross revenue k€	22.297	25.379	32.084	48.709	42.630	171.098	34.196
Gross revenue €/house	30.67	34.91	44.13	67.00	58.64	235.35	47.04

The prices shown in all the following figures and used in the calculation of the rewards are the mFRR market prices for those hours when at least 10 MW has been ordered. For all other hours, the zero price has been used instead of the mFRR market price.

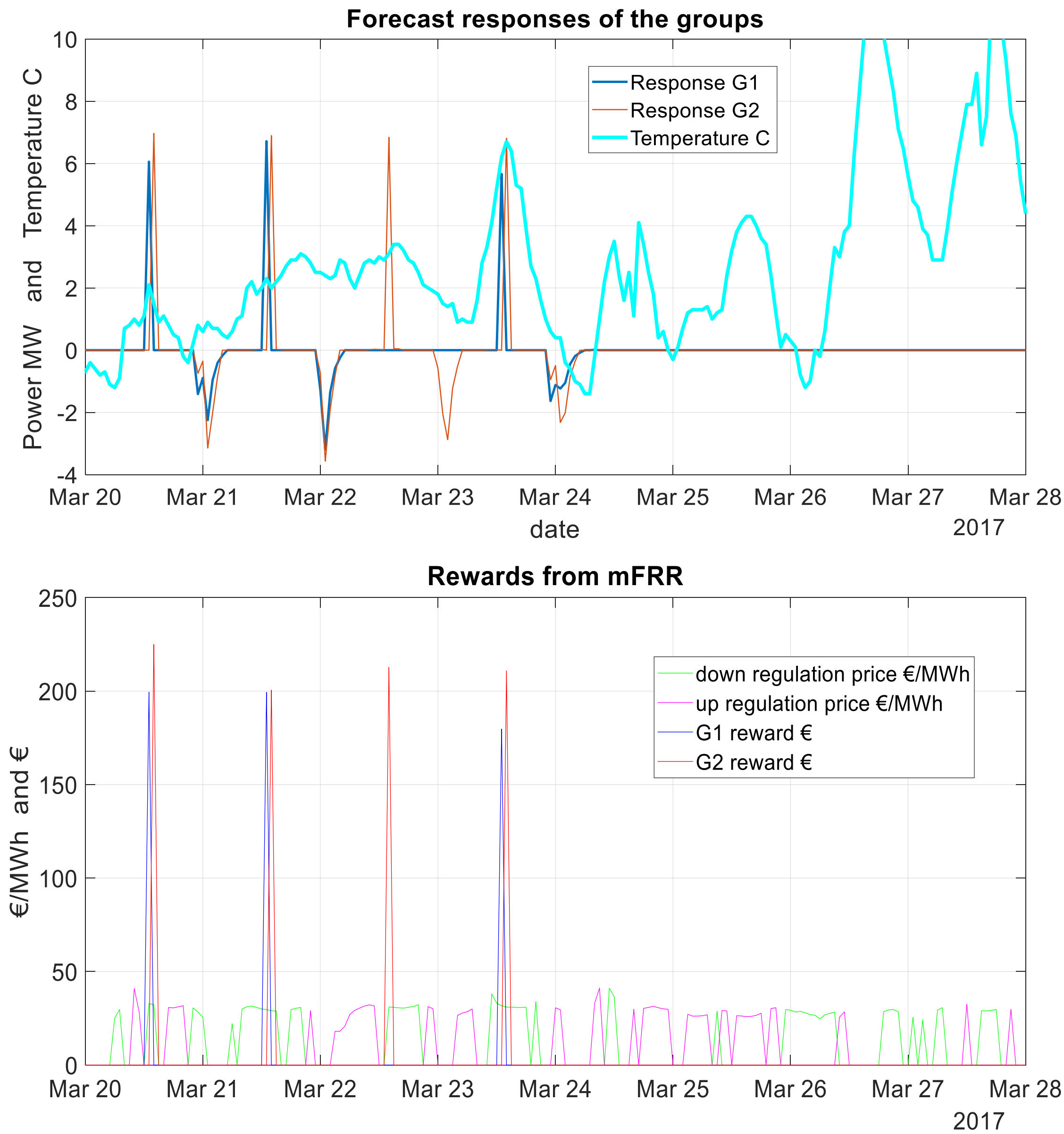


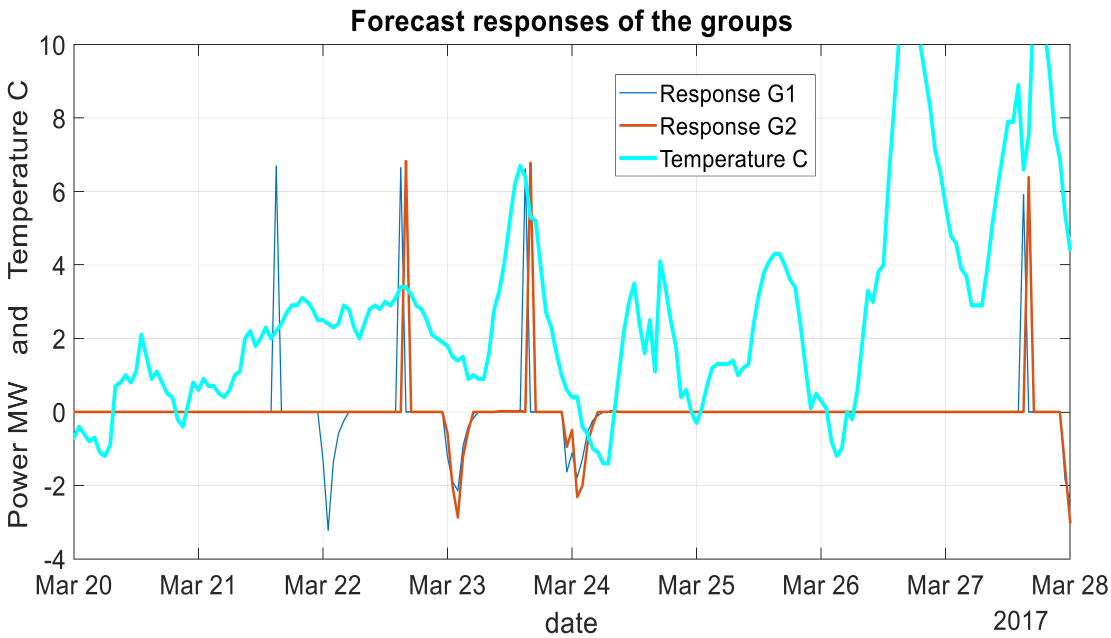
Figure 6. A sample of Case 1a responses and gross rewards.

Only those responses that are offered and sold appear in the two figures above. When heating is turned on during the day, the response of that hour spikes up and the heat storage gets more energy thus reducing the heating of the next night. The energy remains roughly the same and only the timing of heating changes.

Case1b: Load increase group1 at 14:00 to 15:00 and group 2 15:00 to 16:00

The electrical storage heating is turned on for the group 1 at 14:00-15:00 and for the group 2 at 15:00-16:00, if the market price was higher than the bid price and market volume was at least 10 MW. The down response volume of the offered hours was multiplied by the down regulation price of the same hour, and summed over the whole 5 year simulation period, and gave 190293 €, which makes 38032 € annually.

Year	2015	2016	2017	2018	2019	sum	average
Gross revenue k€	24.769	28.423	37.426	50.562	49.114	190.293	38.032
Gross revenue €/house	34.07	39.10	51.48	69.55	67.56	261.75	52.31



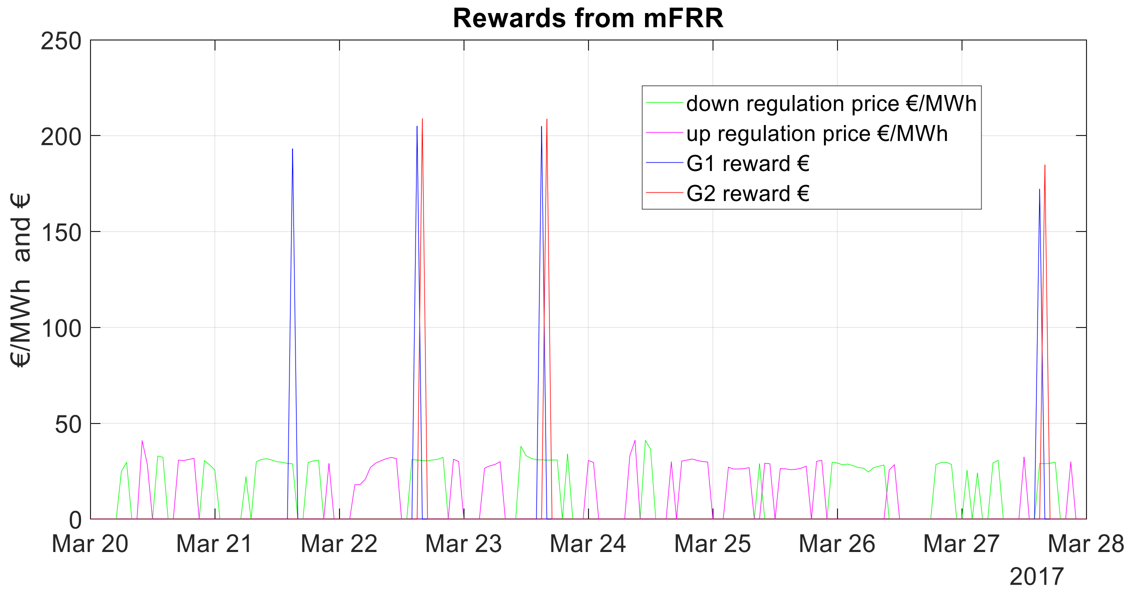


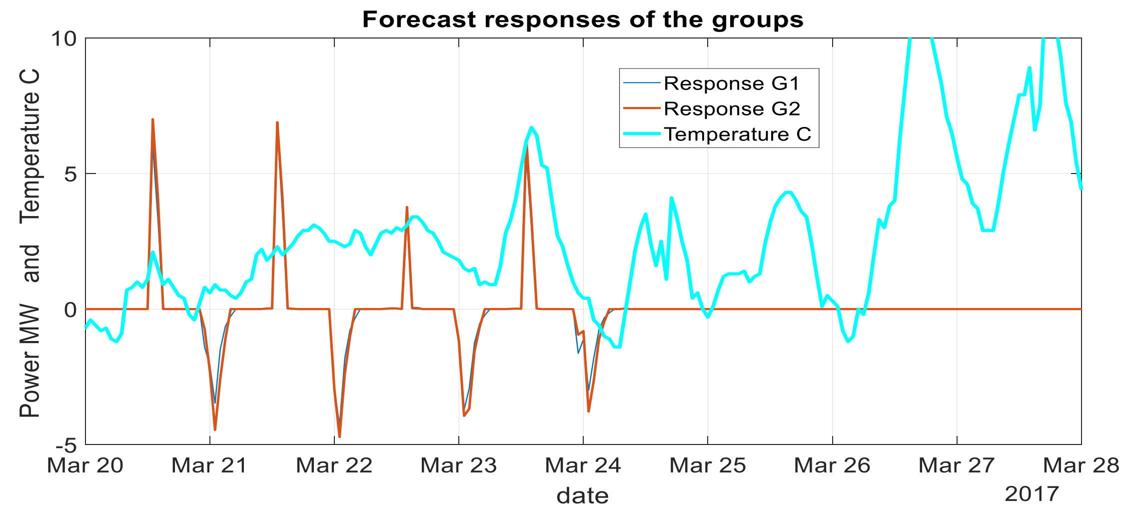
Figure 7. A sample of Case 1b responses and gross rewards.

Case 2a: Load increase 2 hours for both groups between 12:00 and 14:00.

The down regulation price multiplied by the response volume of the offered hour and summed over the whole simulation period was 256736 €, which makes 51311 € annually.

Year	2015	2016	2017	2018	2019	sum	average
Gross revenue k€	32.724	37.264	48.956	73.930	63.862	256.736	51.311
Gross revenue €/house	45.01	51.26	67.34	101.69	87.84	353.14	70.58

The two hours long daytime load increase does not cause any loss of comfort to the consumers. The only impact is that the response on the second hour is much smaller during high out temperatures. This needs to be taken into account when offering load increase (the same as generation down) to two hours during the same day. When the out temperatures are lower, there are no problems. Here the analysis assumes that the bids do not affect the price. Thus, it does not take into account that adding these offers would reduce the market price. Bigger offers will reduce the marginal price much more than smaller ones. Thus distributing the bids to as many hours as possible may likely give the highest rewards.



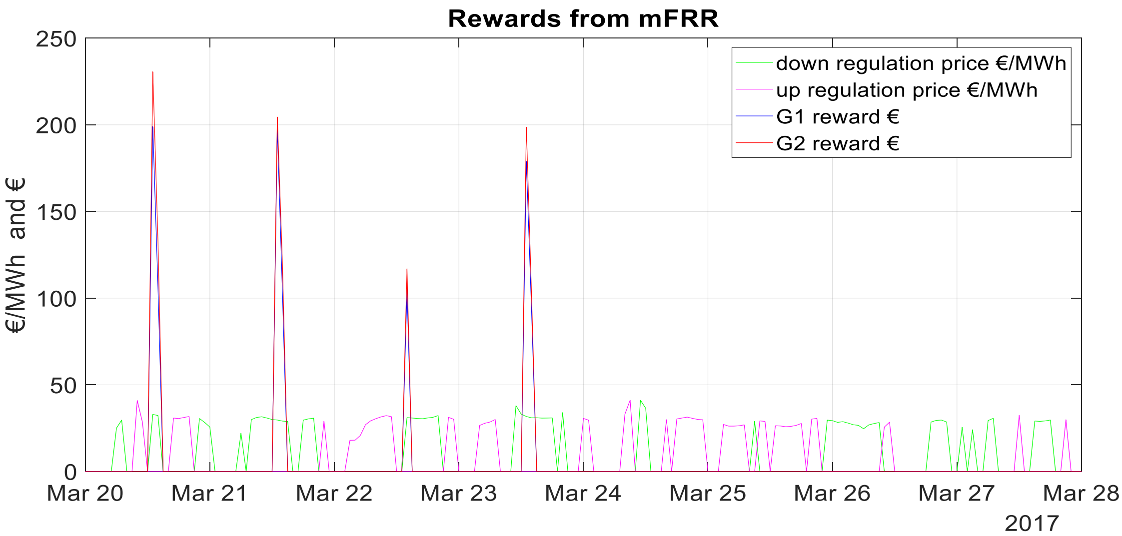


Figure 8. A sample of Case 2a responses and gross rewards.

Case2b: Load increase 2 hours for group 1 between 12:00 and 14:00 and for group 2 between 14:00 and 16:00

The down regulation price multiplied by the response volume of the offered hour and summed over the whole simulation period was 282428 €, which makes 56446 € annually.

Year	2015	2016	2017	2018	2019	sum	average
Gross revenue k€	77.645	41.647	55.393	78.682	71.061	282.428	56.446
Gross revenue €/house	49.03	57.29	76.19	108.23	97.75	388.48	77.64

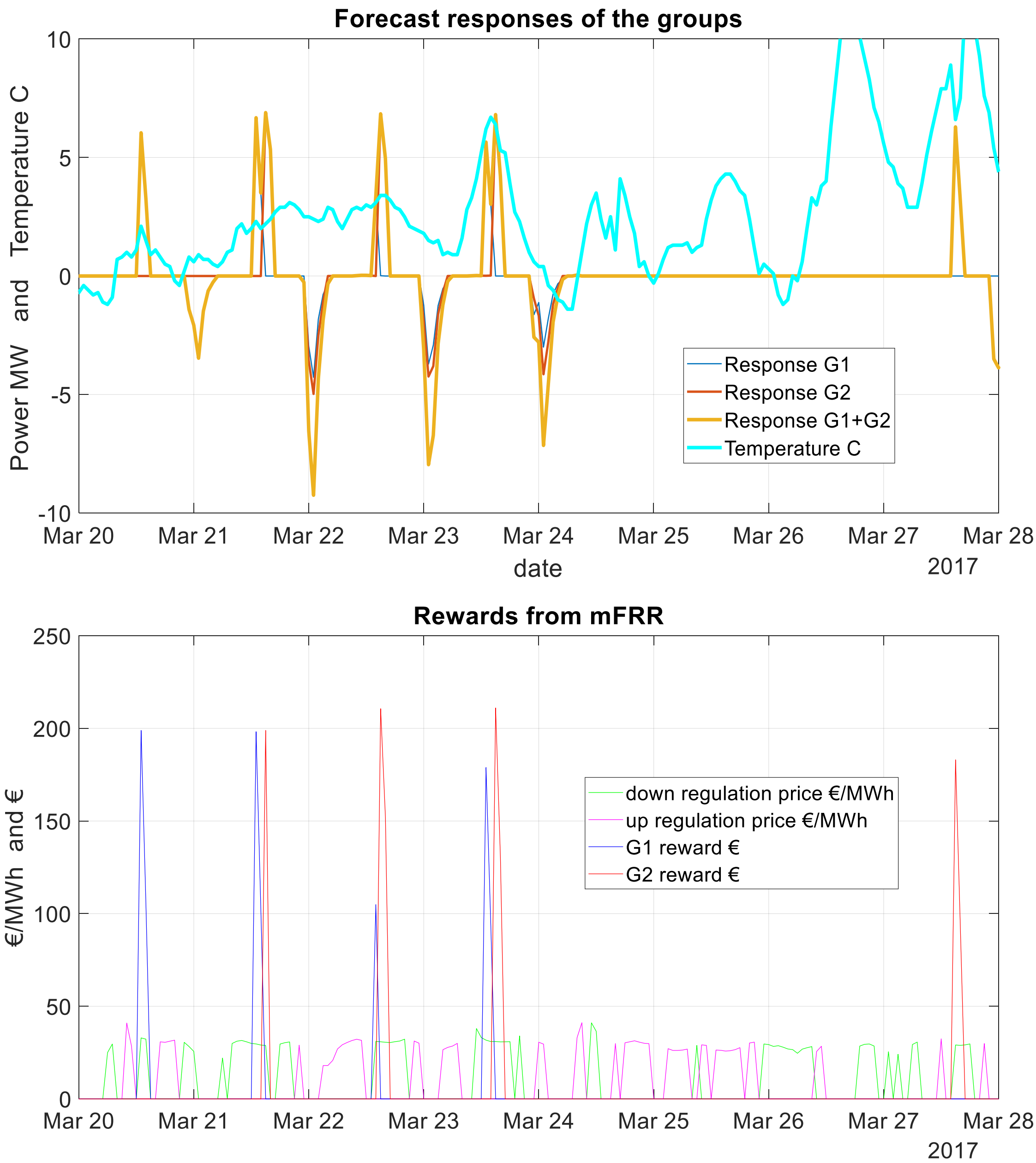


Figure 9. A sample of Case 2b responses and gross rewards.

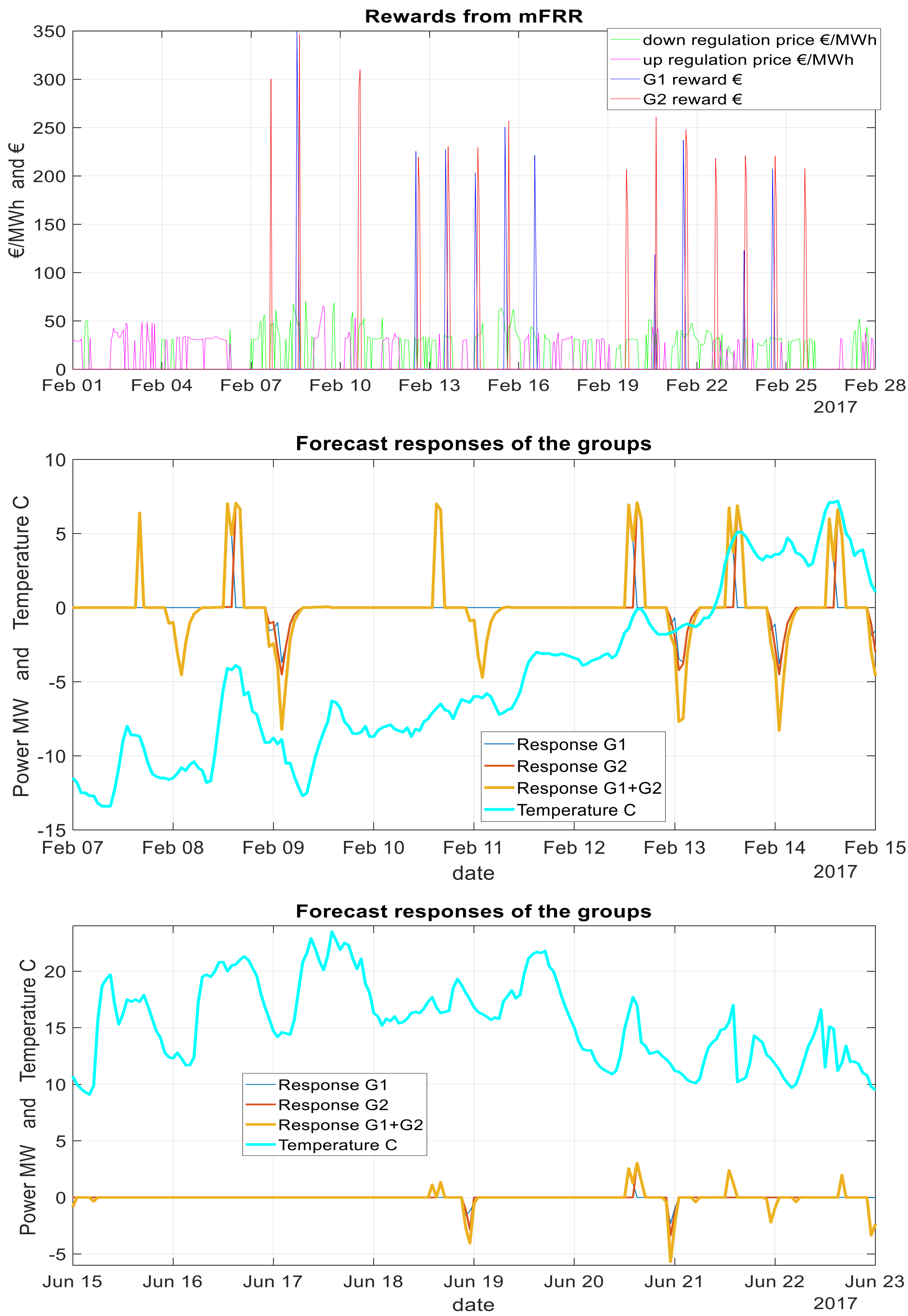


Figure 10. Winter and summer samples of Case 2b responses and gross rewards.

Cases 3a: Load increase for both groups between 12:00 and 13:00.

The down regulation price multiplied by the response volume of the offered hour summed over the whole 5 year simulation period was 162501 €, which makes 32477 € annually.

Year	2015	2016	2017	2018	2019	sum	average
Gross revenue k€	22.711	23.023	29.993	45.766	41.009	162.501	32.477
Gross revenue €/house	31.24	31.67	41.26	62.95	56.41	223.37	44.67

Cases 3B: Load increase for both groups between 13:00 and 14:00

The down response volume of the offered hours multiplied by down regulation price and summed over the whole simulation period was 182819 €, which makes 36538 € annually.

Year	2015	2016	2017	2018	2019	sum	average
Gross revenue k€	22.417	28.220	34.678	52.421	45.083	182.819	36.538
Gross revenue €/house	30.84	38.82	47.70	72.11	62.01	251.47	50.26

case 4: For both groups load decrease between 03:00 and 04:00 and increase between 04:00 and 05:00

Load decrease benefits were estimated as follows. The up response volume of the offered hours up multiplied by the regulation price of that hour was summed over the whole simulation period and gave 25126 €, which makes 5025 € annually. During 2019 the benefit was 3624 €.

Load increase benefits were estimated as follows. The down response volume of the offered hours multiplied by the down regulation price was summed over the whole 5 year simulation period and gave 36928 €, which makes 7386 € annually. During 2019 the benefit was 8134 €.

The combined benefit summed over the whole simulation period was 62055 €, which makes 12402 € annually.

Year	2015	2016	2017	2018	2019	sum	average
Gross revenue k€	6.184	13.476	13.137	17.600	11.758	62.055	12.402
Gross revenue €/house	8.51	18.54	18.07	24.07	16.17	85.36	17.06

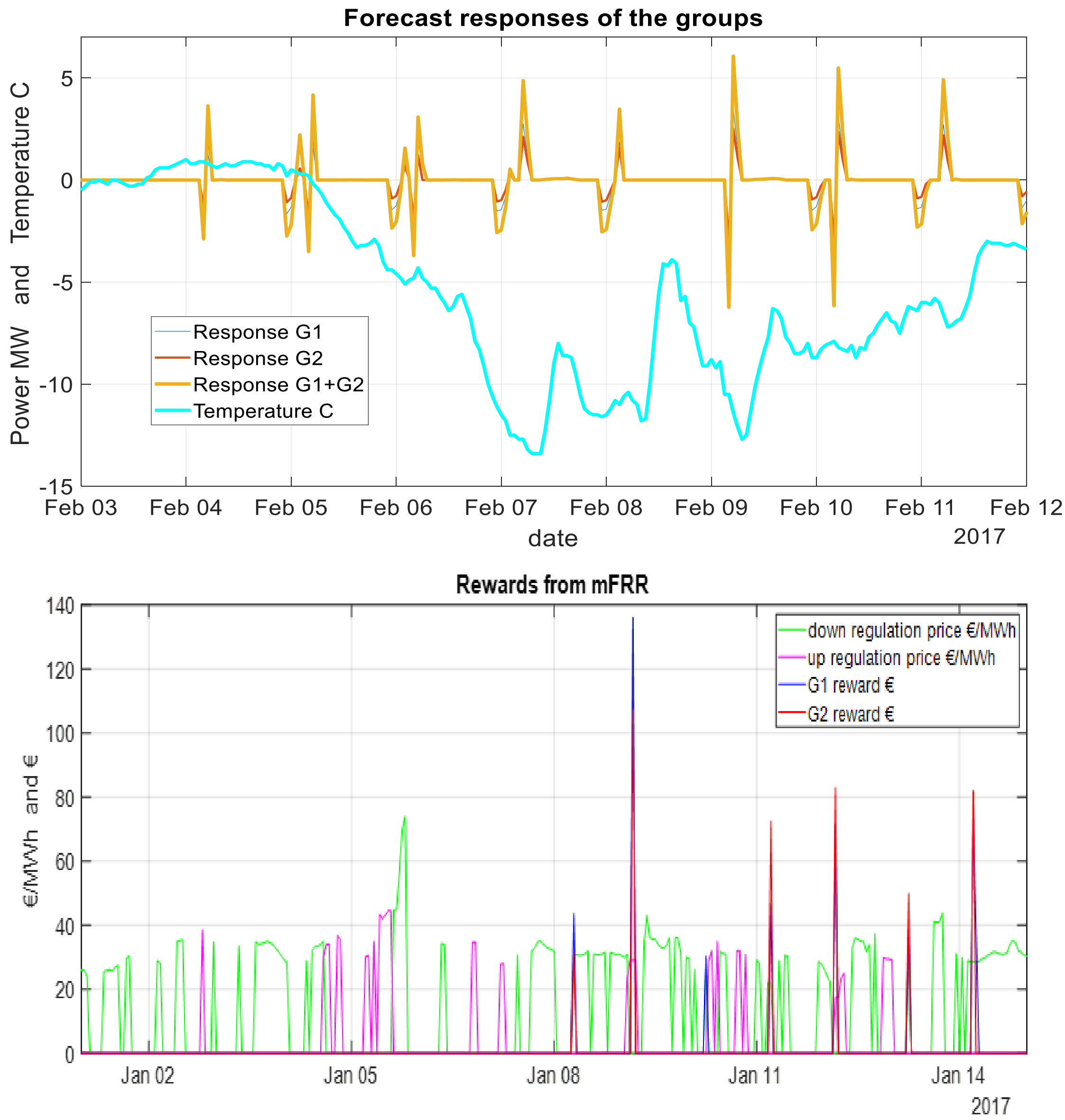


Figure 11. A sample of Case 4 responses and gross rewards.

The load cannot be increased over the maximum heating power, which means that at cold out temperatures one heating hour is not enough for recovering from a one hour long load interruption. The down regulation reward is calculated only for the hour where the flexibility is offered.

Analysis of the impacts on customer's costs

Distribution tariff increase to the customer

Change in the energy component in the grid tariff

Table II below shows how much the energy fees of the grid tariff increase for a customer that has an average load and response in providing flexibility to the mFRR-market in the simulations. The bid price was set to zero and the distribution tariff as in effect in 2019 was used during the whole simulation. (Before 1 July 2017 the actual tariff had higher prices but smaller price difference between the night and day.)

Table II. Response impact on the energy component of the grid fee.

Grid tariff energy component	Annual mean Group 1 € / house	Annual mean Group 2, €/house	2019 Group 1 € / house	2019 Group 2 € / house	Annual mean Groups 1 and 2 € / house	2019, Groups 1 and 2 € / house
Case 1 a	18.35	19.56	18.35	18.72	18.97	18.55
Case 1 b	22.66	21.24	22.80	21.83	21.92	22.30
Case 2 a	25.07	25.15	25.58	25.69	25.11	25.64
Case 2 b	25.07	32.86	25.58	32.55	29.11	29.19
Case 3 a	18.35	17.51	18.35	17.78	17.91	18.06
Case 3 b	21.30	19.54	20.41	18.72	20.38	19.53
Case 4	1.58	0.89	1.88	0.41	1.22	1.12

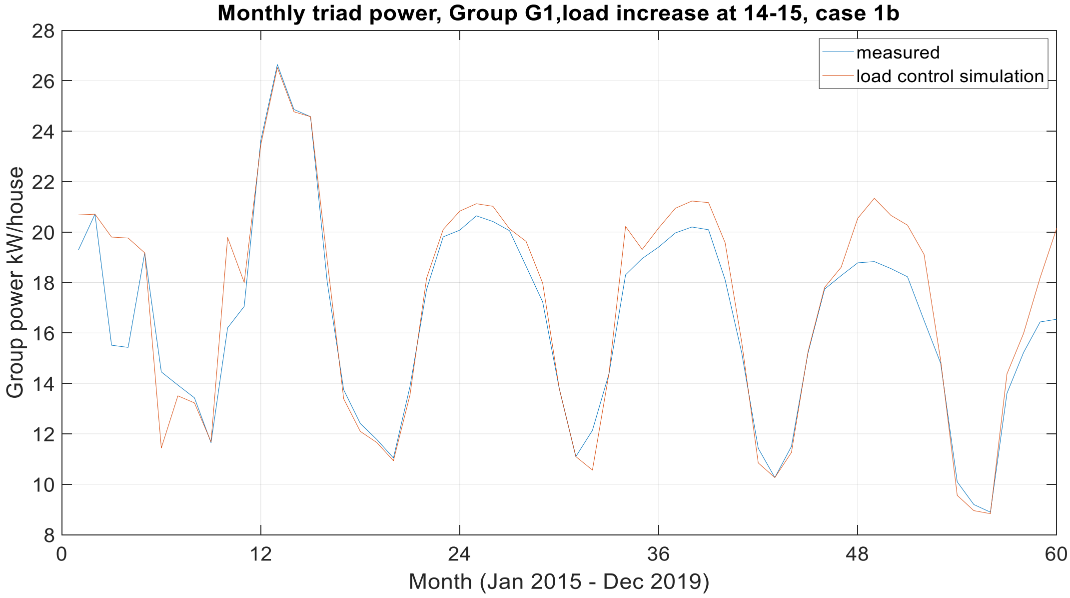
<u>Change in the power component in the grid tariff</u>

The power component was calculated according to the grid tariff. The third highest power of each month is multiplied by and summed over the studied time. In this calculation, in the night time the power taken into account is 80% of the actual power. This grid power fee tariff came into effect in 1 July 2018. Before 1 July 2017 the actual tariff did not yet include any power based fee, but in this simulation the same triad based power component is applied to the whole 5 year simulation period. The following Table III shows the results.

Table III. Response impact on the power component of the grid fee.

Grid tariff power component	Annual mean Group 1 € / house	Annual mean Group 2, €/house	2019 Group 1 € / house	2019 Group 2 € / house	Annual mean Groups 1 and 2 € / house	2019, Groups 1 and 2 € / house
Case 1 a	2.02	2.43	9.21	13.18	2.23	11.27
Case 1 b	12.04	4.75	24.57	20.33	8.26	22.37
Case 2 a	-0.91	-1.12	6.73	6.58	-1.02	6.65
Case 2 b	-0.91	1.36	6.73	15.77	0.27	11.42
Case 3 a	2.02	1.38	9.21	9.24	1.68	9.23
Case 3 b	8.89	2.43	20.64	13.18	5.54	16.77
Case 4	-2.50	-2.56	-0.89	-1.45	-2.53	-1.18

Based on these simulations the power fees can reduce the profitability of the mFRR response significantly. The impact depends on the timing and the behaviour of customers' other loads than heating loads. The main problem with them is that the cost increase to the customer can be high when large other loads happen to be simultaneous with the new daytime load peaks caused by the load control actions and when the outdoor temperatures are suitably low. In the simulated time, the power tariff fees for a whole year increased due to the increased annual load peak. Here the power fee was applied to the monthly third highest load peak and exactly the same power fee tariff was applied in all the years. The group 2 experienced in 2019 very high power fee increases due to the load increasing control actions at 15–16. One reason is that the load was already rather high during the hour as compared to the measured triad power. For group 2 the measured triad power was smaller than for group 1. Also small differences between the response models of the groups may contribute to some extent to the observed results.



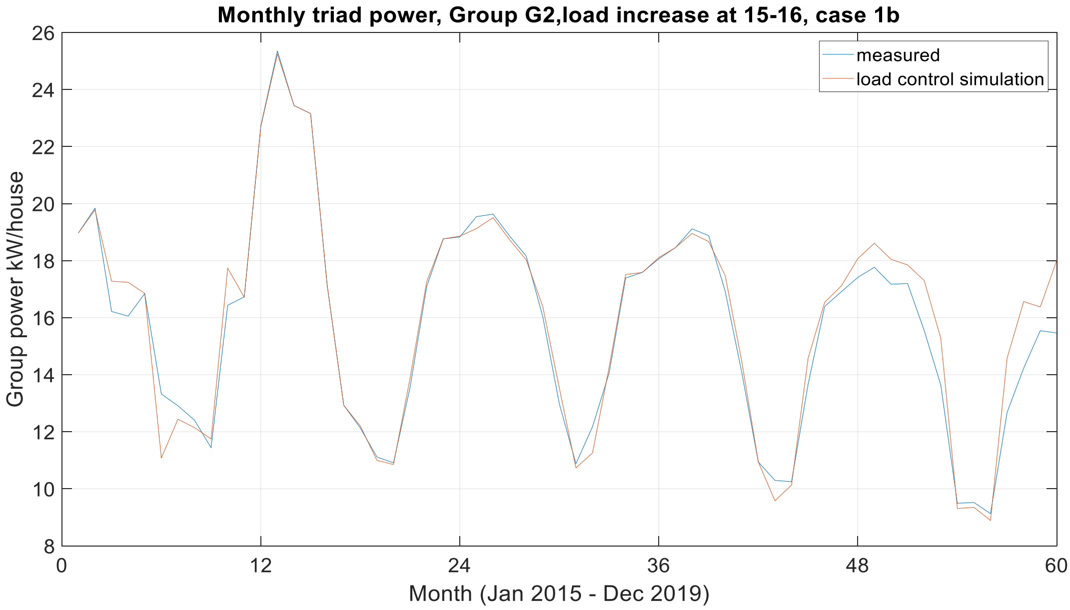
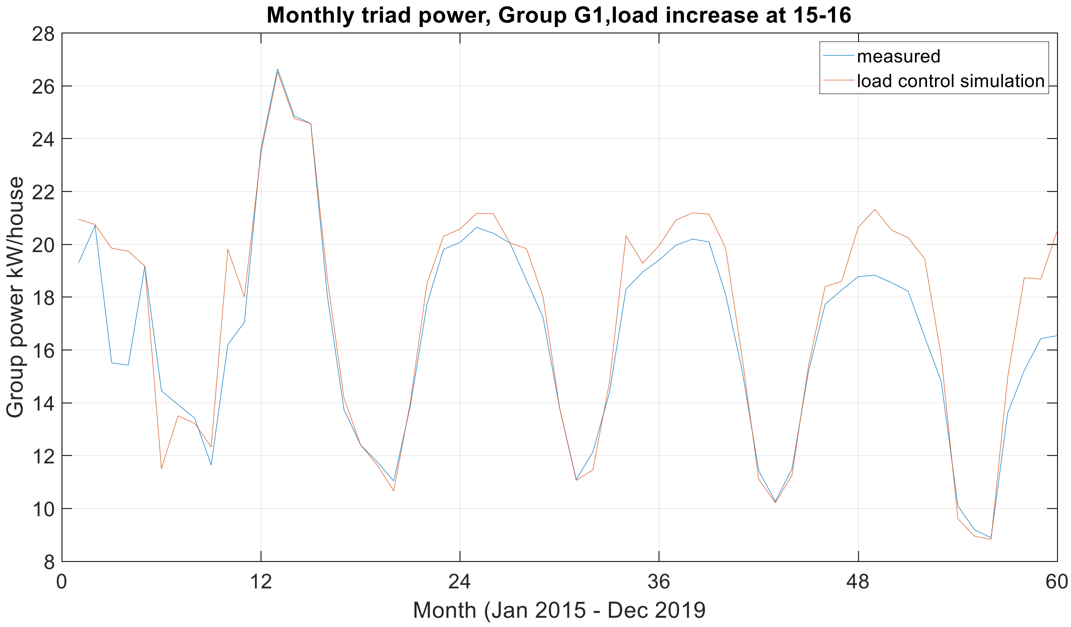


Figure 12.The measured monthly triad power decreases for the groups G1 and G2 significantly but not in the simulations with the group G1 load increase at 14–15 nor with the group G2 load increase at 15–16.

In the Figure 12, it is not obvious to what extent the big increasing difference between the measured and simulated trial powers stems from the different timing of the groups and to what extent from the differences in the group properties. Thus, it was switched the timings of the groups mutually and repeated the simulation. The results in Figure 13 show that the reason for the differences is mainly the changes in group G2 behaviour over the simulation years. In the beginning the houses in the group G2 had smaller dimensioning of the heat storage capacity with respect to the heat demand. Possible reasons for the load behaviour changes include 1) improvements in insulation, 2) additions of heat pump based partial heating, 3) customer adaptation to the introduction of power based grid tariffs. It is beyond the scope of this simulation study to analyse the reasons for load behaviour changes in detail. The conclusion from the Figures 12 and 13 is that the simulation models may overestimate the grid power tariff based cost increases at the end of the simulation period.



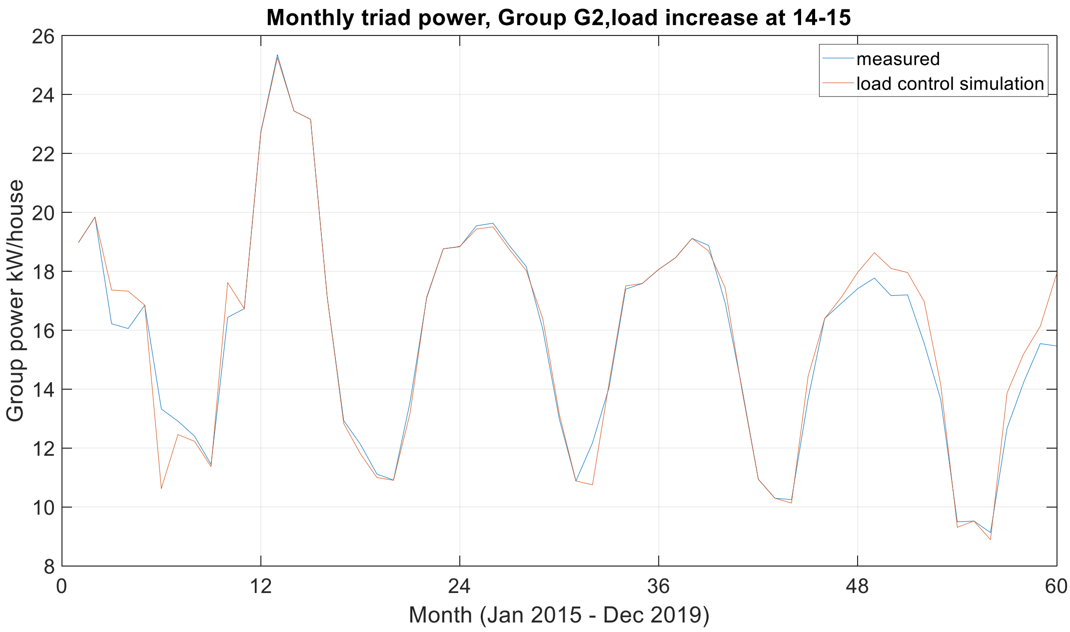


Figure 13. Also with load increase G1 at 15–16 and G2 at 14–15, the difference of the measured and simulated monthly triad power increases significantly towards the end of the test period.

This study is completely based on aggregated customer behaviour. Thus, it is not at all suitable for assessing the impacts of power— based grid tariffs on individual consumers. (The impact of the stochastic variations on the energy component disappears much faster so with them the aggregate models are reasonably good.) The aggregated load is well predictable, but the behaviour on individual consumers is very stochastic. Due to this variation, the impacts of power— based tariffs can be expected to be much higher even on the average and possibly very dramatic on those individual customers that happen to have high other load peak at the same time as the heating loads are turned on. Stochastic analysis of the impacts of the power— based tariffs is necessary in order to have reasonably accurate estimates. Another possible solution is to apply peak load limiting automation at the customers. Such limiting reduces the aggregated response possibly only slightly but can completely prevent the demand response from causing a peak load increase and the resulting customer's grid costs increase.

<u>Changes in electricity spot price costs</u>

Here it is considered the impacts on a customer that has a spot price based dynamic tariff. Increasing load in daytime causes customer load shifting to a more expensive spot price period. This needs to be compensated to the customer. Even when the customer has fixed tariff, his/her retailer is affected by the load shift and these costs are eventually reflected in the electricity retail tariff costs.

Table IV. Response impact on the spot price based customer costs

Case	Hour offered	Group	Annual mean spot market cost change G1 €/house	Annual mean spot market cost change G2 €/house	2019 spot market cost change G1 €/house	2019 spot market cost change G2 €/house	Annual mean spot market cost change G1+G2 €/house	2019 spot market cost change G1+G2 €/house
1a	12-13	1	18.64	17.61	19.43	20.12	18.11	19.79
	13-14	2						
1b	14-15	1	15.79	14.19	17.60	17.51	14.96	17.55
	15-16	2						
2a	12-14	1	16.89	18.02	17.37	19.30	17.48	18.37
	12-14	2						
2b	12-14	1	16.89	15.76	17.37	15.62	16.30	16.46
	14-16	2						
3a	12-13	1	18.64	18.18	19.43	19.50	18.40	19.47
	12-13	2						
3b	13-14	1	18.65	17.61	21.29	20.12	18.11	20.69
	13-14	2						
4	03-04	1 and 2	2.50	-0.15	4.99	-0.11	1.13	2.35
	04-05	1 and 2						

Summary of the mean annual results with zero bid price

Table IV. Simulated annual mean gross and net rewards

Case	Hour offered	Group	Mean annual gross reward €/ house	Mean grid energy fee change	Mean grid power fee change	Mean spot market fee change	Mean an. net reward €/house without power fee	Mean annual net reward €/house
1a	12-13	1	47.04	18.97	2.23	18.11	9.96	7.73
	13-14	2						
1b	14-15	1	52.31	21.92	8.26	14.96	15.43	7.17
	15-16	2						
2a	12-14	1	70.58	25.11	-1.02	17.48	27.99	29.01
	12-14	2						
2b	12-14	1	77.64	29.11	0.27	16.30	32.23	31.96
	14-16	2						
3a	12-13	1	44.67	17.91	1.68	18.40	8.36	6.67
	12-13	2						
3b	13-14	1	50.26	20.38	5.54	18.11	11.77	6.23
	13-14	2						
4	03-04	1 and 2	17.06	1.22	-2.53	1.13	14.71	17.24
	04-05	1 and 2						

Notes:

- Average customer model is not suitable for estimating the grid power fee impacts.
- The grid power fee change is likely slightly overestimated due to changes in the group behaviour that have not been taken into account in the model.

The net reward should cover the investments to reliable and fast control commands and also be shared between the customers and the aggregator. Annual net reward 32 €/house (case2 b) or 32+17€/house (case 2b and 4 together) is small for that purpose.

Summary of the last year results with zero bid price

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Table V. Simulated gross and net rewards in 2019.

Case	Hour offered	Group	2019 reward €/ house	2019 grid energy fee change	2019 grid power fee change	2019 spot market fee change	2019 net reward €/house without power fee	2019 net reward €/house
1a	12-13	1	58.64	18.55	11.27	19.79	20.31	9.04
	13-14	2						
1b	14-15	1	67.56	22.30	22.37	17.55	27.71	5.33
	15-16	2						
2a	12-14	1	87.84	25.64	6.65	18.37	43.83	37.18
	12-14	2						
2b	12-14	1	97.75	29.20	11.42	16.46	52.09	40.67
	14-16	2						
3a	12-13	1	56.41	18.06	9.23	19.47	18.89	9.66
	12-13	2						
3b	13-14	1	62.01	19.53	16.77	20.69	21.79	5.02
	13-14	2						
4	03-04	1 and 2	16.17	1.12	-1.18	2.35	12.70	13.89
	04-05	1 and 2						

Notes:

- The grid power fee change is calculated assuming the every customer behaves as an average customer. Correct estimation of the grid power fee change requires modelling the probability distributions and calculating the impacts from them. Higher values than shown in this table can be expected.
- The grid power fee change is likely slightly overestimated due to changes in the group behaviour that have not been taken into account in the model.

The impact of bid price to profitability

The previous tables show that the activation of the responses causes significant costs to the active consumers. These costs need to be taken into account and compensated. Increasing the bid price from zero may first increase the net income as some non-profitable actions are removed. Increasing the bid price further will remove also profitable actions and the net revenue starts to decrease. In the following, the impact of bid price to the profitability is analysed. The analysis is made separately for 1) the duration of the whole simulation and for 2) the last simulation year.

Case 1a

In the following Figure 14, the mean annual net revenue of Case 1a starts from 7.73 €/house and reaches maximum value 9.37 €/house at bid price 25 €/MWh. When the DSO power fee is ignored the net revenue starts from 9.96 €/house and reaches its maximum 12.32 €/house at bid price 22 €/MWh.

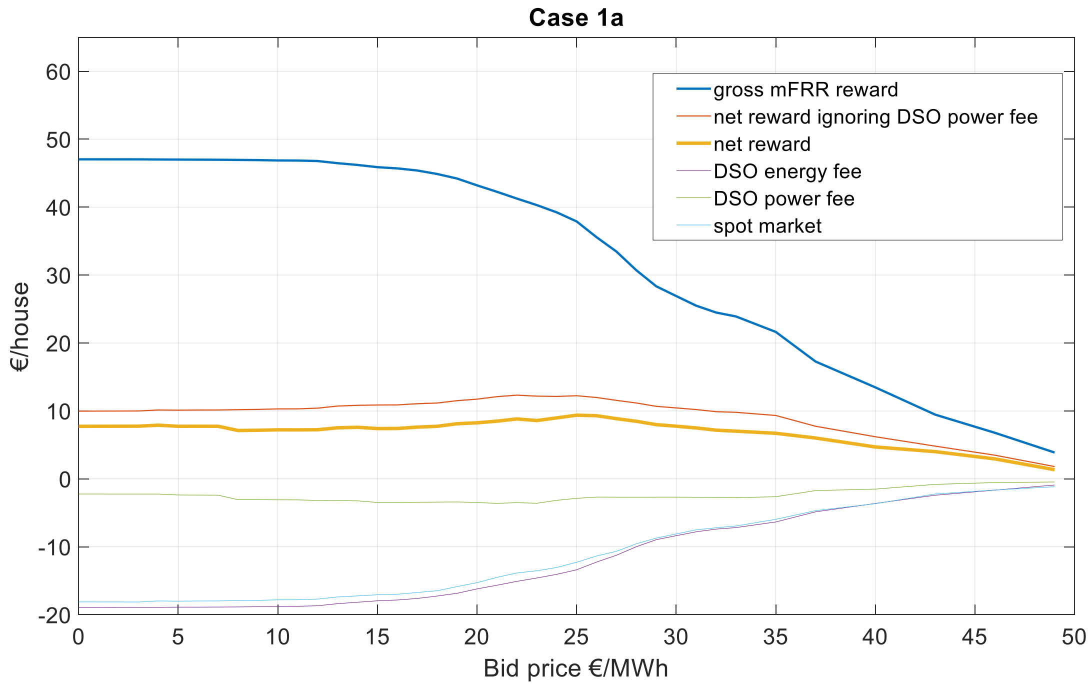

Figure 14. Case 1a annual mean revenues as a function of bid price. G1 offered 12–13 and G2 offered 13–14.

In the following Figure 15, the case 1a last year (2019) net revenue taking into account the grid power fee starts from 9.04 €/house and reaches its maximum 10.48 €/house at bid price 33 €/MWh. The last year net revenue ignoring the grid power fee starts from 20.31 €/house and reaches its maximum 21.77 €/house at bid price 31 €/MWh.

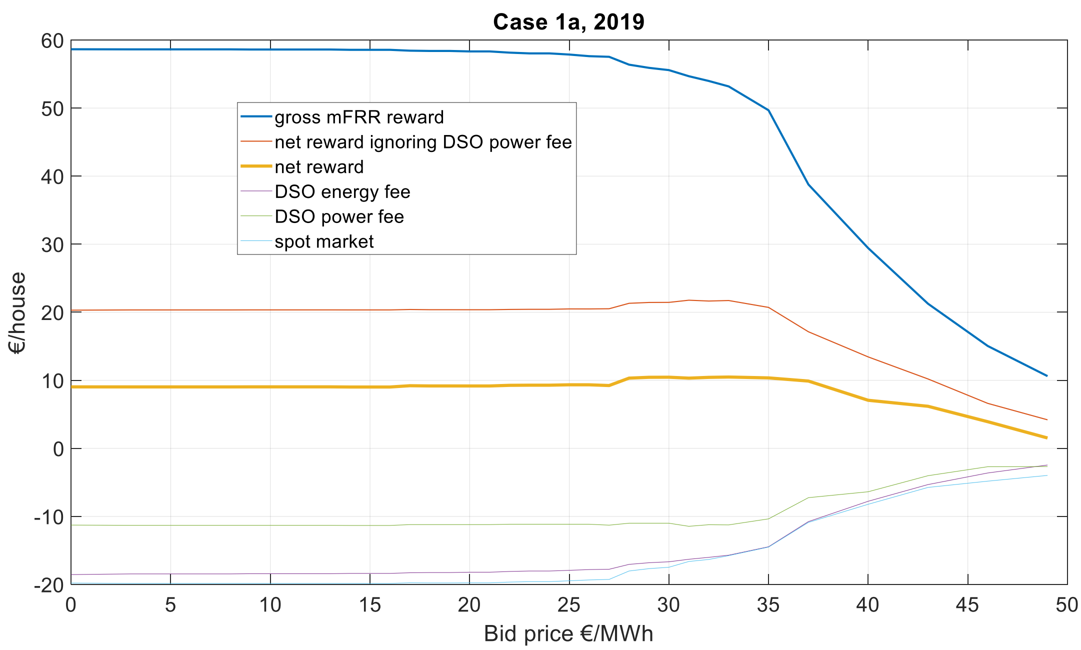

Figure 15. Case 1a revenues in 2019 as a function of bid price. G1 offered 12–13 and G2 offered 13–14.

Case 1b

In the following Figure 16, the mean annual net revenue starts from 7.17 €/house and reaches maximum value 9.36 €/house at bid price 24 €/MWh. When the DSO power tariff is ignored the net revenue starts from 15.43 €/house and reaches its maximum 17.05 €/house at bid price 19 €/MWh.

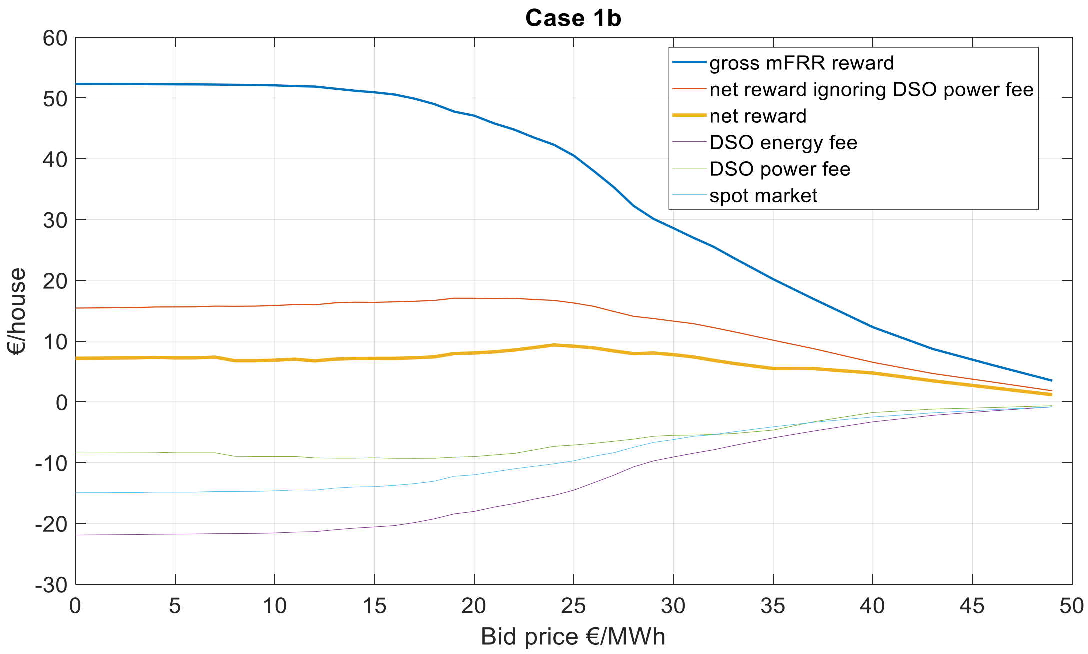

Figure 16. Case 1b annual mean revenues as a function of bid price. G1 offered 14–15 and G2 offered 15–16.

In the following figure, the case 1b last year net revenue taking into account the grid power fee starts from 5.33 €/house, and reaches its maximum 6.98 €/house at bid price 37 €/MWh. The last year net revenue ignoring the grid power fee starts from 27.71 €/house, and reaches its maximum 28.28 €/house at bid price 29 €/MWh.

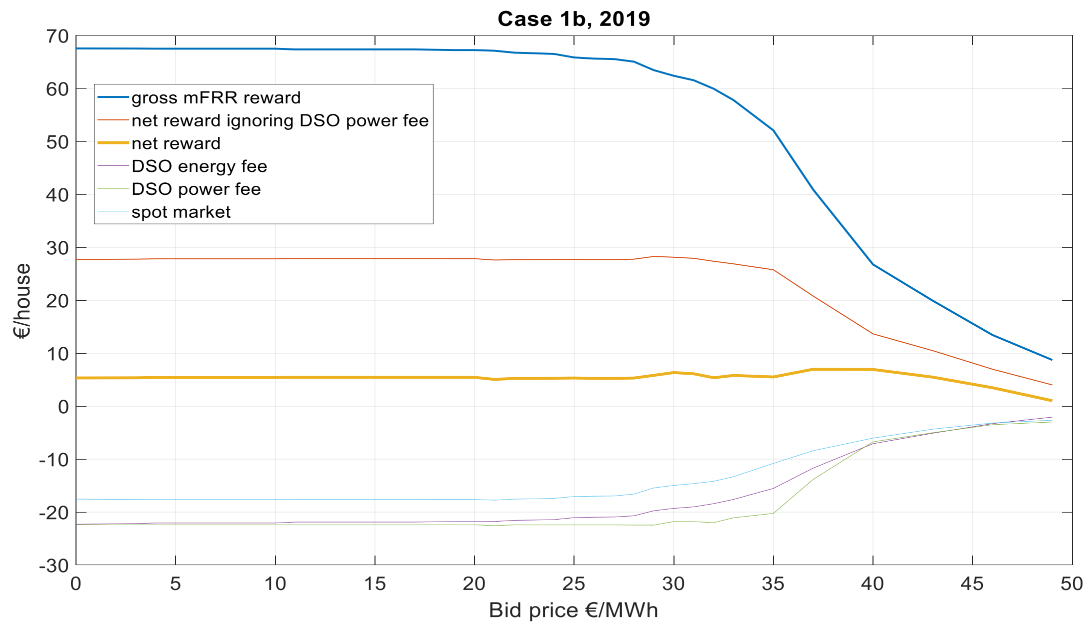

Figure 17. Case 1b revenues in 2019 as a function of bid price. G1 offered 14–15 and G2 offered 15–16.

Case 2a

In the following Figure 18 the mean annual net revenue in case 2a starts from 29.01 €/house and reaches maximum value 29.01 €/house at bid price 0 €/MWh. When the DSO power fee is ignored the net revenue starts from 27.99 €/house and reaches its maximum 29.29 €/house at bid price 22 €/MWh.

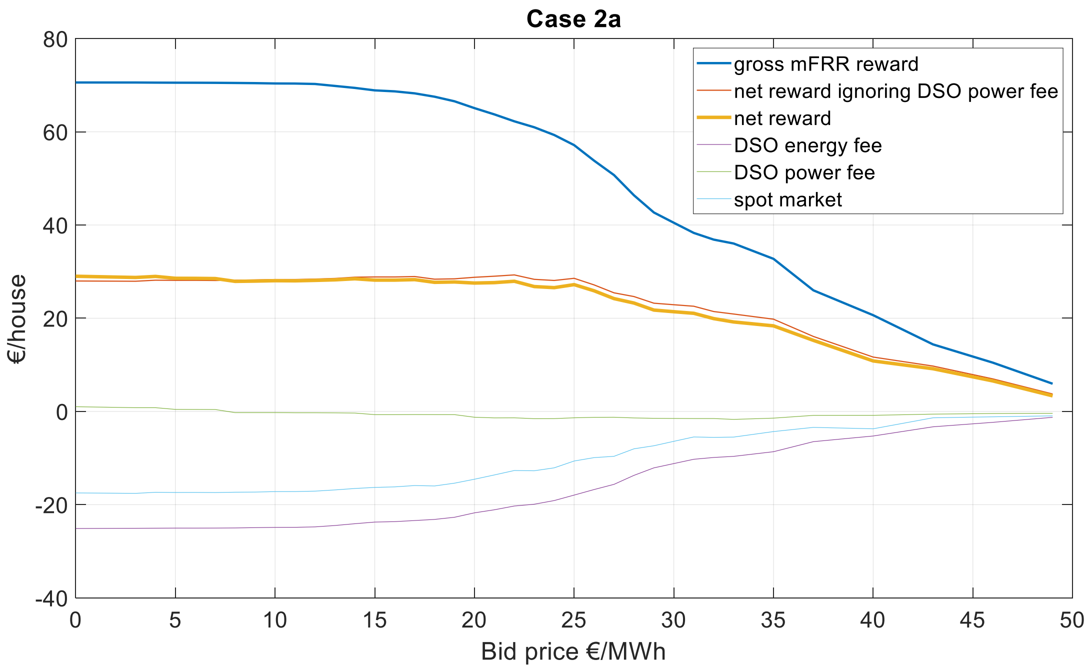

Figure 18. Case 2a annual mean revenues as a function of bid price. G1 and G2 offered 14–16.

In the following Figure 19, the case 2a last year net revenue taking into account the grid power fee starts from 37.18 €/house, and reaches its maximum 39.04 €/house at bid price 28 €/MWh. The last year net revenue ignoring the grid power fee starts from 43.83 €/house, and reaches 45.88 €/house at bid price 28 €/MWh.

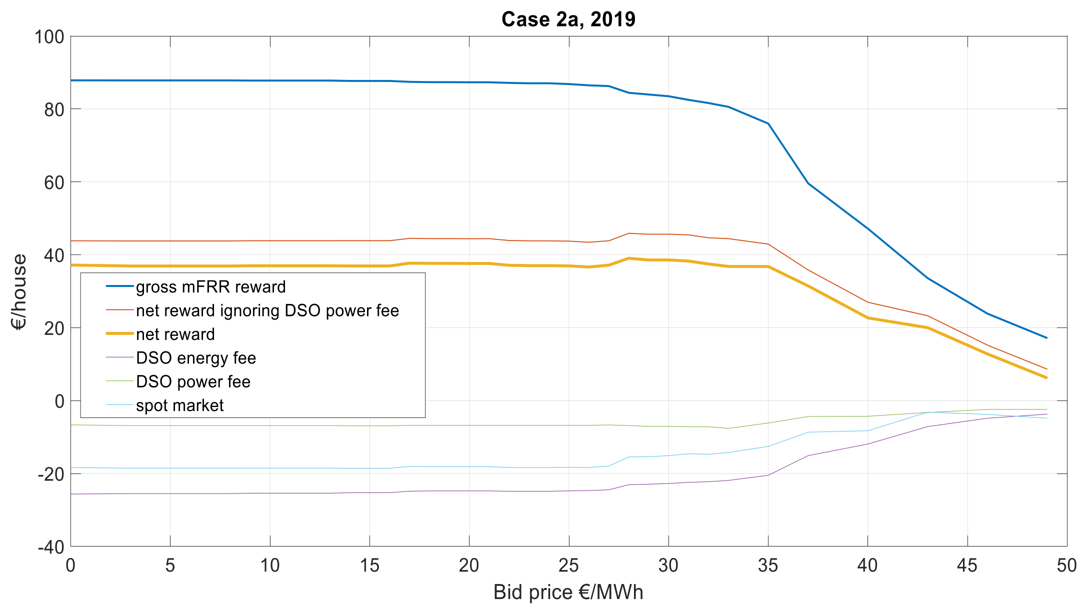

Figure 19. Case 2a revenues in 2019 as a function of bid price. G1 and G2 offered 14–16.

Case 2b

In the following Figure 20 the mean annual net revenue in case 2b starts from 31.96 €/house and reaches maximum value 31.98 €/house at bid price 4 €/MWh. When the DSO power fee is ignored the net revenue starts from 32.23 €/house and reaches its maximum 33.61 €/house at bid price 21 €/MWh.

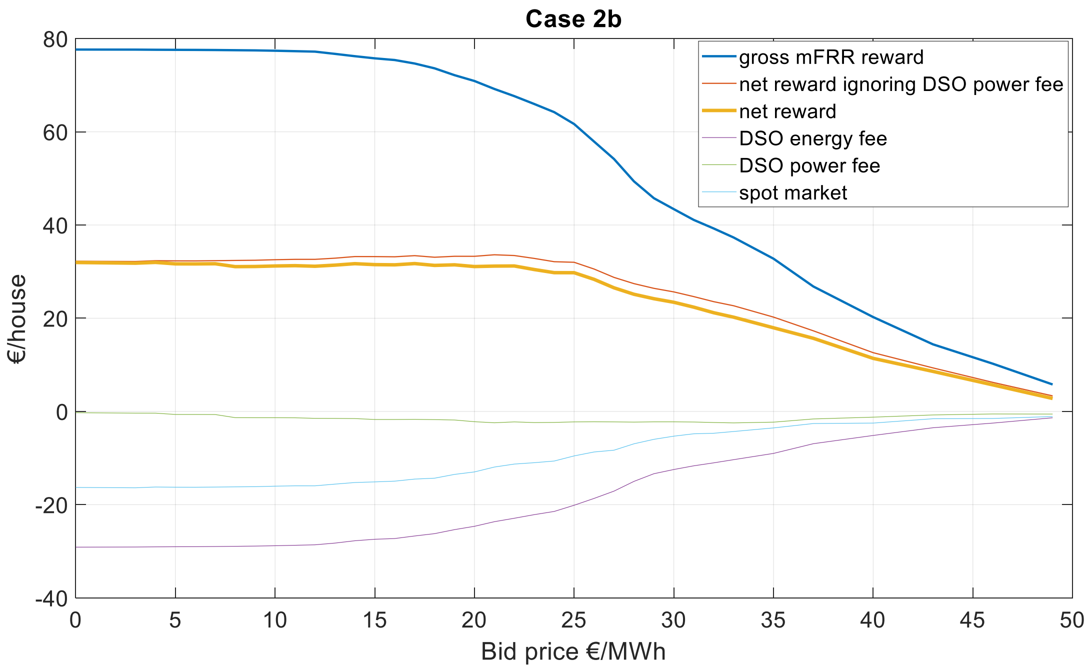

Figure 20. Case 2b annual mean revenues as a function of bid price. G1 offered at 12–14 and G2 offered 14–16.

In the following figure, the case 2b last year net revenue taking into account the grid power fee starts from 40.67 €/house, and reaches its maximum 41.89 €/house at bid price 28 €/MWh. The last year net revenue ignoring the grid power fee starts from 52.09 €/house, which is its maximum 52.87 at bid price 28 €/MWh.

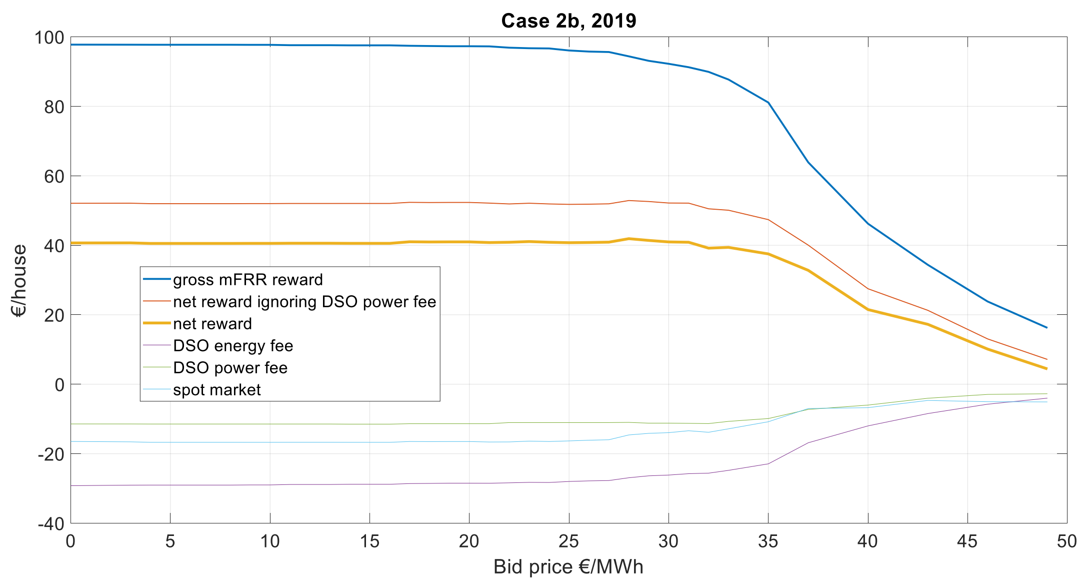

Figure 21. Case 2b revenues in 2019 as a function of bid price. G1 offered at 12–14 and G2 offered 14–16.

Case 3a

In the following Figure 22 the mean annual net revenue in case 3a starts from 6.67 €/house and reaches maximum value 8.50 €/house at bid price 26 €/MWh. When the DSO power fee is ignored the net revenue starts from 8.36 €/house and reaches its maximum 11.04 €/house at bid price 25 €/MWh.

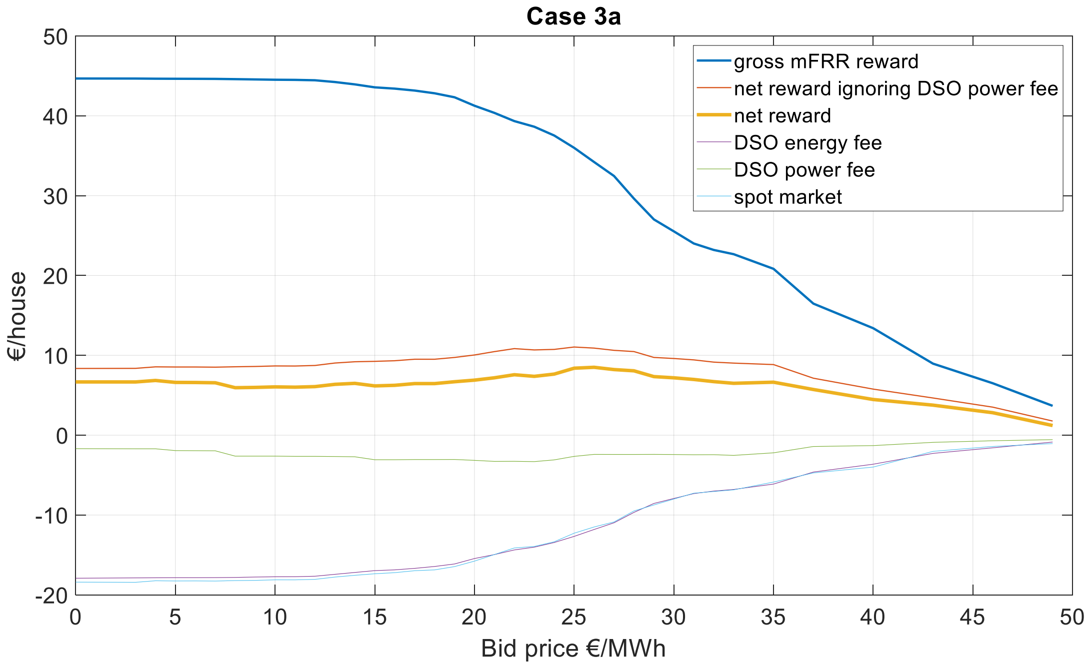

Figure 22. Case 3a annual mean revenues as a function of bid price. G1 and G2 offered at 12–13.

In the following Figure 23, the case 3a last year net revenue taking into account the grid power fee starts from 9.66 €/house, and reaches its maximum 11.57 €/house at bid price 35 €/MWh. The last year net revenue ignoring the grid power fee starts from 18.89 €/house, and reaches its maximum 20.46 €/house at bid price 33 €/MWh.

Figure 23. Case 3a revenues in 2019 as a function of bid price. G1 and G2 offered at 12–13.

Case 3b

In the following Figure 24 the mean annual net revenue in case 3b starts from 6.23 €/house and reaches maximum value 8.39 €/house at bid price 26 €/MWh. When the DSO power fee is ignored the net revenue starts from 11.77 €/house and reaches its maximum 14.00 €/house at bid price 22 €/MWh.

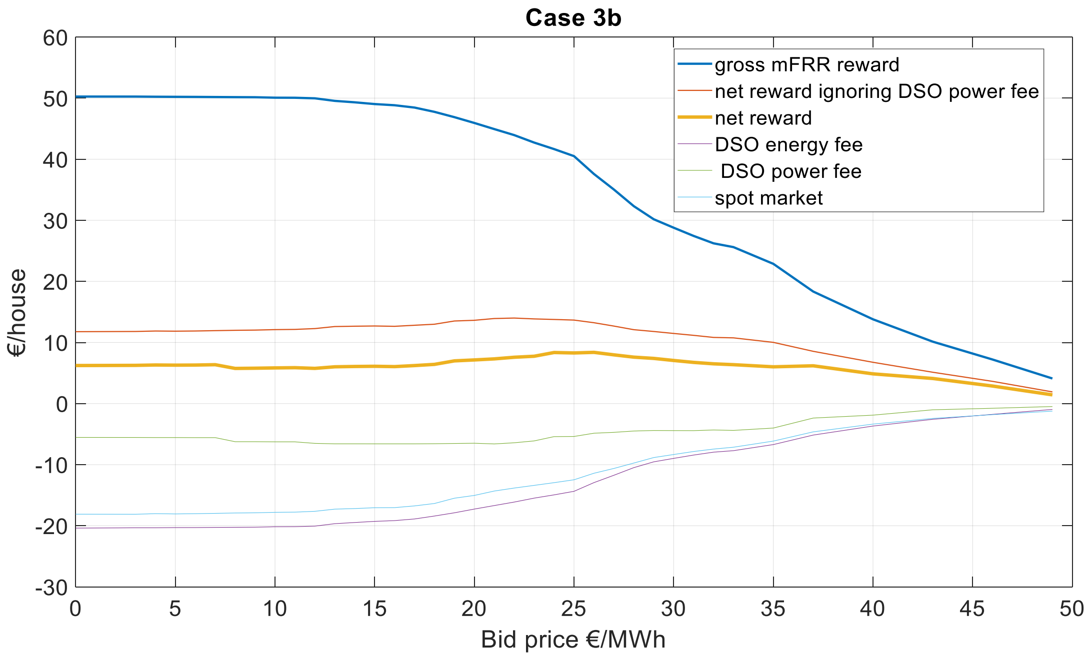

Figure 24. Case 3b annual mean revenues as a function of bid price. G1 and G2 offered at 13–14.

In the following Figure 25, the case 3b last year net revenue taking into account the grid power fee starts from 5.02 €/house, and reaches its maximum 9.14 €/house and at bid prices 37 €/MWh. The last year net revenue ignoring the grid power fee starts from 21.79 €/house, and reaches its maximum 23.08€/house at bid price 31 €/MWh.

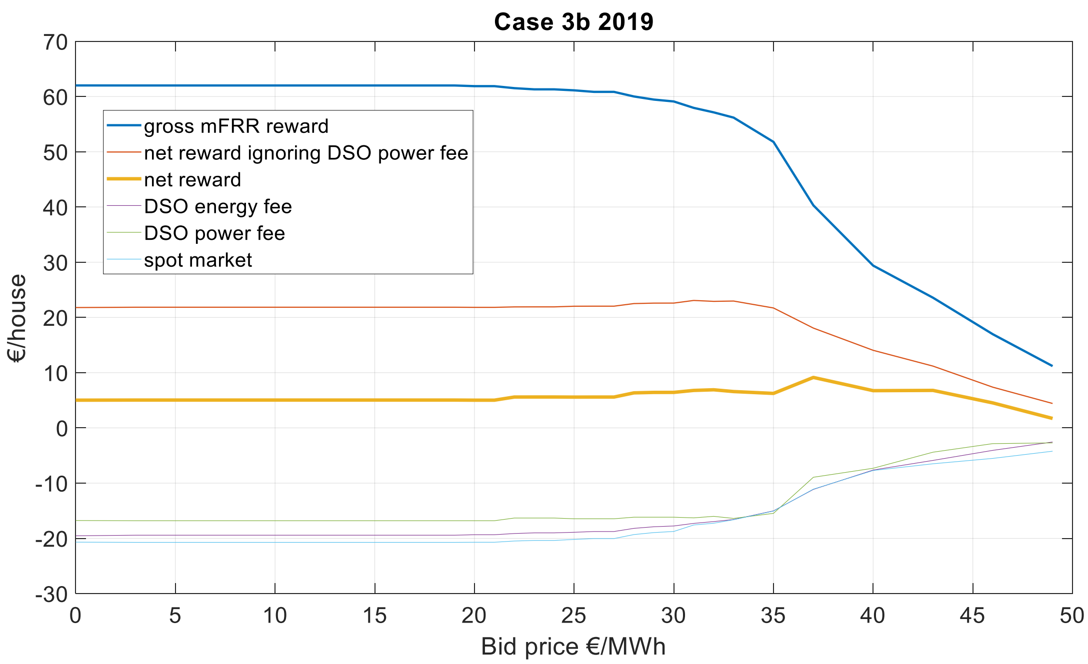

Figure 25. Case 3b revenues in 2019 as a function of bid price. G1 and G2 offered at 13–14.

Case 4

In the following Figure 26 the mean annual net revenue in case 4 starts from 17.24 €/house which is also its maximum value at bid price 0 €/MWh. When the DSO power fee is ignored the net revenue starts from 14.71 €/house which is also its maximum value at bid price 0 €/MWh.

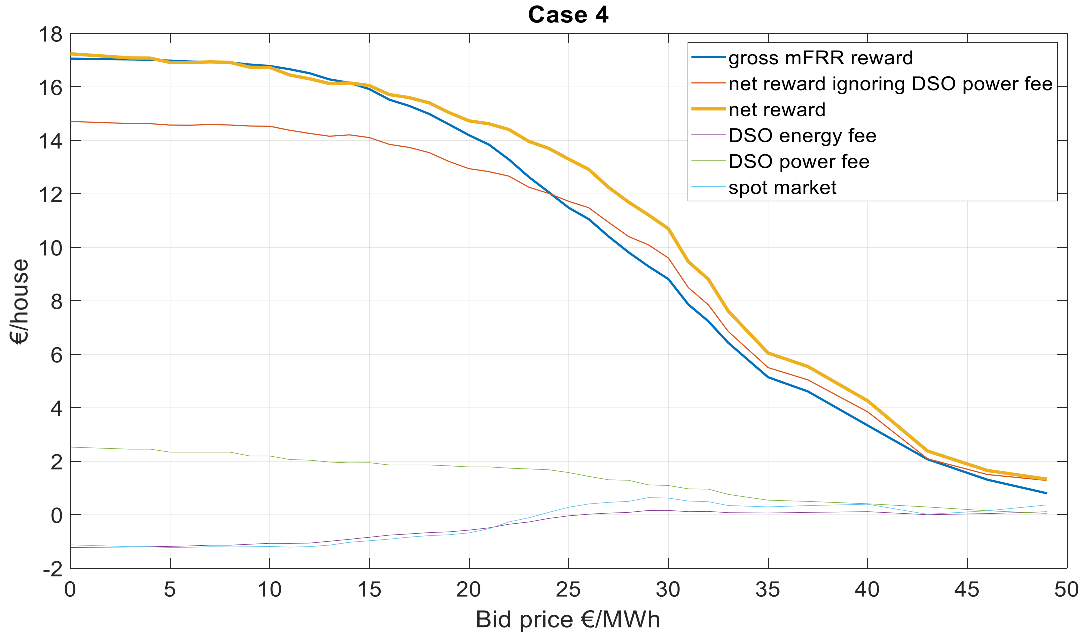

Figure 26. Case 4 annual mean revenues as a function of bid price. Load decrease offered at 03–04 and load increase offered at 04–05.

The last year (2019) net revenue taking into account the grid power fee starts from 13.89 €/house which is its maximum at bid price 0 €/MWh. The last year net revenue ignoring the grid power fee starts from 12.70 €/house which is its maximum at bid price 0 €/MWh.

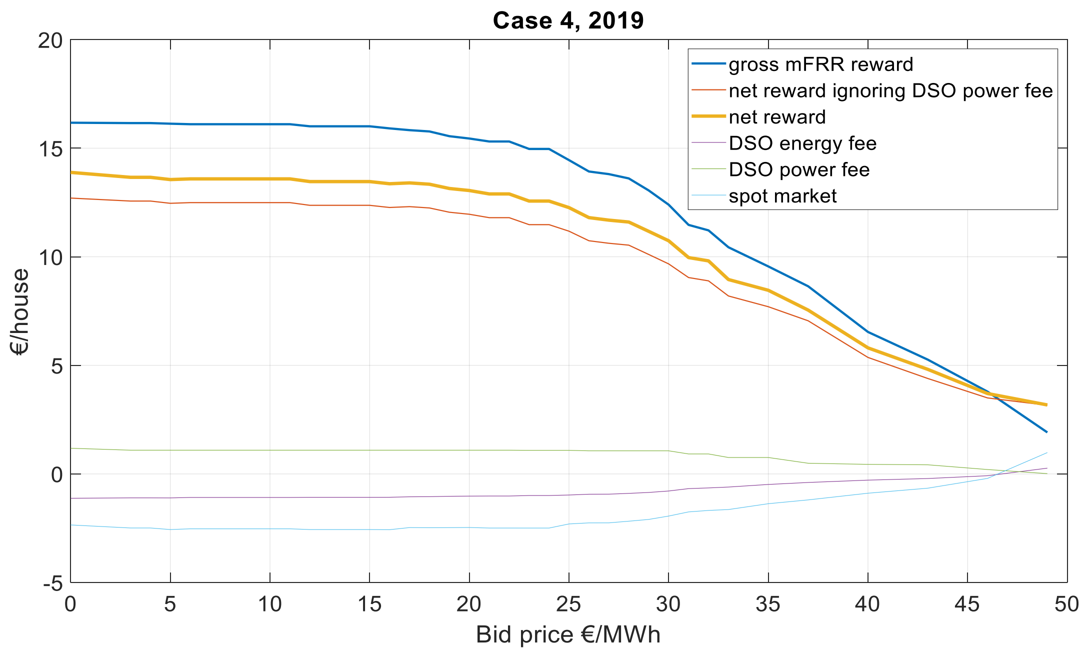

Figure 27. Case 4revenues in 2019 as a function of bid price. Load decrease offered at 03–04 and load increase offered at 04–05.

Summary of the mean annual results with roughly optimised bid price

In the following two tables the bid price is selected for each case so that the net revenue ignoring the DSO power tariff is maximised for the whole 5 year period. The first table shows the annual mean over the whole 5 year period and the second table shows results only for the year 2019.

Table VI. Simulated mean annual gross and net rewards per house optimised ignoring the DSO power tariff.

Case	Hour offered	Group	Mean annual gross reward €/ house	Mean annual grid energy fee change	Mean annual grid power fee change	Mean annual spot market fee change	Mean annual net reward €/house without power fee	Mean annual net reward €/house	Bid Price €/MW
1a	12-13	1	41.26	15.09	3.50	13.85	12.32	8.82	22
	13-14	2							
1b	14-15	1	47.75	18.44	9.11	12.25	17.05	7.95	19
	15-16	2							
2a	12-14	1	62.25	20.29	1.36	12.67	29.29	27.93	22
	12-14	2							
2b	12-14	1	69.19	23.65	2.43	11.93	33.61	31.19	21
	14-16	2							
3a	12-13	1	35.99	12.67	2.65	12.27	11.04	8.39	25
	12-13	2							
3b	13-14	1	43.95	16.12	6.42	13.83	14.00	7.58	22
	13-14	2							
4	03-04	1 and 2	17.06	1.22	-2.53	1.13	14.71	17.24	0
	04-05	1 and 2							

Notes:

- The grid power fee change is calculated assuming the every customer behaves as an average customer. Correct estimation of the grid power fee change requires modelling the probability distributions and calculating the impacts from them. Higher values than shown in this table can be expected.
- The grid power fee change is likely somewhat overestimated due to changes in the group 2 behaviour that have not been taken into account in the model.

Summary of the last year results with roughly optimised bid price ignoring the DSO power tariff

Table VII. Simulated 2019 gross and net rewards per house optimised ignoring the DSO power tariff

Case	Hour offered	Group	2019 gross reward €/ house	2019 grid energy fee change	2019 grid power fee change	2019 spot market fee change	2019 net reward €/house without power fee	2019 net reward €/house	Bid Price €/MW
1a	12-13	1	58.14	18.09	11.15	19.65	20.41	9.26	22
	13-14	2							
1b	14-15	1	67.25	21.79	22.41	17.60	27.86	5.45	19
	15-16	2							
2a	12-14	1	87.13	24.88	6.80	18.35	43.91	37.11	22
	12-14	2							
2b	12-14	1	97.25	28.49	11.35	16.62	52.13	40.78	21
	14-16	2							
3a	12-13	1	55.73	17.44	9.22	19.39	18.90	9.68	25
	12-13	2							
3b	13-14	1	61.52	19.12	16.32	20.48	21.91	5.59	22
	13-14	2							
4	03-04	1 and 2	16.17	1.12	-1.18	2.35	12.70	13.89	0
	04-05	1 and 2							

Notes:

- The grid power fee change is calculated assuming the every customer behaves as an average customer. Correct estimation of the grid power fee change requires modelling the probability distributions and calculating the impacts from them. Higher values than shown in this table can be expected.
- The grid power fee change is likely rather much overestimated due to changes in the group behaviour that have not been taken into account in the model.

Summary of the mean annual results with roughly optimised bid price

In the following two tables the bid price is selected for each case so that the net revenue is maximised for the whole 5 year period. The first table shows the annual mean over the whole 5 year period and the second table shows results only for the year 2019.

Table VIII. Simulated mean annual gross and net rewards per house with optimised bid price.

Case	Hour offered	Group	Mean annual gross reward €/ house	Mean annual grid energy fee change	Mean annual grid power fee change	Mean annual spot market fee change	Mean annual net reward €/house without power fee	Mean annual net reward €/house	Bid Price €/MW
1a	12-13	1	37.90	13.38	2.87	12.27	12.24	9.37	25
	13-14	2							
1b	14-15	1	42.30	15.41	7.33	10.20	16.69	9.36	24
	15-16	2							
2a	12-14	1	70.58	25.11	-1.02	17.48	27.99	29.01	0
	12-14	2							
2b	12-14	1	77.60	29.04	0.37	16.21	32.35	31.98	4
	14-16	2							
3a	12-13	1	34.21	11.81	2.40	11.50	10.91	8.50	26
	12-13	2							
3b	13-14	1	37.58	12.94	4.85	11.41	13.24	8.39	26
	13-14	2							
4	03-04	1 and 2	17.06	1.22	-2.53	1.13	14.71	17.24	0
	04-05	1 and 2							

Notes:

- The grid power fee change is calculated assuming the every customer behaves as an average customer. Correct estimation of the grid power fee change requires modelling the probability distributions and calculating the impacts from them. Higher values than shown in this table can be expected.
- The grid power fee change is likely slightly overestimated due to changes in the group behaviour that have not been taken into account in the model.

Summary of the last year results with roughly optimised bid price

For the following table the bid price was optimised over the 5 year period to maximise the net reward, and with those bid prices the 2019 results were calculated.

Table IX. Simulated 2019 gross and net rewards per house with optimised bid price.

Case	Hour offered	Group	2019 gross reward €/ house	2019 grid energy fee change	2019 grid power fee change	2019 spot market fee change	2019 net reward €/house without power fee	2019 net reward €/house	Bid Price €/MW
1a	12-13	1	57.86	17.92	11.15	19.45	20.49	9.34	25
	13-14	2							
1b	14-15	1	66.52	21.42	22.42	17.39	27.70	5.28	24
	15-16	2							
2a	12-14	1	87.84	25.64	6.65	18.37	43.83	37.18	0
	12-14	2							
2b	12-14	1	97.71	29.02	11.45	16.72	51.97	40.52	4
	14-16	2							
3a	12-13	1	55.50	17.33	9.22	19.27	18.90	9.68	26
	12-13	2							
3b	13-14	1	60.85	18.76	16.45	20.04	22.04	5.59	26
	13-14	2							
4	03-04	1 and 2	16.17	1.12	-1.18	2.35	12.70	13.89	0
	04-05	1 and 2							

Notes:

- The grid power fee change is calculated assuming the every customer behaves as an average customer. Correct estimation of the grid power fee change requires modelling the probability distributions and calculating the impacts from them. Higher values than shown in this table can be expected.
- The grid power fee change is likely slightly overestimated due to changes in the group behaviour that have not been taken into account in the model.

SUMMARY

In all the cases, the profitability of participating to the mFRR-markets was low. At the end of the analysed period 2019 the profitability was roughly the same as the average of the whole 5 year period. The gross benefit increased towards the end but the costs to the consumer increased almost with an equal amount. Especially the DSO power tariff costs increase towards the end. To large extent the explanation is that the simulation model that was identified based on earlier June 2012 – June 2013 data starts to need some updating as the energy consumption of the houses reduces due to renovations and the peak powers reduce as a response to the power tariffs. Some of the studied cases can bring some added value to investments that mainly serve some other market or purpose. It is unlikely that they can alone pay back the investments in ICT that are needed to make it possible to use the flexibility for mFRR that requires rather small control latencies with high reliability.

The aggregate model is not suitable for analysing the impacts of power-based tariffs. An average customer load model likely underestimated the aggregated impacts and is completely unable to reflect the impacts on individual houses. For that purpose, there is a need to develop and add modelling of the highly stochastic behaviour of individual consumers as a probability distribution, for example.

General conclusions regarding the poor profitability of demand response cannot be drawn from these results, because of the following reasons.

1) Some other ancillary service markets than mFRR may be better for these resources.
2) Participation to some ancillary of flexibility service markets does not necessarily exclude participation to mFRR.
3) The existing ancillary service markets are small, fractionalised and inefficient for small distributed resources. The ancillary service markets are being improved which will also increase the profitability of engaging distributed flexible resources to the ancillary services although it will also reduce the prices of flexibility in the wholesale ancillary service markets.
4) It is expected that the ongoing changes in the power generation (such as the move towards renewables and starting the operation of very big nuclear units) increase the need for demand-side flexibility in the electricity grids. This most likely increases the prices in the ancillary service markets