BestRES

Best practices and implementation of innovative business models for renewable energy aggregators

Quantitative analysis of improved BMs of selected aggregators in target countries

Authors:
Daniel Schwabender, Carlo Corinaldesi, Andreas Fleischhacker and Georg Lettner (TUW-EEG)

Co-Authors:
Simon De Clercq (3E) and Venizelos Efthymiou (FOSS)

Contributors:
Danelle Veldsman & Geraldine Carpentier (Good Energy)
Julian Kretz (Next Kraftwerke Germany)
Elias De Keyser (Next Kraftwerke Belgium)
Maximilian Kloess and Friedrich Diesenreiter (oekostrom)
José Rui Ferreira and Gisela Mendes (EDP Portugal)

Reviewers:
Silvia Caneva and Cathal Cronin (WIP)

December 2018
www.bestres.eu

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Acknowledgement

This report has been produced within the BestRES project "Best practices and implementation of innovative business models for Renewable Energy aggregatorS".

The logos of the partners cooperating in this project are shown below and information about them is available in this report and at the website: www.bestres.eu

This report has been written by Daniel Schwabeneder (TUW-EEG). The authors thankfully acknowledge the valuable contributions from all project partners to complete this report.

Disclaimer

Contacts

Project coordinator

Silvia Caneva, Cathal Cronin & Pablo Alonso
WIP – Renewable Energies
Sylvensteinstrasse 2, Munich, Germany

Email: silvia.caneva@wip-munich.de
Email: cathal.cronin@wip-munich.de
Email: pablo.alonso@wip-munich.de

Author(s)

Daniel Schwabeneder, Carlo Corinaldesi, Andreas Fleischhacker, Georg Lettner
Technische Universitaet Wien (TUW-EEG)
Gußhausstraße 25-29/E370-3, 1040 Vienna, Austria

Email: schwabeneder@eeg.tuwien.ac.at
Email: corinaldesi@eeg.tuwien.ac.at
Email: fleischhacker@eeg.tuwien.ac.at
Email: lettner@eeg.tuwien.ac.at

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Table of contents

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

List of Figures

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

List of Tables

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

List of abbreviations and acronyms

ACER	Agency for the Cooperation of Energy Regulators
aFRR	Automatic Frequency Restoration Reserve, see R2
BESS	Battery Energy Storage Systems
BM	Business Model
BMC	Business Model Canvas
BRP	Balancing Responsibility Provider
CACM	Capacity Allocation and Congestion Management
CAPEX	Capital Expenditures
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
DR	Demand Response
DSM	Demand Side Management
EC	European Commission
DSO	Distribution System Operator
EED	Energy Efficiency Directive 2012/27/EC
EPC	Engineering, Procurement, Construction
ESCO	Energy Service company
EV	Electric Vehicles
FCR	Frequency containment reserve also R1
FiP	Feed-in-Premium
FiT	Feed-in-Tariff
GPRS	General Packet Radio Service
IEM	Internal Energy Market
ICT	Information and Communication Technology
KPI	Key Performance Indicator
LCA	Life Cycle Analysis
mFRR	Replacement reserve see R3
MSD	Ancillary Services Market in Italy
OTC	Over-the-counter
OPEX	Operational Expenditures
PCC	Point of Common Coupling

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

PPA	Power Purchase Agreement
TFEU	Treaty on the Functioning of the European Union
R1	Primary reserves also frequency containment reserve (FCR)
R2	Secondary reserves also frequency restoration reserve (aFRR)
R3	Tertiary reserves also replacement reserve (mFRR)
RES-E	Electricity generation from renewable energy sources
RTP	Real-time-pricing
ToU	Time-of-Use
TSO	Transmission System Operator
VPP	Virtual Power Plant

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Executive summary

Within the BestRES project, business models identified in the report "*Existing business models for renewable energy aggregators*" [1] have been further improved allowing aggregators to offer new products and services. In total, 13 improved business models have been developed in a qualitative way using the Business Model canvases. They are presented in the report "*Improved Business Models of selected aggregators in target countries*" [2].

To support the qualitative work, with this report we evaluate economic, technical and ecological key performance indicators for the improved business models based on quantitative analyses in tailor-made case studies. Optimisation and simulation models are used to test the performance of the improved business models in the respective target countries. For each improved business model, we present a detailed description of the defined case study, the methods, assumptions and model scaling. Furthermore, we discuss the results of simulation-based analyses and derive conclusions regarding the benefits of the improved business model.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

1. Introduction

In the past, European electricity markets were designed around centralized fossil-fuel generation along national or regional borders. The electricity market landscape is however changing because a rising share of distributed generation increases intermittency and price volatility in the system. This requires a more flexible system with more flexible consumption. As highlighted in the state aid guidelines published in April 2014 by the European Commission, this implies that renewable sources are better integrated in electricity markets and rely less on subsidies as was the case in the past. Renewable energy aggregation can significantly accelerate the integration of intermittent electricity sources, enhance demand flexibility and decrease the reliance on renewable energy support schemes.

More aggregation and market integration can however not be achieved by single individual, commercial or domestic consumers since they would only have a limited impact. It is only through a coordinated steering of vast amounts and types of consumers and producers in a market that the use of distributed generation, demand response and battery storage can be effective. A lot of literature has been published with respect to demand response management and more and more market players are active in this field but management of distributed generation and storage including electric vehicles is less developed. An explanation for this might be that this requires the extensive use of new technological solutions and ICT to directly control consumption and generation at lower costs.

For this reason, there is an important role for Renewable Energy Aggregators who act on behalf of consumers and use technological solutions and ICT for optimization. They are defined as legal entities that aggregate the load or generation of various demand and/or generation/production units and aim at optimizing energy supply and consumption either technically or economically. In other words, they are facilitators between the two sides of electricity markets. On the one hand, they develop energy services downstream for industrial, commercial or domestic customers who own generation and storage units or can offer demand response. On the other hand, energy aggregators are offering value to the market players upstream such as BRPs, DSOs, TSOs and energy suppliers to optimize their portfolio and for balancing and congestion management. Furthermore, wholesale electricity markets might benefit from aggregation if appropriate incentives are present. A last option is that energy aggregators offer value to specific customers such as is the case for ESCO's. In this situation, the player downstream and upstream could potentially be the same entity.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

1.1 The BestRES project

The main objective of the BestRES project was to investigate the current barriers and to improve the role of Energy Aggregators in future electricity market designs. In the first stage, the project was focusing on existing European aggregation business models taking into account technical, market, environmental and social benefits. In the second stage, we develop improved business models that are replicable in other countries in the EU considering market designs and with a focus on competitiveness and LCA. These improved business models have been then implemented or virtually implemented with real data and monitored in the following target countries: United Kingdom, Belgium, Germany, France, Austria, Italy, Cyprus, Spain and Portugal.

The BestRES entered into force on 1st March 2016 and will end until 28th February 2019.

The target group, the Renewable Energy Aggregators, has been directly involved in the BestRES project consortium as partners:

- Good Energy, renewable energies aggregator active in United Kingdom
- Next Kraftwerke Belgium, renewable energies aggregator active in Belgium
- Oekostrom, renewable energies aggregator active in Austria
- Next Kraftwerke Germany, renewable energies aggregator active in Germany,France and Italy
- Energias de Portugal, renewable energies aggregator active in Spain and Portugal

The BestRES activities to be implemented in Cyprus have been carried out by FOSS, the research centre for sustainable energy of the University of Cyprus. This is due to the fact that there are no aggregators in Cyprus at the time being (2016) and no market entrants are expected until 2020.

The innovative business models to be provided during the project will be based on on-going business models available in Europe and adapted to the future market design by research institutions and energy expert partners such as the Energy Economic Group of the Technical University of Vienna (TUW-EEG) and 3E. The consortium also includes a legal expert, SUER (Stiftung Umweltenergierecht /Foundation for Environmental Energy Law), who will provide a relevant contribution to the development of National and European recommendations on the business models implementation.

The BestRES project is coordinated by WIP – Renewable Energies. The project communication and dissemination will be carried out by WIP with the support of Youris.

A short description of the BestRES project partners is provided in the following paragraphs.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

WIP – Renewable Energies (WIP)

WIP - Renewable Energies has been founded in 1968 in Munich, Germany, and has been active in the renewable energy sector for over three decades, working with both industrial and public sector clients at the international level. The company's mission is to bridge the gap between research and implementation of sustainable energy systems. WIP's interdisciplinary team of professionals provides consultancy services to improve the grid and market integration of renewable energies. WIP offers project development, project management, technical supervision and realization of projects, which involve the co-ordination of international consortia. WIP counts more than 300 projects accomplished. WIP organizes international events in the field of renewable energies. Website: www.wip-munich.de

3E

3E is an independent consultancy and software service company, delivering solutions for performance optimization of renewable energy and energy efficiency projects. We provide expert services to support project developers, asset managers, operators, investors and policy-makers and our key areas of expertise are solar, wind, sustainable buildings & sites and grids & markets. Bridging the gap between R&D and the market, 3E combines in-house innovation and partnerships with leading R&D centres. 3E's international team operates from Brussels (HQ), Toulouse, Milan, Istanbul, Beijing and Cape Town. The company has a project track-record of over 15 years in over 30 countries. Website: www.3e.eu

Technische Universitaet Wien (TUW-EEG)

The Energy Economics Group (EEG) is a department of the Institute of Energy Systems and Electric Drives at TU Wien, Austria. The core fields of research of EEG are: (i) system integration strategies of renewable and new energy technologies, (ii) energy modelling, scenario analysis and energy policy strategies, (iii) energy market analysis in general (competition and regulation), (iv) sustainable energy systems and technologies and (iv) environmental economics and climate change policies. EEG has coordinated and carried out many international as well as national research projects, international and national organizations and governments, public and private clients in several fields of research. Website: www.eeg.tuwien.ac.at

Stiftung Umweltenergierecht (SUER)

The Foundation for Environmental Energy Law (Stiftung Umweltenergierecht – SUER) was created on 1 March 2011 in Würzburg. The research staff of the foundation is concerned with national, European and international matters of environmental energy law. They analyze the legal structures, which aim to make possible the necessary process of social transformation leading towards a sustainable use of energy. Central field of research is the European and German Law of renewable energy and energy efficiency. The different legal instruments aiming towards the substitution of fossil fuels and the rise of energy efficiency are analyzed systematically with regard to their interdependencies. Interdisciplinary questions, e.g. technical and economical questions, are of particular importance. Website: http://stiftung-umweltenergierecht.de/

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Good Energy

Good Energy is a pioneering clean energy company, powering the choice of a cleaner, greener future together with its people, customers and shareholders. Having led the way in renewable energy development since 1999 in areas including small and larger scale wind turbines, solar panels, biogen and hydro, and now in technologies like battery storage and electric vehicles, Good Energy is making it easier for people and businesses to make renewable energy part of their lives. Good Energy powers homes and businesses with 100% renewable electricity from a community of over 1,400 UK generators and owns and operate two wind farms, including the UK's first commercial wind farm, and eight solar farms. In addition, Good Energy offers a green gas product which contains 6% biomethane — gas produced here in the UK from food waste. To make it completely carbon neutral, emissions from the rest of the gas its customers use is balanced through supporting verified carbon-reduction schemes in Malawi, Vietnam and Nepal. As of 30 December 2017, Good Energy had over 250,000 domestic and business customers. Website: www.goodenergy.co.uk

Next Kraftwerke Belgium (NKW BE)

Next Kraftwerke Belgium pools distributed renewable generation and flexible demand in a virtual power plant (VPP). We trade and deliver the aggregated power on the most relevant markets and, most importantly, we make the virtual power plant's flexibility available to the grid operator to support the management of the Belgian power system. Next Kraftwerke Belgium is a joint venture with Next Kraftwerke GmbH in Germany. Website: www.Next-Kraftwerke.be

Next Kraftwerke Germany (NKW DE)

Next Kraftwerke Germany is the operator of a large-scale Virtual Power Plant (VPP) and a certified power trader on various European energy exchanges (EPEX). The concept of a Virtual Power Plant is based on the idea to link and bundle medium- and small-scale power producing and power consuming units. The objective is to smartly distribute supply and demand and to profitably trade the generated and consumed power. Next Kraftwerke's VPP now bundles around 3,000 medium- and small-scale power-producing and power-consuming units. Among other energy sources, it includes biogas, wind, and solar power generators. Next Kraftwerke also operates in Belgium, France and Austria. Website: https://www.next-kraftwerke.com/

Oekostrom

Oekostrom AG is a holding company owned by about 1.900 stockholders. It was founded in 1999 aiming at building a sustainable energy industry, supplying customers with clean energy and supporting the development of renewable energy sources in Austria. All products and services of oekostrom AG represent an active contribution to climate and environmental protection and increase independence from fossil and nuclear energy sources. Oekostrom AG engages in the fields of power production, trading, sales and energy services and currently supplies 100 % renewable energy from Austria to more than 52.000 customers in all parts of the country. Website: http://oekostrom.at/

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Research Center for Sustainable Energy of the University of Cyprus (FOSS)

The Research Centre for Sustainable Energy of the University of Cypruss (FOSS) was created in order to play a key role in research and technological development activities in the field of sustainable energy within Cyprus and at international level with the aim of contributing to the achievement of the relevant energy and environment objectives set out by Europe. FOSS is heavily involved in all spheres of sustainable energy spreading from sources of energy, smoothly merging RES in the integrated solutions of the grid, development of enabling technologies such as storage and ICT that will facilitate the seamless merging of sustainable technologies in the energy system of tomorrow, the complete transformation of energy use by the effective introduction of sustainable alternatives in meeting the needs for mobility, heating and cooling and exploring ways of achieving even higher levels of efficiency in all areas of the economy. Website: http://www.foss.ucy.ac.cy

Centre for New Energy Technology (EDP-CNET)

EDP Group is an integrated energy player, with strong presence in Europe, US and Brazil and the third player in the world in terms of wind installed capacity. EDP is an innovative European Utility with an important presence across all the energy value chain, in Generation, Distribution, Energy Trading and Retail of electricity and gas. EDP owns HC Energia, the 4th Energy Utility in Spain and Energias do Brasil. EDP Centre for New Energy Technologies (EDP CNET) is a subsidiary of the EDP Group with the mission to create value through collaborative R&D in the energy sector, with a strong focus in demonstration projects. Currently, EDP has no activity as an aggregator, but, as the electricity sector evolves, EDP may consider aggregation either on the generation or supplier side through different companies within EDP Group. In the scope of this project EDP has chosen to focus on the supplying activity, therefore the information provided in this report is focused on the retailer side.

Websites: https://rd-new.com and http://www.edp.pt/en/Pages/homepage.aspx

Youris.com (Youris)

youris.com GEIE is an independent non-profit media agency promoting the leading-edge European innovation via TV media and the web. youris.com designs and implements media communication strategies for large research organizations and EU-funded projects and is able to establish permanent links between the research communities and the media. youris.com media products cover a wide spectrum of research areas including ICT, Environment, Energy, Health, Transport, Nanotechnologies, Food, Society, Gender and many others and are designed for large-scale distribution world-wide. Youris.com is a European Economic Interest Group (EEIG) based in Brussels with branch offices in Italy, Germany and France. Website: http://www.youris.com

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

1.2 Purpose of the document

This document provides the description and results of the simulation-based analyses of the improved business models for aggregators of BestRES project. The improved business models that have been developed are presented in the BestRES project report "*Improved BMs of selected aggregators in target countries*" [2].

The analyzed business models differ significantly with respect to considered market segment, considered technologies, considered countries and improvement within the business model. Hence, we provide brief methodology sections for each business model.

Nevertheless, many business model analyses use a similar methodological framework. Common methods and key performance indicators used to evaluate the economic, technological or ecological improvements achieved by the business models are presented in Chapter 2.

Chapters 3 to 10 provide the detailed analyses for each of the business models. They include a use case description, some information on the methods, assumptions and data used in the business models. Furthermore, the main results, KPIs and conclusions are presented for each business model.

Finally, overall conclusions are presented in chapter 11.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

2. Methodology

In this report a multitude of different improved business models focusing on different aspects, technologies and market segments are analyzed in a quantitative way. This means that many different methods are used, and tailor-made simulation or optimization models are applied for various case studies. In this section we try to give a brief overview of different techniques used across multiple business model analyses.

2.1 Optimization models

The core tool applied in most of the case studies in this report are linear or mixed-integer linear optimization models. Linear optimization is a well-established and understood field of mathematics and operations research with plenty of tools available for modelling and solving. For the case studies investigated in this report we use the Femto toolbox, developed at the Energy Economics Group and written in the Julia language [3]. This toolbox provides a flexible framework to implement a broad range of optimization models focusing on the dispatch of power plants, storages and flexible loads on different markets. It uses the JuMP [4] toolbox for model implementation and the Gurobi[1] solver to solve the optimization models.

2.1.1 Objective function

The key objective of most business models is to increase the profit either by increasing the revenue or by reducing the cost. Hence, the objective function in our optimization models in general is to maximize the profit. Let $i \in I$ denote the indices of the different units controlled by an aggregator and $t \in T$ the steps of the considered period. Furthermore, let $x_{i,t}^{sell}$ and $x_{i,t}^{buy}$ denote quantity, sold or bought at an energy market and let p_t be the market price. We write as $E(x_{i,t}^{res,pos})$ and $E(x_{i,t}^{res,neg})$ the expected profit of providing positive and negative balancing reserve for unit i at time t. Furthermore, let $c_{i,t}$ denote operational cost of energy production, like e.g. fuel cost or energy production. We write all production and consumption in MW and all prices in EUR/MWh and denote the length of one time step in hours with Δt. Then a very basic objective function can be written as:

$$\max \sum_{t \in T} \sum_{i \in I} \left(\Delta t \cdot \left(p_t - c_{i,t} \right) \cdot \left(x_{i,t}^{sell} - x_{i,t}^{buy} \right) + E\left(x_{i,t}^{res,pos} \right) + E\left(x_{i,t}^{res,neg} \right) \right)$$

Note that this is just a general representation of an objective function. It has to be adapted to the specific case study. For some business models, the end user retail market price is relevant, while others consider the e.g. the day-ahead spot market. Moreover, not all business models consider balancing markets and different balancing market designs in different countries have to be

[1] http://www.gurobi.com/

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

implemented via various constraints. The expected profit from reserve markets also depends on the degree of perfect foresight we want to assume for the aggregator. Usually you have to bid a reserve volume for a fixed product period, and you are remunerated according your power price bid and the actual activations multiplied with your energy price bid. Some balancing markets only have power price bids, others only energy bids. Different bidding strategies can be simulated here for different implementations of the expected profit reserve markets.

2.1.2 Constraints

2.1.2.1 Balancing market constraints

As indicated above, additional constraints may be required to depict the operation on balancing markets correctly. Typically, a market participant has to provide a constant power reserve for entire market periods. If we denote with $T_p \subseteq T, p \in Pr$ the periods of all considered balancing market products and assume that positive and negative products share the same periods we can write this constraint as:

$$\sum_{i \in I} E\left(x_{i,t}^{res,pos}\right) = \sum_{i \in I} E\left(x_{i,1}^{res,pos}\right) \quad \forall t \in T_p, \forall p \in Pr$$
$$\sum_{i \in I} E\left(x_{i,t}^{res,neg}\right) = \sum_{i \in I} E\left(x_{i,1}^{res,neg}\right) \quad \forall t \in T_p, \forall p \in Pr$$

Possible minimal bid sizes are implemented using binary auxiliary variables.

2.1.2.2 Production units

Dispatch-able production units are modeled using the fuel usage $f_{i,t}$ in MW, fuel cost $c_{i,t}^{f}$ and possible other operational cost $c_{i,t}^{op}$ EUR/MWh, the nominal capacity nc_i and the efficiency η_i:

$$x_{i,t}^{sell} = f_{i,t} \cdot \eta_i$$
$$x_{i,t}^{sell} \leq nc_i$$

The cost in the objective function are $c_{i,t} = c_{i,t}^{op} + c_{i,t}^{f}/\eta_i$. Start-up costs are implemented using binary variables indicating if a power plant is running or offline, and binary variables describing the start-up times of the unit.

2.1.2.3 Flexible profiles

Flexible profiles are implemented using a time series describing the profile and a set of variables and constraints describing the profile flexibility. In general, a flexible profile can be either a production profile like a curtailable wind or PV generation or a consumption profile like a customer's load. The flexibilities are described by a set of linear and binary variables:

$$x_{i,t}^{inc}, x_{i,t}^{red} \geq 0$$
$$b_{i,t}^{inc,active}, b_{i,t}^{red,active}, b_{i,t}^{inc,start}, b_{i,t}^{red,start} \in \{0,1\}$$

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

The linear variables $x_{i,t}^{inc}$ and $x_{i,t}^{red}$ describe the profile increase and reduction at time t. The other binary variables indicate when a flexibility activation is active and starting, respectively. They can be used to implement maximal durations of load changes, maximal numbers of activations or minimal pauses between. With minimal and maximal values for increase and reduction inc_i^{max}, inc_i^{min}, red_i^{max} and red_i^{min} they can be linked with the following set of constraints:

$$
\begin{aligned}
inc_i^{min} \cdot b_{i,t}^{inc,active} &\leq x_{i,t}^{inc} \leq inc_i^{max} \cdot b_{i,t}^{inc,active} \\
b_{i,t}^{inc,active} &\leq b_{i,t-1}^{inc,active} + b_{i,t}^{inc,start} \\
red_i^{min} \cdot b_{i,t}^{red,active} &\leq x_{i,t}^{red} \leq red_i^{max} \cdot b_{i,t}^{red,active} \\
b_{i,t}^{red,active} &\leq b_{i,t-1}^{red,active} + b_{i,t}^{red,start}
\end{aligned}
$$

2.2 Simulation

For business models including balancing markets, we still need to take into account the activations from these markets, after the optimization problems are solved. For this purpose, we consider the energy merit order curves of the products. They are either available online in the form of anonymized bids or constructed based on average price and activation data using least squares optimization. Furthermore, we use historical data for reserve market activations. Based on the activations, the merit order curves and the bidding prices, activations of the aggregator can be simulated.

2.3 Description of the KPIs used in this document

In this section we provide three tables with key performance indicators, commonly used in the case studies, including brief descriptions, and units. Note that not all KPIs are relevant for each business model.

Economic KPIs	Description	Unit
Annual financial turnover	The total annual turnover of the BMs over all customers/technologies	EUR/year or EUR/(MW*year) or EUR/(MWh*year)
Annual financial operation costs	The total annual operational costs of the BMs over all customers/technologies Including costs from different markets, excluding costs for HR, investments and other fixed costs	EUR/year or EUR/(MW*year) or EUR/(MWh*year)

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Economic KPIs	Description	Unit
Annual financial turnover from different markets	The annual turnover from different marketplaces (if exist): • Wholesale spot market (Intraday, Day-ahead) • Balancing markets • Reserve mechanism • Retail market	EUR/year or EUR/(MW*year) or EUR/(MWh*year) for each market
Annual cash flow	The total annual cash flow of the BMs over all customers/technologies (if all cost components are provided) Including revenues and costs from different markets as well as revenues from customer retailing, excluding costs for HR, investments and other fixed costs	EUR/year or EUR/(MW*year) or EUR/(MWh*year)

Ecological KPIs	Description	Unit
Annual CO_2 emissions of the aggregators technology portfolio	The total annual CO_2 emission value for all technologies which are controlled by the aggregator	kg/year or kg/(MW*year) or kg/(MWh*year)
Annual fossil fueled and renewable generation of the aggregators technology portfolio	The total annual energy generation for all technologies which are controlled by the aggregator	MWh/year for each technology
Annual fossil fueled and renewable generation of the aggregators technology portfolio for different markets	The annual energy generation for all technologies which are controlled by the aggregator for different marketplaces (if exist): • Wholesale spotmarket (Intraday, Day-ahead) • Balancing markets • Reserve mechanism • Retail market	MWh/year for each technology and market

For the evaluation of ecological KPIs we use the emission factors for CO_2 of different power plant types provided in [5]. For electricity production from oil we use an emission factor of 650gCO_2eq/kWh as presented in [6]. If a power plant is operating, it replaces other energy production in the market. If a load is increased, it increases demand for energy production on the market. In both cases, we value the energy from the markets with the weighted mean of the emission factors of the power plants currently running in the respective country.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

For this we use the "Actual Generation per Production Type" data available on the ENTSOE Transparency Platform[2].

Technical KPIs	Description	Unit
Annual peak load per contracted flexibility	The peak load is defined as the maximal annual load	MW/year
Annual Load factor per contracted flexibility	The load factor is defined as generated energy per capacity	hours/year or percent
Annual Flexibility activation per contracted flexibility	Flexibility activation is defined as the dispatched flexible energy.	MWh/year or percent

[2] https://transparency.entsoe.eu/ last accessed in Dec 2018

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

3. Improved business models of Good Energy (United Kingdom)

3.1 Automation and control

In this business model analysis we investigate, how price signals and automated reaction of flexible devices can reduce the energy bill of end users. Good Energy supplies their customers with 100% renewable energy that they procure from different sources, such as wind farms, biofuels, solar PV and hydropower. The customer tariff assumed for our investigation is listed in Table 1. It consists of two price levels: a low price level during night between 00:00 and 07:30 and a high price level during the remaining hours; The wholesale power stack represents Good Energy's cost for energy procurement and the remaining stack includes other components such as the DNO tariff, fees and taxes.

Table 1: End user tariff of Good Energy

Energy tariffs	Low Price in pence / kWh	High Price in pence / kWh	Standing charge in pence / day
Total Customer Tariff	11.6	19.13	26.26
Wholesale Power	5.77	7.09	-
Remaining Stack	5.83	12.04	-

3.1.1 Methods

In a first step, we want to investigate the effect of flexible devices automatically reacting to the price signals provided by the current two-level tariff. For this purpose, we consider measured load profiles for seven different household load components: electric shower, fridge, kettle, microwave, toaster, washing machine and other. Figure 1 illustrates the load profiles of the considered devices. For the washing machine, we assume that the electrical load can be shifted at any time during the day. For all other devices, we are more conservative and assume that load shifts are only possible within one hour. To model flexibility activations, we use the methodological framework, presented in Section 2.1.2.3.

First, we evaluate the customer cost with the current tariff and the measured load profiles without any flexibility activations in the **Baseline** scenario. In the **Improved** scenario, we investigate the monetary benefits, individual load component flexibilities can provide by reacting on the price signals provided by the current tariff. However, the existing tariff only provides incentives for load shifting between two price levels and our flexibility assumptions are very restrictive for the majority of devices. Hence, we consider a third **Advanced** scenario. We construct a fictitious real-time-pricing tariff based on the hourly wholesale market prices. We use the price data available from the

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

ENTSOE transparency platform[3]. We replace the Wholesale Power component of the tariff shown in Table 1 with an hourly time series of the wholesale market prices plus an offset. The offset is chosen in a way, that the cost of the original profiles with these constructed tariffs are the same as with the original tariff. In this Scenario, the offset chosen is 1.4 pence / kWh. The remaining stack component stays the same as in the original tariff. This way we can identify the benefit of flexibility activations compared to the **Baseline** scenario.

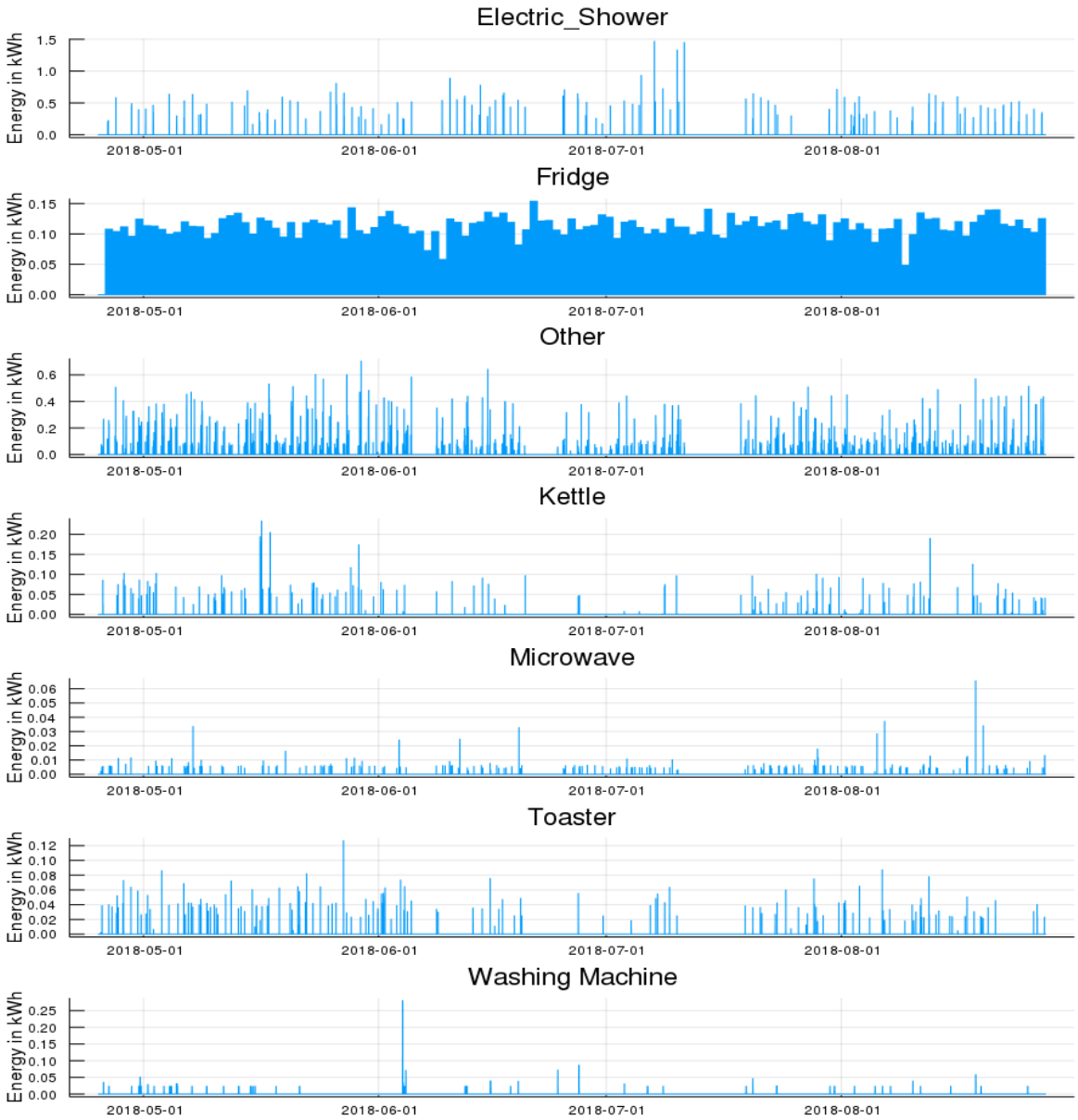

Figure 1: Load profiles of the analyzed devices

[3] https://transparency.entsoe.eu/

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

3.1.2 Results

The different strategies were implemented in Julia using the methods described in Section 2.1.2.3. The electrical loads are shifted differently in the two strategies. Flexibility is used more in the advanced scenario, because the real-time-pricing tariff provides greater incentives than the tariff in the improved scenario, in which there are only two different price intervals: 19.13 £ / MWh and 11.6 £ / MWh. The following table shows the results of the three analyzed scenarios.

Table 2: Different strategies to use flexibilities compared

	Scenario						
	Baseline			improved		Advanced	
Devices	Total Load in kWh	costs of the customer in £	Profit of the Aggregator in £	Shifted Load in kWh	costs of the customer in £	Shifted Load in kWh	costs of the customer in £
Electric Shower	69.84	12.46	0.89	0 (0 %)	12.46 (=)	33.45 (47.9 %)	9.48 (-23.92 %)
Fridge	168.52	29.26	2.05	14.04 (8.3 %)	28.29 (-3.3 %)	94.13 (55.9 %)	22.7 (-22.42 %)
Other	174.23	32.38	2.74	0.2 (0.1 %)	32.34 (-0.02 %)	80.9 (46.4 %)	23.6 (-27.2 %)
Kettle	8.99	1.56	0.14	0 (0 %)	1.56 (=)	4.34 (48.3 %)	1.21 (-22.44 %)
Microwave	1.41	0.27	0.017	0 (0 %)	0.27 (=)	0.81 (57.4 %)	0.198 (-26.26 %)
Toaster	6.9	1.2	0.098	0 (0 %)	1.2 (=)	3.28 (47.5 %)	0.953 (-20.58 %)
Washing Machine	6.16	1.08	0.086	0.89 (14.4 %)	1.02 (-5.6 %)	1.95 (31.7 %)	0.817 (-24.35 %)
Total [4]	436.05	110.64	38.85	15.13 (3.47 %)	109.97 (-0.6 %)	218.87 (50.2 %)	91.77 (-17.06 %)
CO2 Emissions	81 kg (0.186 kg/kWh)			80.9 (-0.12 %)		80.7 (-0.37 %)	

The results show, that the improved scenario represents financial advantages for the consumers. The savings are however very limited (0.6 %), as the loads can be shifted by a maximum of +/- 1 hour and only during the day. Moreover, there are only two different price intervals. Table 2 shows, that in the improved scenario only 3.47 percent of the total load is shifted. The Advanced scenario provides also financial benefits for the consumers. The real-time-pricing tariff allows the consumers to exploit more of their flexibility. The results show, that in the advanced scenario, 50.2 percent of the total load is shifted. This leads to a 17.06 percent decrease in expenses of the consumers. Lower spot market prices

[4] The total costs of the customer and the profit of the Aggregator include the Standing charge of 26.26 Pence / day that the Customer pays to the Aggregator.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

typically correspond to lower average CO_2 emissions and so the emissions decrease with the reduction of the energy prices at the Day-Ahead spot market.

3.1.3 Conclusion

We can establish that flexibilities of loads can be used to create value for the end users. As we can see from Table 2, if the consumers use their flexibility taking into account exclusively their tariff (Improved Scenario), their costs decrease slightly. That is because the loads flexibility is limited and because there are only two different price intervals. The real-time-pricing tariff in the advanced scenario allows the consumers to achieve more savings in comparison with the improved scenario. An important aspect to consider for future research is how to distribute the created value between supplier and flexible consumers in the advanced scenario. To make a real-time-pricing tariff attractive, it is necessary to divide the savings between all the participants, so as to incentivize both of them to adopt this pricing method.

3.2 “Peer-to-peer” (local) energy matching

Even though we tried to provide simulation-based analyses for all improved business models developed in the BestRES project, we decided to exclude Good Energy’s “Peer-to-peer” (local) energy matching for the following reasons. First, as indicated in the report, “Documentation of pilot business model implementation and results” [7], this peer-to-peer platform is not really a commercial tool, but rather proposition for customer acquisition, and hence, very difficult to evaluate in a techno-economic way, because many of the benefits rather relate to visualizations and insights for the customers, than change in production or consumption. Second, the business model is ranked as a group 3 business model and there are significant regulatory and legal obstacles for actual business model implementation. Details about this are presented in the report [7]. Third, there is not enough data available in the project to simulate the consumption, and preferences of many customers and the production of multiple local renewable producers and their matching. An implementation of this business model in a simulation framework would require significantly more assumptions and random data than for other business model analyses and, hence, conclusions from such simulations would be very doubtful and uncertain.

BestRES This project has received funding from the European Union’s Horizon 2020 research and innovation programme under grant agreement N° 691689.

4. Improved business models of Next Kraftwerke Germany (Germany)

4.1 Dispatch flexible generation under changing market design on multiple markets

Next Kraftwerke Germany is pooling flexible renewable generation from e.g. biogas power plants and providing ancillary services via the secondary reserve market (aFRR). In this market, stakeholders can offer to reserve a certain capacity for a given time period. The auction bids consist of a bid size in MW, a power price in EUR/MW and an energy price in EUR/MWh. The bids are sorted with respect to power prices in ascending order and the first bids are accepted until the auction volume is reached. The participants with accepted bids receive the offered power price and are obliged to reserve the capacity for the entire market product duration. Furthermore, the accepted offers are sorted with respect to their energy price in ascending order. If reserve energy is required, the first bids are activated depending on the size of the activation. Each market activated participant is remunerated for the activated energy with the offered energy price. The reserve period depends on the specification of the product and there are products for production increase (positive reserve market) and reduction (negative reserve market).

On July 12, 2018 the weekly aFRR products **Peak** (Mo-Fr 8AM-8PM) and **Off-Peak** (else) are replaced by four-hour products and the auction time changes from week-ahead to day-ahead[5]. In this analysis, we want to investigate the impact of these market changes on the operation of a subsidized 1.3 MW biogas power plant that is operating on the day-ahead spot market and the secondary reserve market.

4.1.1 Methods

The first obstacle in this analysis is the lack of data availability for the new market products. For the weekly aFRR products, anonymized auction results and historical positive and negative activation data from the year 2016, provided on the platform https://www.regelleistung.net/, is used. From the auction results, merit order curves for the power bids and energy bids are assembled for each product. Figure 2 illustrates these curves for a positive reserve market product. The merit orders can be used to simulate acceptance and activation of aFRR auction bids.

The Four-hour products are constructed from the historic weekly products in the following way: Energy prices of a four-hour product are the same as the energy prices for the corresponding weekly product. Power prices are also taken from the weekly product that is active at the same time. The values of the power prices, however, are scaled according to the product length. This means that the

[5] See e.g. http://www.teamconsult.net/news/files/TeamConsult_Kurzanalyse_SRL_2018_20180726.pdf

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

power prices for a four-hour product during off-peak hours are divided by 27 and power prices during peak hours are divided by 15.

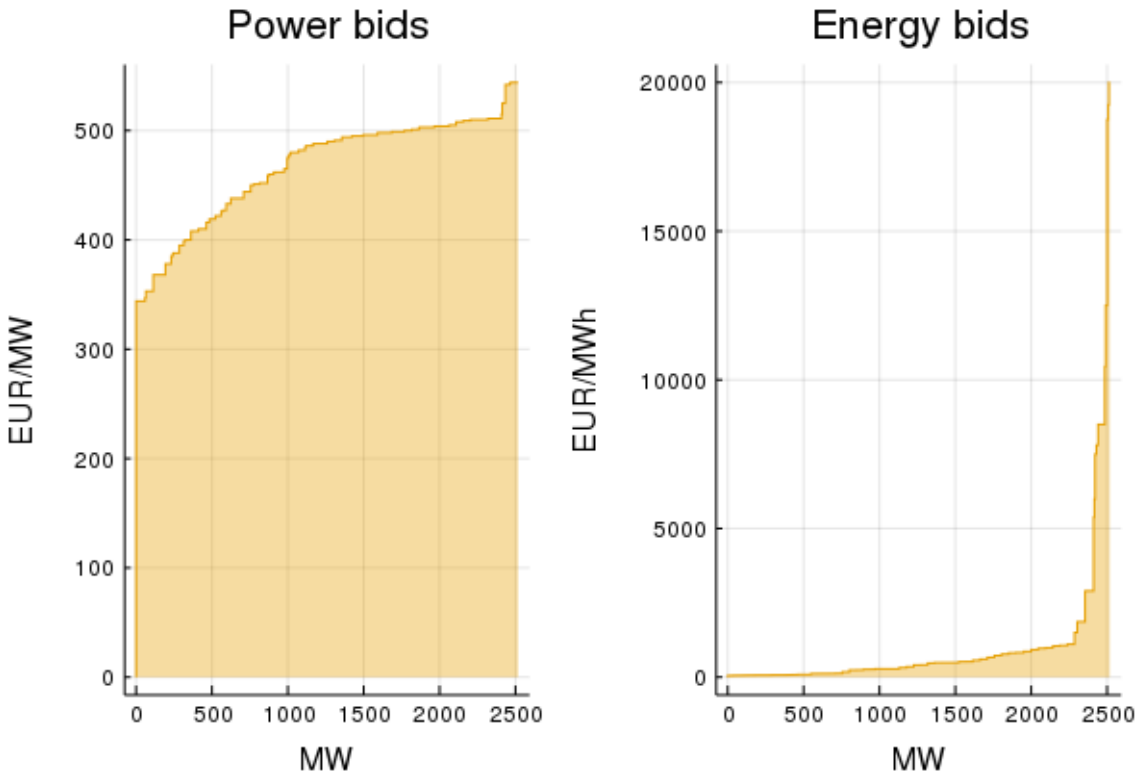

Figure 2: Merit order curves for the power and energy prices of a (positive) reserve market product.

At the moment, the fuel cost of biogas power plants do not allow an economic operation on electricity wholesale markets. Hence, in Germany they are supported by a market premium subsidy scheme specified by the EEG 2017[6]. The value of the market premium is determined through auctions where each actor can bid value of income they would like to receive in EUR per produced MWh. The lowest values are chosen to be subsidized and the market premium they receive is the difference between the income bid and the average monthly day-ahead market price. We assume here, to use the production cost of the biogas power plant as the income bid value. We use two different scenarios for production cost: 100 EUR/MWh and 140 EUR/MWh

Furthermore, there are some restrictions for the biogas unit to receive the market premium. First, the market premium is only paid for the first 5000 full-load hours, and second, a minimum of 20 % of the nominal capacity has to be achieved in average annual production.

After discussions with Next Kraftwerke Germany, we decided that it is more beneficial for the biogas unit, not to be activated too often on the reserve markets. A total of about 10 to 20 full-load hours of reserve market activations are a typical sensible value according to Next Kraftwerke experts. We choose the

[6] https://www.bmwi.de/Redaktion/DE/Gesetze/Energie/EEG.html last accessed in 11/2018

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

energy bidding on the aFRR markets accordingly to be at the respective merit-order position. The energy bids are the same for weekly and corresponding four-hour products. As for power prices, we choose the average power bid for each market product.

4.1.2 Results and KPIs

Table 3 and Table 4 show the profit of the biogas plant on different markets or market components including the market premium subsidy for different fuel cost assumptions. The left column shows the operation with the weekly products and the right column provides the results for the new four-hour products.

Table 3: Annual profit in kEUR from different markets with assumed production cost of 100 EUR/MWh

Market (Component)	Weekly [kEUR]	Four Hours [kEUR]
Spot	100.3	149.3
Market Premium	180.0	279.8
Positive Reserve	35.4	30.7
Negative Reserve	1.4	3.4
Positive Reserve Activations	3.3	4.4
Negative Reserve Activations	0.8	3.7
Fuel	-256.0	-394.0
Total	65.1	77.3

Table 4: Annual profit in kEUR from different markets with assumed production cost of 140 EUR/MWh

Market (Component)	Weekly [kEUR]	Four Hours [kEUR]
Spot	107.1	151.3
Market Premium	305.9	444.7
Positive Reserve	34.4	30.4
Negative Reserve	1.4	3.4
Positive Reserve Activations	3.0	3.7
Negative Reserve Activations	0.8	4.0
Fuel	-387.8	-560.1
Total	64.8	77.3

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Analogously, Table 5 and Table 6 show the volumes, sold, offered and activated on different markets and the fuel usage for the current **Weekly** and the future **Four Hours** scenario.

Table 5: Annual volumes in MWh on different markets with assumed production cost of 100 EUR/MWh

Market (Component)	Weekly [MWh]	Four Hours [MWh]
Spot	2550.6	3937.4
Positive Reserve	8377.2	7196.8
Negative Reserve	1107.6	3042.0
Positive Reserve Activations	11.9	16.6
Negative Reserve Activations	2.6	14.3
Fuel	2559.9	3939.7

Table 6: Annual volumes in MWh on different markets with assumed production cost of 140 EUR/MWh

Market (Component)	Weekly [MWh]	Four Hours [MWh]
Spot	2763.8	4005.0
Positive Reserve	8143.2	7124.0
Negative Reserve	1263.6	3109.6
Positive Reserve Activations	9.1	11.7
Negative Reserve Activations	2.9	15.9
Fuel	2770.0	4000.8

Table 7: Relative profit in EUR/MWh of produced electricity in different scenarios.

Scenario	100 EUR/MWh Production cost	140 EUR/MWh Production cost
Weekly	25.4	23.4
FourHours	19.6	19.3

The CO_2 emissions caused by the biogas power plant are listed in Table 8. We see that the **Four Hours** scenario results in more direct emissions than the **Weekly** scenario. However, the operation of the biogas power plant replaces the production of other power plants. We do not have any information about the

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

type of power plants that are operated on the aFRR market at each hour. The amount of energy activated on the reserve markets is very little anyway. Instead, we consider the average quarter-hourly emissions of energy production in Germany in tCO_2/MWh to value the production that is replaced by the biogas power plant's spot market operation. Note that this is a rather conservative approach, because the power plants replaced by biogas are typically units with higher marginal cost, like coal, gas or oil and typically emit more CO_2 than average production. The avoided CO_2 emissions, due to biogas operation calculated with this methodology are listed in Table 9.

Table 8: Annual CO_2 emissions in tCO_2 caused by the biogas power plant in different scenarios

Production cost	Weekly	Four Hours	Change [%]
100 EUR/MWh	872.9	1343.4	+53.9 %
140 EUR/MWh	944.6	1364.3	+44.4 %

Table 9: Avoided annual CO_2 emissions in tCO_2 by operating the biogas power plant on the day-ahead spot market in different scenarios

Production cost	Weekly	Four Hours	Change [%]
100 EUR/MWh	60.5	116.3	+92.2 %
140 EUR/MWh	57.2	113.5	+98.4 %

It is hard to draw conclusions from these results. In general, we can observe that increased flexibility for power plant operators by shorter market products results in higher profits or less cost, respectively. This is expected, because of the way we constructed the four-hour products from the weekly product data. Basically, the **Weekly** and the **Four Hours** scenario can be considered almost the same optimization problem with the difference that all four-hour products in the **Weekly** scenario that correspond to the same weekly product have to have the same bids, as opposed to the **Four Hours** scenario. Hence, mathematically speaking, this additional restriction in the **Weekly** scenario reduces the solution space of the optimization problem, and is expected to provide worse results, economically.

Nevertheless, one has to be careful with conclusions from these results, because the prices of the four-hour products were constructed. In reality, shorter products will probably provide more options and flexibility for other market participants, too. This will most likely increase competition and, in general reduce market prices.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

4.2 Supplying „mid-scale“ consumers with time variable tariffs including grid charges optimization

Supplying mid-scale consumers with time variable tariffs and optimizing the schedules of loads subject to variable energy prices are already well-known demand-response concepts. The end user bills, however, do not only consist of energy costs, but also comprise of fees, taxes and grid charges. For load-measured customers the grid charges often have a peak-load-pricing component in EUR/MW that is charged for the highest load per year or per month. Here it is investigated, how considering the grid charges in load schedule optimization affects the energy bill of mid-scale consumers.

4.2.1 Methods

For this purpose, two optimization models – with and without the consideration of peak-load-pricing grid charges – are set up, solved and compared. With $p_{\mathrm{en}}(t)$ denoting the energy price at time t and the decision variable for the load $q(t)$ a simplified representation of the first optimization model is given by:

$$\min \sum_t p_{\mathrm{en}}(t) \cdot q(t)$$
$$s.t. \text{Load } (q) \text{ constraints}$$

If a peak-load-pricing component p_{plp} is considered as well, a new variable $q_{\max}$ for the maximal load is required and the resulting simplified optimization problem reads like this:

$$\min(p_{\mathrm{plp}} \cdot q_{\max} + \sum_t p_{\mathrm{en}}(t) \cdot q(t))$$
$$s.t. q_{\max} \geq q(t) \quad \forall t$$
$$\text{Load } (q) \text{ constraints}$$

4.2.2 Model scaling

In the analysis of this improved business model six water pumps with a total capacity of 55 MW, a total annual consumption of 155 GWh and a total flexibility availability of 32 MW is investigated. It is assumed that the daily consumption after the optimization must match the daily consumption of the original load profile.

The EPEX Spot[7] day-ahead market prices from the year 2016 are used and the grid charges of the distribution system operators Mitnetz GmbH[8], Westnetz[9] and Netze BW[10], respectively, are considered. Here both, a yearly and a monthly peak-load-pricing component are investigated. The respective grid tariff components are listed in Table 10. Furthermore, 8.04 EUR/MWh for the first

[7] https://www.epexspot.com/
[8] https://www.mitnetz-strom.de
[9] https://iam.westnetz.de/
[10] https://www.netze-bw.de/

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

1000 MWh and 5.32 EUR/MWh afterwards are assumed as fees based on the information in the price sheets of the distribution system operators.

Table 10: Grid tariff assumptions for the water pump loads.

	Unit	Mitnetz	Westnetz	Netze BW
Fix annual component	EUR/a	465	420.47	612.86
Energy component	EUR/MWh	10.7	6.5	12.8
Peak-load-pricing component (yearly or monthly)	EUR/MW_{max} yearly	133550	83770	79630
	EUR/MW_{max} monthly	22250	13960	13270

4.2.3 Results and KPIs

The original load and the resulting loads from the different optimization routines for the Netze BW tariffs are illustrated in Figure 3. Subplot (1) shows the original load profile. If the flexible load is adapted just considering the variable energy prices, i.e. the spot market prices, it results in the profile shown in subplot (2). In general, in this case the maximum power of the load is increased, because as much energy as possible is consumed during hours of low prices. In contrast, the peak load is reduced if the grid charges are considered in the optimization process: Subplot (3) shows the load optimized for energy prices and the grid tariff with a yearly peak-load-pricing component. If the tariff option with monthly peak-load-pricing is chosen, the maximum load is minimized individually for each month. This can be observed in subplot (4).

Figure 4 shows the annual cost components for different optimization strategies with the Netze BW tariffs. The left subplot shows the results for a yearly peak-load-pricing component and the right subplot for a monthly peak-load-pricing component, respectively. In both cases, optimizing with respect to spot market prices yields a lower energy cost and total cost. Considering the grid charges in the optimization results in a slightly higher spot market cost, but achieves significantly lower grid charges and, consequently, a lower total cost.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

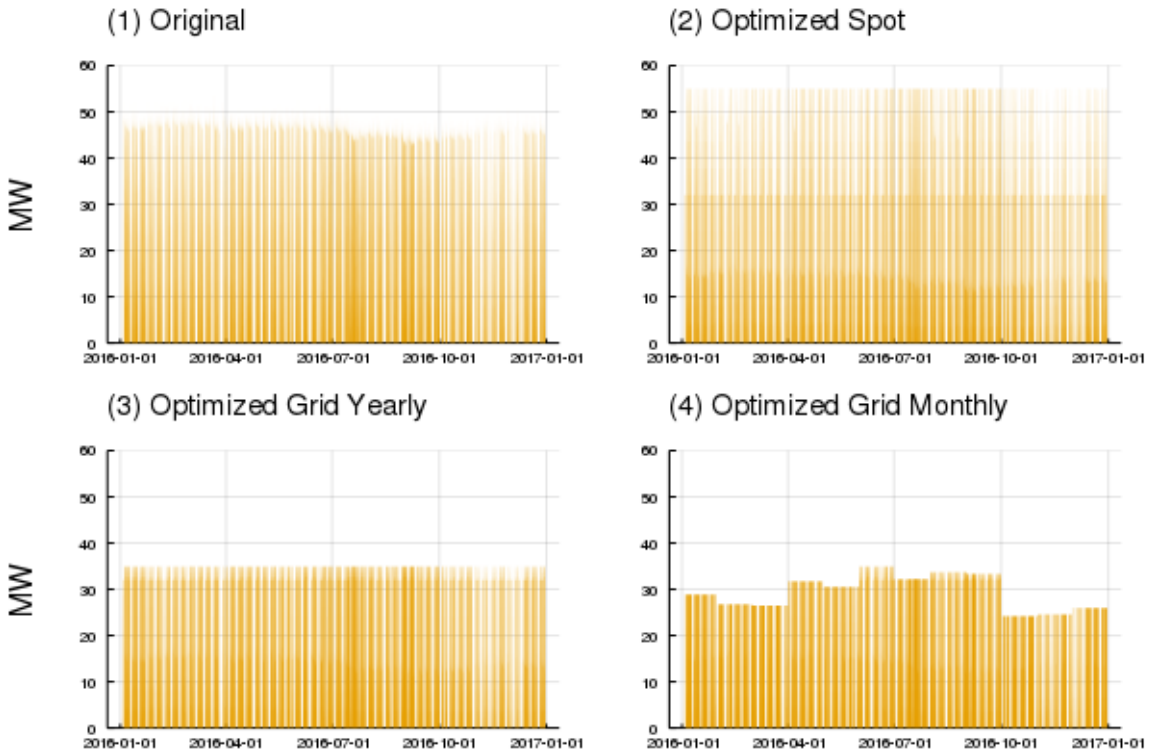

Figure 3: Load profiles resulting from different optimization routines for the Netze BW tariffs.

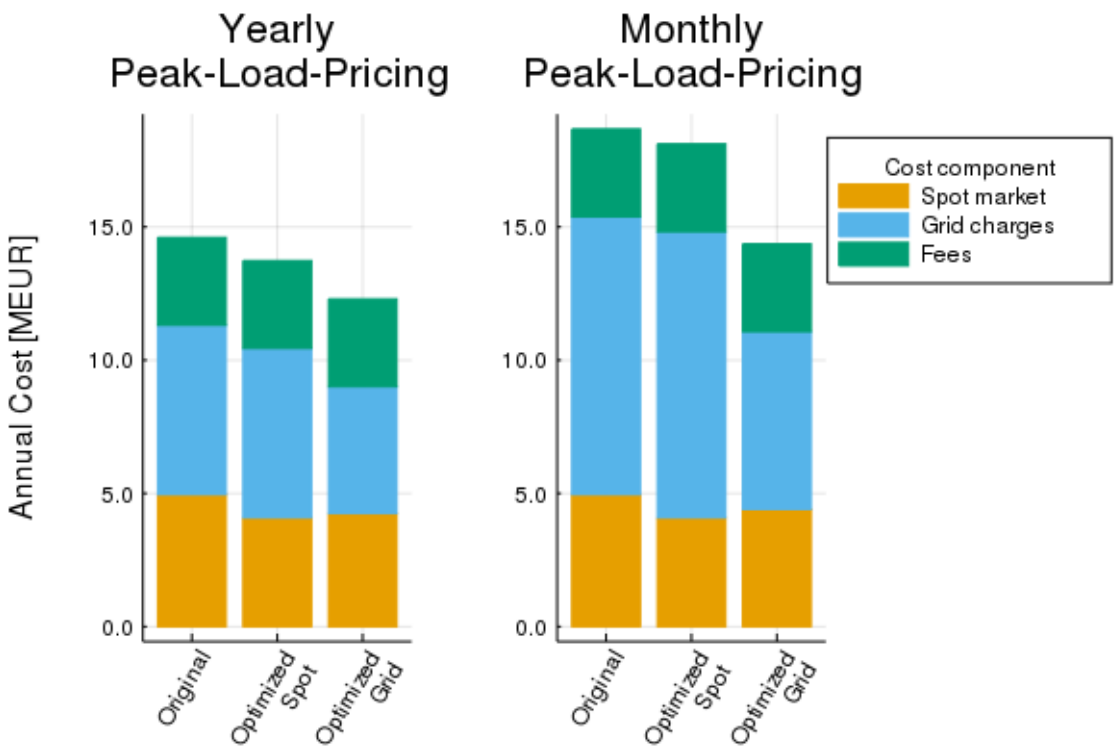

Figure 4: Annual cost for different optimization routines with the Netze BW tariffs.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

In the following sections, different KPIs for the Netze BW grid charges are listed. The corresponding KPIs for the tariffs of the other distribution system operators can be found in the Appendix A.1.1.

4.2.3.1 Economic KPIs

The annual financial turnover of the aggregator (total and from different markets) in this improved business model cannot be easily determined in a quantitative way. The major change and improvement lies in the reduced cost from electricity purchases of the customer and it is thus assumed that this business model can tighten the relationship to existing customers and attract new customers. The only economic KPI that can be evaluated sensibly in a quantitative way is the annual financial operation costs of the aggregator customers, which in this case corresponds to their electricity bill. It is listed in Table 11 for a tariff with annual peak-load-pricing and in Table 12 for monthly peak-load pricing.

Table 11: Economic KPIs for the Netze BW grid charges with annual peak-load-pricing.

Netze BW yearly	Unit	Spot Optimization	Grid Optimization	Change [%]
Annual financial operation costs	MEUR	13,74	12,3	-10,48
	EUR/MWh	88,9	79,58	-10,48
	kEUR/MW	249,73	223,57	-10,48

Table 12: Economic KPIs for the Netze BW grid charges with monthly peak-load-pricing.

Netze BW monthly	Unit	Spot Optimization	Grid Optimization	Change [%]
Annual financial operation costs	MEUR	18,11	14,36	-20,71
	EUR/MWh	117,24	92,96	-20,71
	kEUR/MW	329,34	261,14	-20,71

4.2.3.2 Ecological KPIs

In this improved business model only flexible loads, but no energy producing technologies are considered. Thus, the improved business model affects no fossil fueled or renewable generation of the aggregator's portfolio. However, the CO_2 emissions that are caused indirectly by the flexible load can be quantified. For this purpose, the average quarter-hourly emissions caused by energy production in Germany in tCO_2/MWh are used. The resulting ecological KPIs for the Netze BW grid charges are listed in Table 13 for annual peak-load-pricing and in Table 14 for monthly peak-load-pricing, respectively. In both cases, the improved business model, considering grid charges, results in slightly higher CO_2 emissions

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

related to the flexible load than the status quo business model. This can be explained by the fact that lower spot market prices typically correspond to lower average CO_2 emissions, as shown in Figure 5. Only considering spot market prices in the optimization, results in more energy consumption during hours of low prices compared to the improved business model, and, hence, yields slightly lower CO_2 emissions.

Table 13: Ecological KPIs for the Netze BW grid charges with annual peak-load-pricing.

Netze BW yearly	Unit	Spot Optimization	Grid Optimization	Change [%]
CO_2 emissions caused by the load	tCO_2	53335,1	53628,57	+0,55
	tCO_2/MWh	0,35	0,35	+0,55
	tCO_2/MW	969,73	975,06	+0,55

Table 14: Ecological KPIs for the Netze BW grid charges with monthly peak-load-pricing.

Netze BW monthly	Unit	Spot Optimization	Grid Optimization	Change [%]
CO_2 emissions caused by the load	tCO_2	53335,1	53772,73	+0,82
	tCO_2/MWh	0,35	0,35	+0,82
	tCO_2/MW	969,73	977,69	+0,82

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

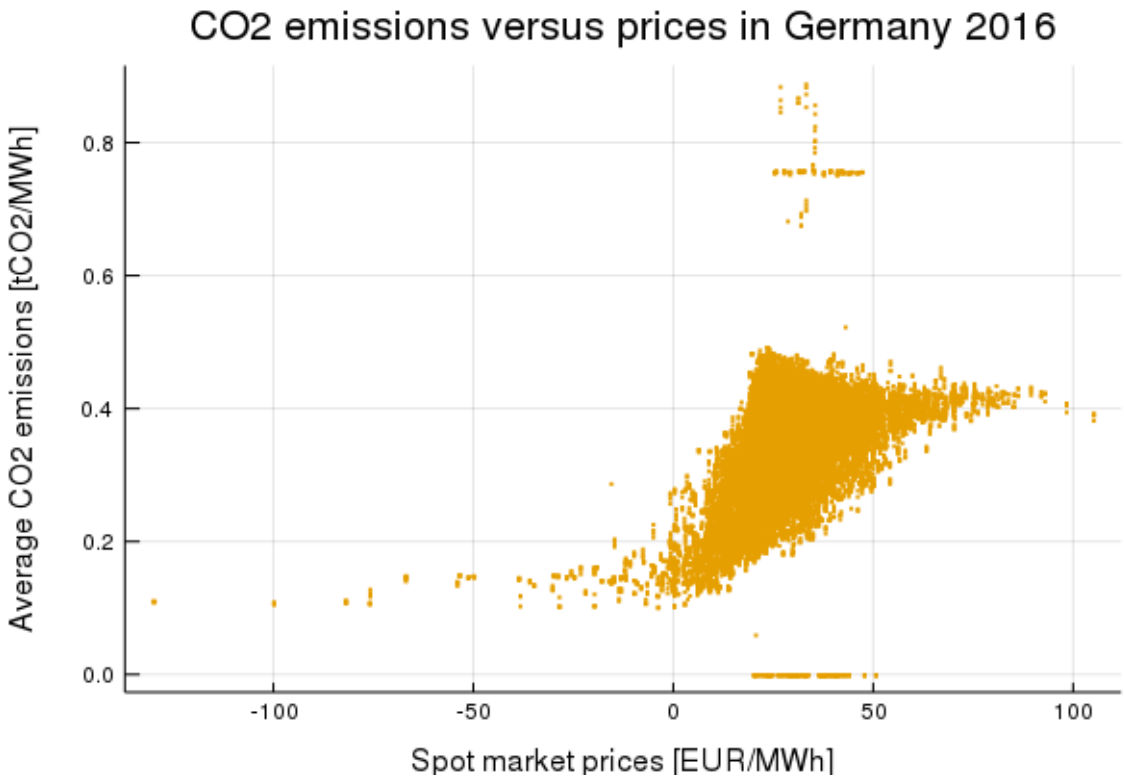

Figure 5: Quarter-hourly average CO_2 emission versus day-ahead spot market prices in Germany 2016

4.2.3.3 Technical KPIs

For shiftable flexible loads, the load factor or the full load hours are not specifically interesting because these yearly values are not affected by shifting demand from one hour to another. The Peak load however is one of the most important KPIs in this improved business model because it is responsible for the cost reduction. Furthermore, the activation of flexibilities is affected by different operational routines. Both indicators are listed in Table 15 for yearly peak load pricing and in Table 16 for monthly peak-load-pricing.

Table 15: Technical KPIs for the Netze BW grid charges with yearly peak-load-pricing

Netze BW yearly	Unit	Spot Optimization	Grid Optimization	Change [%]
Peak load	MW	55	34,93	-36,49
	%	100	63,51	-36,49
Flexibility Activation	MWh	70501,46	66905,3	-5,1
	MWh/MW	1281,84	1216,46	-5,1

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Table 16: Technical KPIs for the Netze BW grid charges with monthly peak-load-pricing

Netze BW monthly	Unit	Spot Optimization	Grid Optimization	Change [%]
Peak load	MW	55	34,93	-36,49
	%	100	63,51	-36,49
Flexibility Activation	MWh	70501,46	65887,53	-6,54
	MWh/MW	1281,84	1197,96	-6,54

4.2.4 Conclusion

It has been shown that considering the entire customer's electricity bill, including the grid charges in the optimization routine, can significantly reduce the energy cost and reduce the peak load. By offering such load scheduling algorithms or corresponding price signals the aggregator can tighten customer relationship or possibly attract new customers.

However, it has to be noted that the success of this improved business model highly depends on the characteristics of the flexible load. If there are peak loads at certain hours that cannot be reduced for some reason, considering the peak-load-pricing component of grid charges in the optimization does not yield a cost reduction.

Furthermore, it is important to remark that the optimization models in this quantitative analysis have perfect foresight with respect to market prices and, more importantly, load profiles. In real life, without this knowledge about the future, it is far more difficult to get close to an optimal solution for the load schedule. Reducing the maximal load in one week does not yield benefits if a higher load appears in the subsequent week. It can be very challenging to implement an effective algorithm in real life.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

5. Improved business model of Next Kraftwerke Germany (France)

5.1 Providing decentralized units access to balancing and reserves markets

In this business model analysis, it is investigated how the flexible generation of energy can be used to enhance market participation through the reserve markets. This BM mainly aims to enable pooled controllable producers to participate in further flexibility markets. The French energy market allows aggregated renewable sources to participate in balancing markets and tap additional revenue streams. This analysis investigates the potential profit of a flexible biogas power plant generator on the French balancing market.

5.1.1 Methods

The operation of power transmission networks involves ensuring that the electricity generation is balanced with the demand in real time. However, several types of incidents may disrupt this balance (generation unit outage, damaged transmission line, demand imbalance). Generators and consumers which are directly connected to the power transmission grid can sell their flexibility to the power transmission operator by modifying their operating schedule. So, the Balance Responsible Entity system provides market parties with the opportunity to carry out all types of commercial transactions within the electricity sector. Any player who becomes a Balance Responsible Entity can create his own activity portfolio, also known as his balance perimeter. The balancing mechanism is a market mechanism, which allows the supply and demand of electricity to be balanced at all times. “Réseau de Transport d' Électricité” (RTE) is the electricity transmission system operator of France. It is responsible for the operation, balance, maintenance and development of the French transmission system. RTE has three types of reserves - primary, secondary and tertiary - to reduce imbalances between electricity generation and consumption. The primary and secondary reserves are automatically activated to contain the frequency deviation, restore the frequency to 50 Hz and reduce the energy exchange at the borders to their expected value. The primary reserve, activated in a decentralized manner at the level of each production group, intervenes in 15 to 30 seconds; the secondary reserve, activated automatically by RTE, in 400 seconds.

In this analysis, we investigate the potential that flexibility can have if exchanged within the tertiary reserve market. The tertiary reserve is divided into 2 different reserves. The Rapid Reserve (RR) (capable of being activated in less than 13 minutes) and the Complementary Reserve (CR) (capable of being activated in less than 30 minutes). The Rapid Reserve is composed of 1000 MW electric power and can be activated in less than 15 minutes and for two hours. The Complementary Reserve is composed of 500 MW electric power and can be activated in less than 30 minutes and for 1.5 hours. The balancing mechanism is

BestRES This project has received funding from the European Union’s Horizon 2020 research and innovation programme under grant agreement N° 691689.

a market mechanism, in which generators and consumers can make offers to increase or decrease their output or consumption. Furthermore, the market players communicate the technical and financial conditions, on the basis of which RTE can modify their generation, consumption or injection schedules on borders. RTE makes up for any imbalances by selecting offers, after having ranked them according to economic precedence and by taking into account the technical constraints expressed by the players. To participate in this market, the tenderer must have certain technical characteristics. The bidder communicates to RTE the power availability/flexibility for a certain time. After that, the bidder must have sufficient energy, to be able to provide the power and energy he offered for two times a day. Depending on the need of the power transmission network, the energy offered can be used, or not. In this chapter, we analyze the case in which two bio-gas power plants with two different energy generation costs sell their flexible generations at the Rapid Reserve (RR) market. We assume that the generators are activated only if the Rapid Reserve market prices are higher than the energy generation costs.

5.1.2 Results and conclusions

The revenues were calculated in both cases. The cases of a generator with energy generation costs of 60 and 120 €/MWh were investigated. The offers on the Rapid Reserve market represent the optimal value, i.e. exactly the highest offer bought on the rapid reserve market. It is therefore an ideal case, which can give an indication of the potential profits that the Rapid Reserve market can offer to a flexible generator. The offered volume of energy at each activation is 1 MWh. The CO_2-Emissions for a biogas power plant are 0.341 tCO_2/MWh[11].

Table 17: Potential profits of a biogas power plant, which optimally trade at the French Rapid Reserve market

Optimal trading at the French Rapid Reserve market in 2016	Generator with energy generation costs of 60 €/MWh	Generator with energy generation costs of 120 €/MWh
Profit in €	101,355	20,985
Traded Volume	2960	444
Profit in €/MWh	34.24	47.26
CO_2 -Emissions	1009.4	151.4

As we can see from the results, the profit in € of the generator with lower energy generation costs is higher compared to the profit in € of the generator with higher energy generation costs. This is due to the fact that the generator with low energy production costs sells a greater volume of energy, since it can even operate during hours of between 60 and 120 €. In fact, the volume sold in that case is 2960 MWh, while, in the case of production cost of 120 €/MWh, the traded

[11] https://www.umweltbundesamt.de/sites/default/files/medien/1410/publikationen/2017-10-26_climate-change_23-2017_emissionsbilanz-ee-2016.pdf

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

volume is 444 MWh. Interestingly, the relative profits in € /MWh increase by 38 % when the production costs are doubled. CO_2-Emissions are only dependent on the amount of energy produced and in fact, they are greater in the case of low energy generation costs, where more energy is generated. However, it is hard to draw conclusions about the effect on avoided CO_2 emissions in the system, because we do not have any information about the power plants that would be replaced by the biogas unit operation and their respective carbon emissions.

The opening of a new market for electrical flexibility can open the door to new energy trading strategies. Nowadays in France, however, this market is open exclusively to stakeholders who can offer a flexibility of at least 10 MW in terms of power. This limit does not allow small market participants to be part of it.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

6. Improved business model of Next Kraftwerke Germany (Italy)

6.1 Market renewables on multiple market places

Italy's national electricity market is divided into six geographical areas (North, Central North, Center South, South, Sicily, Sardinia), five poles of limited production (Monfalcone, Foggia, Brindisi, Rossano, Priolo) and virtual foreign areas (France, Switzerland, Austria, Slovenia, Greece). In general, in each of these zones, a different price is determined at each hour. This analysis investigates the potential profit of three different RES power plants, namely wind (Onshore and Offshore) and a solar PV, in the different Italian market areas.

Figure 6 The six geographical Italian market areas[12]

6.1.1 Methods

The Italian Electricity Market is divided into:

- Day-ahead market (MGP)
- Intra-day market (MI)
- Daily Products Market (MPEG)
- Ancillary Services Market (MSD)

In the MGP, hourly energy blocks are traded for the next day. Participants submit bids or asks where they specify the quantity and the price limits at which they are willing to sell or purchase. The Day-Ahead Market (MGP) hosts most of the electricity sale and purchase transactions[13]. For this reason, in this analysis, the other markets will be ignored. Furthermore, energy generation forecast errors are not considered and the scheduled generation will be sold at the day-ahead spot market. The investigated technologies are one solar plant and two wind plants (onshore and offshore)

[12] www.entsoe.eu last access 12.09.2018
[13] http://www.mercatoelettrico.org/en/mercati/mercatoelettrico/mpe.aspx last access 04.12.2018

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

6.1.2 Results and conclusions

In the following table, the potential profit for each technology in each market area is given for every produced unit (MWh).

Table 18: Potential profit in the different market areas

Potential Profit in € / MWh per year	North market	Central North market	Center South market	South market	Sicily market	Sardinia market
Solar	39.8	38.2	37.0	35.1	41.2	36.9
Wind Onshore	42.3	41.7	41.1	40.1	47.1	41.1
Wind Offshore	42.7	42.3	41.6	40.6	47.6	41.6

As we can see, the value of single technologies varies according to the market area taken into consideration with variations up to 17.4 %. The market area, in which the potential profit of renewable is lower is the south market. Especially the photovoltaic production that is sold at 15 % less than in Sicily. So, as the results show, the Day-Ahead electricity price for Sicily is substantially higher than the average national price. This is because islands typically have a limited generation capacity. The problem for Sardinia was solved with the installation of an interconnector of 1 GW that connects Sardinia with the mainland. The same problem was addressed and partially solved also in Sicily with the installation of a 2 GW interconnector[14]. The demand of capacity is much higher in Sicily than in Sardinia and so the Sicilian interconnector had not the same effect of the one installed in Sardinia. That is the reason, why in Sicily the electricity prices are still high. In the following tables, we show how the different renewable technologies affect the CO_2 Emissions.

Table 19: CO_2 avoided emissions in the different market areas for every installed MW

Potential avoided CO_2 emissions in tCO_2 / MW_P per year	North market	Central North market	Center South market	South market	Sicily market	Sardinia market
Solar	69.0	143.6	256.8	515.7	309.2	139.6
Wind Onshore	207.7	342.0	566.7	924.9	665.8	385.4
Wind Offshore	363.2	592.1	960.8	1554.2	1128.0	652.4

[14] https://www.icis.com/explore/resources/news/2011/05/19/9461617/sardinia-and-sicily-electricity-prices-still-high-despite-interconnectors/ last access 05.12.2018

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Table 20: CO_2 avoided emissions in the different market areas for every generated MWh

Potential avoided CO_2 emissions in tCO_2 / MWh	North market	Central North market	Center South market	South market	Sicily market	Sardinia market
Solar	0.056	0.117	0.210	0.421	0.253	0.114
Wind Onshore	0.179	0.292	0.473	0.765	0.555	0.321
Wind Offshore	0.062	0.102	0.169	0.275	0.198	0.115

Table 19 shows that the potential avoided CO_2 Emissions for every installed unit are lower for the solar plants. That is because the solar plants produce significantly less electrical energy than the other renewable technologies taken into account in this analysis. In the south market area, fossil hard coal plants characterize a great part of the installed capacity [15] and so renewable technologies have a great impact on the avoided CO_2 Emissions.

[15] https://transparency.entsoe.eu/ last access 05.12.2018

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

7. Improved business models of Next Kraftwerke (Belgium)

7.1 Trading PV and wind power from third party assets

In this business model analysis, it is investigated how the generation of energy by solar, wind onshore and wind offshore plants can be traded in Belgium. Currently, NKW Belgium is scheduling the generation forecast to be sold at the day-ahead spot market. However, there are typically forecast errors and, hence, actual generation differs from the predicted production. Market participants are penalized for deviations from their schedules with imbalance prices.
Assuming that short-term forecasts are more accurate than day-ahead forecasts, day-ahead schedule deviations can also be balanced by intraday market trades, in order to avoid or reduce imbalance cost. Here it is analyzed, if this improved business model with intraday trading provides economic benefits for RES operators.

7.1.1 Methods

The considered market data are those of the Belgian transmission system operator Elia, while the source of the generation data of the plants is the ENTSO-E Transparency[16] platform. The investigated technologies are two solar plants (Belgium and NKW) and two wind plants (onshore and offshore)[17]. With solar (Belgium) and wind plants (onshore and offshore) we mean the average generation profiles of photovoltaic and wind systems in Belgium, while with solar (NKW) we mean the average generation profile of photovoltaic plants belonging to Next Kraftwerke. The aim of this analysis is to evaluate and compare the improved business model to the baseline trading strategy. Here, we consider how to trade different CO_2-friendly technologies generation profiles in Belgium at the intraday spot market to reduce the balancing costs and to maximize subsequently the financial turnovers of the plants. In this analysis we assume that the generation forecast will be entirely sold at the day-ahead market.

This means that the deviation of energy generation from the forecast will be balanced through the intraday spot market or the balancing energy. First of all, in the **Baseline** strategy it is shown how market participants are influenced by the imbalance prices due to the deviations from their schedules. Furthermore, in the **Improved** strategy, the case is investigated, in which the forecast deviation is entirely marketed at the intraday spot market. Subsequently we investigate the **Optimal** trading case, in which the excesses and the deficits of the expected energy generation are traded at the intraday spot market only when its prices are more convenient than the balancing costs. The installed power of the examined technologies is normalized to 1 MW_P.

[16] https://transparency.entsoe.eu/
[17] The considered production data are taken from http://www.elia.be/e last access 02.07.2018

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

7.1.2 Results

Table 21 shows the resulting revenues of the different trading strategies. The case with the highest turnover is obviously the optimal trading case, in which the excesses and the deficits of the expected energy generation are traded at the intraday spot market, only if it offers a more advantageous price compared to the balancing costs. Hence, we analyze this case more precisely. First, we investigate if there is a correlation between forecast error and market price to easily determine the best trading strategy. Therefore, the accuracy of the forecast was measured with the mean absolute percentage error (MAPE) and the market prices were provided by the ENTSO-E Transparency platform. The Pearson's coefficient was used to measure the correlation between those variables for each technology in the years 2015 and 2016. However, we could not find a significant relationship between the two variables.

Table 21: Comparison between the possible trading strategies

Revenues in EUR / MWh	Technology	Day-Ahead Market	Baseline	Improved	Optimal
2015	Solar (BE)	45.27	46.4	45.8 (-1.3 %)	48.63 (4.8 %)
	Solar (NKW)	47.33	45.89	46.72 (1.8 %)	51.26 (11.7 %)
	Wind Onshore	37.88	36.51	36.07 (-1.2 %)	39.43 (8 %)
	Wind Offshore	37.56	43.41	42.15 (-2.9 %)	47.75 (10 %)
2016	Solar (BE)	36.17	36.4	36.01 (-1.1 %)	38.49 (5.7 %)
	Solar (NKW)	36.25	33.44	33.2 (-0.7 %)	37.57 (12.4 %)
	Wind Onshore	33.08	31.05	31.02 (-0.01 %)	33.55 (8.1 %)
	Wind Offshore	32.9	34.01	34.72 (2.1 %)	37.48 (10.2 %)

In this business model, the production of the renewable power plants is not changed. We only look at different possibilities to valorize a fixed generation profile. Hence, the different scenarios do not affect CO_2 emissions.

Table 22: Mean average percentage error (MAPE) and traded volumes for different RES technologies on different markets.

Technology	Mean average percentage error (2015)	Traded volumes at the different markets applying the optimal strategy in MWh / y (2015)	Mean average percentage error (2016)	Traded volumes at the different markets applying the optimal strategy in MWh / y (2016)
Solar (BE)	1.99	Imbalance: 127 Intraday: 109 Total: 236	1.93	Imbalance: 124 Intraday: 104 Total: 228
Solar (NKW)	3.21	Imbalance: 191 Intraday: 175 Total: 366	3.27	Imbalance: 197 Intraday: 173 Total: 370

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Technology	Mean average percentage error (2015)	Traded volumes at the different markets applying the optimal strategy in MWh / y (2015)	Mean average percentage error (2016)	Traded volumes at the different markets applying the optimal strategy in MWh / y (2016)
Wind Onshore	4.19	Imbalance: 241 Intraday: 231 Total: 472	3.84	Imbalance: 227 Intraday: 202 Total: 429
Wind Offshore	8.83	Imbalance: 623 Intraday: 544 Total: 1167	6.71	Imbalance: 379 Intraday: 460 Total: 839

Table 22 shows that the traded volumes at the different markets applying the optimal strategy are almost always equally divided between intraday spot market and imbalance power market. Consequently, it is important to analyze the when and the way in which the generated energy is marketed at the intraday spot market. Figure 7 shows the hourly traded volumes at the different markets for each technology in 2015.

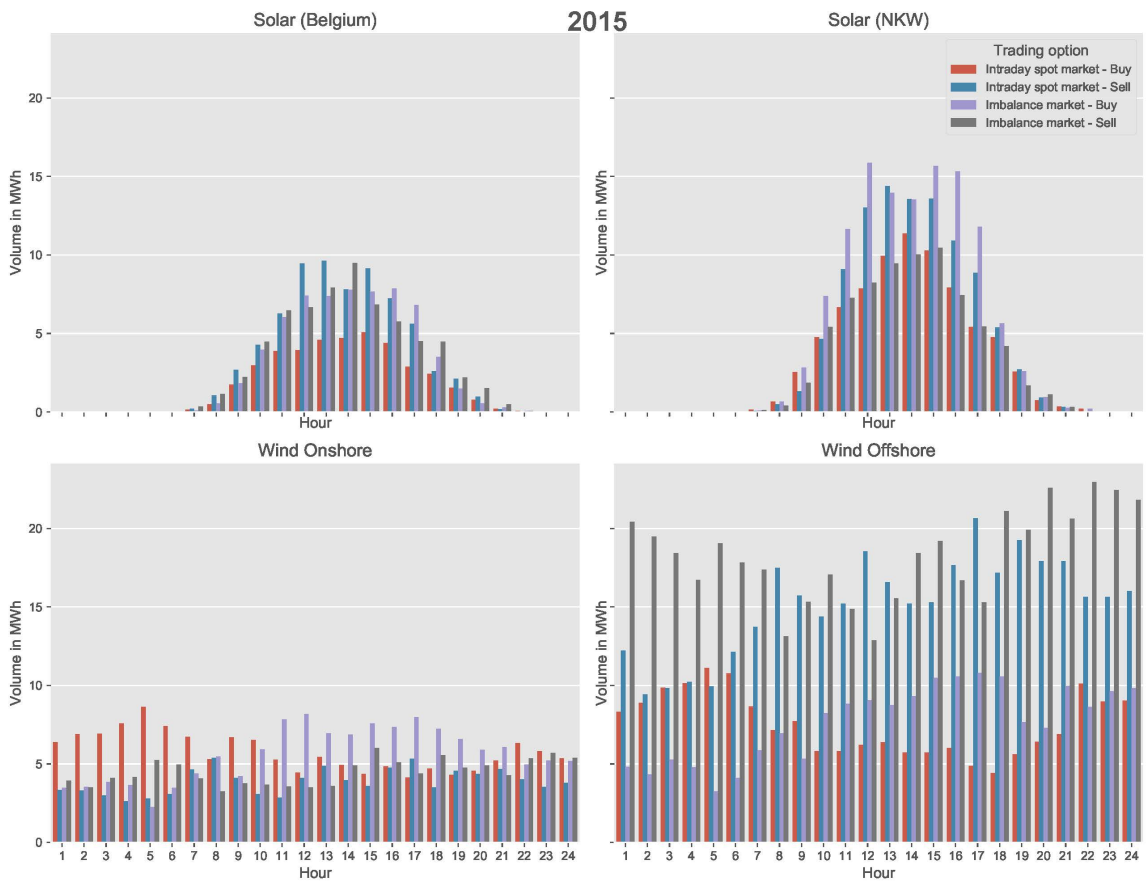

Figure 7: Hourly traded volumes at the different markets in 2015

As we can see from Figure 7 and Table 21, the solar (Belgium) plant generation prediction is the most accurate (MAPE: 1.99) of the four considered plants. The yearly traded energy volume of every installed MW_P is 236 MWh of which 109 MWh

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

(46 %) are traded at the intraday spot market. The optimal trading strategy allows to increase the gains by 4.8 % compared to the baseline trading strategy. Figure 7 shows that for the solar plant (Belgium) it is more financially beneficial to buy the energy at the intraday spot market only from 7 pm onwards. Furthermore, the energy generation excesses are more likely sold at the intraday spot market in the case of the solar (Belgium) plant. Only at 2 pm and at 6 pm it is preferable not to sell the energy at the intraday spot market.

The solar (NKW) plant generation forecast is slightly less accurate (MAPE: 3.21) than the solar (Belgium) plant generation prediction. In this case is the yearly traded energy volume per installed MW_P is 366 MWh. 175 MWh (48 %) of the entire volume are traded at the intraday spot market. The optimal trading strategy allows to increase the gains by 11.7 % compared to the baseline trading strategy. Paying the balancing costs is in sum cheaper than purchasing the energy deficits at the intraday spot market during all hours. Regarding the excesses of energy, it is financially more convenient to sell them at the intraday spot market during the peak production hours.

The mean absolute percent error of the wind onshore plant generation forecast is 4.19. The yearly traded energy volume every installed MW_P is 472 MWh. 231 MWh (49 % of the yearly generation) are traded at the intraday spot market. The optimal trading strategy allows to increase the gains by 8 % compared to the baseline trading strategy. Paying the balancing energy costs is cheaper from 11 am till 9 pm. In the remaining hours, it is cheaper to buy the energy deficits at the intraday spot market. Furthermore, only in some hours of the day, the intraday spot market is the best spot to sell the energy excesses.

The wind offshore plant generation prediction is the least accurate (MAPE: 8.83) of the four considered plants. Hence, the yearly traded energy volume per installed MW_P is very high: 1167 MWh, of which 544 MWh (47 %) are traded at the intraday spot market. The optimal trading strategy allows to increase the gains by 10 % compared to the baseline trading strategy. In this case, the forecast is mostly pessimistic and for this reason most of the exchanged energy is sold. The intraday spot market almost never represents the best choice for selling the excess of the energy generation. On the contrary, in the first nine hours of the day, the purchase of energy is more convenient at the intraday spot market, while in the remaining hours the balance costs are clearly cheaper than the purchase of the energy deficits at the intraday spot market.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

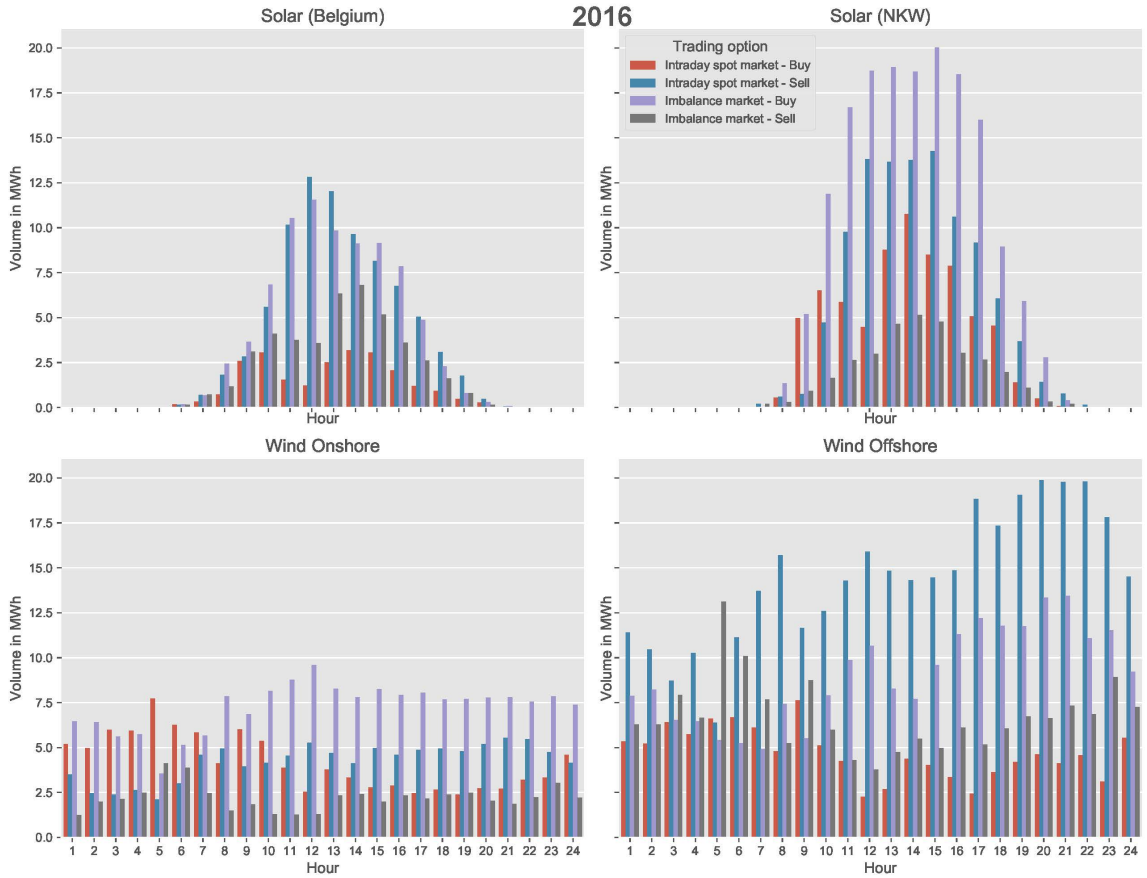

Figure 8: Hourly traded volumes at the different markets in 2016

The solar (Belgium) plant generation prediction is also in 2016 the most accurate (MAPE: 1.93) of the four considered plants. The yearly traded energy volume of every installed MW_P is 228 MWh. 104 MWh (46 % of the yearly generation) are traded at the intraday spot market. The optimal trading strategy allows to increase the gains by 5.7 % compared to the baseline trading strategy. Similar to 2015 it is better not to buy the energy deficits of the expected energy generation at the intraday spot market. On the contrary it is more profitable to sell the excesses of the energy production at the intraday spot market.

The MAPE of the solar (NKW) plant generation forecast is 3.27. The yearly traded energy volume of every installed MW_P is 370 MWh. 173 MWh of them (47 % of the yearly generation) are traded at the intraday spot market. The optimal trading strategy allows to increase the gains by 12.4 % compared to the baseline trading strategy. Also in this case the optimal trading strategy looks similar to 2015: Not to purchase the deficits of the energy generation at the intraday spot market and rather sell there the excesses.

The forecast accuracy of the wind onshore plant generation has slightly improved in 2016 compared to 2015 and the MAPE is 3.84. The yearly traded energy volume every installed MW_P is 429 MWh. 202 MWh of them (47 %) are traded at the intraday spot market. The optimal trading strategy allows to increase the gains by 8.1 % compared to the baseline trading strategy. In this case the optimal trading strategy is different; The purchase of energy is cheaper at the intraday spot

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

market only from 5 am to 7 am. Contrary to 2015, the energy generation excesses are more likely sold at the intraday spot market. Only at 5 am and 6 am are the balancing costs more convenient than selling the energy excesses at the intraday spot market.

Also in 2016, the wind offshore plant generation prediction is the least accurate (MAPE: 6.71) of the four considered plants. The yearly traded energy volume every installed MW_P is 839 MWh. 460 MWh (55 % of the yearly generation) are traded at the intraday spot market. The optimal trading strategy allows to increase the gains by 10.2 % compared to the baseline trading strategy. Contrary to 2015, the intraday spot market almost every hour is the best choice of where to sell the excesses of energy generation. Contrariwise, just for a few hours of the day is the purchase of energy more convenient at the intraday spot market, while in the remaining hours are the balance costs clearly cheaper than the purchase of the energy deficits at the intraday spot market.

7.1.3 Conclusion

It has been shown that the optimal trading strategy changes depending on the renewable technologies taken into consideration. However, it has to be noted that historical data could give an objective indication based on statistics of which is probably the more convenient market to trade the energy deviation for a certain technology at a certain time.

On the basis of the historical data of 2015 and 2016, it can be stated that for the solar (Belgium) plant and the solar (NKW) plant it is more beneficial not to buy the energy deficits of the expected energy generation at the intraday market. On the contrary, it is more profitable to sell the excesses of the predicted energy generation at the intraday spot market. The indications given by the historical data of the wind turbines are less clear than those given by the solar plants. Based on the historical data it is just possible to affirm that in the case of the wind onshore plant it is more convenient not to purchase the lack of energy at the intraday spot market from 11 am to 9 pm and to purchase it form this market only from 5 am to 7 am. Furthermore, it is statistically more convenient not to sell the excesses of energy at the intraday spot market from 5 am to 6 am. The sale of energy at the intraday spot market is only profitable at 7 am, 8 am and 5 pm. In the remaining hours, it is impossible to clearly define an optimal strategy with only the historical data.

Regarding the wind offshore plant, it is just possible to state that statistically it is not profitable to sell the excesses of energy generation at the intraday spot market at 5 am. The intraday spot market represents the best market to sell the energy from 8 am to 9 am, from 11 am to 1 pm and from 4 pm to 5 pm. Also in this case it is impossible to conjecture an optimal strategy with only the historical data for the remaining hours. In conclusion, we can state, that by performing an analysis implementing more historical data could offer a concrete way to avoid the balancing costs.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

The analysis based on historical price and generation data does not yield a clear recommendation. In some cases, avoiding intraday market activities and paying or receiving imbalance prices instead, is more economical from a plant operator's perspective. While other cases provided the opposite result.
Hence, we cannot provide a clear recommendation, always or never, to use the intraday market for balancing of forecast errors. Nevertheless, it provides a useful opportunity to reduce imbalances in the BRP and to avoid possibly high imbalance costs.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

7.2 Using flexibility of customers as third party

In this case study, it is assumed that the aggregator uses the flexibility of customers that have a different supplier and aims to valorize it on various markets. The issues that may arise in this configuration are already discussed in the report "Improved BMs of selected aggregators in target countries"[18]. Here, they are illustrated using an example. For this purpose, an aggregator pooling three different loads – lighting, cooling and industrial processes – and a diesel generator as backup is considered. Table 23 provides a description of the aggregator's portfolio and the different customer load profiles.

Table 23: Portfolio description

Name	Nominal Capacity / Peak Load	Annual Demand	Description
Lighting (Load)	1 MW	2.5 GWh	• Only available at night between 8 PM and 6 AM • The load may be changed by up to 50 %. • Daily increases and reductions have to balance out.
Cooling (Load)	1 MW	2.5 GWh	• The load may be changed by up to 0.1 MW. • Daily increases and reductions have to balance out. • A load reduction or increase may only last for one hour. • There has to be a pause of at least half an hour between two increases or reductions. • There may be at most four flexibility activations per day.
Industry (Load)	1 MW	1.5 GWh	• The load may be changed by 0.1 MW to 0.2 MW. • Weekly increases and reductions have to balance out. • A load reduction or increase may last at most for four hours. • There may be at most ten flexibility activations per week.
Diesel Generator (Production)	1 MW	-	• Efficiency of 35 % • Fuel cost of 155 EUR/MWh

[18] A. Fleischhacker et al, Deliverable D3.2: Improved Business Models of selected aggregators in target countries, Technical Report, August 2017

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Figure 9 shows the annual load profiles of the considered loads. A weekly extract is illustrated in Figure 10 and Figure 11 provides the load duration curves.

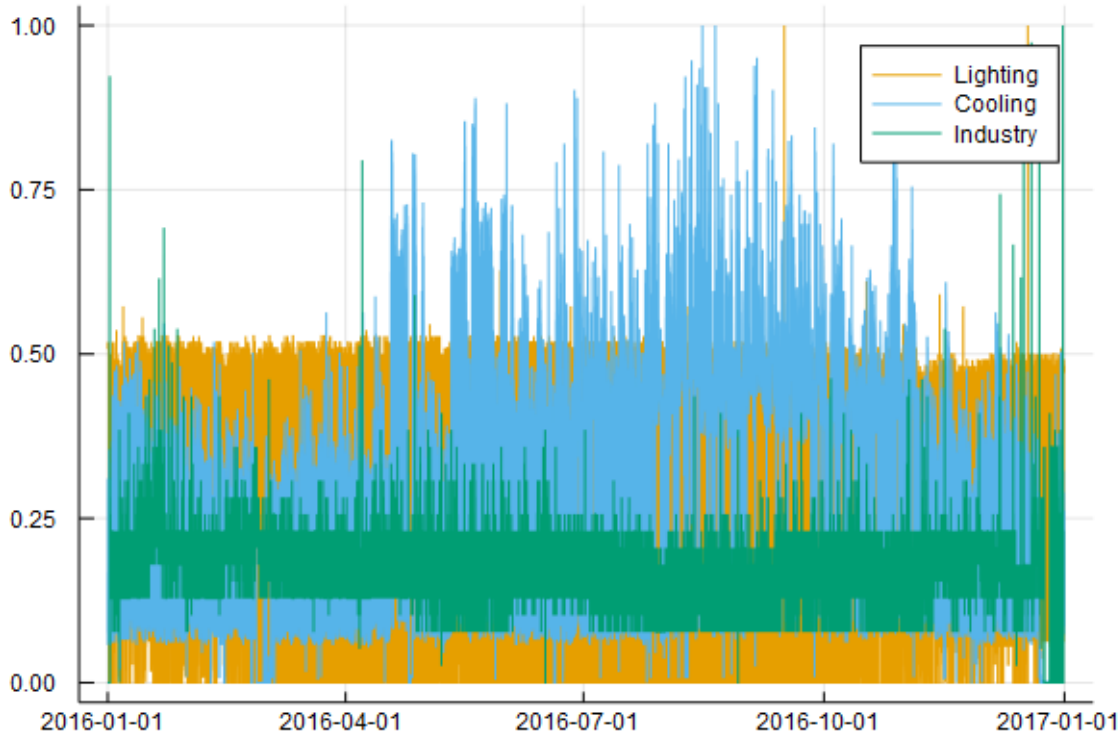

Figure 9: Annual load profiles of the three considered customer types.

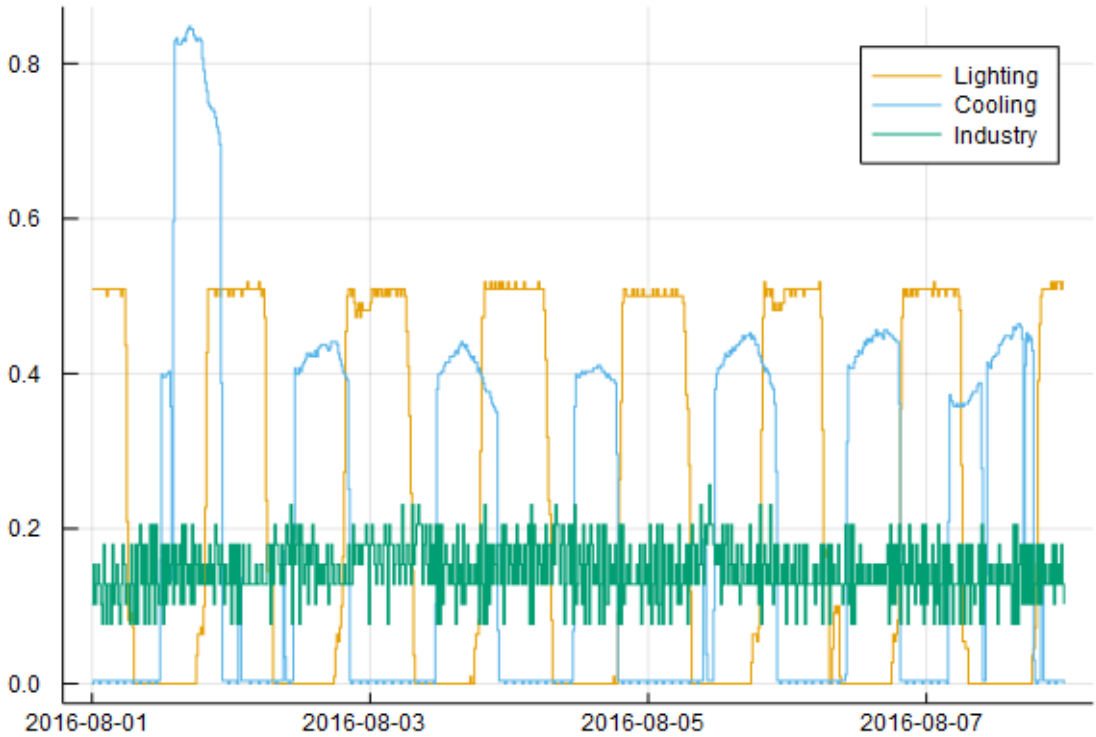

Figure 10: Weekly load profiles of the three considered customers.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

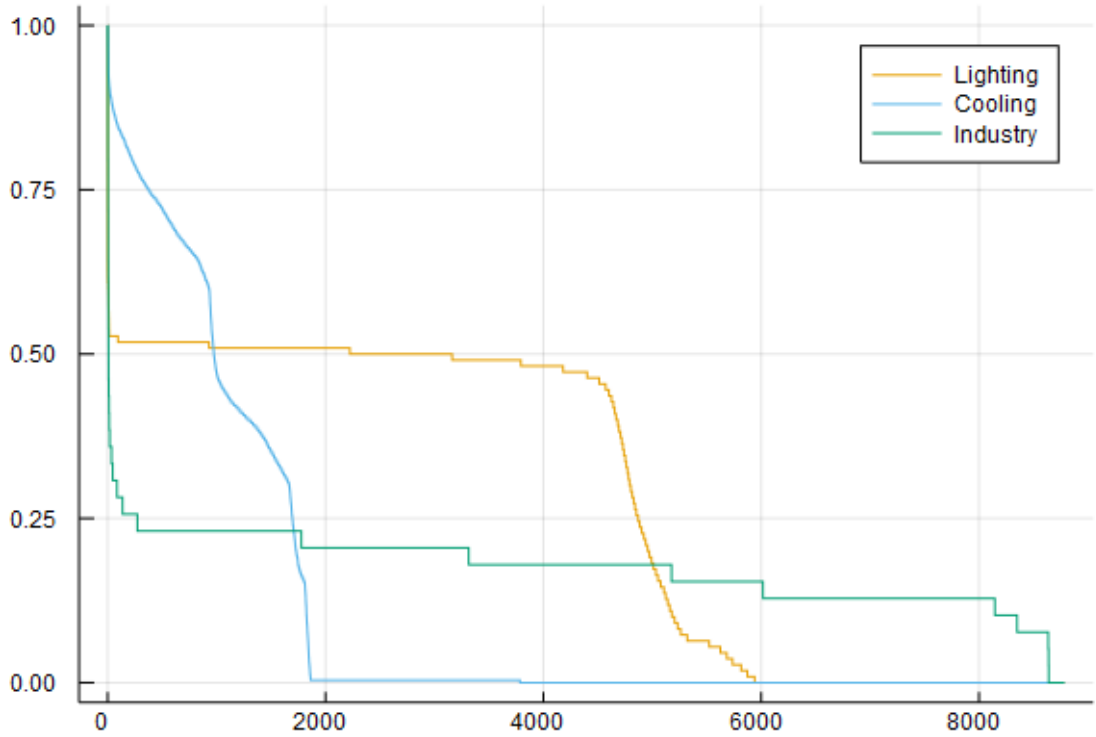

Figure 11: Load duration curves of the three considered customers.

7.2.1 Methods

In this BM analysis, the operation of the aggregator on the day-ahead spot market, the positive tertiary reserve market (mFRR) and the intraday market is simulated. The market data used for the simulations is from the year 2017 and downloaded from the website of the Belgian TSO Elia[19].

The Belgian positive tertiary reserve market (R3+) consists of monthly products. For each product the actors can place a bid consisting of a bid size in MW and a power price in EUR/MW. The bids are sorted by their price and the cheapest bids are accepted until the auctioned volume is reached. If a bid gets accepted the respective stakeholder is remunerated with the offered power price and has to provide energy whenever they are activated.

The aggregator activates flexibility options that belong to a third party supplier's balancing group. Hence, the aggregator may cause imbalances, depending on the market rules and the specifications of a bilateral contract between supplier and aggregator.

For the **day-ahead market**, we assume that there is a bilateral contract that assures that the supplier can still announce the aggregator's flexibility activations day-ahead. Hence, day-ahead activations will not result in imbalances. The settlement of supplied energy between the

[19] http://www.elia.be/en/grid-data/data-download

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

consumer/aggregator and the supplier happens according to the corresponding day-ahead market price.

For the **intraday market** we assume again that there is a bilateral deal on pass-through and settlement of missed or gained supply income at the day-ahead price. However, intraday activations may cause imbalances in the supplier's BRP. For the sake of simplicity, we assume that there are no imbalances except the imbalances caused by the aggregator and that the supplier passes on imbalance costs or gains to the aggregator. For the R3+ **reserve market** we assume that Transfer of Energy (ToE) rules apply. This means that imbalances in the supplier's BRP caused by reserve market activations for the aggregator's bids are corrected in the supplier's BRP. Possible deviations from reserve activations are added as imbalances in the aggregator's BRP. The aggregator still has to compensate the supplier for missed supply income caused by reserve activations. Again, we assume the day-ahead spot market price for this compensation.

To illustrate the effects of third party flexibility activations we consider three scenarios. The **Baseline** scenario does not consider any flexibility activations by the aggregator and serves as a reference point. In the **Baseline** scenario we consider the original load profiles and assume that the diesel generator is not producing at all. In the **Spot** scenario the flexibilities are used solely for day-ahead market optimization. In the **Reserve** scenario, on the other hand, all flexibility potential is offered at the R3+ reserve market. For reserve activations, the flexible loads are prioritized, and the diesel generator provides backup capacity. Reserve market participation is valued with the average power price for the respective monthly reserve product. Since we are considering shiftable loads, we have to balance reserve activations. This is done on the intraday market.

7.2.2 Results and Discussion

Table 24 shows the customer profit (negative cost) for the individual loads on different markets in the **Baseline** scenario. The profit of the supplier is listed in Table 25. We assume here that the customers are paying the day-ahead spot market price as customer tariff. We neglect other supplier tariff components as well as network charges and taxes in all three scenarios. In the **Baseline** scenario, no flexibility is activated and the supplier provides all energy demanded by the customer at the day-ahead spot market price.

Table 24: Customer profit in EUR on different markets in the Baseline scenario

Customer	Fuel	Supply	Reserve	Day Ahead	Intraday	Supply Transfer	Total
Lighting	0,0	-94128,2	0,0	0,0	0,0	0,0	-94128,2
Cooling	0,0	-97725,1	0,0	0,0	0,0	0,0	-97725,1
Industry	0,0	-60370,3	0,0	0,0	0,0	0,0	-60370,3
Diesel generator	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Total	0,0	-252223,6	0,0	0,0	0,0	0,0	-252223,6

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Table 25: Supplier profit in EUR on different markets in the Baseline scenario

Customer	Supply	Reserve	Day Ahead	Intraday	Imbalance	Supply Transfer	Total
Lighting	94128,2	0,0	-94128,2	0,0	0,0	0,0	0,0
Cooling	97725,1	0,0	-97725,1	0,0	0,0	0,0	0,0
Industry	60370,3	0,0	-60370,3	0,0	0,0	0,0	0,0
Diesel generator	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Total	252223,6	0,0	-252223,6	0,0	0,0	0,0	0,0

7.2.2.1 Spot

In the **Spot** scenario, the aggregator uses the flexibility potential of the customers to reduce their energy costs. The flexibility activations for one day are illustrated in Figure 12. Since we assume that there is a bilateral contract between aggregator and supplier and all flexibility activations can be nominated day-ahead, no imbalance costs are caused in this scenario. However, the flexibility activations of the aggregator change the load profile that the customers are billed for by the supplier. The cost of this difference in the load – valued with the respective day-ahead market price - is passed on to the supplier. Furthermore, the customer (or the aggregator) has additional benefits from the spot market flexibility activations.

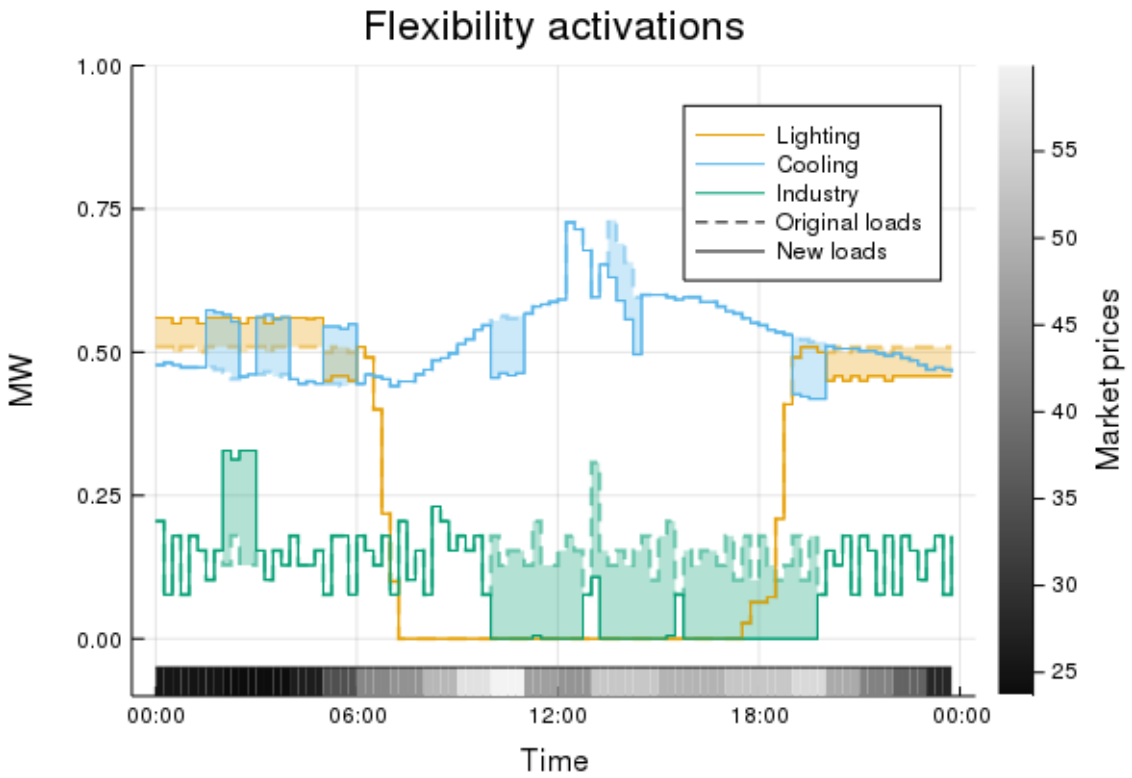

Figure 12: Flexibility activations of the three loads during one day. The gray bar at the bottom indicates the day-ahead spot market price at the respective hour.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

The profit of the customers and the supplier in the **Spot** scenario is listed in Table 26 and Table 27. Note that the customer table includes the common profit of aggregator and supplier. The columns *Supply* and *Supply Transfer* add up to the Baseline cost of the customer. The column Day-Ahead shows the profit achieved by the aggregator by offering the flexibility potential on the spot market. This benefit has to be split among the aggregator and customer. We see that the diesel generator is not used at all for the day-ahead market flexibility activations. The reason for this is the high fuel costs that does not allow profit from spot market sales. Furthermore, we notice that the total combined cost for customer and aggregator have decreased by around 6 % compared to the Baseline scenario, while the profit of the supplier remains unchanged. The supplier earns less from energy supply, but still buys for the original load profiles from the day-ahead spot market. However, they are remunerated for this with the Supply Transfer value.

Table 26: Customer profit in EUR on different markets in the **Spot** scenario

Customer	Fuel	Supply	Reserve	Day Ahead	Intraday	Supply Transfer	Total
Lighting	0,0	-90176,6	0,0	3951,6	0,0	-3951,6	-90176,6
Cooling	0,0	-94776,8	0,0	2948,2	0,0	-2948,2	-94776,8
Industry	0,0	-52219,5	0,0	8150,8	0,0	-8150,8	-52219,5
Diesel generator	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Total	0,0	-237173,0	0,0	15050,6	0,0	-15050,6	-237173,0

Table 27: Supplier profit in EUR on different markets in the **Spot** scenario

Customer	Supply	Reserve	Day Ahead	Intraday	Imbalance	Supply Transfer	Total
Lighting	90176,6	0,0	-94128,2	0,0	0,0	3951,6	0,0
Cooling	94776,8	0,0	-97725,1	0,0	0,0	2948,2	0,0
Industry	52219,5	0,0	-60370,3	0,0	0,0	8150,8	0,0
Diesel generator	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Total	237173,0	0,0	-252223,6	0,0	0,0	15050,6	0,0

The total flexibility activations and the relative benefit in EUR/MWh are listed in Table 28.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Table 28: Flexibility activations and relative benefit of the customers in the **Spot** scenario.

Customer	Activations [MWh]	Benefit [EUR]	Relative Benefit [EUR/MWh]
Lighting	899,1	3951,6	4,4
Cooling	277,4	2948,2	10,6
Industry	692,0	8150,8	11,8
Diesel generator	0,0	0,0	0,0
Total	1868,5	15050,6	8,1

Table 29 shows the change in average CO_2 emissions of electricity consumed by the loads compared to the **Baseline** scenario.

Table 29: Change of average CO_2 emissions of electricity consumed by the loads in the **Spot** scenario compared to the **Baseline** scenario.

Customer	Change of average CO_2 emissions [tCO_2/year]	Relative chang [%]
Lighting	-3,00	-1,02
Cooling	-1,00	-0,36
Industry	-6,07	-3,46
Total	-10,07	-1,35

7.2.2.2 Reserve

Table 30 and Table 31 show the profit of the customers/aggregator and the supplier in the **Reserve** scenario. Again, the reserve activations and the intraday purchases change the load profiles that the customers are billed for by the supplier. Furthermore, intraday trades cause imbalances in the supplier's BRP. The aggregator or the customers reimburse the supplier for these imbalances and for the cost related to the changed load and production profiles.

Table 30: Customer profit in EUR on different markets in the **Reserve** scenario

Customer	Fuel	Supply	Reserve	Day Ahead	Intraday	Supply Transfer	Total
Lighting	0,00	-94128,19	0,00	0,00	0,00	0,00	-94128,19
Cooling	0,00	-97723,18	2371,03	0,00	-26,37	-126,34	-95504,87
Industry	0,00	-60366,35	4488,56	0,00	-50,88	-224,43	-56153,10
Diesel generator	-2305,38	270,82	23360,73	0,00	0,00	-270,82	21055,35
Total	-2305,38	-251946,90	30220,32	0,00	-77,26	-621,59	-224730,81

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Table 31: Supplier profit in EUR on different markets in the **Reserve** scenario

Customer	Supply	Reserve	Day Ahead	Intraday	Imbalance	Supply Transfer	Total
Lighting	94128,2	0,0	-94128,2	0,0	0,0	0,0	0,0
Cooling	97723,2	0,0	-97725,1	0,0	-124,5	126,3	0,0
Industry	60366,3	0,0	-60370,3	0,0	-220,5	224,4	0,0
Diesel generator	-270,8	0,0	0,0	0,0	0,0	270,8	0,0
Total	251946,9	0,0	-252223,6	0,0	-344,9	621,6	0,0

The total flexibility activations in the **Reserve** scenario and the relative benefit in EUR/MWh compared to the **Baseline** scenario are listed in Table 32. We notice that the lighting load flexibility is not activated at all in the **Reserve** scenario. The reason for this is that the lighting flexibility is not available at the times of reserve activations and, hence, is replaced by the diesel generator. The revenue from offering 1 MW on the reserve market is divided among the customers according to the actual activations. While the total cost for the customers is reduced by about 12 % in the **Reserve** scenario compared to the Baseline, it is important to note that most of the benefits are provided by the diesel generator. For the flexible loads the **Spot** scenario results in greater cost reduction than the **Reserve** scenario.

Table 32: Flexibility activations and relative benefit of the customers in the **Reserve** scenario.

Customer	Activations [MWh]	Benefit [EUR]	Relative Benefit [EUR/MWh]
Lighting	0,00	0,00	0,00
Cooling	1,06	2220,19	2096,14
Industry	2,01	4217,23	2103,22
Diesel generator	5,22	21055,35	4035,26
Total	8,28	27492,77	3319,52

The reserve CO_2 emissions caused by reserve activations of the diesel generator amount to 5.47 tCO_2. However, it is unclear what type of technology it would replace on the reserve market. The same is true for the flexibility activations. Table 33 shows the change in emissions if these replaced emissions are valued with the average CO_2 emissions in Belgian energy production at the respective time.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Table 33: Change of average CO_2 emissions of electricity consumed by the loads and of electricity produced by the diesel generator in the **Reserve** scenario compared to the **Baseline** scenario.

Customer	Change of average CO_2 emissions [tCO_2/year]	Relative chang [%]
Lighting	0,00	0,00
Cooling	0,00	0,00
Industry	0,00	0,00
Diesel Generator	0,47	-
Total	0,47	0,09

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

8. Improved business models of Oekostrom AG (Austria)

8.1 Demand Side flexibilization of small customers

In this business model analysis, we investigate how the demand side flexibilization of small customers can provide benefits for both, the supplier Oekostrom and their customers. Oekostrom is purchasing energy from the day-ahead spot market and ensuring 100% renewable energy supply by paying 1.5 EUR/MWh for renewable energy certificates. The customers, however, are billed a constant, i.e. time independent, tariff. Here we want to analyze the effects of a time-of-use tariff on the cost of both, Oekostrom and their customers.

8.1.1 Methods

For the quantitative analysis, we consider four different customer types of Oekostrom. For each customer type we aggregate the loads of 5000 individual flats. The load profiles of the flats were generated with the modeling tool for residential energy consumption "Load profile generator"[20].The corresponding average daily load profiles are illustrated in Figure 13. In order to evaluate the effects of a time-of-use tariff we first calculate the cost of the customers as well as the cost of the aggregator Oekostrom in a **Baseline** scenario.

For this case, we use a constant supplier tariff of 59.9 EUR/MWh[21].Subsequently, in the **Flexible** scenario, we investigate the reaction of the customers to a price signal provided by a time-of-use tariff consisting of two price levels: A high price level during the day from 8AM to 8PM and a lower price level during the remaining hours at night.

[20] https://www.loadprofilegenerator.de/ last access 07.12.2018
[21] Sample Invoice, online available at https://oekostrom.at/Content/uploads/downloads/Rechnungserkla%CC%88rung_Strom.pdf, last access 07.12.2018

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

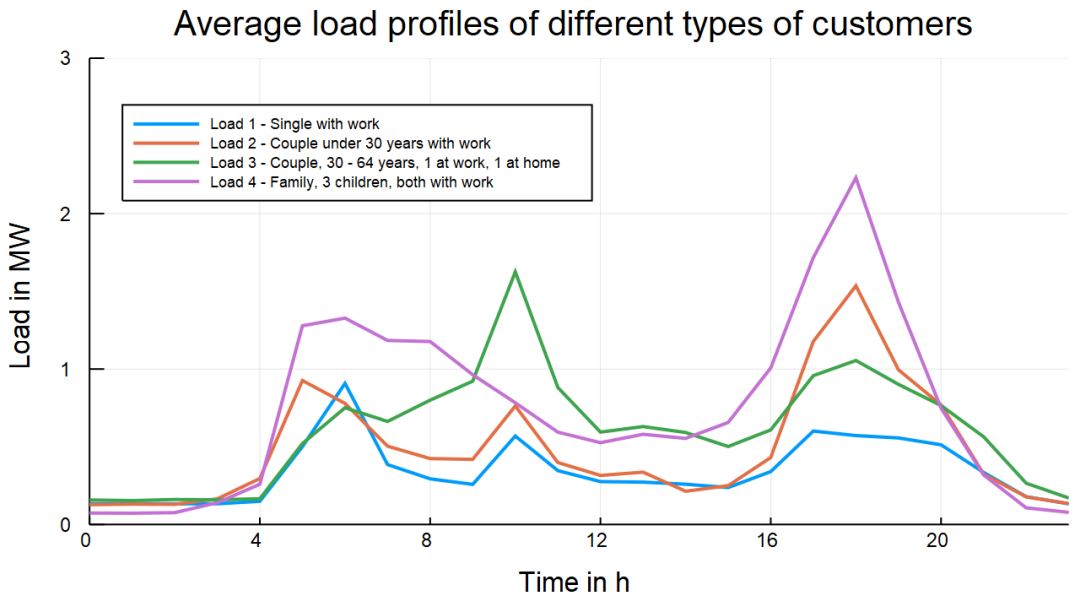

Figure 13: Average daily load profiles of the four analyzed types of customers

We use the EXAA[22] spot market prices from the year 2017 plus 1.5 EUR/MWh for renewable certificates to quantify the market purchase cost of Oekostrom. The price level intervals of the time-of-use tariff and the average EXAA spot prices are shown in Figure 14.

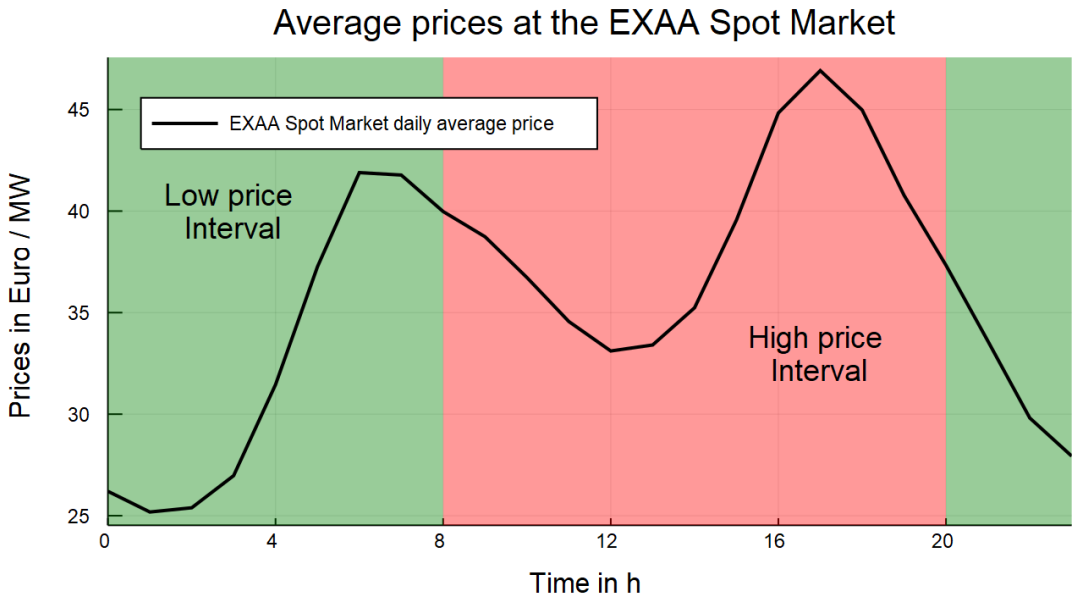

Figure 14: Average prices at the EXAA Spot Market (2017)

The high and low price intervals incentivize the customers to shift their demand to low cost times. To simulate demand response, we have made some assumptions on the available flexibility potential of the customers. Table 34 shows the restrictions on the flexibility options considered for the different customer types.

[22] https://www.exaa.at/

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Table 34: Flexibility of the analyzed loads

	Max. profile increase in MW	Max. profile reduction in MW	Max. rel. increase in %	Max. rel. reduction in %	Max. activation time in h	Equilibrium period	Min. activation pause in h	Max. activations
Load 1	1.5	1.1	100	100	unlimited	Month	0	Unlimited
Load 2	1.2	1.4	50	80	unlimited	Week	0	8 a day
Load 3	1.8	1.9	35	35	5	Week	2	5 a day
Load 4	1.8	2.3	100	60	unlimited	Day	0	Unlimited

The maximal profile increase and reduction define the maximum power that a customer can add or remove to its current load. The maximal relative increase and reduction indicate the maximal power increase and decrease relative to the current load values. The maximal activation time indicates the maximum duration of deviation from the non-flexible profile. The Equilibrium period determines the period within all the profile increases and reductions have to be balanced. The minimal activation pause defines the minimal duration of a period without load alterations between two profile changes. Finally, the maximal activations determine how often a profile can change within a period. The model is implemented in Julia using the methods described in Section 2.1.2.3. The objective in the **Flexible** scenario is to maximize the load consumed during the hours of the low price level.

8.1.2 Results

To illustrate the functionality of the model, Figure 15 shows the flexibility activations of Load 1 in the first week of December. We can see that in the hours of the day the load is reduced, while at night it is increased.

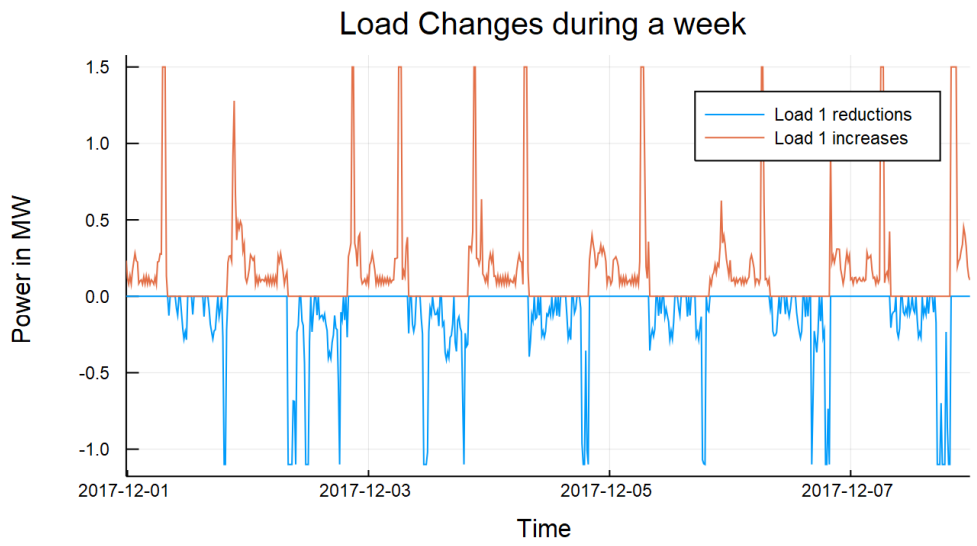

Figure 15 Optimized load changes of load 1 during the first week of December

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

This solution offers the lowest costs for a customer with the considered time-of-use tariff, respecting the load flexibility limits described in Table 34. Table 35, illustrates the amount of activated flexibility per year.

Subsequently, we look at the cost of the individual customer types and the profit of the aggregator. To evaluate the customers' cost, we first have to define the price levels of the time-of-use tariff. For this purpose, we choose different values for the higher price level and determine, for each customer type the maximum value of the lower price level, so costs do not exceed the Baseline cost. Furthermore, again for each customer type, we identify the minimum value of the lower price level, so that the aggregator's profit is not reduced compared to the **Baseline** profit. The resulting feasible price bands for each customer type and for all customers together are illustrated in Figure 16.

Table 35: Shifted load per profile

	Load 1	Load 2	Load 3	Load 4
Total consumption in MWh / year	2999.6	4278.5	5316.4	6527.6
CO_2 -Emissions in tCO_2 / MWh	0.392	0.374	0.389	0.370
Shifted load in MWh / year	1131.9	826.8	432.9	1495.54
Shifted load in %	37.74	19.33	8.14	22.91
Change of the CO_2 -Emissions in %	+ 1.18	+ 0.83	- 0.64	0.00

The flexible tariff must allow the aggregator to earn more and the customers to pay less compared to the baseline strategy. Figure 16 shows the price band (lower and upper cost limits) that the aggregator can apply on the different types of consumer, so to accommodate the energy buyers and seller. The analysis is based on the 2017 market and load data.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

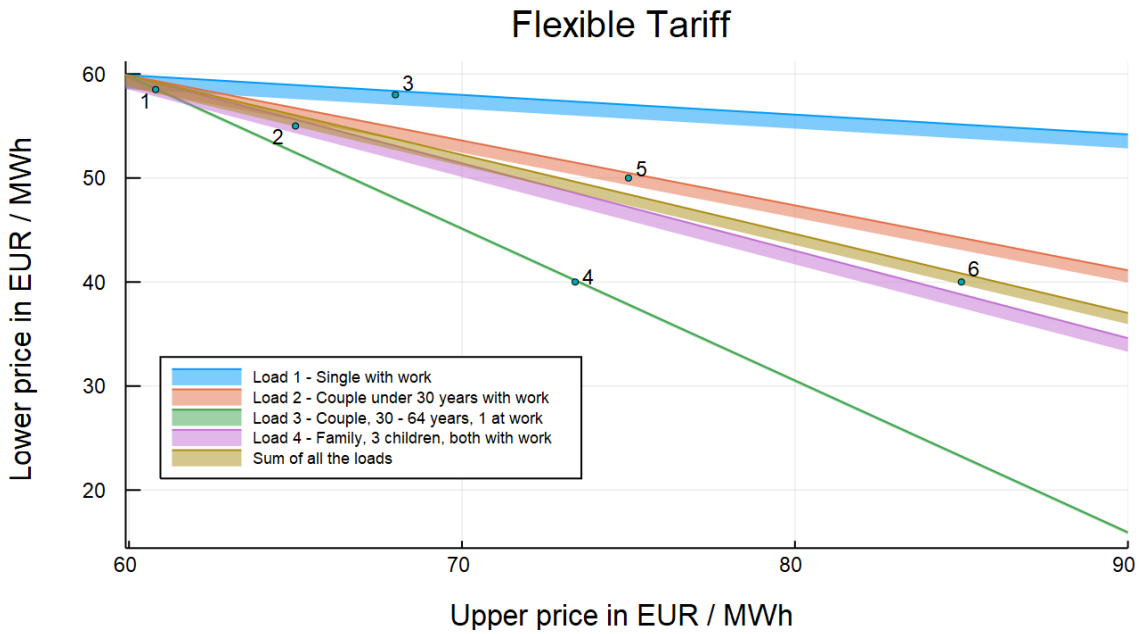

Figure 16: Price bands to get a win-win game

We marked several points in Figure 16, to describe the results in more detail. Table 36 lists for all tariffs specified by these points, the cost for each customer type and the profit of the aggregator Oekostrom from supplying the respective customer type. Finally, the last row shows the aggregated cost of all customer types and the total profit of Oekostrom.

Table 36: Resulting cashflows for different flexible tariffs

Tariffs in $\frac{EUR}{MWh}$	Baseline Tariff	Flexible Tariff (Point 1)	Flexible Tariff (Point 2)	Flexible Tariff (Point 3)	Flexible Tariff (Point 4)	Flexible Tariff (Point 5)	Flexible Tariff (Point 6)
Lower price level	59.9	58.5	55	58	40	50	40
Upper price level	59.9	60.8	65	68	73.4	75	85
Total Cost for Load 1	59.9	58.86 (- 1.73 %)	56.6 (- 5.52 %)	58.79 (- 0.51 %)	45.32 (- 24.34 %)	53.98 (- 9.88 %)	47.17 (- 21.25 %)
Profit of the Aggregator for Load 1	23.99	24.09 (+ 0.43 %)	21.67 (- 9.67 %)	24.87 (+ 3.67 %)	9.64 (- 59.8 %)	18.89 (-21.28 %)	11.62 (- 51.58 %)
Total Cost for Load 2	59.9	59.39 (- 0.86 %)	58.84 (- 1.77 %)	61.84 (+ 3.24 %)	52.83 (- 11.8 %)	59.6 (- 0.5 %)	57.28 (- 4.37 %)
Profit of the Aggregator for Load 2	22.96	23.18 (+ 0.97 %)	22.60 (- 1.56 %)	25.81 (+ 12.43 %)	16.17 (- 29.57 %)	23.42 (+ 2 %)	20.94 (- 8.81 %)
Total Cost for Load 3	59.9	59.86 (- 0.06 %)	60.94 (+ 1.73 %)	63.94 (+ 6.74 %)	59.82 (- 0.13 %)	64.84 (+ 8.24 %)	66.71 (+ 11.37 %)
Profit of the Aggregator for Load 3	23.18	23.23 (+ 0.22 %)	24.38 (+ 5.16 %)	27.58 (+ 19 %)	23.19 (+ 0.03 %)	23.91 (+ 3.16 %)	30.55 (+ 31.79 %)

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Tariffs in $\frac{EUR}{MWh}$	Baseline Tariff	Flexible Tariff (Point 1)	Flexible Tariff (Point 2)	Flexible Tariff (Point 3)	Flexible Tariff (Point 4)	Flexible Tariff (Point 5)	Flexible Tariff (Point 6)
Total Cost for Load 4	59.9	59.55 (- 0.58 %)	59.57 (- 0.56 %)	62.57 (+ 4.45 %)	55.25 (- 7.76 %)	61.42 (+ 2.53 %)	59.55 (+ 1.08 %)
Profit of the Aggregator for Load 4	23.16	23.55 (+ 1.68 %)	23.57 (+ 1.75 %)	26.78 (+ 15.61 %)	18.95 (- 18.17 %)	25.54 (+ 10.29 %)	24.62 (+ 6.29 %)
Total Cost for all the loads	59.9	59.49 (- 0.68 %)	59.32 (- 0.97 %)	62.32 (+ 4.04 %)	54.43 (- 9.14 %)	60.8 (+ 1.5 %)	59.43 (- 0.78 %)
Profit of the Aggregator for all the loads	23.25	23.46 (+ 0.92 %)	23.28 (+ 0.11 %)	26.48 (+ 13.91 %)	18.04 (- 22.39 %)	24.86 (+ 6.91 %)	23.4 (+ 0.64 %)

As we can see from the results, the flexibility determines the range between the high price and low price in which there is a win-win situation. Furthermore, flexibility also determines the slope of the straight lines, which delimit this price range. The flexible tariff in Point 1 shows the case in which there is a win-win situation between all the participants. It should be noted that if a point is located above the win-win price band of a load, the customer would have to pay more than when the fixed rate is applied. On the contrary, if the point is below the win-win price band of a load, the customer will have high gains, while the aggregator will have losses compared to the baseline strategy. The aggregator, however, will not take into account the individual gains, but the overall earnings. In fact, for the aggregator it is convenient to apply for these loads together all the rates inside and above the yellow price band, which consists of the sum of all the loads taken into consideration. As we can see from the results indeed the flexible rates analyzed in the Points 1, 2, 3, 5 and 6 provide profit increase for the aggregator. These rates, excluding the first one, do not suit all the consumers. For example, the tariff analyzed in Point 6 provides benefits for both, Oekostrom and all customer types combined. However, if we focus on the individual consumers, we see that the consumers of type 3 (green) and 4 (violet) would pay more than in the **Baseline** scenario with a constant tariff. The only tariff that is not convenient to the aggregator is the one described by Point 4, which in fact is below the price band of the total load (yellow).

8.1.3 Conclusion

We have seen that flexibilities of loads can be used to create win-win situations between the consumers and the aggregator/supplier Oekostrom. A single optimal price band cannot be easily determined for all the load types, because the bands depend heavily on the flexibility that a consumer can offer. However, it is important to underline the fact that flexibilities create value. This value would be automatically distributed among all consumer types, if the aggregator distinguished every single load and applied to each load a flexible tariff contained in their price band.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

In reality, this is unattainable because the aggregator would be forced to make a different flexible rate for each individual customer. For further research, it could be interesting to analyze how to distribute this value created by the customers' flexibilities. Differences in flexibilities lead to a big divergence between optimal flexible tariffs for different types of consumers. It is conceivable that an aggregator divides the customers into large groups of consumers with similar flexibility characteristics. Furthermore, an optimal flexible tariff could be defined and provide monetary benefits both to the consumers with similar flexibility characteristics and to the aggregator. Based on this analysis, we can state that flexibilities of electrical loads can be used to create value.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

8.2 Valorize distributed generation of customers in apartment houses

Currently the most economical way of investing and operating PV plants on buildings is to maximize self-consumption. In that case, PV generation is used instead of consuming electricity from the grid. In most European countries, this BM is restricted to residential homeowners residing in single-family houses. Generation can be allocated to one metering point, only. In this section we investigate the case of a shared PV plant on an apartment building with multiple flats.

8.2.1 Methods

In order to achieve realistic results, typical profiles of apartment houses in Vienna are used[23]. Table 37 shows the composition of the inhabitants of a typical Austrian apartment house with 10 flats. Figure 17 shows the corresponding average load profiles.

Table 37: Typical inhabitants of an apartment house in Austria

Flat 1	Flat 2	Flat 3	Flat 4	Flat 5
Single with work	Single woman, 30 - 64 years, with work	Student with Work	Single man over 65 years	Couple over 65 years
Flat 6	**Flat 7**	**Flat 8**	**Flat 9**	**Flat 10**
Couple under 30 years with work	Couple, 30 - 64 years, 1 at work, 1 at home	Family, 1 child, both at work	Family, 3 children, both with work	One at work, one work home, 3 children

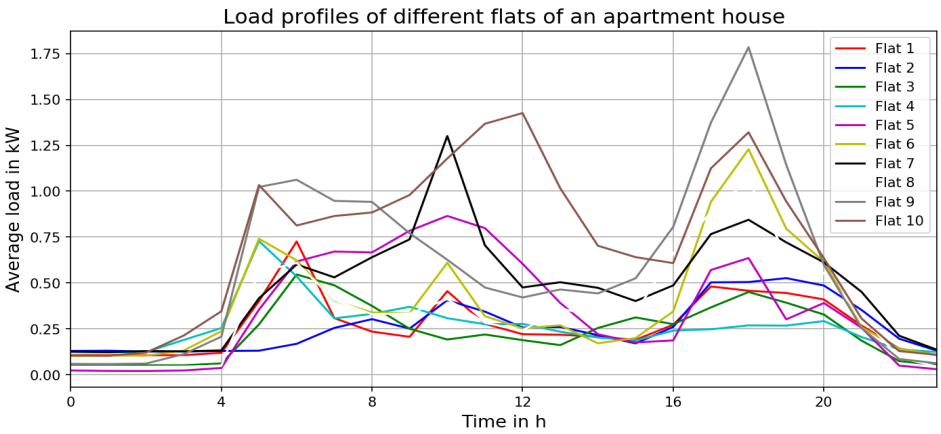

Figure 17: Average daily load profiles of different flats of an apartment house

Three scenarios are considered in the business model analysis:

[23] https://www.wko.at/service/zahlen-daten-fakten/daten-bevoelkerung-haushalte-wohnungen.html last access 04.07.2018
https://www.destatis.de/DE/Publikationen/Thematisch/Bevoelkerung/HaushalteMikrozensus/EntwicklungPrivathaushalte5124001179004.pdf?__blob=publicationFile last access 04.07.2018

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

- In the **Status quo** case, there is no PV plant installed and the customers procure all energy from a supplier via the grid.

- In the **Static** scenario, every participant owns a fixed share of the PV system. The produced energy is allocated among the inhabitants statically according to these fixed shares. In this case the PV generation cannot be traded between the inhabitants of the apartment house. The energy that is produced and not used by the owner, is sold to the electric grid.

- The **Dynamic** case represents the most flexible case. Every participant owns a part of the photovoltaic panel, just like in the **Static** case. The PV plant generation however, can be traded among the inhabitants of the apartment house. If, at one point in time, a participant has excess PV generation, i.e. their share of PV production exceeds their consumption, and another participant's load surpasses their share of generation, the energy can be sold from the former to the latter resident. It is assumed that all participants share a common distribution grid connection point. Hence, by trading among the residents, aggregation effects of the loads are expected to yield reduction in network charges, fees, taxes and energy supply cost.

To find the optimal solution for the three cases, we formulate an optimization problem that minimizes the overall costs for energy procurement. The model is implemented in Python using the Pyomo package and the Gurobi solver. The variables of the optimization problem are the installed solar power, the maximal energy procured from the grid of every flat and the energy traded by each flat. The maximum installed power is dependent on the area available for the photovoltaic plant, which in this case is 150 square meters. For this reason, the maximum installed photovoltaic power is 22.8 kW_P. The solar irradiation values and the PV plant costs are taken from the Solar radiation Data (SoDa) servers.[24] For network charges and the supplier tariff, we use a sample invoice for Oekostrom customers.[25]

8.2.2 Results

Figure 18 shows the total cost for all customers in the three scenarios. The different cost components are indicated by color. The "Grid Procurement Costs: Energy" correspond to the cost for the supplier tariff and, hence, to the aggregator's revenue.

[24] http://www.soda-pro.com/soda-products last access 04.12.2018

[25] https://oekostrom.at/strom/#privatkunden last access 28.06.2018

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

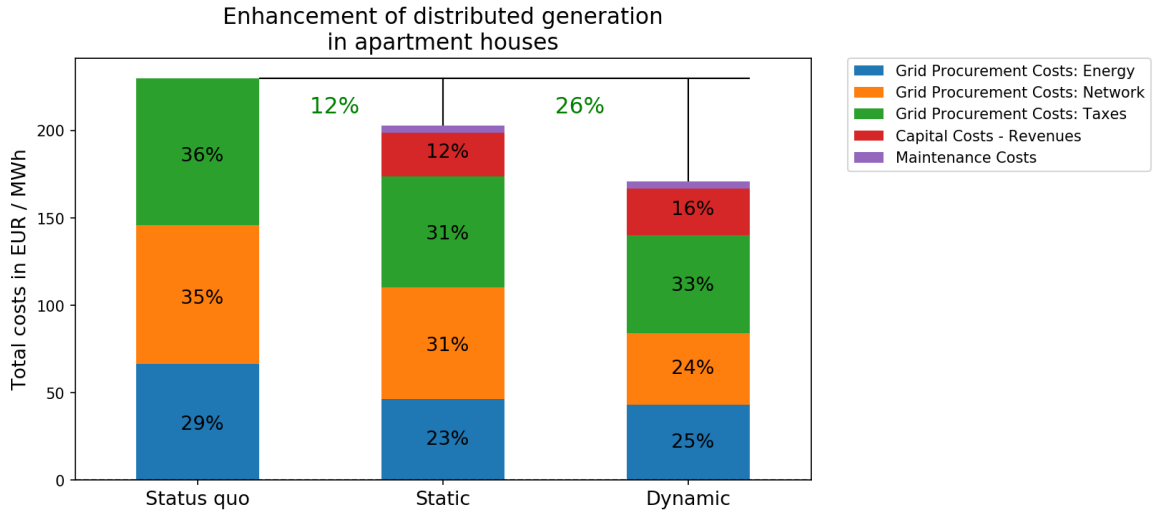

Figure 18: Enhancement of distributed generation in apartment houses

The percentages of the individual costs show, how the different components of the cost affect the overall costs in the three cases. Table 38 lists all the costs that make up the price of electrical energy of an apartment house.

Table 38: Comparison of the overall costs components

Overall cost components	Status quo costs in EUR / MWh	Static costs in EUR / MWh	Dynamic costs in EUR / MWh	Change in % Status quo vs Static	Change in % Status quo vs Dynamic	Change in % Static vs Dynamic
GPC: Energy	66.5	46.63	43.13	-30	-35.1	-7.5
GPC: Network	79.62	63.55	40.88	-20.2	-48.7	-35.6
GPC: Taxes	83.77	63.66	56.15	-24	-33	-11.8
Investments	0	39.8	39.8	-	-	=
Revenues	0	14.86	13.09	-	-	-12
Maintenance	0	3.89	3.89	-	-	=
Overall	229.89	202.65	170.74	-11.8	-25.7	-15.7

Table 39 shows the total consumption and the avoided CO_2 emissions in the different scenarios. For the avoided CO_2 emissions, the electricity from the grid is valued with the average CO_2 emissions of electricity production in Austria at the respective time.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Table 39: Total consumption and avoided CO_2 emissions

	Status quo	Static	Dynamic
Total consumption from the grid in MWh / year	34.5	23.1	21.1
Avoided CO_2 -Emissions in tCO_2 / MWh	0	0.106	0.11

8.2.2.1 Cost Benefit analysis: Customers

The case with the lowest expenses is obviously the **Dynamic** case, because of its flexibility and the possibility of exchanging solar energy between the inhabitants of the apartment house with low additional costs. This allows using the PV generation instead of consuming electricity from the grid and by this means maximizing the self-consumption of the building.

Comparing the **Status quo** and the **Static** case, the results show that all cost components decline by approximately 25 percent. The photovoltaic panels however require investment and maintenance costs and therefore the saving on the overall costs is 11.8 percent.

If we compare the **Status quo** and the **Dynamic** case, the components costs decrease more than in the **Static** case, yielding an overall cost reduction of 25.7 percent. The Grid network costs are those that improve more consistently, 48.7 percent. The reason for this considerable reduction is the fact, that in the **Dynamic** case the needed peak network power for each flat is significantly lower than in the **Status quo** case. Unlike the **Dynamic** case, the **Static** method does not allow to reduce consistently the grid network costs, because each flat owner has to cover their electricity peaks with only the connection to the grid and his part of photovoltaics. The possibility of exchanging the solar energy between the inhabitants of the apartment house with low additional costs affects strongly the needed peak network power, especially because the electrical peaks of the flats do not appear at the same time in, general. It is also worth noting, that the optimal installed solar power in both cases, **Static** and **Dynamic**, is the maximum allowed power of 22.8 kW_P. Table 40 shows the peak network power in each flat.

Table 40: Required network power in each flat in kW

Case	Flat 1	Flat 2	Flat 3	Flat 4	Flat 5	Flat 6	Flat 7	Flat 8	Flat 9	Flat 10	Total
Status quo	4.2	4.5	4.4	1.6	3.9	4.4	4.8	3.7	6.6	7.2	45.3
Static	3.9	4.5	4.4	1.4	3.5	4.4	2.9	3.4	6.6	7.2	42.4
Dynamic	1.1	2.7	0.9	0.6	1.6	1.9	1.9	1.6	2.6	3.8	18.8

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

The big savings in "GPC: Network" are due to the fact that the maximum required power decreases significantly in the **Dynamic** case. In the real case, however, it is not realistic that the photovoltaic panel produces exactly what is expected. For this reason, from now on, all the calculations we assume that the required network power remains unchanged to the **Status quo**. Figure 19 and Table 41 show the enhancement of distributed generation in apartment houses and the comparison of the overall cost's components, considering that the required network power does not change in relation to the **Status quo**.

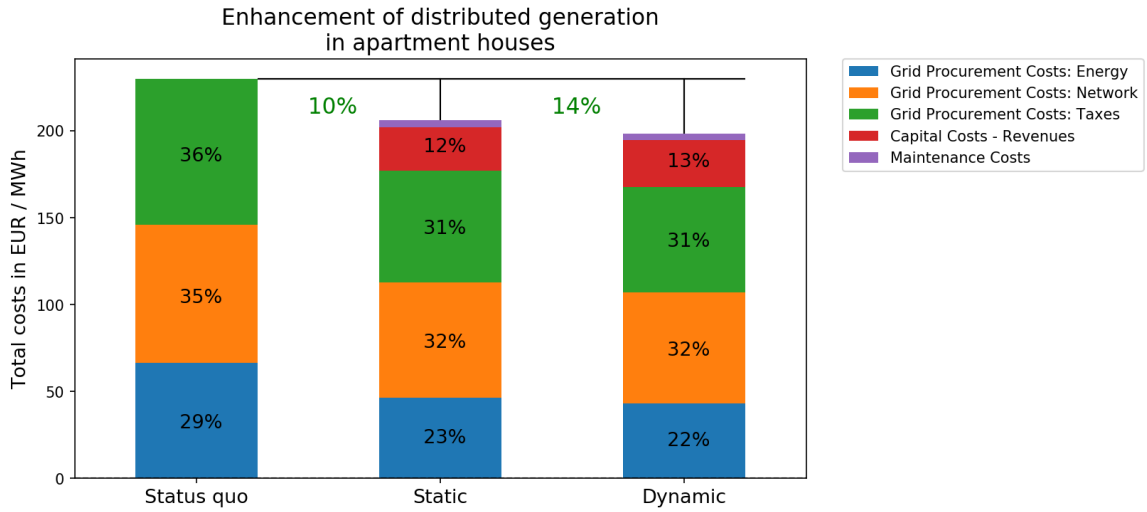

Figure 19: Enhancement of distributed generation in apartment houses 2

Table 41: Comparison of the overall costs components 2

Overall cost components	Status quo costs in EUR / MWh	Static costs in EUR / MWh	Dynamic costs in EUR / MWh	Change in % Status quo vs Static	Change in % Status quo vs Dynamic	Change in % Static vs Dynamic
GPC: Energy	66.5	46.63	43.13	-30	-35.1	-7.5
GPC: Network	79.62	66.26	63.91	-16.8	-19.7	-3.6
GPC: Taxes	83.77	64.2	60.75	-23.4	-27.5	-5.4
Investments	0	39.8	39.8	-	-	=
Revenues	0	14.86	13.09	-	-	-12
Maintenance	0	3.89	3.89	-	-	=
Overall	229.89	205.9	198.38	-10.4	-13.7	-3.7

The results show that the overall costs in the **Dynamic** case are significantly lower.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Furthermore, we investigate if the reduction of the costs are equally distributed between the apartment flat inhabitants. Figure 20 shows the components of the electrical energy costs for each flat comparing the **Status quo**, the **Static** and the **Dynamic** cases.

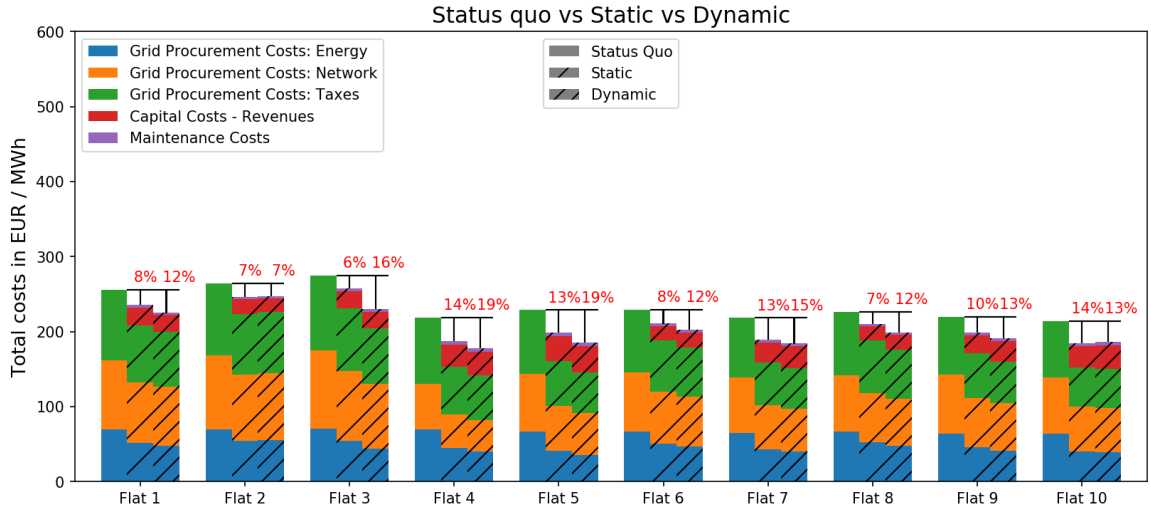

Figure 20: Components of the electrical energy costs for each flat

Figure 20 shows that the **Dynamic** case provides the least total cost for all the inhabitants of the apartment house, except for flat 10. In fact, we note that the costs reductions and the investment & maintenance costs are not equally distributed between the flats. It is also interesting to see that the apartments with more savings in the **Static** case do not necessarily have a greater cost reduction in the **Dynamic** case. For example, Flat 3 has a reduction of 6 percent if we compare the **Status quo** and the **Static** cases. On the other hand, the costs reduction of Flat 3 in the **Dynamic** case is 16 percent. Conversely Flat 10 has a reduction of 14 percent in the **Static** case and 13 percent in the **Dynamic** case. Lastly, considering the blue bars, we note that the "GPC: Energy" costs contribute the most to the overall cost reductions in the different cases.

8.2.2.2 Cost Benefit analysis: Aggregator

The reduction of the need of energy from the grid causes a decrease in aggregator's revenue. To realize the PV installation, however, it is necessary to provide benefits for all market participants involved in the improved business model. For this reason, it is important to analyze, how the aggregators' profit is influenced by the overall costs reduction of the customers. In this analysis, the aggregator buys the energy at the Central European energy exchange EXAA. Furthermore, the aggregator pays the price of the guarantee of origin and sells the energy to the customers for 5.99 cent/kWh. The profit of the aggregator is the difference between the revenue from selling energy to customers and the cost for purchasing it at the EXAA and paying the renewable energy certificates (1.5 € / MWh). Figure 21 shows the total profit of the aggregator in the different scenarios. The light green bar indicates the minimal additional revenue for the aggregator so that their profit is higher than in the **Status quo** scenario. This additional revenue can come e.g. from a service fee from the customers for this

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

improved business model. The dark green bar, on the other hand, shows how much the aggregator's revenue can be increased, while still ensuring lower overall costs of the apartment house customers than in the **Status quo** case.

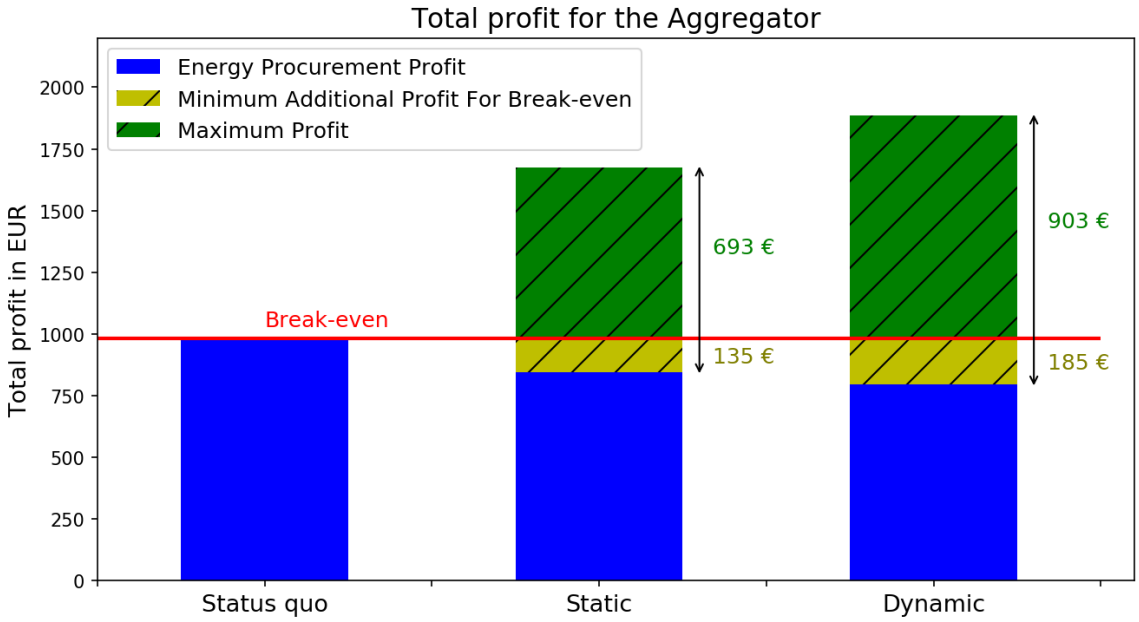

Figure 21: Profit analysis of the energy Aggregator

As we can see in Figure 21, the total costs of the customers decrease in the **Static** case of 828 € while in the **Dynamic** case of 1088 € compared to the **Status quo**. To make this distribution method competitive on the market it is necessary to offer possibly fairer savings for all participants. In order for the aggregator to have the same profit as in the **Status quo**, it is necessary for it to an additional profit: 135 € in the **Static** case and 185 € in the **Dynamic** case. This means that in the **Dynamic** case, if the aggregator is willing to have no further gains compared to the **Status quo**, the participating flats would have a reduction of the overall costs of 903 € at a cost of 185 € to the aggregator.

8.2.3 Conclusion

It has been shown that the **Dynamic** strategy for the distributed generation is the strategy, in which the cost savings potential of operating PV plants on buildings can be exploited to the fullest. This strategy guarantees a profit for all the participants of the building. However, for a life cycle business model analysis, additional managerial and organizational expenses for the aggregator have to be considered as well. For further research, it could be interesting to analyze how to distribute the overall savings to make this energy distribution method competitive on the market. Differences in savings between participating flats could result in rivalry, which would make this model, which is based on cooperation, unachievable.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

9. Improved business models of EDP (Portugal and Spain)

9.1 Activation and marketing of end user's flexibility in Portugal

This analysis examines the activation of the flexibility of metered customers of EDP for different purposes. In particular, the flexibilities shall be used either for reducing costs from purchasing energy on the day-ahead spot market or for reducing imbalance cost for EDP.

9.1.1 Methods

For the optimal dispatch of flexibility options of different load profiles an optimization model is set-up, minimizing the cost of flexibility activations on different markets. The optimization problem simulates the flexibility activations of an entire year with a quarter-hourly resolution. The decision variables are the load increase inc_t and the load reduction red_t at time t. Furthermore, the auxiliary binary variables inc_t^{active}, red_t^{active}, inc_t^{start} and red_t^{start} are introduced, describing if a flexibility activation is active or starting, respectively, at time t. Their relation to the decision variables is described in the following constraints:

$$inc_t \leq inc_{max} \cdot inc_t^{active}$$
$$inc_t \geq inc_{min} \cdot inc_t^{active}$$
$$inc_t^{active} \leq inc_{t-1}^{active} + inc_t^{start}$$

Analogous constraints are implemented for red_t. These auxiliary variables to depict different restrictions on the flexibility activations, like e.g. the maximal number of activations during a certain period or the maximal duration of a load change, in the optimization model constraints.

9.1.2 Scenario Description and Model Scaling

For the analysis of the improved business model three different customer loads from the year 2016, labelled **Heat**, **Water** and **Other**, are considered. Their profiles for one week and their load duration curves are illustrated in Figure 22 and their key characteristics are listed in Table 42.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

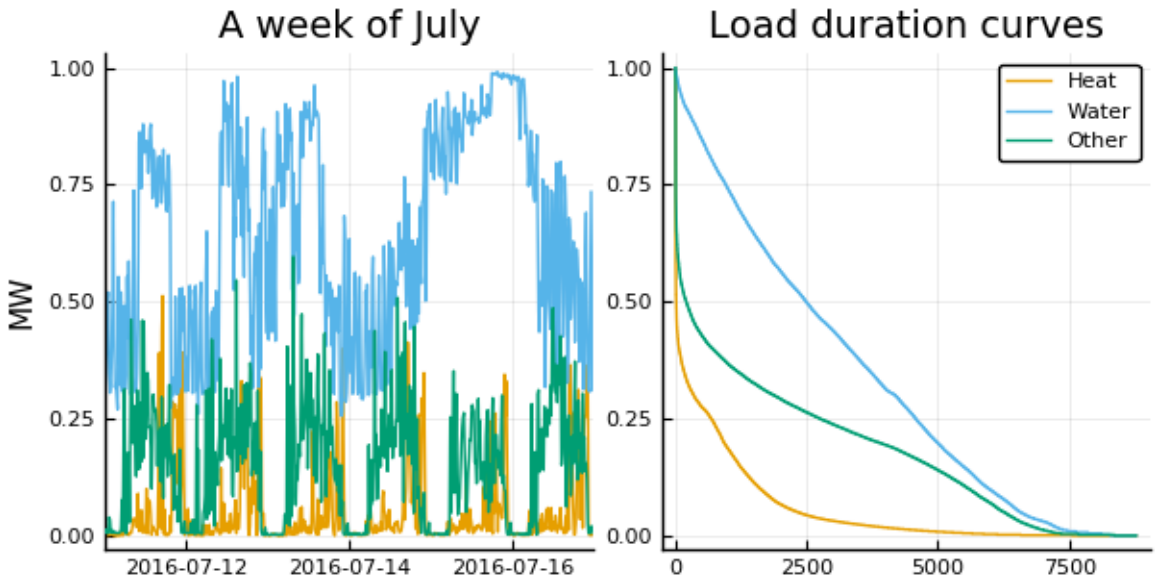

Figure 22: Considered load profiles: A week in July (left) and the load duration curves (right).

Table 42: Load characteristics

	Heat	Water	Other
Maximal load [MW]	1	1	1
Annual demand [MWh]	494	2850	1570

We assume the following restrictions on load flexibilities for the different load profiles:

- **Flex1 (Water):**
  - Maximal relative load change of ±10% for each time step.
  - Flexibility activations must not change the total daily consumption.
- **Flex2 (Heat):**
  - Maximal two load changes for each 15 minutes per day.
  - Flexibility activations must not change the total daily consumption.
- **Flex3 (Other):**
  - Maximal load change of ±0.1 MW.
  - Maximal three load changes per day for each at most two hours.
  - Flexibility activations must not change the total weekly consumption.

For the day-ahead spot market operation, the MIBEL spot market prices for Portugal from the year 2016 are considered. For the portfolio imbalance, the imbalance of EDP from the year 2016 is used and the imbalance reduction caused by flexibility activations is valued with the average hourly imbalance prices from the year 2016.

In order to evaluate the improved business model, the following scenarios are investigated:

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

- **Spot:** The flexibility is used exclusively to reduce electricity purchase cost from the day-ahead spot market. The imbalance cost reduction in this scenario is zero by definition.
- **Imbalance:** Conversely, here all available flexibility is used to reduce the imbalance of EDP's portfolio. For this it is assumed that the direction of the portfolio's deviation is known, but not the imbalance prices. The spot market cost reduction is zero in this scenario and the imbalance cost reduction is valued with the average positive or negative imbalance price, depending on the direction of the portfolio's deviation.
- **Optimal:** In this scenario, the model chooses the optimal marketplace for the flexibilities. This means that part of the flexibility is used for spot market purchase cost reduction if price spreads are high, and the rest is used for imbalance cost reduction, depending on which option provides more cost reduction. Note, that this scenario is not realistic, because imbalance prices are only settled after reserve market activations and cannot be known before. The purpose of this scenario is to provide a theoretical optimum.

9.1.3 Results and KPIs

The optimal flexibility activations for one week in different scenarios is illustrated in Figure 23, Figure 24 & Figure 25. Figure 23 shows the **Spot** scenario. The colored bar at the bottom indicates the spot market prices in the respective hour. The **Imbalance** scenario is shown in Figure 24. Here, the bottom bar illustrates the imbalance direction of EDP at the corresponding time. An imbalance direction of 1 means excess production. Hence, it is beneficial to increase load during these hours. Conversely, an imbalance direction of -1 corresponds to excess demand, which is tackled by load reductions. Figure 25 illustrates the operation in the **Optimal** scenario. The top subplot shows the flexibility activations triggered by the spot market and corresponding prices. The activations to reduce imbalances and respective imbalance prices can be seen in the bottom subplot.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

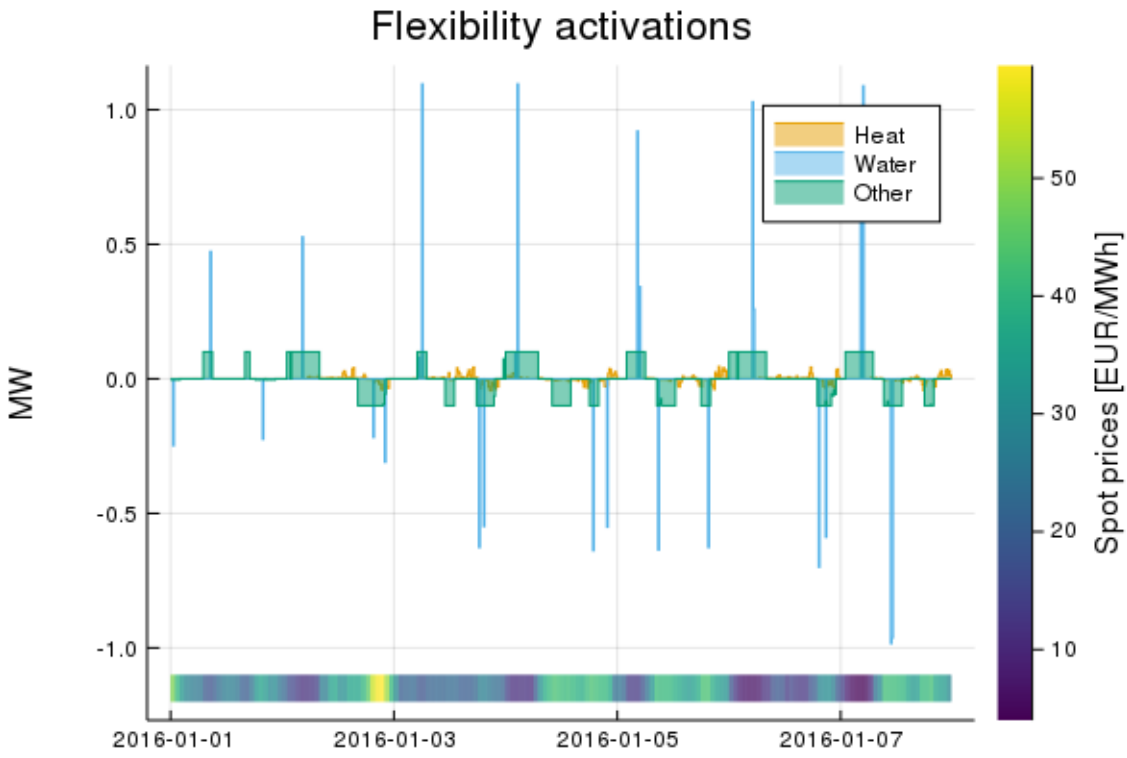

Figure 23: Flexibility activations of the different loads for one week in the **Spot** scenario.

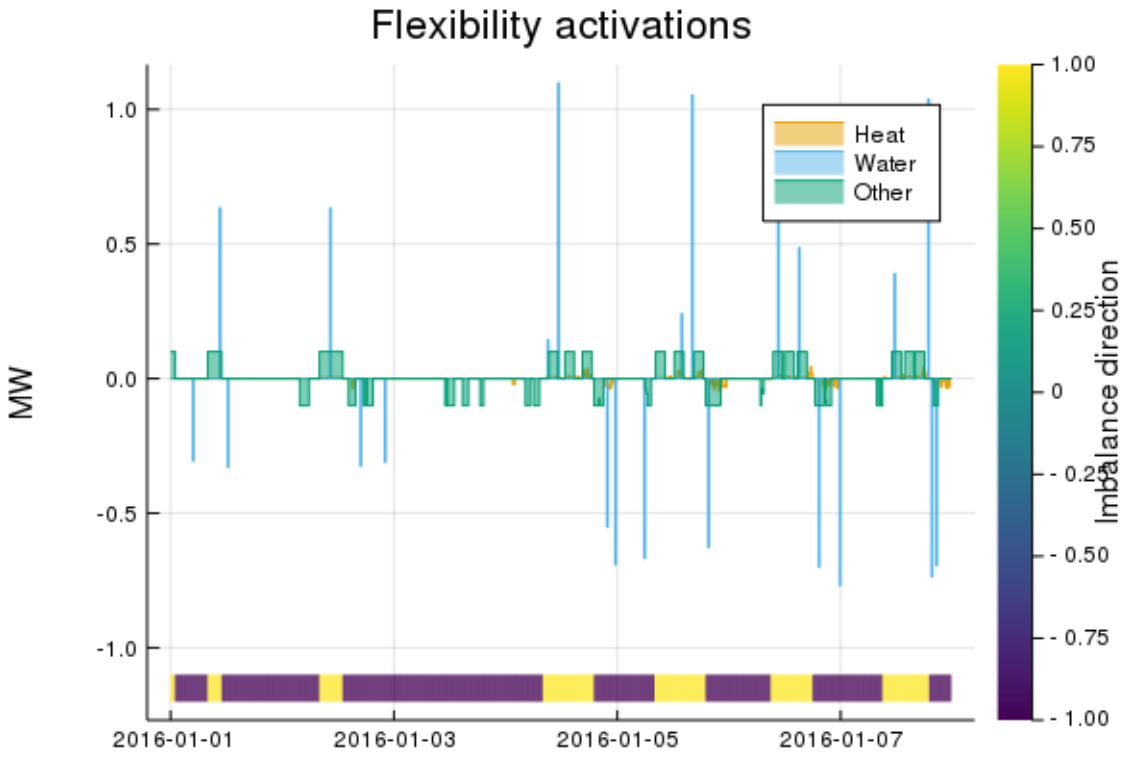

Figure 24: Flexibility activations of the different loads for one week in the **Imbalance** scenario.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

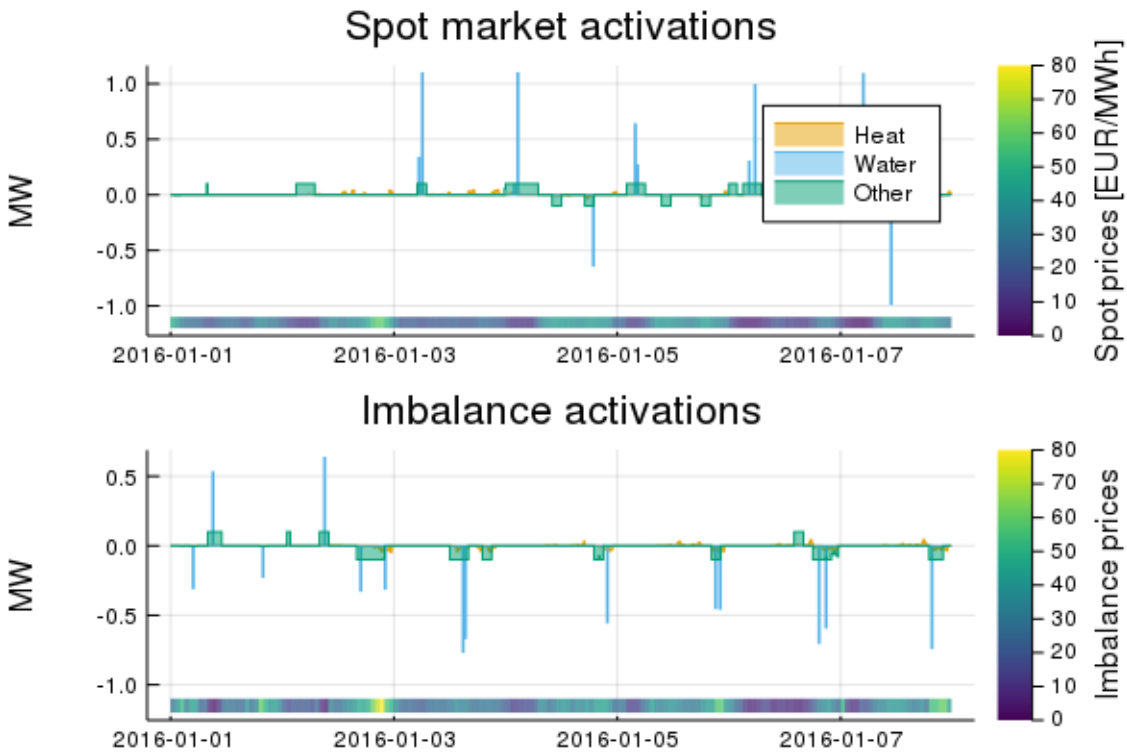

Figure 25: Flexibility activations of the different loads for one week in the **Optimal** scenario.

9.1.3.1 Economic KPIs

The achieved cost reduction compared to a passive baseline scenario for different scenarios is listed in Table 43. For each scenario the cost reduction for spot market purchases and the cost reduction for portfolio imbalances is provided in absolute numbers [EUR/a] and in relative numbers [EUR/MWh]. The relative values are given in Euro per MWh of activated flexibility (positive and negative) on the considered marketplace.

Table 43: Economic KPIs for the considered load portfolio

Cost Reduction	Spot	Imbalance	Optimal
Spot market [EUR]	-4920.4	0.0	-89.2
Spot market [EUR/MWh]	-7.7	0.0	-0.4
Imbalance cost [EUR]	0.0	-4627.3	-10296.2
Imbalance cost [EUR/MWh]	0.0	-9.7	-22.6
Total [EUR]	-4920.4	-4627.3	-10385.4
Total [EUR/MWh]	-7.7	-9.7	-15.9

The economic KPIs per load are listed in Table 44-Table 46.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Table 44: Economic KPIs for the **Heat** load

Cost Reduction	Spot	Imbalance	Optimal
Spot market [EUR]	-168.7	0.0	126.5
Spot market [EUR/MWh]	-3.7	0.0	8.2
Imbalance cost [EUR]	0.0	-247.1	-629.7
Imbalance cost [EUR/MWh]	0.0	-10.4	-18.6
Total [EUR]	-168.7	-247.1	-503.3
Total [EUR/MWh]	-3.7	-10.4	-10.2

Table 45: Economic KPIs for the **Water** load

Cost Reduction	Spot	Imbalance	Optimal
Spot market [EUR]	-1626.9	0.0	271.3
Spot market [EUR/MWh]	-7.6	0.0	6.0
Imbalance cost [EUR]	0.0	-1667.5	-4317.7
Imbalance cost [EUR/MWh]	0.0	-9.1	-26.4
Total [EUR]	-1626.9	-1667.5	-4046.4
Total [EUR/MWh]	-7.6	-9.1	-19.4

Table 46: Economic KPIs for the **Other** load

Cost Reduction	Spot	Imbalance	Optimal
Spot market [EUR]	-3124.8	0.0	-487.0
Spot market [EUR/MWh]	-8.2	0.0	-3.5
Imbalance cost [EUR]	0.0	-2712.7	-5348.7
Imbalance cost [EUR/MWh]	0.0	-10.0	-20.8
Total [EUR]	-3124.8	-2712.7	-5835.8
Total [EUR/MWh]	-8.2	-10.0	-14.7

9.1.3.2 Technical KPIs

The flexibility activations in MWh on different marketplaces for the three scenarios **Spot**, **Imbalance** and **Optimal** are listed in Table 47. In the cases **Spot** and **Imbalance** with a single market place, the load reductions have to match

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

the load increases per market, because only shiftable loads are considered. In the theoretical **Optimal** scenario, the spot market load increase is almost twice the spot market load reduction.

Table 47: Technical KPIs for the considered load portfolio.

Flexibility Activations	Spot	Imbalance	Optimal
Spot increase [MWh]	319.2	0.0	124.9
Spot reduction [MWh]	319.2	-0.0	75.1
Spot activation [MWh]	638.5	0.0	200.1
Imbalance increase [MWh]	0.0	238.5	202.5
Imbalance reduction [MWh]	-0.0	238.5	252.3
Imbalance activation [MWh]	0.0	476.9	454.8
Total increase [MWh]	319.2	238.5	327.4
Total reduction [MWh]	319.2	238.5	327.4
Total activation [MWh]	638.5	476.9	654.8

The technical KPIs per load are listed in Table 48-Table 50.

Table 48: Technical KPIs for the **Heat** load.

Flexibility Activations	Spot	Imbalance	Optimal
Spot increase [MWh]	22.9	0.0	10.6
Spot reduction [MWh]	22.9	-0.0	4.8
Spot activation [MWh]	45.9	0.0	15.4
Imbalance increase [MWh]	0.0	11.9	14.0
Imbalance reduction [MWh]	-0.0	11.9	19.8
Imbalance activation [MWh]	0.0	23.9	33.8
Total increase [MWh]	22.9	11.9	24.6
Total reduction [MWh]	22.9	11.9	24.6
Total activation [MWh]	45.9	23.9	49.3

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Table 49: Technical KPIs for the **Water** load.

Flexibility Activations	Spot	Imbalance	Optimal
Spot increase [MWh]	106.6	0.0	31.4
Spot reduction [MWh]	106.6	-0.0	14.2
Spot activation [MWh]	213.1	0.0	45.6
Imbalance increase [MWh]	0.0	91.4	73.1
Imbalance reduction [MWh]	-0.0	91.4	90.3
Imbalance activation [MWh]	0.0	182.9	163.4
Total increase [MWh]	106.6	91.4	104.5
Total reduction [MWh]	106.6	91.4	104.5
Total activation [MWh]	213.1	182.9	208.9

Table 50: Technical KPIs for the **Other** load.

Flexibility Activations	Spot	Imbalance	Optimal
Spot increase [MWh]	189.8	0.0	83.0
Spot reduction [MWh]	189.8	-0.0	56.1
Spot activation [MWh]	379.5	0.0	139.1
Imbalance increase [MWh]	0.0	135.1	115.4
Imbalance reduction [MWh]	-0.0	135.1	142.2
Imbalance activation [MWh]	0.0	270.2	257.5
Total increase [MWh]	189.8	135.1	198.3
Total reduction [MWh]	189.8	135.1	198.3
Total activation [MWh]	379.5	270.2	396.6

9.1.3.1 Ecological KPIs

Table 51, Table 52 and Table 53 show the change in CO_2 emissions of electricity consumed by the loads for different scenarios compared to the baseline scenario of no flexibility activations. Interestingly, in this case the optimization of flexible loads on the spot market does not yield a reduction in CO_2 emissions as expected. In general, it is assumed that hours of lower market prices correlate with hours of high renewable production and low CO_2 emissions, as Figure 26 indicates. To explain this result, Figure 27 shows the average CO_2 emissions in energy production in Portugal versus the day-ahead spot market price for all quarter-

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

hours of the year. Hours of load increase are colored in orange, while hours of load reduction are marked blue. We see that in this case a shift from right to left, i.e. from higher to lower prices, does not yield a shift from top to bottom. This can probably best be explained by load shifts from gas power plants that are more expensive to coal power plants that emit more CO_2.

Table 51: Change in CO_2 emissions of electricity consumed by all loads for different scenarios in tCO_2

Load	Spot [tCO_2]	Imbalance [tCO_2]	Optimal [tCO_2]
Heat	0.5	-0.1	0.2
Water	5.9	-2.3	1.1
Other	7.1	1.3	3.6
Total	13.4	-1.0	4.9

Table 52: Change in CO_2 emissions of electricity consumed by all loads for different scenarios in tCO_2/MWh of activated flexibility

Load	Spot [tCO_2/MWh]	Imbalance [tCO_2/MWh]	Optimal [tCO_2/MWh]
Heat	0.01	-0.001	0.005
Water	0.028	-0.011	0.005
Other	0.019	0.004	0.009
Total	0.021	-0.002	0.008

Table 53: Change in CO_2 emissions of electricity consumed by all loads for different scenarios in %

Load	Spot [%]	Imbalance [%]	Optimal [%]
Heat	0.1	-0.0	0.0
Water	4.8	-1.8	0.9
Other	1.8	0.3	0.9
Total	1.0	-0.1	0.4

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

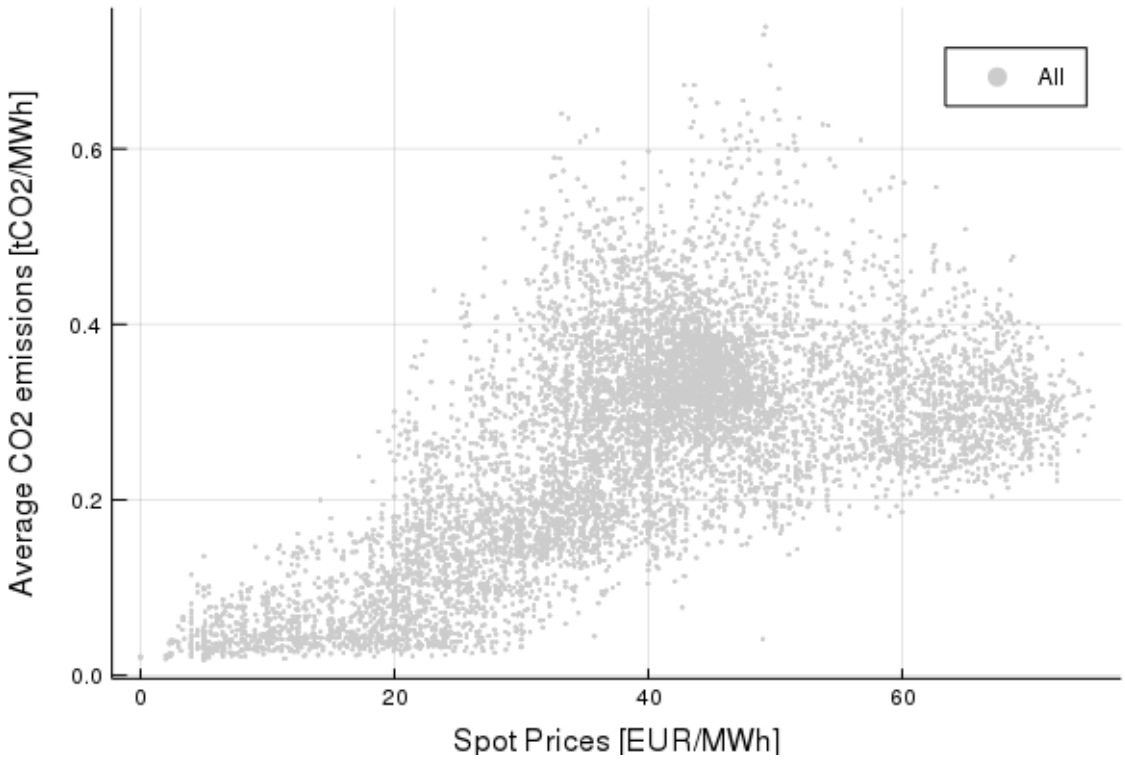

Figure 26: Average CO_2 emissions in energy production versus day-ahead spot market prices for Portugal

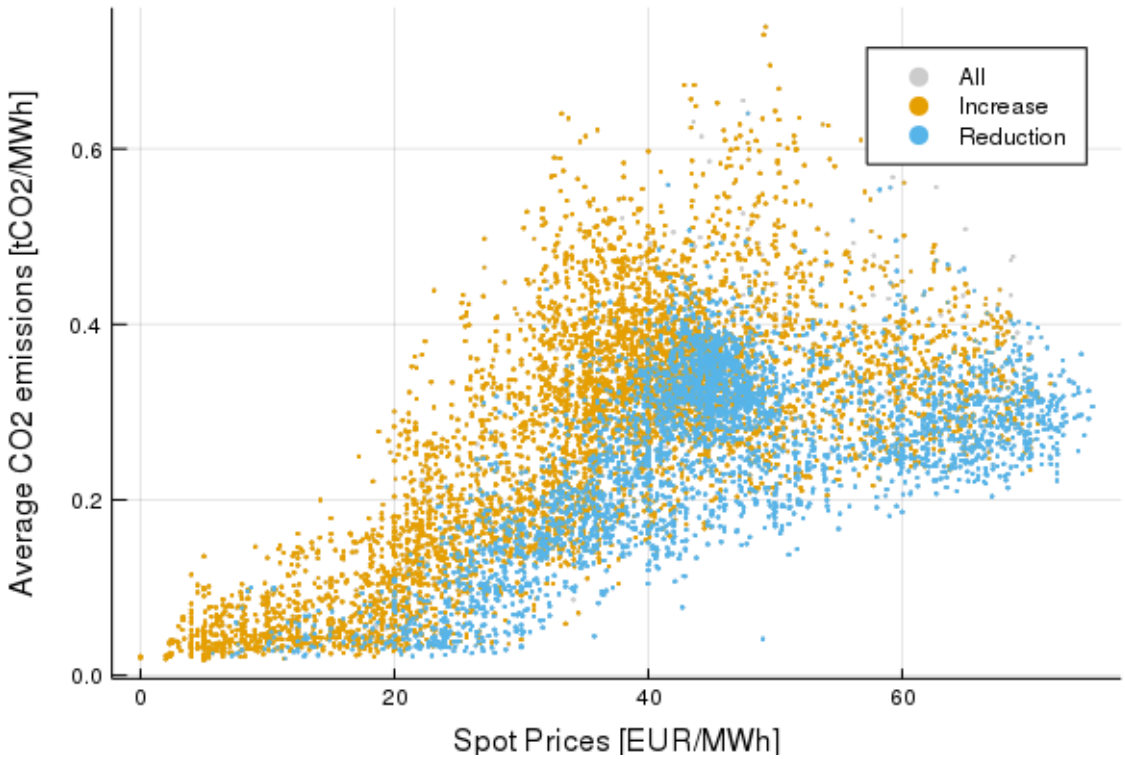

Figure 27: Average CO_2 emissions in energy production versus day-ahead spot market prices for Portugal colored by load increases and reductions

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

9.2 Activation and marketing of end user's flexibility in Spain

For Spain, a similar analysis as in Portugal is conducted. For this we use the same methodology but different data. This way we can gain insight on how country-specific market prices affect the profitability of business models.

9.2.1 Scenario Description and Model Scaling

In this investigation, we consider an office building that is supplied by EDP Spain. Three different load component data are available for the office building: **HVAC** (Heating, Ventilation and Air Conditioning), **Power** and **Lighting**. The respective annual load profiles for the year 2016 are illustrated in Figure 28. Furthermore, we consider Day-ahead spot market prices, imbalance prices and the imbalances for EDP Spain for the year 2016. The data is retrieved from the ENTSOE Transparency platform[26] or provided by project partner EDP respectively.

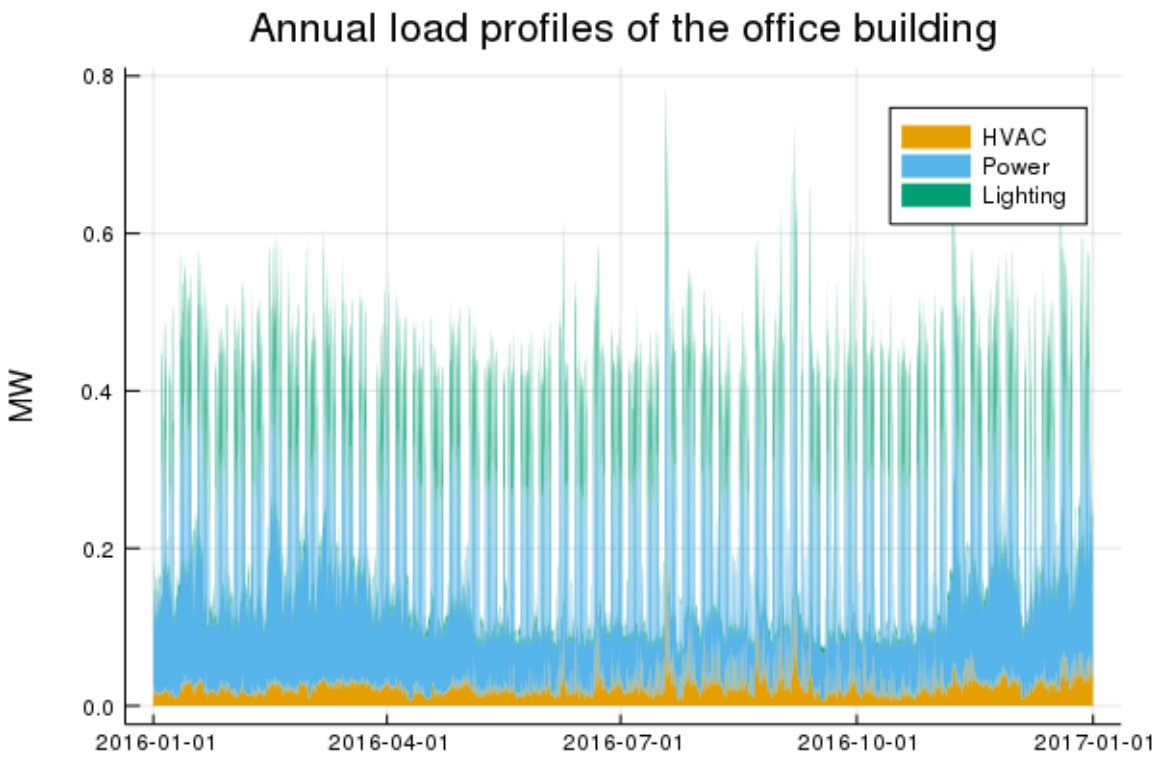

Figure 28: Annual load profiles of the office building for the year 2016

The key characteristics of the three considered loads are listed in Table 54. We assume the following restrictions on load flexibilities for the different load profiles:

[26] https://transparency.entsoe.eu/ last accessed November 2018

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

- **HVAC:**
  - Maximal relative load change of ±10% for each time step.
  - Flexibility activations must not change the total daily consumption.
- **Power:**
  - Load change of ±0.1 MW possible for 2 hours 5 times a week
  - Flexibility activations must not change the total weekly consumption.
- **Lighting:**
  - Maximal relative load change of ±10% for each time step.
  - Only available during the day from 6 AM to 8 PM.
  - Flexibility activations must not change the total daily consumption.

Table 54: Load characteristics

	HVAC	Power	Lighting
Maximal load [MW]	0.239	0.496	0.18
Annual demand [MWh]	252.94	1469.59	537.884

9.2.2 Results and KPIs

The optimal flexibility activations for one week in different scenarios are illustrated in Figure 29, Figure 30 and Figure 31. Figure 23 shows the **Spot** scenario. The colored bar at the bottom indicates the spot market prices in the respective hour. The **Imbalance** scenario is shown in Figure 24. Here, the bottom bar illustrates the imbalance direction of EDP at the corresponding time. An imbalance direction of 1 means excess production. Hence, it is beneficial to increase load during these hours. Conversely, an imbalance direction of -1 corresponds to excess demand, which is tackled by load reductions. Figure 25 illustrates the operation in the **Optimal** scenario. The top subplot shows the flexibility activations triggered by the spot market and corresponding prices. The activations to reduce imbalances and respective imbalance prices can be seen in the bottom subplot.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

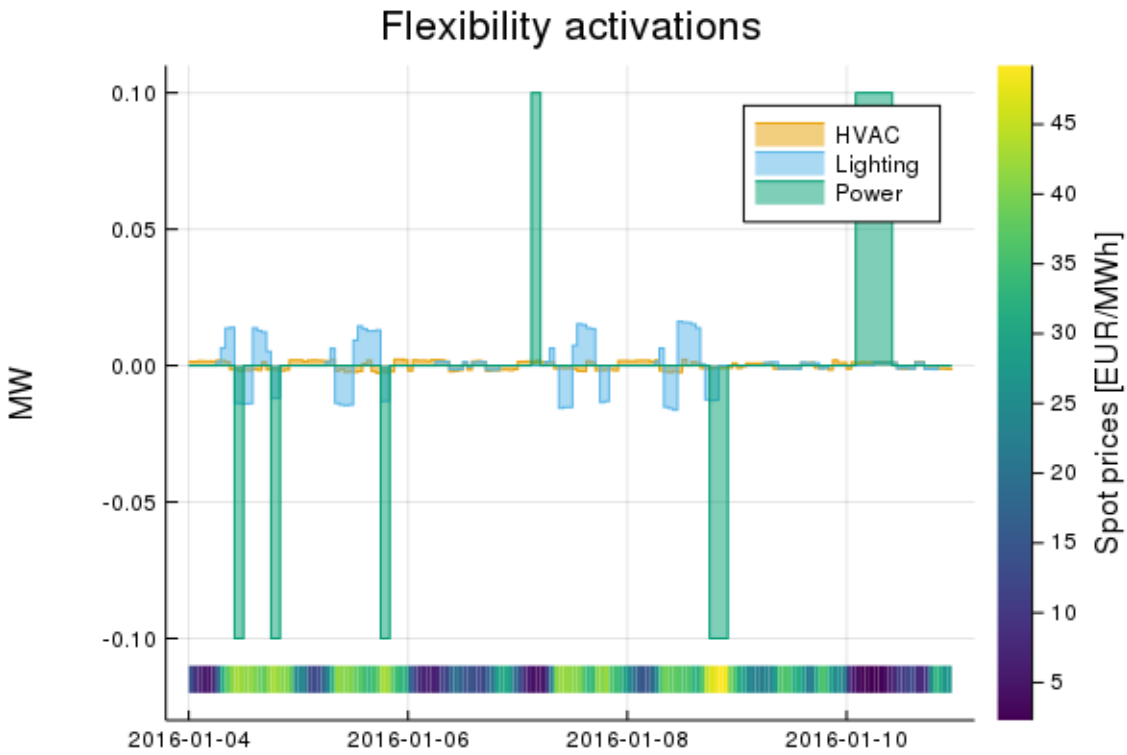

Figure 29: Flexibility activations of the different loads for one week in the **Spot** scenario.

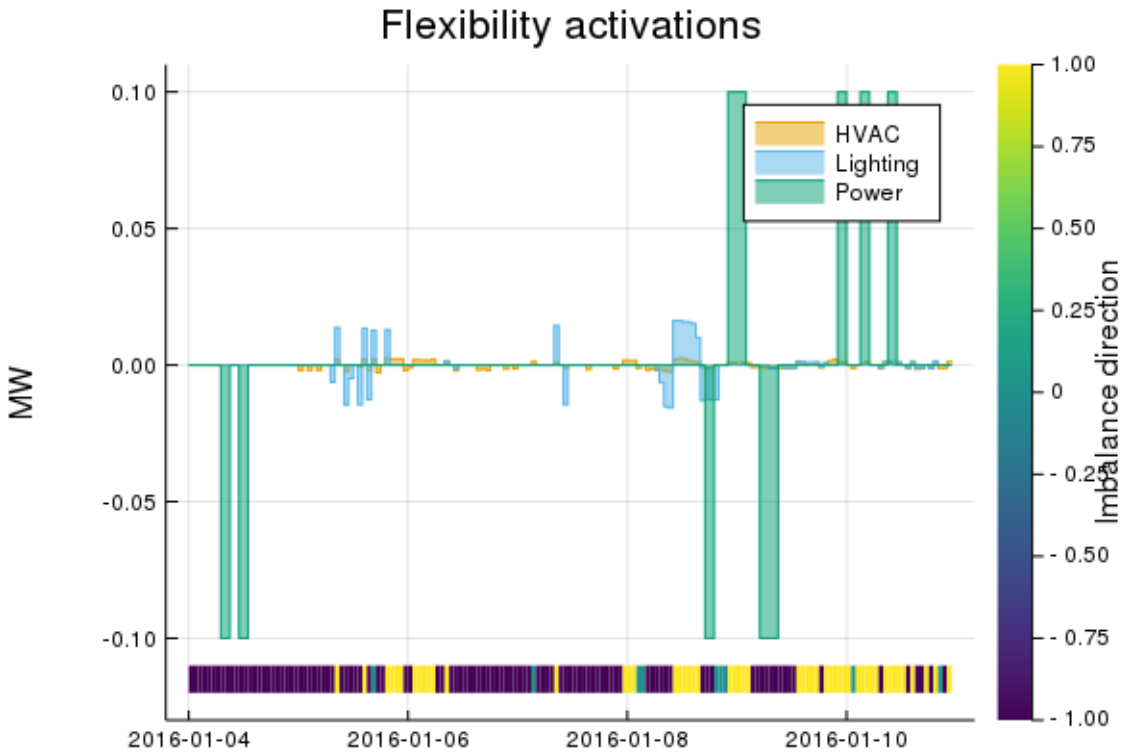

Figure 30: Flexibility activations of the different loads for one week in the **Imbalance** scenario.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

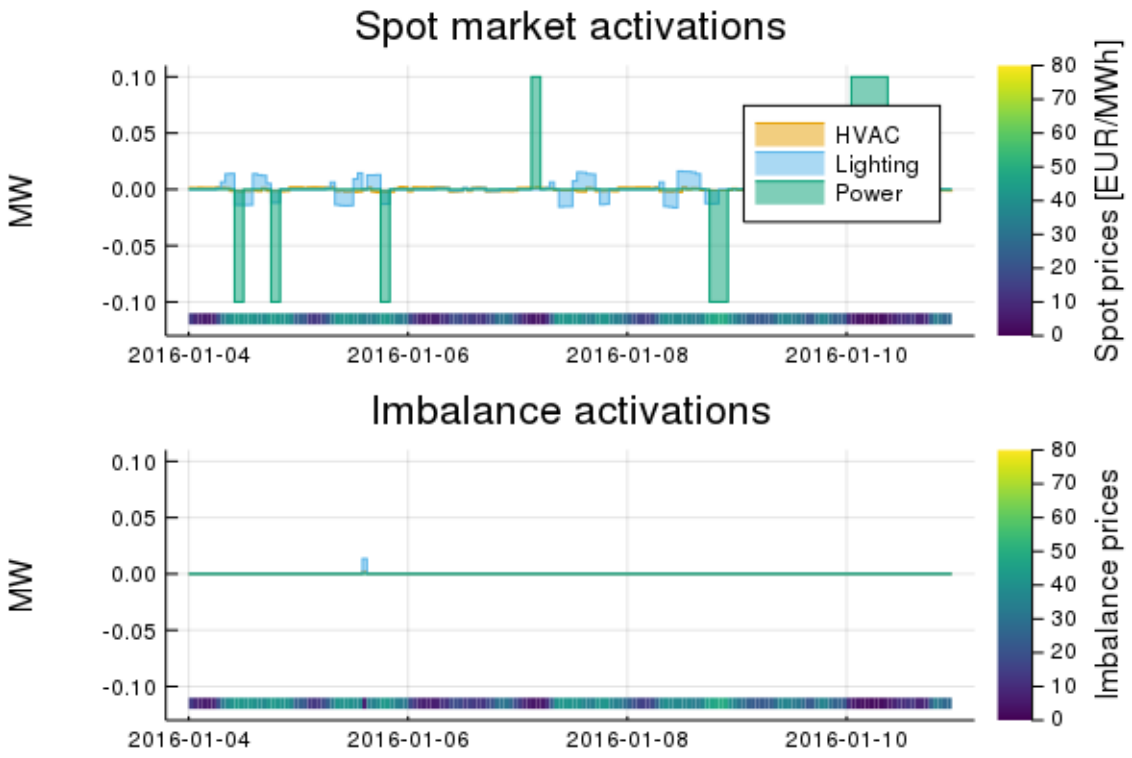

Figure 31: Flexibility activations of the different loads for one week in the **Optimal** scenario.

9.2.2.1 Economic KPIs

The achieved cost reduction compared to a passive baseline scenario for different scenarios is listed in Table 43. For each scenario the cost reduction for spot market purchases and the cost reduction for portfolio imbalances is provided in absolute numbers [EUR/a] and in relative numbers [EUR/MWh]. The relative values are given in Euro per MWh of activated flexibility (positive and negative) on the considered marketplace.

Table 55: Economic KPIs for the considered load portfolio

Cost Reduction	**Spot**	**Imbalance**	**Optimal**
Spot market [EUR]	-1670.6	0.0	-1669.6
Spot market [EUR/MWh]	-9.7	0.0	-9.7
Imbalance cost [EUR]	0.0	-156.7	-2.9
Imbalance cost [EUR/MWh]	0.0	-1.1	-5.5
Total [EUR]	-1670.6	-156.7	-1672.5
Total [EUR/MWh]	-9.7	-1.1	-9.7

The economic KPIs per load are listed in 56-58.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Table 56: Economic KPIs for the **HVAC** load

Cost Reduction	Spot	Imbalance	Optimal
Spot market [EUR]	-95.3	0.0	-97.4
Spot market [EUR/MWh]	-3.9	0.0	-4.0
Imbalance cost [EUR]	0.0	5.6	1.7
Imbalance cost [EUR/MWh]	0.0	0.4	22.6
Total [EUR]	-95.3	5.6	-95.7
Total [EUR/MWh]	-3.9	0.4	-3.9

Table 57: Economic KPIs for the **Lighting** load

Cost Reduction	Spot	Imbalance	Optimal
Spot market [EUR]	-101.7	0.0	-106.4
Spot market [EUR/MWh]	-2.3	0.0	-2.4
Imbalance cost [EUR]	0.0	-5.6	3.7
Imbalance cost [EUR/MWh]	0.0	-0.2	23.8
Total [EUR]	-101.7	-5.6	-102.7
Total [EUR/MWh]	-2.3	-0.2	-2.3

Table 58: Economic KPIs for the **Power** load

Cost Reduction	Spot	Imbalance	Optimal
Spot market [EUR]	-1473.6	0.0	-1465.8
Spot market [EUR/MWh]	-13.9	0.0	-13.9
Imbalance cost [EUR]	0.0	-156.7	-8.3
Imbalance cost [EUR/MWh]	0.0	-1.5	-27.6
Total [EUR]	-1473.6	-156.7	-1474.1
Total [EUR/MWh]	-13.9	-1.5	-13.9

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

9.2.2.2 Technical KPIs

The flexibility activations in MWh on different marketplaces for the three scenarios **Spot**, **Imbalance** and **Optimal** are listed in Table 47. In the cases **Spot** and **Imbalance** with a single market place, the load reductions have to match the load increases per market, because only shift-able loads are considered.

Table 59: Technical KPIs for the considered load portfolio.

Flexibility Activations	**Spot**	**Imbalance**	**Optimal**
Spot increase [MWh]	85.9	0.0	85.7
Spot reduction [MWh]	-85.9	0.0	-85.7
Spot activation [MWh]	171.9	0.0	171.4
Imbalance increase [MWh]	0.0	71.9	0.3
Imbalance reduction [MWh]	0.0	-71.9	-0.2
Imbalance activation [MWh]	0.0	143.7	0.5
Total increase [MWh]	85.9	71.9	85.9
Total reduction [MWh]	-85.9	-71.9	-85.9
Total activation [MWh]	171.9	143.7	171.8

The technical KPIs per load are listed in Table 48-Table 50.

Table 60: Technical KPIs for the **HVAC** load.

Flexibility Activations	**Spot**	**Imbalance**	**Optimal**
Spot increase [MWh]	12.2	0.0	12.1
Spot reduction [MWh]	-12.2	0.0	-12.2
Spot activation [MWh]	24.4	0.0	24.3
Imbalance increase [MWh]	0.0	6.9	0.1
Imbalance reduction [MWh]	0.0	-6.9	-0.0
Imbalance activation [MWh]	0.0	13.9	0.1
Total increase [MWh]	12.2	6.9	12.2
Total reduction [MWh]	-12.2	-6.9	-12.2
Total activation [MWh]	24.4	13.9	24.4

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Table 61: Technical KPIs for the **Lighting** load.

Flexibility Activations	Spot	Imbalance	Optimal
Spot increase [MWh]	22.5	0.0	22.4
Spot reduction [MWh]	-22.5	0.0	-22.5
Spot activation [MWh]	45.1	0.0	44.9
Imbalance increase [MWh]	0.0	12.0	0.1
Imbalance reduction [MWh]	0.0	-12.0	-0.0
Imbalance activation [MWh]	0.0	24.0	0.2
Total increase [MWh]	22.5	12.0	22.5
Total reduction [MWh]	-22.5	-12.0	-22.5
Total activation [MWh]	45.1	24.0	45.1

Table 62: Technical KPIs for the **Power** load.

Flexibility Activations	Spot	Imbalance	Optimal
Spot increase [MWh]	53.0	0.0	52.9
Spot reduction [MWh]	-53.0	0.0	-52.8
Spot activation [MWh]	106.0	0.0	105.7
Imbalance increase [MWh]	0.0	53.0	0.1
Imbalance reduction [MWh]	0.0	-53.0	-0.2
Imbalance activation [MWh]	0.0	106.0	0.3
Total increase [MWh]	53.0	53.0	53.0
Total reduction [MWh]	-53.0	-53.0	-53.0
Total activation [MWh]	106.0	106.0	106.0

9.2.2.3 Ecological KPIs

Table 51, Table 52 and Table 53 show the change in CO_2 emissions of electricity consumed by the loads for different scenarios compared to the baseline scenario of no flexibility activations. Interestingly, the case considering the optimization of flexible loads on the spot market does not yield a reduction in CO_2 emissions as expected. In general, it is assumed that hours of lower market prices correlate with hours of high renewable production and low CO_2 emissions, as Figure 26 indicates. To explain this result, Figure 27 shows the average CO_2 emissions in energy production in Portugal versus the day-ahead spot market price for all

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

quarter-hours of the year. Hours of load increase are colored in orange, while hours of load reduction are marked blue. We see that in this case a shift from right to left, i.e. from higher to lower prices, does not yield a shift from top to bottom. This can probably best be explained by load shifts from gas power plants that are more expensive to coal power plants that emit more CO_2.

Table 63: Change in CO_2 emissions of electricity consumed by the loads for different scenarios in tCO_2

Load	Spot [tCO_2]	Imbalance [tCO_2]	Optimal [tCO_2]
HVAC	0.0	-0.1	-0.0
Power	-3.0	-0.5	-3.4
Lighting	-0.1	-0.0	-0.1
Total	-3.0	-0.6	-3.6

Table 64: Change in CO_2 emissions of electricity consumed by the loads for different scenarios in tCO_2/MWh of activated flexibility

Load	Spot [tCO_2/MWh]	Imbalance [tCO_2/MWh]	Optimal [tCO_2/MWh]
HVAC	0.001	-0.002	-0.001
Power	-0.028	-0.004	-0.032
Lighting	-0.002	-0.001	-0.003
Total	-0.018	-0.003	-0.021

Table 65: Change in CO_2 emissions of electricity consumed by the loads for different scenarios in %

Load	Spot [%]	Imbalance [%]	Optimal [%]
HVAC	0.1	-0.1	-0.0
Power	-1.0	-0.2	-1.2
Lighting	-0.1	-0.0	-0.1
Total	-0.7	-0.1	-0.8

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

9.2.3 Conclusions

This analysis shows that flexibilities from medium to large-scale customers can be used to reduce costs for a combined aggregator supplier. The flexibilities can either be activated to reduce energy procurement cost on the wholesale market or to reduce the imbalances of the aggregator's BRP. However, the economic feasibility of the business model depends very much on the provided flexibility potential of the flexible consumers and on the energy market or imbalance prices.

We see, for instance, that the imbalance reduction in Portugal yields lower cost than wholesale market optimization, even if we only consider the BRPs imbalance direction without taking into account any information about the imbalance prices. In Spain, however, the imbalance reduction yields a very insignificant cost decrease. When looking at the Optimal scenario in Spain, we see that it provides almost the same results as the Spot scenario. Hence, we can conclude that the wholesale market is preferable compared to imbalance reduction at almost all time steps. Thus, the imbalance prices in Spain do not provide sufficient incentives for flexibility activation.

The dependence on the flexibility potential can be observed best, when considering the Power load in the Spanish case. While it may only be activated five times a week for each two hours, the other two loads have no limitation on the number of activations. Nevertheless, the Power load flexibility offers the most cost reduction, because it needs to balance increases and reductions within a week, while the other two loads have to do this within a day.

We only considered total cost reduction for energy purchase or imbalance in this scenario. However, if the aggregator wants to use the flexibility of end users for this purpose, they have to be remunerated for the provision of the flexibility. Several different models are possible here. The benefits and the risk can, for instance, be shared between the aggregator and the customers at equally. Another possibility is to provide a fixed bonus or price for flexibility to the consumer and use the flexibility at own risk.

We also see that providing more flexibility to the system, in general, reduces CO_2 emissions. However, with the data for Portugal we stumbled upon a case, where this general statement is not true. The reasons, in this case, are that demand shifts from hours where the marginal operating power plant is a gas power plant to hours of marginal coal operation. The latter has lower marginal cost but a higher emission factor. If the merit order curve for power plant operation was also sorted with respect to CO_2 emission factors (e.g. with a sufficiently high CO_2 price), cost-minimizing flexibility activations would always yield a reduction in emissions.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

10. Improved business model for FOSS (Cyprus)

10.1 Local aggregation services for providing flexibility to grid operation including congestion management

10.1.1 Introduction

Local aggregation services for providing flexibility to grid operation including congestion management is currently a possible business case for Cyprus, of which we aim to quantify possibilities in this report. Utilizing net billing and net metering tariffs with embedded time of use cost elements offers options for minimizing energy cost through effective use of local RES generation and storage. This process will generate options for flexibility trading in support of the local grid as an added benefit. This case is being investigated in Cyprus with two distinct use cases:

- Single mid-scale commercial or industrial consumers through the control of all assets from a single point of connection to the grid
- Spread small prosumers who are aggregated through the use of appropriate in-house energy management systems and smart connectivity with the local DSO

10.1.2 The University of Cyprus Campus

This report covers the case study of the University of Cyprus as a mid-size commercial consumer with local PV generation and storage. Spread prosumers are also investigated in Cyprus but no simulated analysis is available at present. The objective is to transform the large campus of University of Cyprus into a self-consumption controllable microgrid, which will be fed by PV and central and distributed energy storage systems. The campus microgrid will be able to operate either grid-connected, offering at the same time the possibility for ancillary services to the DSO, or isolated in case of a grid fault or other operational necessities. In order to design the campus microgrid, initial simulation tests are carried out. During the simulation work, exhaustive tests on the already existing system are conducted to validate results and assist the simulated analysis work.

10.1.3 Economical evaluation of the microgrid

The objective of the economic analysis is related to the current operation of the FOSS microgrid and the future operation of the University of Cyprus campus microgrid. The viability and the feasibility of a microgrid with PV intermittent generation and Battery Energy Storage System is studied, while the billing scheme incorporated in this analysis is the net-billing scheme, which is the actual tariff agreement with the local supplier and is described appendix A.2. An initial Cost-benefit analysis of the UCY campus microgrid is analyzed in this section and extended to cover the cost benefit analysis of the FOSS microgrid pilot, while the present data acquisition is used in order to enhance the reliability of the

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

followed approach and contribute to the correct sizing of the equipment. As more real-data is fed from the pilot's smart meters, the cost-benefit approach will be populated and further analyzed.

10.2 Definition of the University of Cyprus campus microgrid

10.2.1 Energy management of the University of Cyprus campus

Currently, the measured peak load of the campus is 2.4 MW, while the locally installed photovoltaic (PV) systems at the rooftop of the buildings have a nominal power of 394.8 kWp. Additionally, each of the campus main buildings is equipped with a different Building Energy Management System (BEMS) that automatically monitors the electrical load demand and controls a range of building services. At the moment, the produced energy is totally fed into the grid following a feed-in-tariff pricing policy, while the UCY electricity demand is covered by the utility grid. In the upcoming years, the UCY plans to install a new solar PV installation of 10 MWp together with a BESS at the university, in order to enhance the self-consumption and enable the provision of ancillary services to the grid. When the whole project will be finished, the university campus will be transformed into a fully operational microgrid, being able to fulfil its own energy consumption by its own RES installations, while it will be connected to the utility grid via a single point of common coupling (PCC). Thus, it will serve as a controllable section of the grid that will be able to disconnect from the distribution grid under emergency or planned operational regimes and operate autonomously, as an independent electrical island.

The university campus is currently undergoing new construction infrastructure, so the investment project and the purchase of the PV and battery equipment will be implemented in the following two phases; firstly, the partial integration of the large PV installation with the properly sized BESS in order to enable the microgrid operation and secondly, an additional PV

installation with the BESS in order to cover all the newly constructed buildings within the UCY campus microgrid. According to the preliminary study, this installation will be implemented in two phases: in the first phase, 5MWp of PV will be installed combined to 2.35MWh battery energy storage system, in the second phase an additional 5MWp of PV will be installed combined to another 5.15MWh battery energy storage system. The model developed in this report consider the whole-year operation of the university microgrid.

10.2.2 Electrical Consumption

In order to evaluate the possible aggregated business options, the electrical consumption of the UCY campus will be initially presented. For this reason, electricity consumption and demand profiles of the university have been extracted based on measurements provided at the point of common coupling, the distribution substation of the DSO (at the MV busbar of the transformer), with a 15-minute interval, for the year 2016. The UCY is an educational institution

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

with variations in electricity demand across different days of the week and within the seasons, so it is interesting to analyze its load profile depending on the following classification: Working days, from Monday to Friday, and non-working days, such as public holidays, Saturdays, Sundays and non-school days. The analysis considers these two basic classifications in order to distinguish all the possibilities of the consumption profiles. The current and future average daily electricity consumption of the University campus under these classifications can be seen in Figure 11, where a consumption peak in September is obvious. The reason behind the peak is the type of electrical loads, which mainly consist of electrical cooling, due to high temperatures in Cyprus and the occupancy of the campus in this period. The high consumption period is within the working summer months (June-July) and September. Furthermore, the type of heating loads should also be considered. Currently, the fuel oil is used, while in the new buildings electrical heat pumps are planned to be installed. This is an important factor for the future design and sizing of the microgrid.

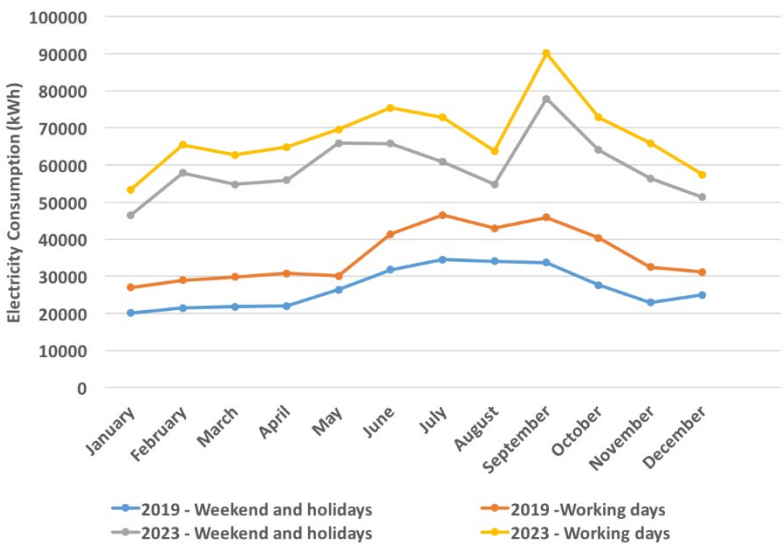

Figure 32: Current and estimated future average daily electricity consumption of UCY campus

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

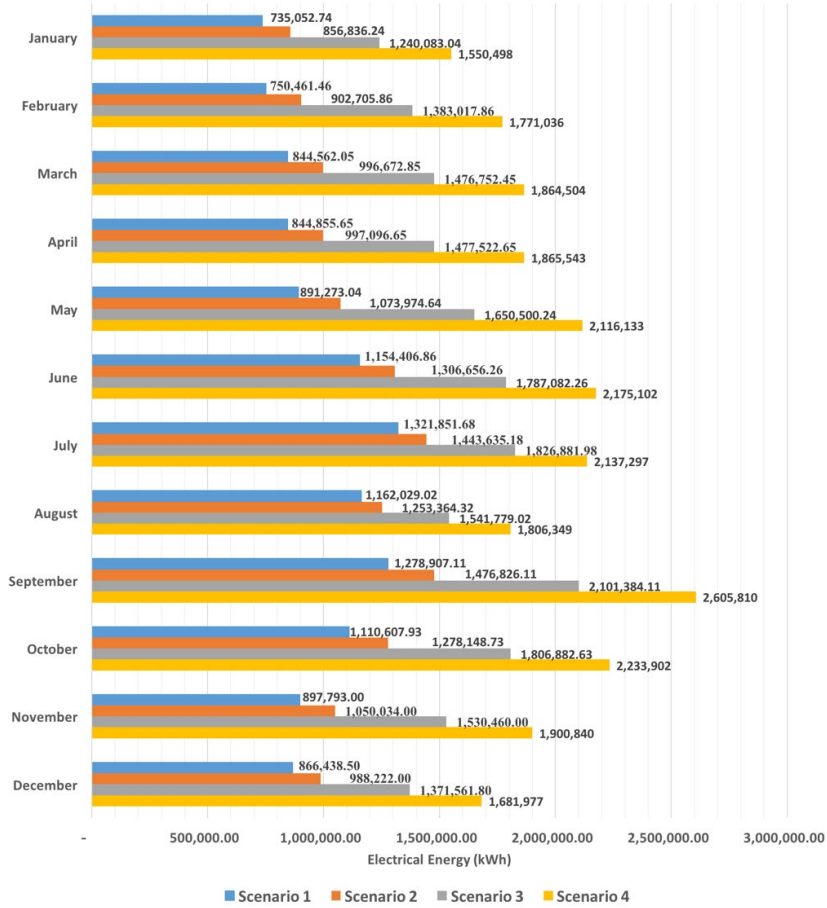

Figure 33: Current and future load profile of UCY campus

10.2.3 PV energy production

In this section, actual measurements from the existing PV installation have been used, in order to extrapolate the expected annual energy yield of a 10 MWp PV system. Furthermore, the unity power factor of the campus load and an annual degradation rate of 1% of the PV systems have been considered in the presented calculations, in order to estimate precisely the energy yield of the system for a period of 20 years. The generated energy of the 10 MWp system has been adapted to hourly generation profiles and compared with the hourly consumption profiles of the campus for the whole year, in order to identify the energy excesses and deficits of the PV system along a specific period of time. Figure 11 shows the hourly PV generation profile of the 10 MWp PV system on the typical day of each month.

The planning period in the case study is 20 years and the technical considerations of the microgrid design aim at minimizing the cost of energy through the use of local generated energy, storage and future aggregated flexibilities for the benefit of the grid.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

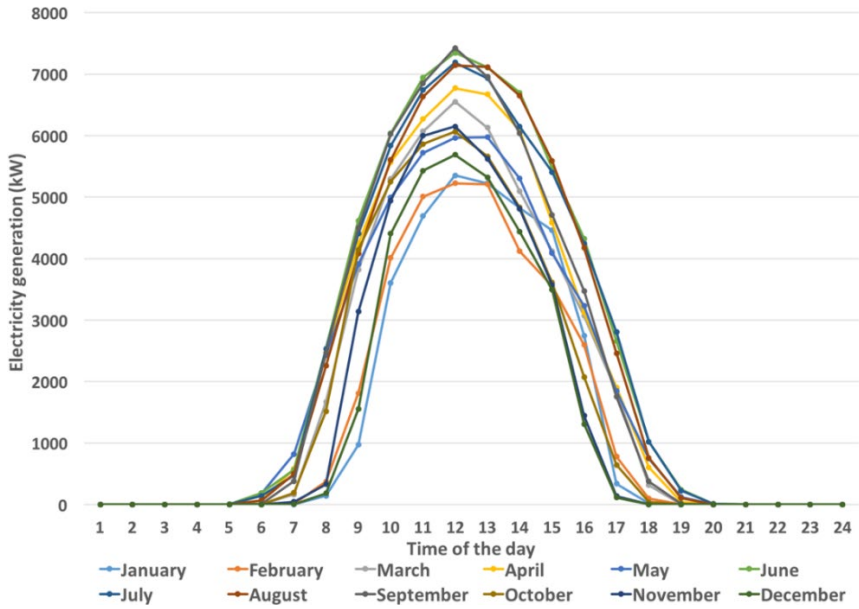

Figure 34: Hourly generation curve from the projected 10MWp PV installation

10.2.4 Optimization strategy

The optimization method decides the optimum BESS size that will minimize the costs of the electricity bill for the UCY campus microgrid in combination with the PV production on site and the net billing tariff that prevails (see appendix for details). The BESS is generally charged during periods that PV generation exceeds the campus loads, in order to optimize the energy cost of the university by minimizing grid purchases during peak hours. In order to find the most feasible investment option, different BESS / PV sizes are considered. The generation and consumption profiles are compared throughout a year, while an economic analysis that assesses the residual cost component of the investment based on various profitability indices, is considered next.

Table 66: Monthly energy analysis of UCY campus

Month	Consumption (kWh)
January	1,550,498
February	1,771,036
March	1,864,504
April	1,865,543
May	2,116,133
June	2,175,102
July	2,137,297
August	1,806,349
September	2,605,810
October	2,233,902
November	1,900,840
December	1,681,977
Annual	***23,708,992***

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

10.2.5 Results and sensitivity analysis

The main profitability indices, such as the IRR, the Net Present Value (NPV) and the Discounted Payback Time (DPBT), which is the number of years required for the sum of the cash inflows to meet the investment cost, are calculated in order to reach the optimum decision. The economic profitability analysis considers the initial investment phase of the microgrid. Different configurations have been studied, namely:

- No PV, no Storage
- PV, no storage
  - 5 MWp PV
  - 6 MWp PV
  - 7 MWp PV
  - 8 MWP PV
- PV & storage
  - 5 MWp PV, 2.35 MWh Storage
  - 6 MWp PV, 2.35 MWh Storage
  - 7 MWp PV, 2.35 MWh Storage
  - 8 MWP PV, 2.35 MWh Storage

The results of the studied configurations for the initial phase of investment can be seen in the Table below.

Table 67: Monetary saving of assessed microgrid configurations

Description	Annual energy cost in €	PV in kWp	Storage in kWh	Savings in mil €	capital cost in mil €	Generation in kWh
Without PV and S	2,413,969	0	0	0.000	0.000	0
With PV and without S	1,213,483	5,000	0	1.200	5.000	8,100,000
With PV and without S	1,008,058	6,000	0	1.406	6.000	9,720,000
With PV and without S	807,759	7,000	0	1.606	7.000	11,340,000
With PV and without S	609,486	8,000	0	1.804	8.000	12,960,000
With PV and S	1,398,670	4,000	2,350	1.015	5.410	6,480,000
With PV and S	1,286,764	4,500	2,350	1.127	5.910	7,290,000
With PV and S	1,179,485	5,000	2,350	1.234	6.410	8,100,000
With PV and S (licensed sizes)	1,075,717	5,500	2,350	1.338	6.910	8,910,000
With PV and S	974,060	6,000	2,350	1.440	7.410	9,720,000
With PV and S	773,761	7,000	2,350	1.640	8.410	11,340,000
With PV and S	674,425	7,500	2,350	1.740	8.910	12,150,000
With PV and S (Generated energy equivalent to load)	575,488	8,000	2,350	1.838	9.410	12,960,000

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

It can be seen that the benefits of the installation of the PV system outweigh its investment cost in all scenarios, resulting in a positive NPV. The real IRR of the studied configurations ranges from 6.7% to 13.42%. The savings to the electricity bill due to the operation of the microgrid is the main factor that is considered for the profitability of the investment, in a pure economical point of view. By taking into consideration the IRR and NPV of the investment, the obtained results point to the direction of the installation of **a PV installation of 8 MWp and a battery capacity of 2.35 MWh**. A payback period of less than 7 years is evaluated with the current electricity prices giving a strong positive message for the opted solution and the adapted microgrid architecture. It should be noted that, in this analysis, the BESS has only been considered for supplying PV generated energy to the university microgrid. Other uses of battery, such as tariff arbitraging, ancillary and flexibility services that would increase the BESS's cost-effectiveness are not considered. These ancillary and flexibility services will be profitable for the UCY campus microgrid, when the electricity market will move into a liberalized form.

According to the results obtained, it is concluded that the operation of a microgrid with PV and BESS is a very promising investment and its low pay back period is assured under all investigated scenarios allowing areas for further benefits through additional market options.

10.2.6 Benefits for the DSO

Energy demand of the system is expected to be increasing year by year and may lead to blackouts, or failures. The increasing load demand leads to increased grid congestion or increased voltage drop, while the opposite effect of voltage increase may happen in case of injecting a high PV production directly into the grid. If an operational limit (such as thermal limit of the line) is reached, new investments on network components are needed to mitigate this issue. The presence of distributed generation and energy storage within the microgrid can reduce the maximum load demand, thereby extending the life cycle of grid components. This allows a deferral of grid investments to the future, with associated benefits to the DSO. Since maximum demand occurs only a few hours per year, the microgrid operation can provide a reliable way to avoid Transmission and Distribution grid reinforcements by relieving peaks in demand, compensating for large feed-in from renewables and generally helping to balance the system and stabilize the grid. An estimation of the financial gains can be made, based on the assumption that the estimated grid investments of the DSO are avoided.

A first estimation of the financial gains is modelled by the difference in maximum peak demand between the Basic Load Curve, and the Resulting Load Curve after the operation of the microgrid. The equation used to estimate the ratio of investment savings is the following:

$$PD_{ratio} = \frac{PD_{RLC}}{PD_{BLC}} \quad (1)$$

where PD_{BLC} is the peak demand of the base scenario curve, PD_{RLC} is the peak demand of the load curve after the microgrid operation and PD_{ratio} is the ratio between the maximum values of the two load curves.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

As it is shown in Table 5, the microgrid operation allows internal DG sources and BESS to reduce the peak demand of the campus at the PCC. A peak demand reduction of at least 3.08% is achieved in year 2019 and a peak demand reduction of 6.45% is achieved in year 2023. The load curve is reshaped, and peak demand is maintained at the same level for the whole investment period. Taking into account that the average annual load growth in Cyprus ranges at 1.5%, this reduction in peak grid loading allows distribution network investment and upgrade costs to be deferred for the 20-year planning horizon of the investment.

In order to estimate the financial benefits of the differed grid investments, economic data of the DSO of Cyprus regarding the Transmission and Distribution Network development, upgrade and maintenance costs from 2012 to 2016 were examined. These costs range from 16.86 to 50.26 million € per year, resulting to average annual costs of 31.34 million €. To obtain typical figures, the estimated upgrade cost of the distribution grid of Cyprus was taken into consideration and the average marginal grid investments per total system capacity were used as an approximation for the cost per megawatt of investments. Thus, it was estimated that the microgrid operation results to annual grid deferral savings of €21,200 per year.

The postponed future grid investments in 20 years are then valued and discounted over the years in order to obtain an NPV. The NPV of all the postponed investments is calculated using the total cost of the planned grid investments for the scheduled year *i* and the interest rate as follows:

$$NPV_{inv} = \sum_{i=1}^{20} \frac{C_i}{(1+r)^i} \qquad (2)$$

where NPV_{inv} is the NPV of all the postponed investments, C_i is the value of the postponed investment of the ith year and r is the discount rate that refers to the interest rate used in cash flow analysis to determine the present value of future cash flows.

Furthermore, reduced grid losses, which can be represented by the difference between the grid losses before and after the microgrid operation, have a potential to represent savings in monetary terms for the DSO. Total savings from avoided PV generation grid losses take into account the system availability and grid connection power losses (ηPPC) that are saved due to increased self-consumption of the PV generated energy. These losses, based on grid data of the past 5 years, range on average at 4.42% in the island of Cyprus. The annual financial benefit of the avoided distribution losses is calculated as follows:

$$\pi_{losses} = \sum_{d=1}^{365} [\eta_{PPC} * PV'_{cons_i} * P_{PV}] \qquad (3)$$

where P_{PV} is the wholesale electricity price that is offered by the utility for the energy that is sold to the grid and PV'_{cons_i} is the amount of PV generation that is directly consumed or stored by the microgrid in a single day.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Table 68: Peak demand before and after the microgrid operation in years 2019-2023

Month	2019			2023		
	PD_{BLC} (kW)	PD_{RLC} (kW)	PD_{Ratio} (%)	PD_{BLC} (kW)	PD_{RLC} (kW)	PD_{Ratio} (%)
January	424.49	411.33	96.90	891.3	822.7	92.30
February	485.33	470.30	96.90	1160.0	1044.2	90.02
March	465.49	443.85	95.35	1046.0	942.2	90.08
April	483.28	439.65	90.97	1127.6	928.1	82.30
May	645.46	563.97	87.35	1316.3	1130.9	85.92
June	777.42	624.58	80.34	1421.8	1044.3	73.45
July	792.83	690.30	87.07	1291.7	1158.7	89.70
August	684.89	532.45	77.74	1036.6	757.9	73.11
September	736.11	604.83	82.17	1573.8	1319.7	83.86
October	650.71	600.98	92.36	1336.7	1237.0	92.54
November	512.31	496.51	96.92	1101.9	1027.0	93.20
December	462.11	447.83	96.91	919.7	860.34	93.55

Reducing the losses through the microgrid operation, provides the DSO with an economical incentive to support microgrid integration if the benefits are significant enough. The function that expresses the NPV of the DSO profit is formulated for the 20-year period using the following equation:

$$NPV_{DSO} = NPV_{inv} + \sum_{i=1}^{Y} \frac{\pi_{losses} + PV_{excess}}{(1+r)^i} \qquad (4)$$

where PV_{excess} is the annual amount of PV generated energy that is fed back to the grid without compensation.
The operation of the microgrid results in monetary benefits of €1,002,282.4 for the DSO. The gains obtained under this scenario are derived from the reduction of distribution grid losses and the deferral of grid investments. It is assumed in this study that the DG and BESS investment can be a direct substitute to the "wires and poles" assets; thus, the same discount rate has been applied to both cases. Nevertheless, it is apparent from the obtained results that the microgrid operation would be both beneficial and profitable for the DSO.

10.3 Conclusions

In this section, the technical and economic evaluation of the microgrid in Cyprus is extensively presented. Regarding the technical analysis, the FOSS microgrid case is examined. The results of the FOSS microgrid and the measured data from the installed equipment are utilized to complete the planned expansion of the infrastructure of the University of Cyprus.

The optimal sizing of the PV - battery storage combination has been determined based on an optimization exercise for the energy needs of the university. The quantitative results of the studied scenarios in all of the cases that have been proposed in the sensitivity analysis, show that the installation of the BESS would

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

increase the benefit for the microgrid and that the obtained benefits from the operation of the microgrid outweigh its investment cost giving a payback period of less than 7 years with many other added advantages.

Moreover, this report has examined the potential for the microgrid to act as an alternative DSO option to grid investment but also managing operational congestion by providing an assessment of the possible benefits that can form the business opportunity for aggregators in Cyprus. Obtained results show that the microgrid operation can defer the upgrade of transmission and distribution grids and is able to lower their capacity demand. Furthermore, the electricity benefit brought by the reduction of grid losses provides another indirect benefit for the environment as well as the DSO.

This analysis has revealed that the opted business enhancement for aggregators in Cyprus can be in the first phase the following: Local aggregation services for providing flexibility to grid operation including congestion management

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

11. Conclusions

This report provides tailor-made case studies and quantitative results for many very different business models. Hence, it is impossible to provide overall conclusions that apply to all of them. Nevertheless, we see similar results for groups of related business models. We can categorize the analyzed business models into three major groups according to the considered technology: Business models considering flexible demand, business models considering variable generation and business models considering flexible generation.

For business models considering flexible demand, we see that using demand side flexibility to react on price signals can create value and reduce cost for the customers. The price signals can be provided by wholesale market prices or by time-of-use tariffs, offered by a supplier. They could also be based on expected imbalances of a Balance Responsible Party. However, we also find that the profitability of such business models depends very much on the characteristics of load flexibilities and on the market prices or price signals. Compare, for instance, the imbalance reduction in Portugal and in Spain. The major flexibility characteristics that influence the profitability are the available power, the available duration of an activation, and the opportunity cost or, for shiftable loads, the period, in which flexibility activations have to balance.

For flexible producers, like biogas power plants, we see that reserve or balancing markets are in general more suitable than energy-only wholesale markets, because of high fuel prices and resulting high short-run marginal cost. In the analysis of the German case, shorter reserve market products provide more flexibility to the wholesale market operation of the power plant and hence increase the profit. In the French case, smaller-scale biogas power plants could profit from participating on the balancing market and this could also increase market competition and add more flexibility to the energy system. However, a minimal power plant capacity of 10 MW is required for market participation.

For business models considering variable renewable energy generation, we see very different results depending on the opportunity cost. The economic feasibility of wholesale market sales of intermittent renewable producers is determined by their market value. For other business models focusing on decentralized investments of renewable generation on household level, the opportunity cost is given by the end user bill for electricity. This also includes network charges, fees and taxes and, hence, these business models provide a better economic value.

Based on the analyzed data, we could not find a clear recommendation, whether forecast errors of variable generation should be balanced via intraday market trades or settled via imbalance prices. Different production profiles and data from different years yield diverging results. Nevertheless, intraday markets provide a useful tool to mitigate risks with respect to imbalance cost. Furthermore, the aggregation of multiple variable renewable producers can reduce the relative forecast error.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Regarding the activation of flexibilities as a third party, we see that it is possible to provide economic benefits to the end users and the third party aggregator, without decreasing the profit of the energy supplier. However, this requires careful analysis of all the cash and energy flows caused by flexibility activations and the effects on energy bills and imbalances of the supplier's balance responsible party. Bilateral contracts between the supplier and the third party aggregator are required to ensure win-win situations. A clear regulatory framework for such third party business models would simplify their implementation.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

References

[1] R. Verhaegen and C. Dierckxsens, "Existing business models for renewable energy aggregators, BestRES Deliverable D2.1," 2016.

[2] A. Fleischhacker, G. Lettner, D. Schwabeneder and F. Moisl, "Improved Business Models of selected aggregators in target countries, BestRES Deliverable D3.2," 2017.

[3] J. Bezanson, A. Edelman, S. Karpinski and V. B. Shah, "Julia: A Fresh Approach to Numerical Computing," *SIAM Review: 59,* p. 65–98, 2017.

[4] I. Dunning, J. Huchette and M. Lubin, "JuMP: A Modeling Language for Mathematical Optimization," *SIAM Review: 59,* pp. 295-320, 2017.

[5] S. Schlömer, T. Bruckner, L. Fulton, E. Hertwich, A. McKinnon, J. Roy, R. Schaeffer, R. Sims, P. Smith and R. Wiser, "2014: Annex III: Technology-specific cost and performance parameters. In: Climate Change 2014: Mitigation of Climate Change.," Cambridge University Press, Camebridge, 2014.

[6] Parliamentary Office of Science and Technology, "Carbon Footprint of Electricity Generation," 2006.

[7] R. Verhaegen, R. Beaumont, G. Lettner and A. Fleischhacker, "An assessment of the economics of and barriers for implementation of the improved business models, BestRES Deliverable D4.1," 2017.

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Technical references

Project Acronym	BestRES
Project Title	Best practices and implementation of innovative business models for Renewable Energy aggregatorS
Project Coordinator	Silvia Caneva WIP – Renewable Energies silvia.caneva@wip-munich.de
Project Duration	1st March 2016 – 28th February 2019

Deliverable No.	D3.3
Dissemination level*	PU
Work Package	WP 3 - Testing of improved business models
Task	T3.3 - Analysis of improved BMs in target countries and for selected aggregators (quantitative)
Lead beneficiary	3 (TUW-EEG)
Contributing beneficiary/ies	2 (3E), 5 (Good Energy), 6 (NKW BE), 7 (NKW DE), 8 (oekostrom), 9 (FOSS), 10 (EDP CNET)
Due date of deliverable	31st December 2018
Actual submission date	20th December 2018

* PU = Public

PP = Restricted to other programme participants (including the Commission Services)

RE = Restricted to a group specified by the consortium (including the Commission Services)

CO = Confidential, only for members of the consortium (including the Commission Services)

v	Date	Beneficiary	Author
1.0	19/02/2018	TUW-EEG	Daniel Schwabeneder
2.0	26/10/2018	TUW-EEG	Daniel Schwabeneder, Carlo Corinaldesi and Venizelos Efthymiou
3.0	14/12/2018	TUW-EEG	Daniel Schwabeneder, Carlo Corinaldesi
4.0	19/12/2018	WIP	Silvia Caneva, Cathal Cronin

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

A Appendix

A.1 Improved business models of Next Kraftwerke Germany (Germany)

A.1.1 Supplying „mid-scale“ consumers with time variable tariffs including grid charges optimization

A.1.1.1 Economic KPIs

Table 69: Economic KPIs for the Mitnetz grid charges with annual peak-load-pricing.

Mitnetz yearly	Unit	Spot Optimization	Grid Optimization	Change [%]
Annual financial operation costs	MEUR	16,38	13,86	-15,4
	EUR/MWh	105,99	89,67	-15,4
	kEUR/MW	297,75	251,91	-15,4

Table 70: Economic KPIs for the Mitnetz grid charges with monthly peak-load-pricing.

Mitnetz monthly	Unit	Spot Optimization	Grid Optimization	Change [%]
Annual financial operation costs	MEUR	23,72	17,21	-27,43
	EUR/MWh	153,49	111,39	-27,43
	kEUR/MW	431,2	312,93	-27,43

Table 71: Economic KPIs for the Westnetz grid charges with annual peak-load-pricing.

Westnetz yearly	Unit	Spot Optimization	Grid Optimization	Change [%]
Annual financial operation costs	MEUR	12,99	11,47	-11,72
	EUR/MWh	84,07	74,22	-11,72
	kEUR/MW	236,17	208,5	-11,72

BestRES This project has received funding from the European Union’s Horizon 2020 research and innovation programme under grant agreement N° 691689.

Table 72: Economic KPIs for the Westnetz grid charges with monthly peak-load-pricing.

Westnetz monthly	Unit	Spot Optimization	Grid Optimization	Change [%]
Annual financial operation costs	MEUR	17,6	13,63	-22,52
	EUR/MWh	113,88	88,23	-22,52
	kEUR/MW	319,92	247,87	-22,52

A.1.1.2 Ecological KPIs

Table 73: Ecological KPIs for the Mitnetz grid charges with annual peak-load-pricing.

Mitnetz yearly	Unit	Spot Optimization	Grid Optimization	Change [%]
CO_2 emissions caused by the load	tCO_2	53335,1	53628,1	0,55
	tCO_2/MWh	0,35	0,35	0,55
	tCO_2/MW	969,73	975,06	0,55

Table 74: Ecological KPIs for the Mitnetz grid charges with monthly peak-load-pricing.

Mitnetz monthly	Unit	Spot Optimization	Grid Optimization	Change [%]
CO_2 emissions caused by the load	tCO_2	53335,1	53772,88	0,82
	tCO_2/MWh	0,35	0,35	0,82
	tCO_2/MW	969,73	977,69	0,82

Table 75: Ecological KPIs for the Westnetz grid charges with annual peak-load-pricing.

Westnetz yearly	Unit	Spot Optimization	Grid Optimization	Change [%]
CO_2 emissions caused by the load	tCO_2	53335,1	53626,3	0,55
	tCO_2/MWh	0,35	0,35	0,55
	tCO_2/MW	969,73	975,02	0,55

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Table 76: Ecological KPIs for the Westnetz grid charges with monthly peak-load-pricing.

Westnetz monthly	Unit	Spot Optimization	Grid Optimization	Change [%]
CO_2 emissions caused by the load	tCO_2	53335,1	53773,05	0,82
	tCO_2/MWh	0,35	0,35	0,82
	tCO_2/MW	969,73	977,69	0,82

A.1.1.3 Technical KPIs

Table 77: Technical KPIs for the Mitnetz grid charges with yearly peak-load-pricing

Mitnetz yearly	Unit	Spot Optimization	Grid Optimization	Change [%]
Peak load	MW	55	34,93	-36,49
	%	100	63,51	-36,49
Flexibility Activation	MWh	70501,46	66879,63	-5,14
	MWh/MW	1281,84	1215,99	-5,14

Table 78: Technical KPIs for the Mitnetz grid charges with monthly peak-load-pricing

Mitnetz monthly	Unit	Spot Optimization	Grid Optimization	Change [%]
Peak load	MW	55	34,93	-36,49
	%	100	63,51	-36,49
Flexibility Activation	MWh	70501,46	66002,39	-6,38
	MWh/MW	1281,84	1200,04	-6,38

Table 79: Technical KPIs for the Westnetz grid charges with yearly peak-load-pricing

Westnetz yearly	Unit	Spot Optimization	Grid Optimization	Change [%]
Peak load	MW	55	34,93	-36,49
	%	100	63,51	-36,49
Flexibility Activation	MWh	70501,46	66912,17	-5,09
	MWh/MW	1281,84	1216,58	-5,09

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.

Table 80: Technical KPIs for the Westnetz grid charges with monthly peak-load-pricing

Westnetz monthly	Unit	Spot Optimization	Grid Optimization	Change [%]
Peak load	MW	55	34,93	-36,49
	%	100	63,51	-36,49
Flexibility Activation	MWh	70501,46	65992,31	-6,4
	MWh/MW	1281,84	1199,86	-6,4

A.2 Net-Billing tariff

The energy bill payment of the university is estimated using predefined Time of Use (ToU) tariffs. There are several consumption tariffs and eight different price periods (P1-P8), that are based on the definition of different electrical seasons and type of days. Table 81 shows the ToU tariffs, the hourly energy price and the fixed power fees, including taxes, that are paid by the University.

Table 81: ToU tarriffs applied to the UCY electricity bill

Months	Days	Hours	Price Periods	Energy Price (€ kWh^{-1})	Fixed Fee (€)
October to May	Monday to Friday	16:00 - 23:00	P1	0.1783	0.086 per day
		23:00 - 16:00	P2	0.1644	
	Weekends	16:00 - 23:00	P3	0.1738	
		23:00 - 16:00	P4	0.1605	
June to September	Monday to Friday	09:00 - 23:00	P5	0.2229	
		23:00 - 09:00	P6	0.1745	
	Weekends	09:00 - 23:00	P7	0.1771	
		23:00 - 09:00	P8	0.1719	

BestRES This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 691689.