Hybrid-VPP4DSO

Deliverable 3

Work Package 3

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New concepts for hybrid-VPP business-models and simulation based technical and economical validation

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1 Introduction

1.1 Hybrid VPP4DSO approach

In different European research projects and activities first applications for virtual power plants (VPP), which focus on trading on selected power markets, have been developed. These VPPs use 'flexibilities' like curtailment of aggregated loads, generation and "unused" capacities like emergency power supplies as "resource", which can be delivered to different customers like transmission system operators (TSOs) or power traders. On the other hand, there are technically orientated VPPs, which try to manage loads and generation in distribution grids in order to keep the power quality parameters within tolerable limits. These VPPs are part of the smart grid idea, nevertheless there are no suitable business models fitting into the regulatory framework in most European countries. The legal and regulatory framework and recommendations are further elaborated in the report "Regulatorische Rahmenbedingungen für hybride Virtuelle Kraftwerke" (regulatory framework for hybrid virtual power plants) [14].

According to the above-mentioned background of VPPs in the European markets the main objectives of the project hybrid-VPP4DSO are the following: Stepwise simulation-based development, evaluation and validation of a hybrid VPP concept and an implementation process of two hybrid VPP research systems to manage distribution grid issues and "normal" DR resource aggregator business with one VPP system including:

- A simulation-based validation of hybrid VPP operation concerning grid impacts (power flow simulation), technical-economic simulation of demand response (DR) resource aggregation and simulation of suitable business models.
- A technical proof of concept that will be first realized at laboratory level followed by test switching of real customer loads in two distribution grid sections in Slovenia and Styria, including a security analysis of such a concept.

The project performed the following 4 step approach: i.) Preparation of the simulation environment including the definition and selection of the system boundaries (technical, economic and legal) and models of specific distribution network areas including a customer VPP data base (customers and generators), as well as the preselection of business models; ii.) Development and modelling of future scenarios for generation and loads in the network areas and modelling of future scenarios including a cost benefit analysis for different market models; iii) Design and validation of a hybrid VPP aggregation concept via dynamic load flow simulations including the previous mentioned models; iv.) based on the results of the simulation-based validation of the developed hybrid VPP concept, the concept was verified in a proof of concept in real networks. These results are described in the report [15].

The results of this project are validated hybrid virtual power plant concepts to provide services especially for the requirements of distribution grid operators by combining network driven and market driven approaches in one concept including a proof of concept in selected distribution network areas in Austria and Slovenia. Additionally, the most promising business case will be further evaluated regarding non-technical aspects (e.g. legal and regulatory) resulting in recommendations for possible adjustments of market rules to better enable hybrid VPPs in Austria and Slovenia.

The project hybrid-VPP4DSO interacts with the projects eBADGE and evolvDSO, funded by the European Union in order to push the internationalization and coupling of balancing power markets in general and VPP business in particular.

1.2 Contents of this document

The aim of the project *hybrid*-VPP4DSO is the design, evaluation and validation of a hybrid virtual power plant concept including electricity generation from renewable resources as well as consumer-related measures (provision of negawatts) to optimize the power system. Network and market driven approaches will be combined, especially to provide services for the requirements of distribution grid operators. The simulation-based development of the hybrid-VPP-concept will be performed with real company data. After successful validation, a proof of concept in two specific network areas in Slovenia and in Austria is planned. Furthermore, the possibilities for business models, technical and not-technical barriers of the VPP market will be evaluated.

Chapter 2 describes the technical grid simulations. Grid models are built for the two chosen grid areas using DIgSILENT PowerFactory®, for a base year as well as two future scenarios. The grids are analysed to locate possible grid problems. Using the business cases defined in the Deliverable D1, several hybrid-VPP use cases are defined. They are analysed from a technical point of view, using the created grid models. Thus, the possible positive or negative influences of the hybrid-VPP on the grid are evaluated.

In section 3, results of the economic cost-benefit and stakeholder analyses of the different use cases are presented. Key questions to be answered are the identification of key roles and stakeholders, analyses of revenues from and cost and cost structures of VPPs (hybrid and non-hybrid). On this basis, minimum sizes of VPPs in terms of capacity of controlled flexibilities as well as profitability of a hybrid-VPP investment are assessed by using life cycle cost benefit, break-even and cash flow analyses.

The procedures and algorithms of the coupled simulation of power flow in the distribution grid and VPP aggregation are explained in chapter 4. The hybrid-VPP business simulation is developed in a bottom up approach, starting with algorithms to form a pool of flexibilities, assess the required backup and forecast the seasonally available capacity. Following, the algorithms for simulation of participation in a tertiary control market and the activation of flexibility resources as part of the pool due to disaggregation of the pools' set point are discussed. The calculated dispatch of individual units in the pool is sent to the power flow tool, which evaluates the impact of the hybrid-VPP in a final simulation run. Finally, the financial results of the 15 min-intervals are summed up for the entire year to provide the data for economic analyses.

Chapter 5 summarizes the technical and economic results and the conclusions are presented.

1.3 Use Case description

In Deliverable D1 four different hybrid-VPP business cases from a grid view were defined [13]:

1. Minimizing connection costs for the customer
2. Minimizing grid investments for the DSO
3. Energy provision during failures
4. Minimizing grid tariffs charged by DSO/TSO

Furthermore, business cases from a market view were defined as well in the [13]:

1. Energy only market
2. Balancing market
3. Capacity market
4. Minimizing imbalance costs

Out of those grid and market business cases, several use cases were formed for the technical and economic analysis. It was decided early on that the fourth grid business case would not be analysed further since the upstream network was not part of the simulations. From the market business cases, it was decided to focus on the day-ahead spot market and the balancing market for tertiary control due to the technical capabilities of the flexible resources. Tertiary control (manual frequency restoration reserve, mFRR) combines attractive revenue expectations with technical requirements, which are feasible for the resources investigated by surveys in the work package 1 [13]. Therefore, the following use cases were selected for the further investigation of this project and the economic and technical results for these use cases will be described in more detail in the next chapters:

1) **Market oriented use cases**

   The pure market use cases represent the current state-of-the-art of VPP application, operating only market driven. Figure 1 shows the procedure of the simulation for this use case. The grid simulation and the market simulation were run in parallel. The optimization of the market driven operation had two main results: First, the economic benefits as the objective function, which will be analysed further in chapter 3, and second the related change in the load profiles. Those market-optimized load-profiles were then run through the grid simulation once more and the two grid states, with and without spot market optimization were compared (see 2.2.1).

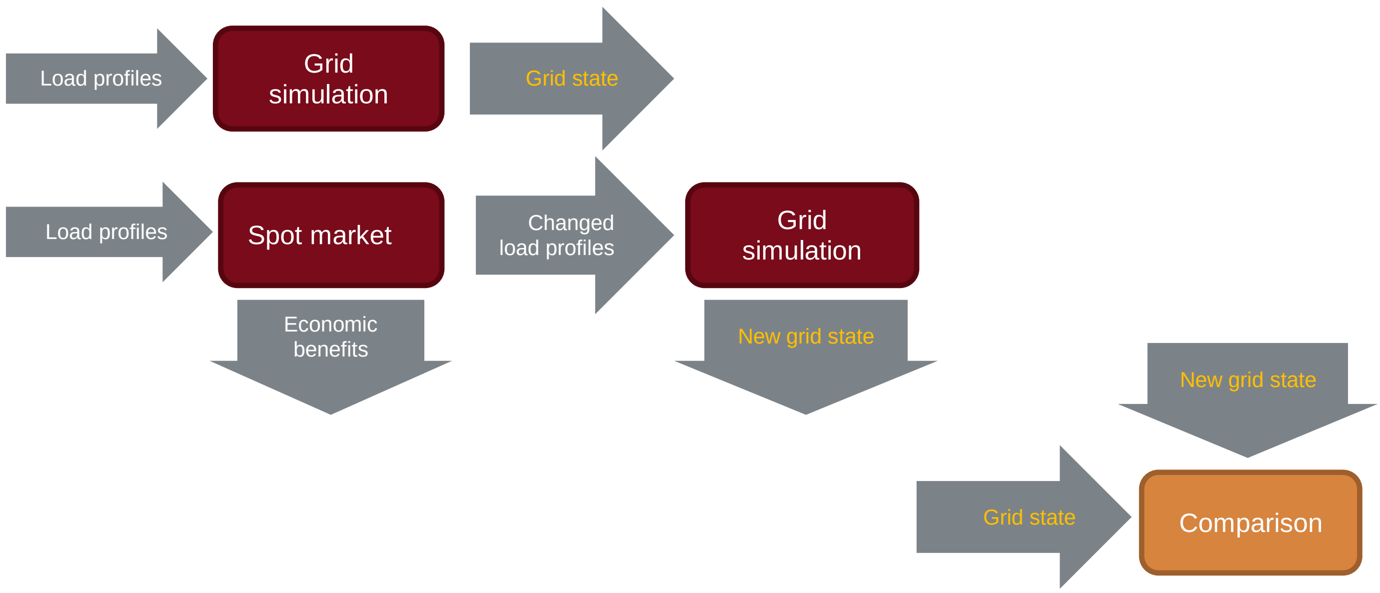

Figure 1: Simulation procedure of the market use case (exemplary for the spot market)

a) **VPP for day ahead spot market**
The aim of this analysis is to determine the influence of the participation of the hybrid-VPP in the day-ahead spot market. This use case was analysed for Austria and Slovenia, for the base year (2013/1014) and the two future scenarios. Additionally, an energy efficient price scenario was calculated for the two future years, as well two analyses for the year 2015, comparing hourly and quarter hourly prices.

b) **VPP for tertiary reserve market**
In this use case, the participation of the hybrid-VPP on the tertiary reserve market (mFRR) was simulated. The use case was calculated for Austria and Slovenia, for 2013/2014 as well as for 2030.

2) **Customer oriented use cases**
The integration of new customers (or the expansion of existing customers) could require new investments into the electricity grid, in case the available network capacities are not sufficient. According to current regulations, customers have to bear the costs for a connection to the closest suitable connection point. If the customers participate in the hybrid-VPP and allow the DSO to curtail load or feed-in temporarily, they can reduce grid connection costs. As this use case is highly dependent on the specific customer and grid situation, it was decided to analyse it in several case studies.

a) **VPP to minimize grid connection cost for new generators**
For Austria, the customer use case was analysed for the connection of new generators in the year 2020. Several case studies for feed-in of different generator types (PV, wind power, hydropower) and different plant sizes were conducted.

b) VPP to minimize grid connection cost for new consumers

In the Slovenian grids, this use case was analysed for the connection of a new industrial consumer both for the year 2014 and for the year 2030.

3) DSO oriented use cases

In the third part of use cases, the VPP provides services for the DSO. Since the economic evaluation showed early on that the DSO oriented use cases on their own are not economic in the current regulatory framework, the focus was set to the hybrid use cases. The pure DSO oriented use cases were only analysed in several case studies.

a) VPP for optimization of grid investments

With an increasing number of consumers and producers, the DSO has to invest into expansion of the grid. Those investments can be prevented or delayed by making use of the flexibility of the hybrid-VPP; this application is analysed in this use case. This use case is only relevant if grid investments are actually necessary; this was only the case for the one of the two Slovenian grid areas in the future scenarios. Therefore, the use case was analysed for this grid for the year 2030 in several case studies. The assumptions for the development of the future grids were based on realistic baseline assumptions from the participating distribution grid operators (e.g. no huge installation of e-vehicles was assumed).

b) VPP to support grid operation during maintenance and special switching states

The ability to control the behaviour of customers temporarily can also be used specifically during unexpected grid faults as well as for planned switchings due to maintenance. This use case was analysed in a case study for the Austrian grid areas in the year 2030. Since only one MV-feeder was available in both of the Slovenian grids, no reasonable switching scenario could be defined in these grids.

Additionally, the following hybrid use cases were analysed that are realistic combinations of the previous single market, customer and grid use cases:

4) Hybrid use cases

For the hybrid use cases it was decided to combine the market use case 1b) tertiary control with different customer and DSO use cases. The market use case 1a) day ahead spot market was not analysed in a hybrid case, since the economic value of this use case is not very high (see chapter 3.3.3). It was decided to use the future scenario 2030 for all hybrid use cases, since it proved to be the most interesting for applying a hybrid-VPP. The general simulation procedure is shown in Figure 2. First, the grid simulations determine the current grid state and communicate potential grid problems to the hybrid-VPP. The hybrid-VPP tries to solve those problems and additionally optimizes the remaining flexibilities on the market. The resulting change of the schedule is communicated to the grid simulations. There, the old and the new grid states are compared to determine the influence of the hybrid-VPP. Furthermore, the economic benefits are evaluated.

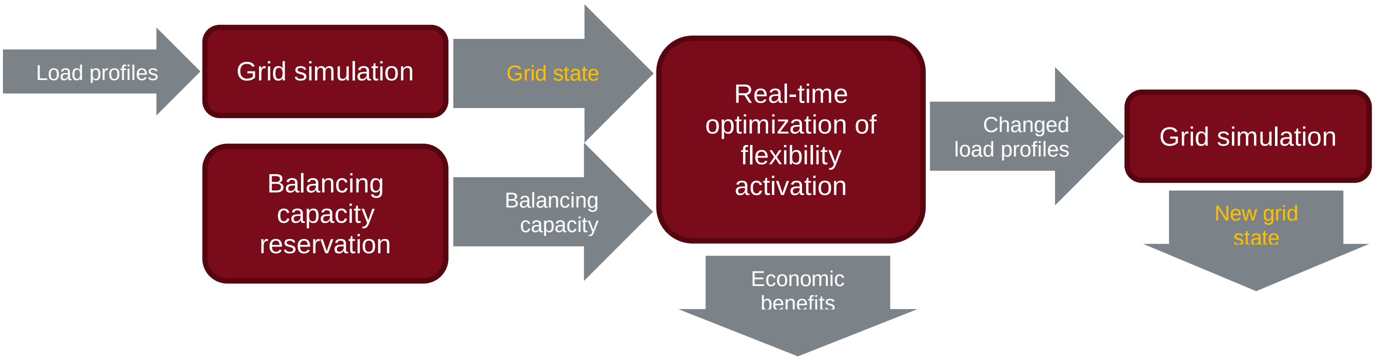

Figure 2: Simulation procedure of the hybrid use cases

a) **1b) + 3a)**
In this hybrid case, the tertiary reserve market is combined with services to optimize the grid investments for the DSO. This use case was simulated for the Slovenian grid areas.

b) **1b) + 2b) + 3a)**
The previous Slovenian hybrid use case was further expanded by including the services for customers as well. A new industrial customer is connected to the grid and participates in the hybrid-VPP in order to save grid connection costs.

c) **1b) + 3b)**
For the Austrian grids, the tertiary reserve market was combined with the DSO use case for supporting the grid operation during maintenance and special switching states. During those switching states, the hybrid-VPP supported the DSO, during the rest of the year it could act market oriented.

d) **1b) + 2a)**
Finally, the minimization of grid connection costs for new generators was combined with the participation at the tertiary reserve market. This use case was again simulated for the Austrian grids.

Table 1 gives an overview of the use cases and shows which ones were analysed for which year and which country. The case 0) in the table refers to the base analysis of the grids (see chapter 2.1). The yellow marked cases could not be analysed due to technical constraints, as described above. From the remaining cases, the green ones were selected for a detailed simulation.

Table 1: Overview of the analysed use cases.

Austria (Grid 1+2)

	0)	1a)	1a) EnEff	1b)	2a)	3a)	3b)	4a)	4b)	4c)	4d)
2013	✓	✓	-	✓		-		-	-		
2020	✓	✓	✓		✓	-		-	-		
2030	✓	✓	✓	✓		-	(✓)	-	-	✓	✓
	+ 1a) 2015, hourly + quarter hourly										
Slovenia (Grid 2)											
	0)	1a)	1a) EnEff	1b)	2b)	3a)	3b)	4a)	4b)	4c)	4d)
2014	✓	✓	-	✓	✓	-	-	-	-	-	
2020	✓	✓	✓		✓		-			-	
2030	✓	✓	✓	✓		(✓)	-	✓	✓	-	
Slovenia (Grid 1)											
	0)	1a)	1a) EnEff	1b)	2b)	3a)	3b)	4a)	4b)	4c)	4d)
2014	✓	✓	-	✓		-	-	-	-	-	
2020	✓	✓	✓			-	-	-	-	-	
2030	✓	✓	✓	✓		-	-	-	-	-	

1.4 Traffic light model

In the first Deliverable D1 [13], the coordination scheme between grid and market was described, defining a market- and grid-VPP as well as an active and passive hybrid-VPP, with differing degrees of market and grid interactions. Whilst working on the simulated implementation of the hybrid-VPP in Work package 3, however, it was identified that the focus of this project will be on the active hybrid-VPP and a more detailed interaction model between DSOs and markets was developed based on the general traffic light model. A general traffic light concept was described by the “Bundesverband für Energie- und Wasserwirtschaft” in [1] and was adapted to fit the specific needs of the project. In the traffic light model, the degree of interaction between market and grid is not predefined once, but is dependent on the current situation of each individual grid area and thus changes over time.

In the hybrid-VPP4DSO traffic light model the DSOs analyse the state of their grid and determine for each time-step and each grid-section (e.g. one week in advance) whether it is critical (red), semi-critical (yellow) or non-critical (green). This information is transferred to the hybrid-VPP operator. In the green phase, the hybrid-VPP can participate in the market, freely, since the grid-section has enough reserve and is not congested. In the yellow phase the grid voltage is already close to its limits. Here, the market participation is restricted and only either an increase or a decrease of power is allowed. Thereby, it can be avoided that the participation on the balancing market causes additional grid problems. During red phases, the grid is in a critical situation and faces some over- or undervoltage problems or congestions, if connected units would not change their feed-in or consumption. Here, the hybrid-VPP operates solely grid-driven and it supports the DSO by using its available flexibilities to decrease those problems.

1.5 Overview of flexible resources

The list of flexibilities for the year 2014 was derived from surveys carried out in Styria and Slovenia and represent real units which can change generation or consumption for a certain duration [13]. For the future scenarios, additional units, mainly generators, were defined generically, but taking into account the future planning scenarios of the DSO's. Due to non-disclosure agreements, only aggregated values can be shown in this report. The flexibilities shown in Table 2 are used for the basic cases. Additional customer flexibilities were added in the customer oriented use cases. The shown flexibilities are nominal values, not considering availabilities of the individual units. For market simulations, flexibility with high reliability is required, which is calculated on weekly basis during the simulations.

Table 2: Overview of flexibilities in Slovenia and Austria, existing flexibilities were assessed by surveys, assumptions about new commissionings were made based on information provided by the connecting DSOs

		Timeline	Number of units	Nominal flexibility (in MW) positive	negative
Slovenia	connected to simulated network	existing in 2014	6	1,65	1,22
		generic, 2016-2020	4	0,25	1,25
		generic, 2021-2030	3	0,05	3,05
		total in 2030	**13**	**1,95**	**5,52**
	outside of simulated network	existing in 2014	11	15	14
		generic, 2016-2020	0	0	0
		generic, 2021-2030	0	0	0
		total in 2030	**11**	**15**	**14**
		Slovenia, total in 2030	**24**	**16,95**	**19,52**
Austria	connected to simulated network	existing in 2013	12	7,2	8,12
		generic, 2016-2020	18	0	13,84
		generic, 2021-2030	0	0	0
		total in 2030	**30**	**7,2**	**21,96**
	out sid e of sim	existing in 2013	4	7,56	4,83

		generic, 2016-2020	0	0	0
		generic, 2021-2030	0	0	0
		total in 2030	**4**	**7,56**	**4,83**
		Austria, total in 2030	**34**	**14,76**	**26,79**

About 70% of the units shown in Table 2 were generators, the rest of the flexibilities was provided by flexible loads. It was expected that mainly hydropower will be installed in the Austrian grid sections, while mainly combined heat and power (CHP) and wind will be installed in Slovenian grid sections. These scenario assumptions were derived from the DSO's planning scenarios.

Depending on the type of the flexibilities, different technical characteristics as ramping characteristics, maximal and minimal activation time as well as availabilities during the seasons (mainly for generators) and weekdays (mainly for loads) were taken into account.

2 Technical grid simulations

The aim of the technical grid simulations is creating grid models for the chosen grids of Energienetze Steiermark (ENS) and Elektro-Ljubljana (ELj) and analysing the influence of demand response and VPPs on those grid sections, using a load flow analysis. This project analyses grid sections that are diverse regarding the influence of different generation and load on the grid (more load, more generation; CHP, wind, PV, different types of demand response) as well as grid typology as rural and urban grids as well as radial and meshed grids were analysed. The four grid areas, two of which are located in Slovenia and two in Austria, were presented in detail in Deliverable 1 [13] as well as the grids and intermediate results in [2], [3] and [4].

The two Austrian grid areas are located in Styria, in a rural region with mountains, a high degree of overhead lines and they have a high infeed of hydro power plants and several new generators are planned in the next years. In these grids, generation spikes happen especially during spring and early summer. Moreover, due to the mountainous area special switching states are more likely to happen in this region. The Austrian grids sections belong to the 30 kV grid and are interlinked at one switching station but operated disconnectedly for most of the year. In the following chapters, grid area 1 refers to the southern grid and grid area 2 to the northern grid.

In Slovenia, grid area 1 is a 20 kV rural grid and grid area 2 is a 10 kV urban grid. The grid area 1 has a low population density and a high infeed of photovoltaics and CHP. The imbalance between generation and consumption could be solved so far with a tab changer transformer, but planned new power plants will further increase the problems in the grid. The grid area 2 has several customers that are interested in demand response solutions. Moreover, the future generation was increased by several CHP plants and a large PV plant.

2.1 Simulation scenarios and grid models

The simulation models were created for three scenarios: The first was the base scenario for a current year, which was 2013 for Austria and 2014 for Slovenia. Furthermore, two future scenarios for the years 2020 and 2030 were created. The scenarios were evaluated for each of the areas to identify the type and location of possible future network problems.

The simulations for the project were carried out using the software DIgSILENT PowerFactory®, while ENS and ELj use different software tools, namely NEPLAN® and GREDOS®. Since no direct interface exists between those platforms, the necessary grid data had to be converted to the right format in a first step. Apart from the grid topology, load-profiles of the producers and consumers were needed for the simulations, which were partly provided by ENS and ELj and partly simulated.

Only the medium-voltage grid is taken into account in all simulations. Since no measurements of the high-voltage side of the primary substations were available, the slack node was placed at the medium-voltage busbar of the transformer. Hence, the deadband of the transformer's on-load-tap-changer (OLTC) controller (AVC – automatic voltage controller) was also not taken into account. As an example, in the Austrian grid code 2% of the voltage band are reserved for the operation of the AVC. Therefore, for all analyses the total available voltage band for MV grid voltages was defined 2% (= the margin reserved for AVC) smaller than specified in the grid code. This can be seen in Figure 3 exemplarily for the second Austrian grid area.

Since all evaluated grids are operated far below their full capacity limits, no grid elements came close to being overloaded. The voltage limits turned out to be the most critical system boundaries. Therefore, the focus of the further analysis will be on avoiding violation of voltage limits. In the two Austrian grid areas, the first measures taken to solve upcoming voltage band problems were assumed to be a Q(U) control for generation units and line-drop compensation. The implemented characteristics for both of them are shown in Figure 4.

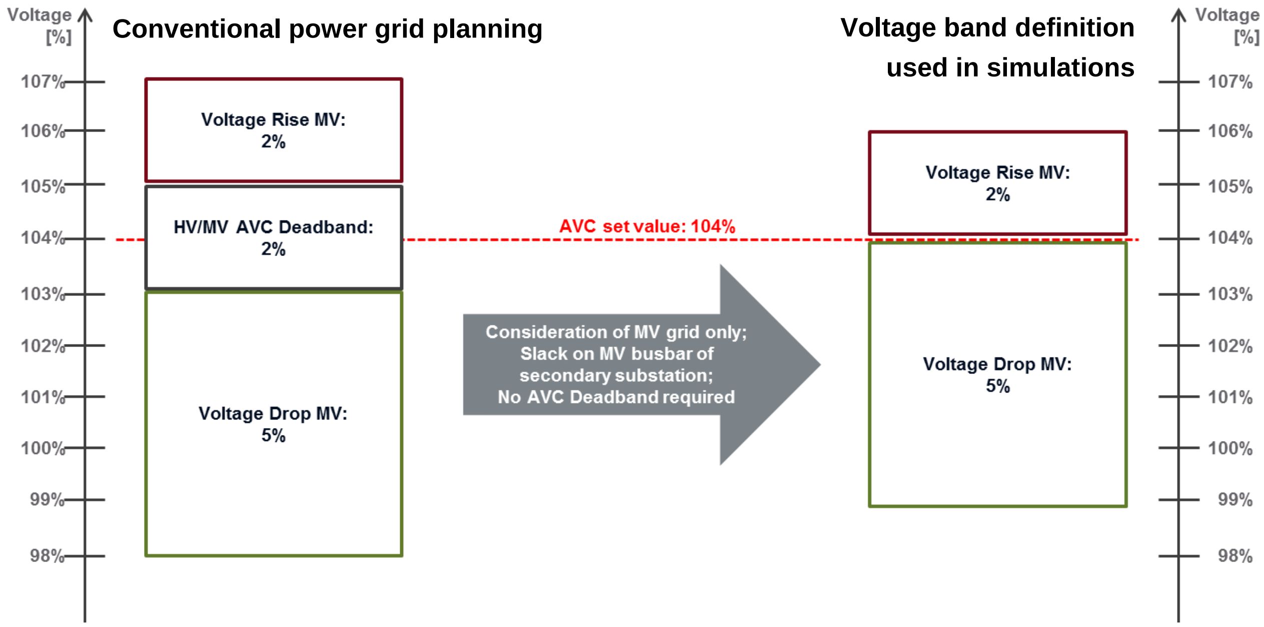

Figure 3: Change of voltage band when the deadband of the HV/MV-transformer's OLTC controller is not considered. This graphic exemplarily shows the voltage band of the second Austrian grid area; however, the equivalent adjustment was made for all four grid areas.

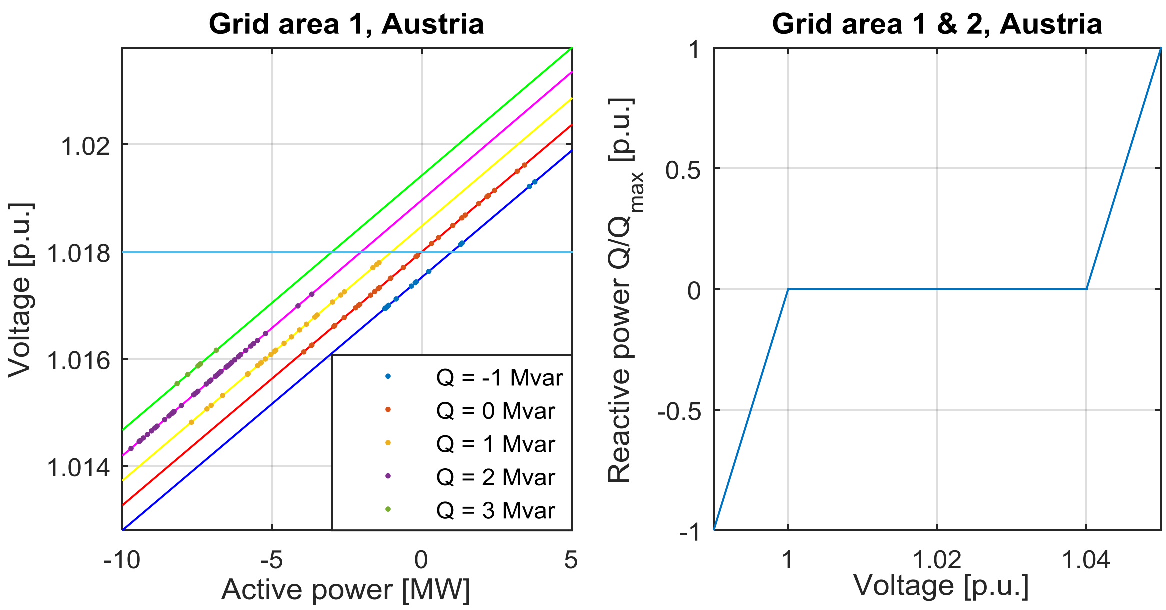

Figure 4: Characteristics for the line-drop compensation and Q(U) control applied in the Austrian grid areas

For the two Slovenian grids, the usage of line-drop compensation was not feasible, since only one feeder of each transformer was available for the project (and the line-drop compensation thus would not have had the necessary information about the rest of the grid). Since no measurements of the reactive power for the base year were available, only the active power profiles could be included in the simulation and a local Q(U) control was not implemented in the initial simulations. However, during the validation in Work Package 5 some reactive power measurements were available for the year 2016. One recommendation from the validation was to model the reactive power via a constant cos(φ) based on the measurements of 2016 in the Slovenian grids (see Deliverable D5 for more details). The constant cos(φ) was assumed for all generators and consumers and determined by comparing the active and reactive power at the slack node of the measurements with the simulations (see Figure 5). For Siska the cos(φ) was set to 0.975, for Crnomelj to 0.97. This constant cos(φ) for the base year, as well as an on-site Q(U) control for the future generators (see Figure 6), was considered for all following simulations, which were especially the Slovenian hybrid use cases. The main findings for the use cases previously simulated without considering the reactive power remain valid, nevertheless.

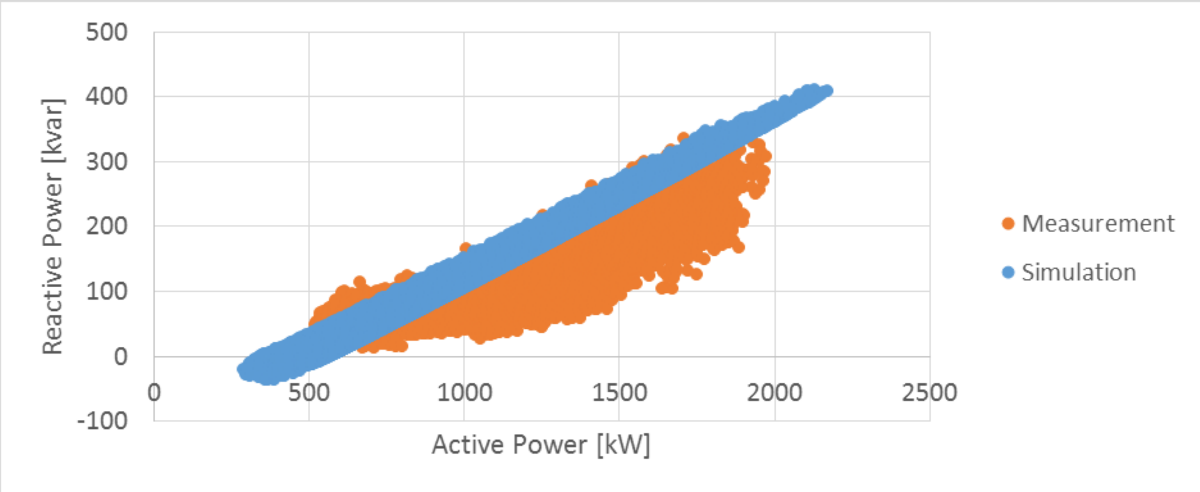

Figure 5: Comparison of the active and reactive power at the slack node of the measurements and simulation in the second Slovenian grid area

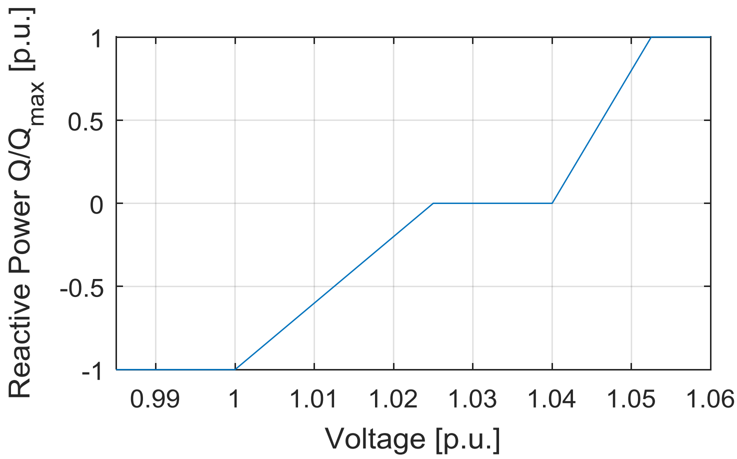

Figure 6: Q(U) control in the Slovenian grid areas. The Q(U)-characteristic was chosen according to the findings in [5] and the requirements of the DSO.

For better understanding, only the minimum and maximum voltages of all simulated nodes in the grid are depicted in all following graphics.

2.1.1 Base scenario

The simulation models in the base scenario were created for a current year. In the Austrian grids the data was collected for the year 2013, in the Slovenian case data from the year 2014 was used. The models were based on measured load profiles provided by ENS and Elj. In case that no measured profiles were available, synthetic load profiles were applied.

For the Austrian models, the grid simulations were validated with real measurement values and adjusted as close as possible to the current real grid. For this, the measured power flow over the transformer station of both grids was compared to the simulated power at that point. Since some of the profiles were missing, especially several load-profiles, the simulated power was significantly below the measured power in both grids, as can be seen in the upper plots of Figure 7 and Figure 8. In order to get a closer match between the simulation and the real measurements and to compensate for the missing load profiles, the existing load profiles were linearly increased to approach to the real active power balance of the grids. For the first grid area, all existing loads were increased by 10% and for the second grid area by 20%. By this, a relatively close match between the measured and the simulated power over the transformer station could be achieved, as can be seen in the lower plots of Figure 7 and Figure 8.

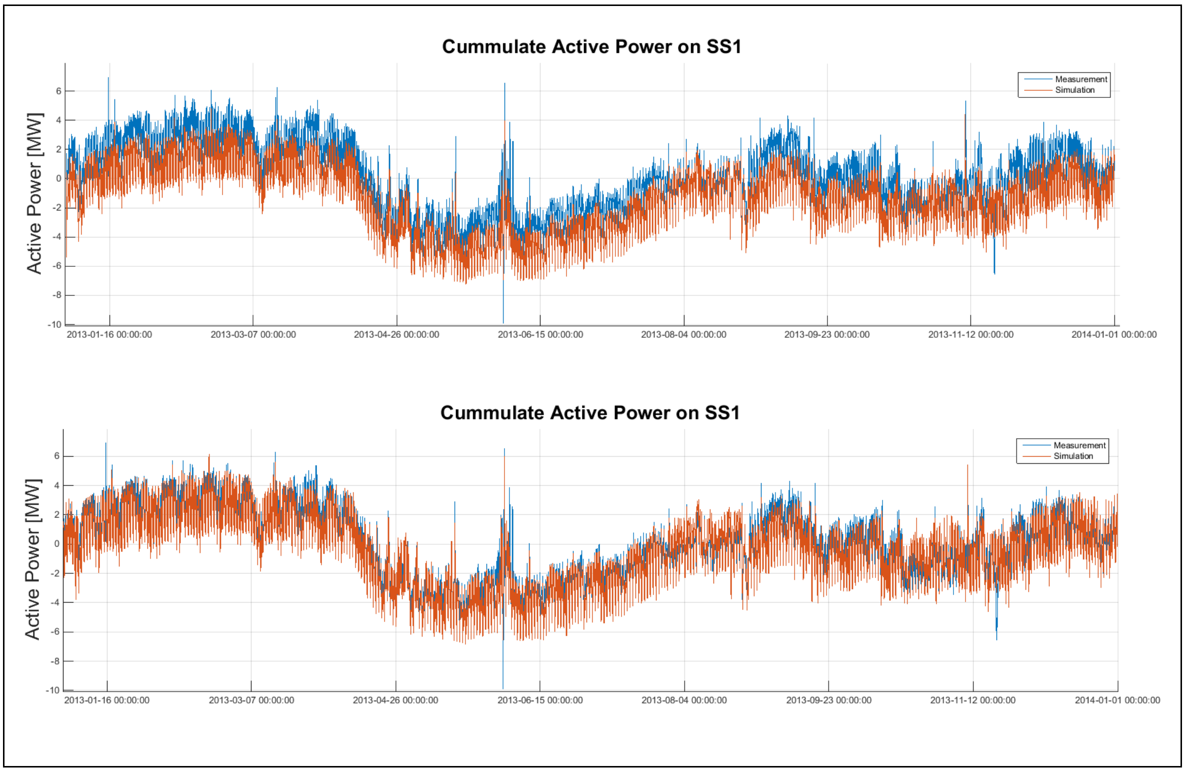

Figure 7: Comparison between the measured (blue) and the simulated active power (red) at the HV/MV-transformer station of the first Austrian gird area. The upper figure shows the original active power profile with missing datasets; in the lower figure all loads were increased by 10% to compensate the missing time series.

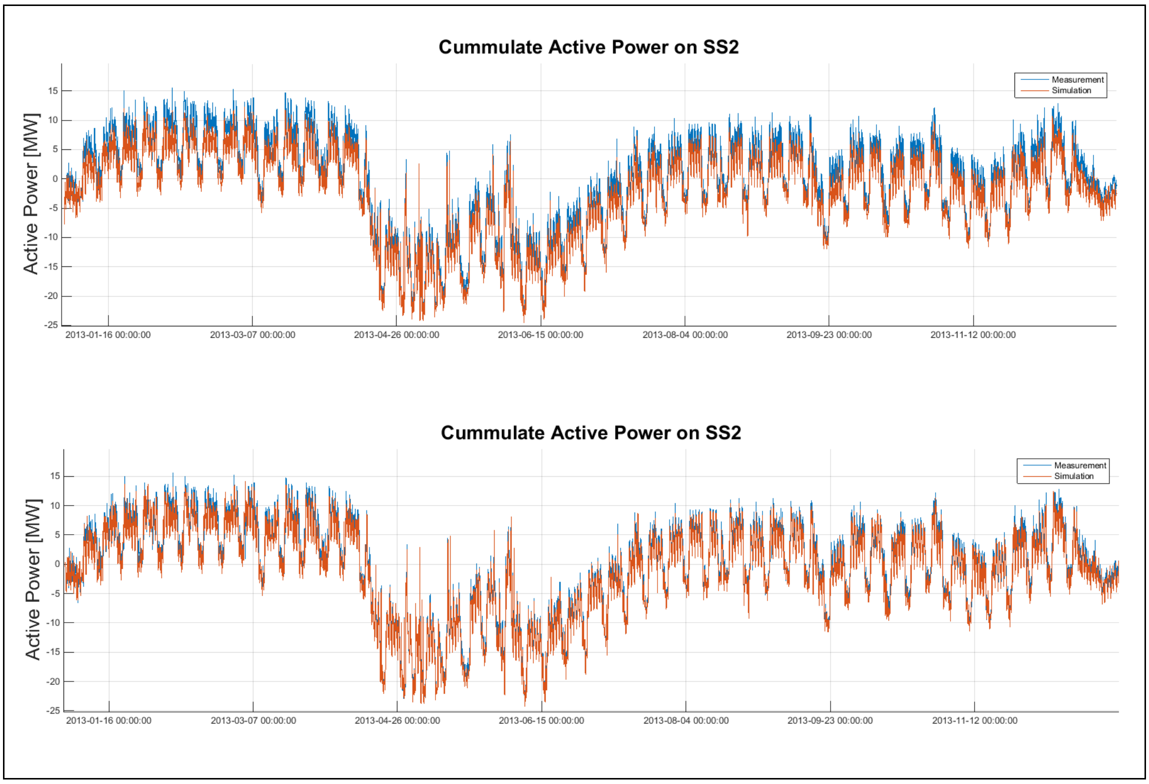

Figure 8: Comparison between the measured (blue) and the simulated active power (red) at the HV/MV-transformer station of the second Austrian gird area. The upper figure shows the original active power with missing datasets in the lower figure all loads were increased by 20% to compensate the missing time series.

Since no measurements at the HV/MV-transformer station were available for the Slovenian grids for the base year, this comparison could not be made here. However, the later validation in Work Package 5 showed that the designed grid models fits the reality quite well. More details to the comparison of the grid models with real measurements can be found in the Deliverable D5 [15].

The main grid characteristics for all four selected areas are summarized in Table 3. Beside the voltage level, the transformer rated power of the HV/MV transformer stations is given. In the second Austrian grid area, two 22 MVA transformer stations are available to cover the peak power. Furthermore, the number of branches originating from the transformer station is listed as well as the maximum branch length. The peak consumption and infeed in the selected areas is given for the base year 2013 for Austria and 2014 for Slovenia.

Table 3: Main grid characteristics of the selected grid areas

Grid Characteristics	Grid area			
	Austria 1	Austria 2	Slovenia 1	Slovenia 2
Voltage level [kV]	30	30	20	10

Transformer rated power [MVA]	32	22(x2)	20	31.5
Branches	2	5	1	1
Maximum branch length [km]	36.8	28.7	8.4	8.9
Peak consumption [MW]	12.03	23.93	3.117	2.095
Peak infeed [MW]	14.46	28.77	2.175	0.116

Figure 9 shows the result of the simulation for the two Austrian grid areas for the whole base year. In the second grid area, 2% of the voltage band is reserved for voltage rise and 5% for voltage drop, which are common values for the medium voltage grid in Austria (see Figure 9). In the first grid area, the set point was reduced from 104% to 100.8% to allow a high share in decentralized production units. In both grids, the highest voltage rises occur during spring and summer, due to the snowmelt and the high amount of hydropower stations. The largest voltage drops occur during wintertime.

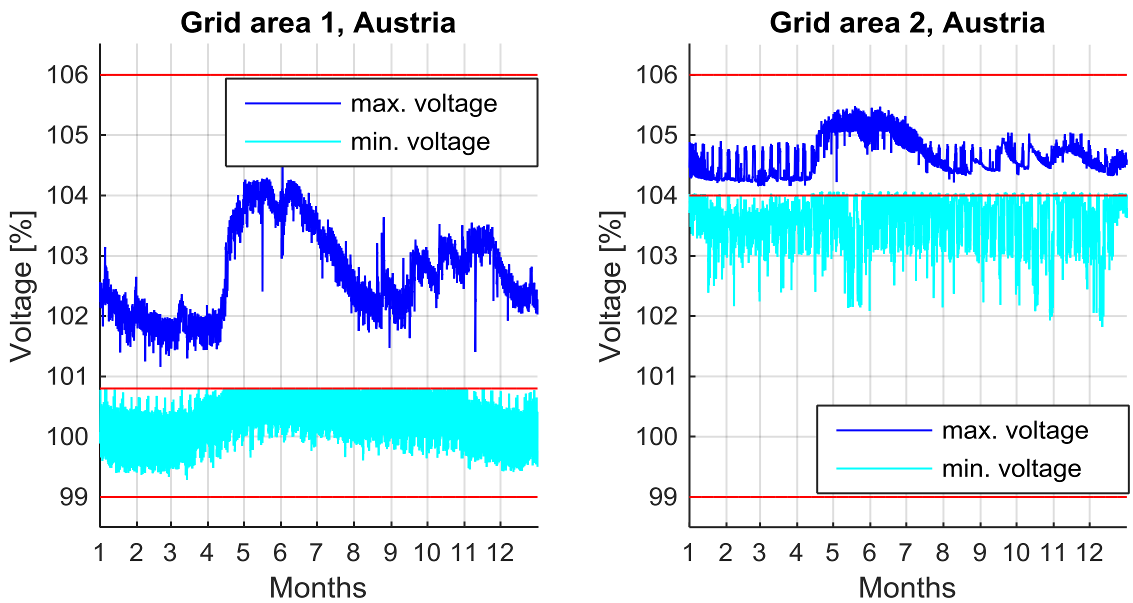

Figure 9: Minimum and maximum voltage in the two Austrian grid areas in the base scenario. (The red lines show the voltage band reserved for voltage rise (top) and voltage drop (bottom), as well as the set-point (middle), according to the DSO's network planning (see Figure 3).)

In Figure 10, the simulation results for the two Slovenian grid areas are shown without considering the reactive power. The voltage set point was set to 103.5%; 2.5% of the voltage band are reserved for a voltage rise and 5% for a voltage drop in the medium-voltage grid. It was defined that a safety margin of 0.5% should be kept for the voltage rise and the same for voltage drop. The DSO has to reserve this proportion of the voltage band, which might not be used during a normal operation of the grid. Reasons for this are a possible outage or switching in the grid, as well as customers with very stochastic, non-predictable consumption or production.

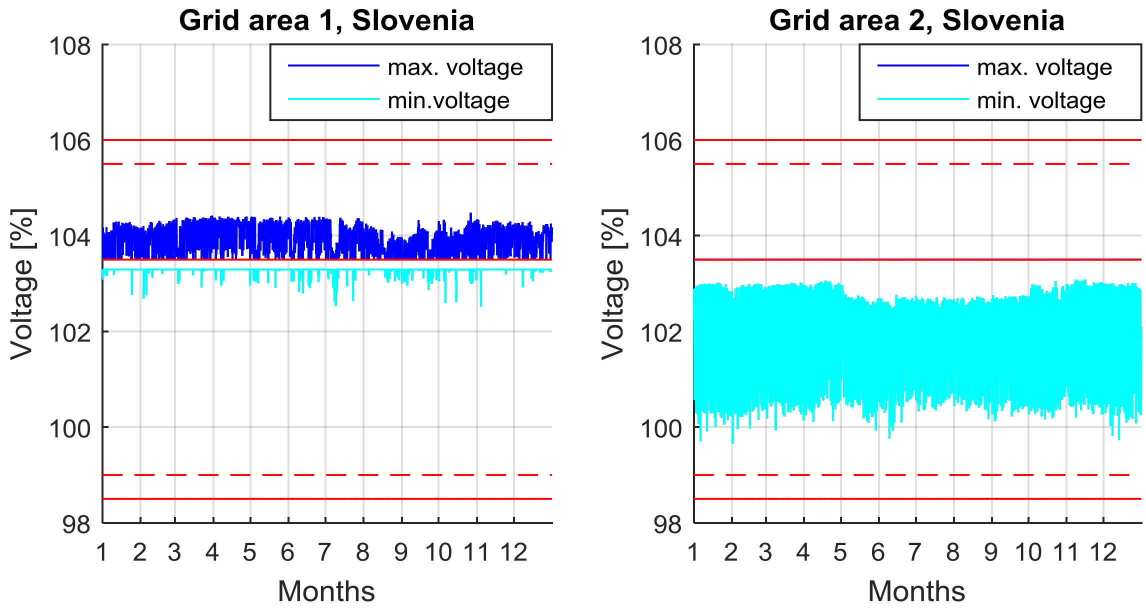

Figure 10: Minimum and maximum voltage in the two Slovenian grid areas in the base scenario, without considering the reactive power of the customers. The red lines show the voltage band reserved for voltage rise (top) and voltage drop (bottom), as well as the set point (middle) and the reserve area (dashed).

If a constant cos(φ) for all loads and generators is considered, the additional infeed of inductive reactive power leads to lower grid voltages than in the case without the consideration of the reactive power. Nevertheless, the voltage remains within the desired limits. The simulation results for this case can be seen in Figure 69 in the Appendix.

In the first grid area, combined heat and power (CHP) as well as PV plants produce a rather constant rise of the maximum voltage over the whole year. The second grid area however, contains very few production units.

As expected, the simulation did not show any violations of limits in any of the grid areas in the base scenario, since the status quo of all grids is built according to current standards of network planning. This leads to the conclusion that no grid support of the hybrid-VPP is necessary in the base scenario and the hybrid-VPP operation can focus on participation in balancing or energy markets.

2.1.2 Future scenario 2020

For the future scenarios, additional production and consumption units were integrated into the grid models based on known connection requests, on the results of the analyses in WP2 and on assumptions made in consultation with the respective DSOs. The assumed development of peak consumption and of infeed power of distributed generation (DG) are shown in Table 4.

For the Austrian grid areas, the simulated loads were increased by 6% in comparison to the base year. Furthermore, already projected power plants were integrated, based on information of connection requests provided by the DSO. For Slovenia, the simulated loads were increased by 7.4% in comparison to the base year (which is an increase of 1.2% per year). Additional power plants were included as well, as suggested by the DSO.

Table 4: Peak consumption and distributed generation infeed power in the base and future scenarios

Consumption/DG infeed power	Grid area			
	Austria 1	Austria 2	Slovenia 1	Slovenia 2
Peak consumption base [MW]	12.03	23.93	3.117	2.095
Peak consumption 2020 [MW]	12.75	25.37	3.349	2.251
Peak consumption 2030 [MW]	13.85	27.56	3.773	2.536
Peak infeed base [MW]	14.46	28.77	2.175	0.116
Peak infeed 2020 [MW]	18.37	34.61	3.987	1.551
Peak infeed 2030 [MW]	20.21	38.07	5.547	2.802

Significant voltage rises occur in both Austrian grid areas in comparison to the base scenario (see Figure 11). Due to the additional generators, mainly photovoltaic and hydropower stations, the highest voltage occurs during spring and summer. Additionally, the lowest voltage in the grid decreases due to the increase in consumption during winter. Thus, the voltage band in the first grid area is already completely utilized. Not all new connections could be integrated with conventional grid planning.

As described above, the first measures taken to prevent voltage band problems were implementing a local Q(U)-control, as well as a line-drop compensation (see Figure 4). Only if those measures are not sufficient, an active power control (either locally or via a VPP) are usually considered. It was assumed that all power plants of the base scenario can provide reactive power with $\cos(\varphi) = 0.95$ and all newly built power plants can follow the described Q(U)-characteristic. The line-drop compensation was applied for the first grid area, where the set point was increased from 100.8% to 102%. With those steps, the voltage constraints can be maintained and an additional margin is available, which can be seen in Figure 12. Therefore, the hybrid-VPP is not needed for grid-support in either of the grid areas in the scenario 2020 and it can participate in the market unrestrictedly.

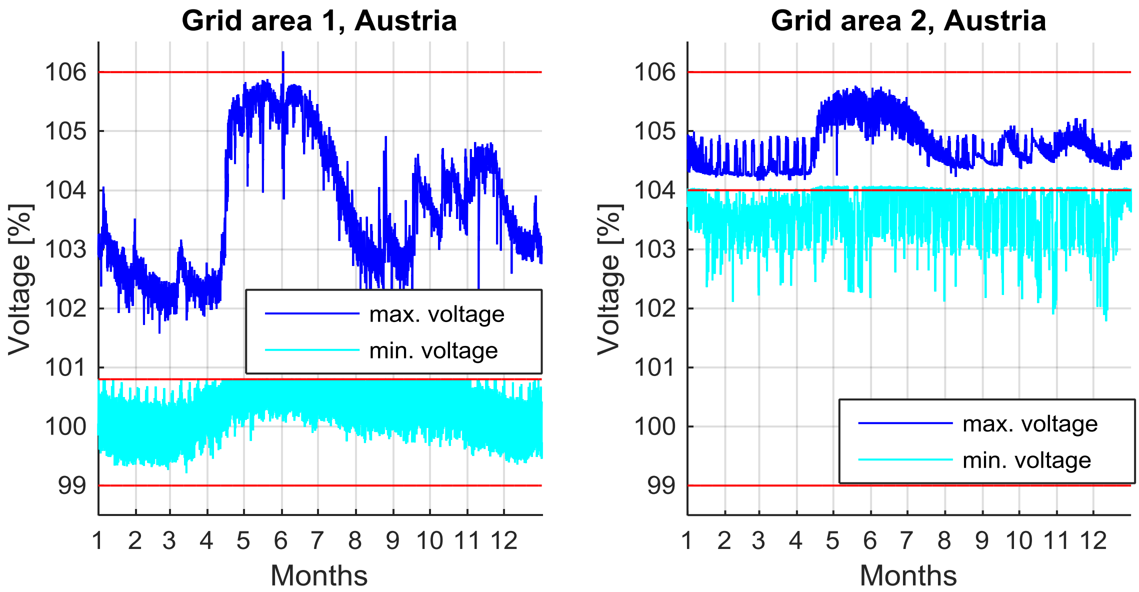

Figure 11: Minimum and maximum voltage in the two Austrian grid areas in the future scenario 2020.

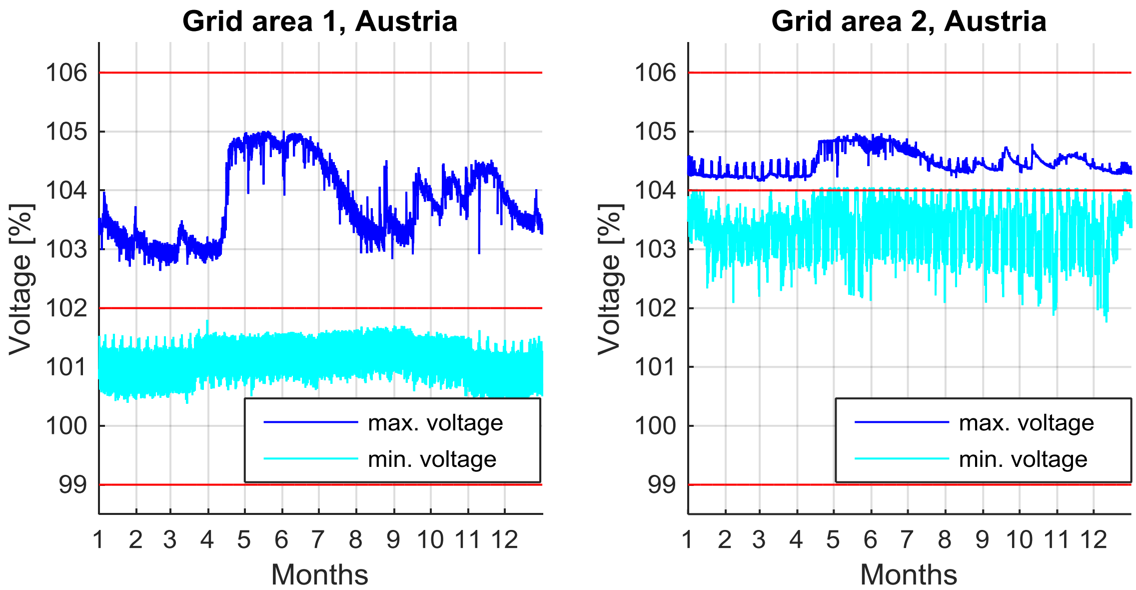

Figure 12: Minimum and maximum voltage in the two Austrian grid areas in the future scenario 2020, with Q(U)-control and cos(φ) = 0.95 in both grid areas and line-drop compensation and increase of set point in the first grid area.

Despite the increase in distributed generation and consumption, no problems occurred in the Slovenian grid area 1 in the scenario 2020 (see Figure 13). Here, the hybrid-VPP can participate in the market freely. However, in the second grid area two big CHP units result in a significant voltage rise especially during winter. The voltage band is already completely utilized here and some violations of the desired upper margin occurred. When including a constant cos(φ) for all customers of the base year and a Q(U)-control for all future generators, it was possible to keep the voltage between the limits at nearly all times. This can be seen in Figure 14. However, since some under voltage problems occurred, an expansion of the grid, or the utilization of the hybrid-VPP would still be necessary in this area.

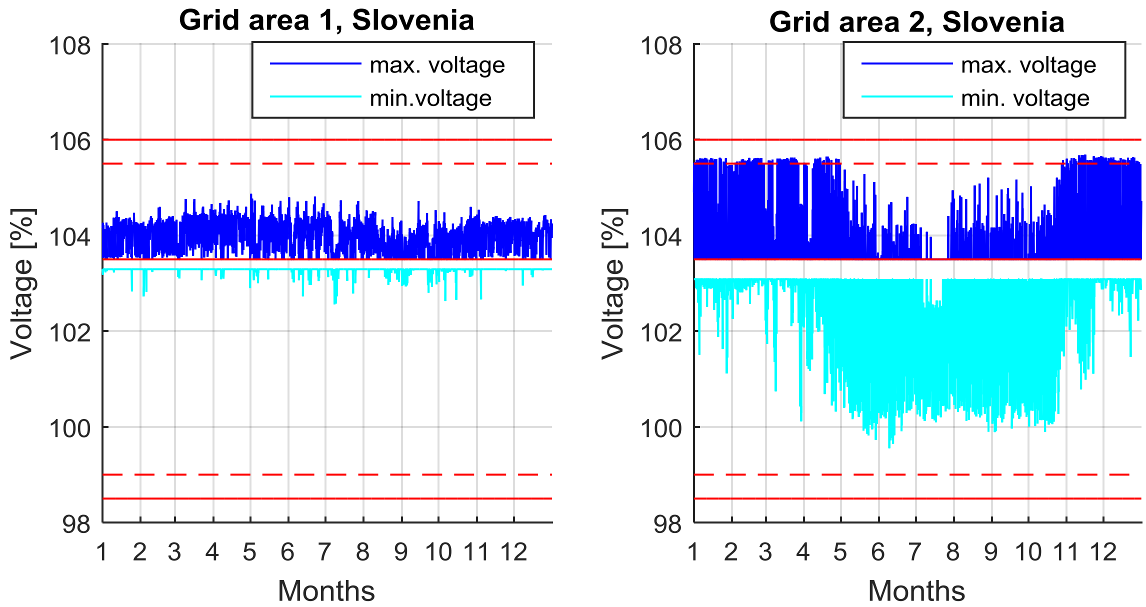

Figure 13: Minimum and maximum voltage in the two Slovenian grid areas in the future scenario 2020, without considering the reactive power of the customers.

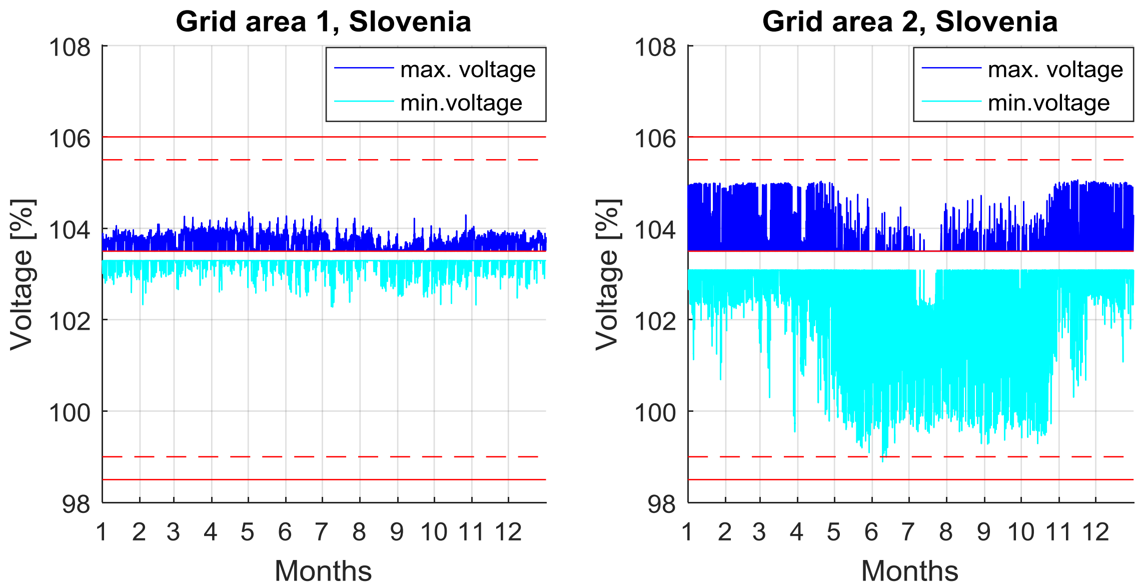

Figure 14: Minimum and maximum voltage in the two Slovenian grid areas in the future scenario 2020, with a constant cos(φ) for all customers of the base year and a Q(U)-control for all future generators.

2.1.3 Future scenario 2030

The production and consumption power was further increased in the second future scenario representing the year 2030, as listed in Table 4. For the two Austrian grids, all loads were increased by 15.2%, compared to the base year. The infeed of all power plants from the scenario 2020 were furthermore increased by 10%. For the Slovenian grid areas, the loads were increased by 21.0%, compared to the base year. Here, additional power plants were added to the simulation, as suggested by Electro Ljubljana.

The simulation results for the two Austrian grid parts are shown in Figure 15. There is still plenty of room for the integration of additional customers until this would be the reason for voltage problems, especially in the second grid area. In the first grid area, about 1% of the voltage band is still available in the simulation. However, it can be assumed that in this future scenario this grid is already close to its capacity-limits, since only the normal switching state is considered here. A margin in the voltage band has to be available to allow alternative switching states and backup supply.

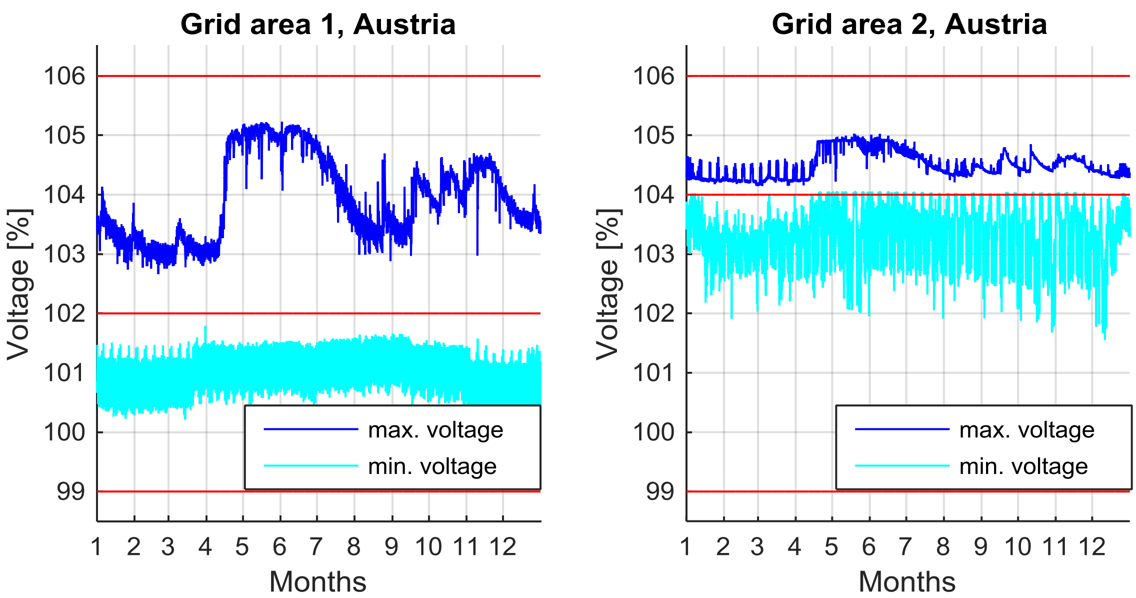

Figure 15: Minimum and maximum voltage in the two Austrian grid areas in the future scenario 2030, with Q(U)-control and cos(φ) = 0.95 in both grid areas and line-drop compensation and increase of set point in the first grid area.

An interesting finding was that in grids with a lot of hydropower, like here in the Austrian grid areas, VPPs are only of limited use. Unlike with wind or PV, the voltage in the grid is not very volatile in areas with hydropower plants. Therefore, voltage rises and possible over voltages occur over a relatively long period. A thus necessary long running curtailment of generation units by a virtual power plant would not be economical under the current regulatory framework.

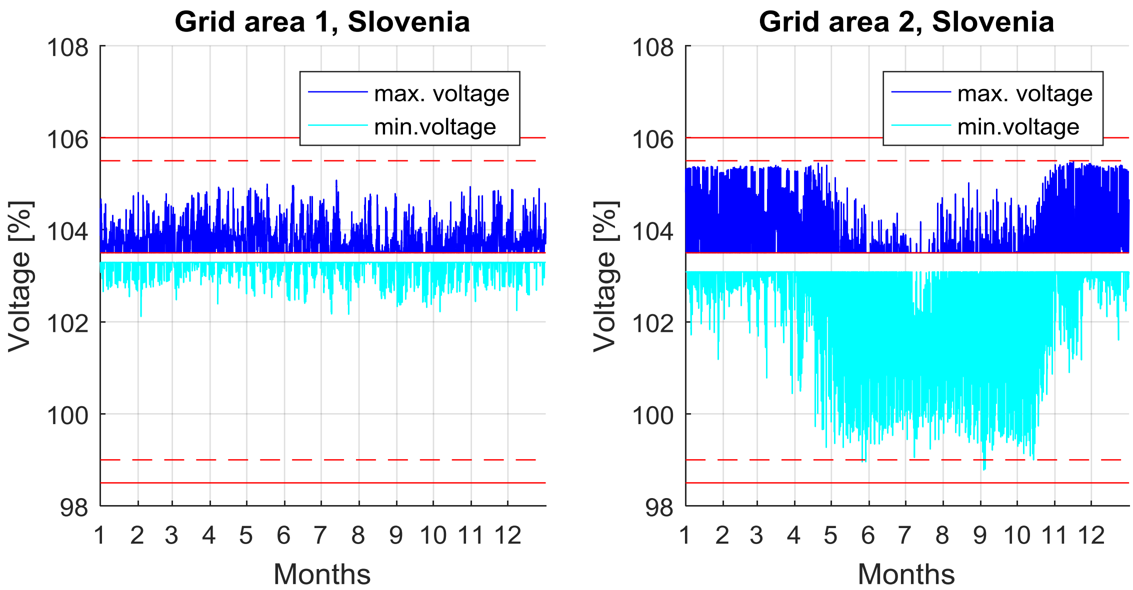

Figure 16 illustrates the simulated voltages in the two Slovenian grid areas for the future scenario 2030: A large wind power plant causes voltage peaks in the first grid area. In the second grid area, the production was further increased with a CHP plant and a large PV plant. Without considering the reactive power, those enhancements would lead to violations of the voltage band (see Figure 70 in the Appendix for details). However, with including a constant cos(φ) for all customers of the base year and a Q(U)-control for all future generators, the grid situation could be improved significantly: In the first grid area, no voltage band problems occur anymore. In the second grid area, there are still some under voltage problems. Therefore, an expansion of the grid, or the utilization of the hybrid-VPP would be necessary in in the second Slovenian grid area for 2030. This will be further covered in chapter 2.2.3.

Figure 16: Minimum and maximum voltage in the two Slovenian grid areas in the future scenario 2030, with a constant cos(φ) for all customers of the base year and a Q(U)-control for all future generators.

2.2 Technical use case analysis

In this chapter, the influences of the hybrid-VPP on the grid are analysed for the different use cases.

2.2.1 Market use cases (1)

As a first proof of concept, it was evaluated in a case study, whether the operation on the market can actually lead to voltage band violations in the considered grids. The case study was carried out for the second Slovenian grid area. The activation by the market was set to a critical time, where the voltage was already rather high; it was simulated to occur three times, for one hour each. The upper voltage limit is violated due to the usage of the hybrid-VPP as can be seen in Figure 17.

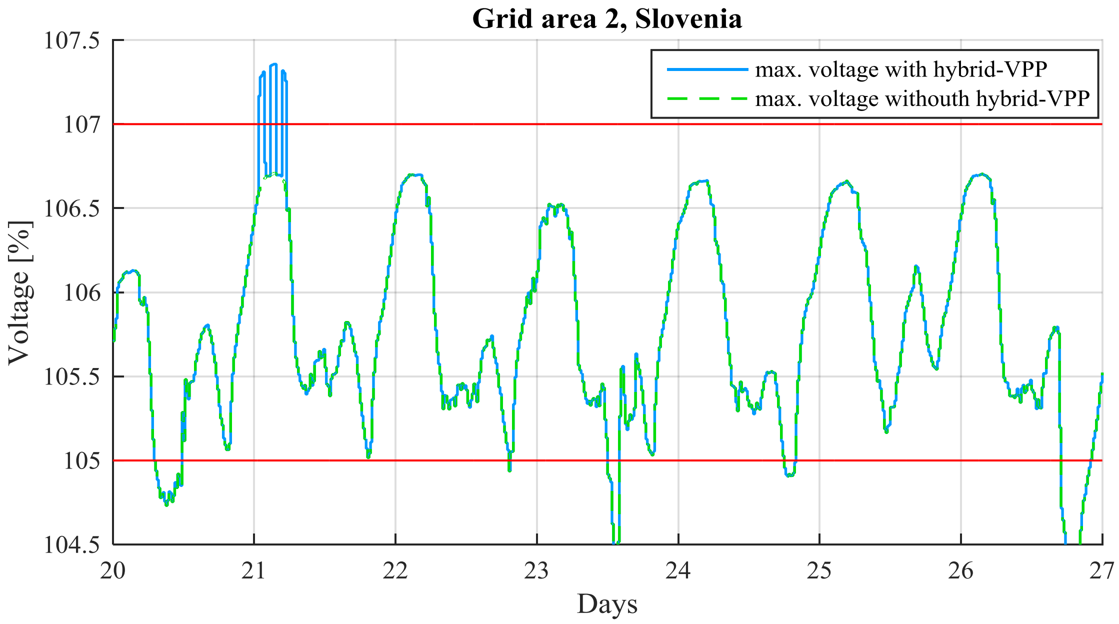

Figure 17: Case study for the influence of the market participation on the grid, in the second Slovenian grid area, evaluated for one exemplary week[1]

The analysis showed that the utilization of flexibilities by means of the VPP could cause an overvoltage situation in the distribution grid during critical times. Therefore, a procedure between DSO and VPP operator to avoid activations in critical sections during peak hours is necessary and the hybrid-VPP concept is reasonable.

2.2.1.a VPP for day ahead spot market (1a)

This use case was only relevant for the second grid area in Austria, since there were no flexible loads in the first one. The grid simulations showed that the participation in the spot market would have no significant influence on the voltage in this grid area in any of the scenarios. This is shown exemplarily in Figure 18 for the future scenario 2030. As the rest of the scenarios showed very similar results in the grid simulation, they are summarized in Figure 71 in the Appendix.

[1] The voltage band limits as well as the set-point are different in this case study than in the rest of this deliverable. The reason for this is that this case study was done in an earlier stage of the project. The used voltage band limits and set-point were slightly adjusted in accordance with ELj at a later point.

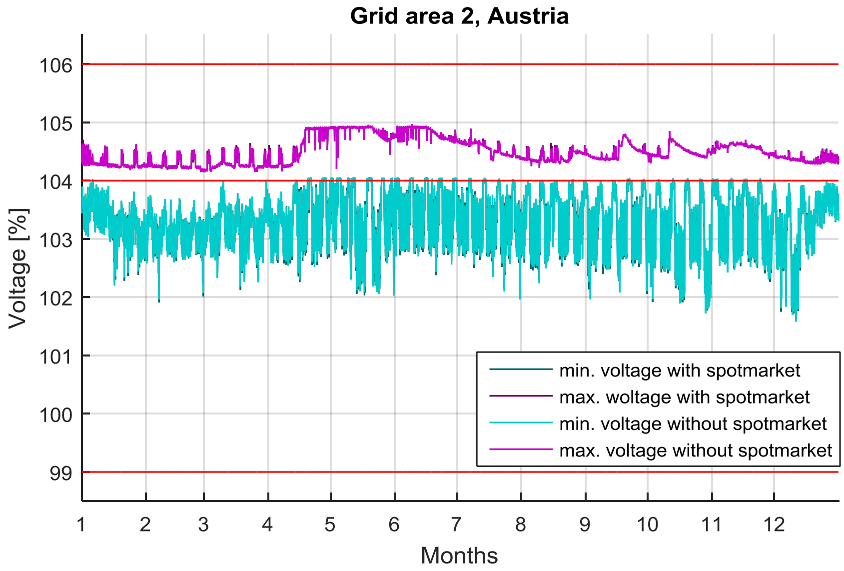

Figure 18: Participation of the hybrid-VPP on the spot market in the Austrian grid area 2 for the future scenario 2030. The figure shows the minimum and maximum voltage, as well as the voltage band reserved for voltage rise and voltage drop and the set point in red.

In Slovenia, this use case was only relevant for the second grid area, since it was the only one with a flexible load. Here as well, the grid simulations showed that the participation in the spot market would have no significant influence on the voltage in this grid area in any of the scenarios. This is shown exemplarily in Figure 27 for the future scenario 2030. The rest of the calculated scenarios can be found in in Figure 72 in the Appendix.

It should be noted, however, that the results of these case study analyses strongly depend on the specific situation in the grid and on the amount of available flexibility.

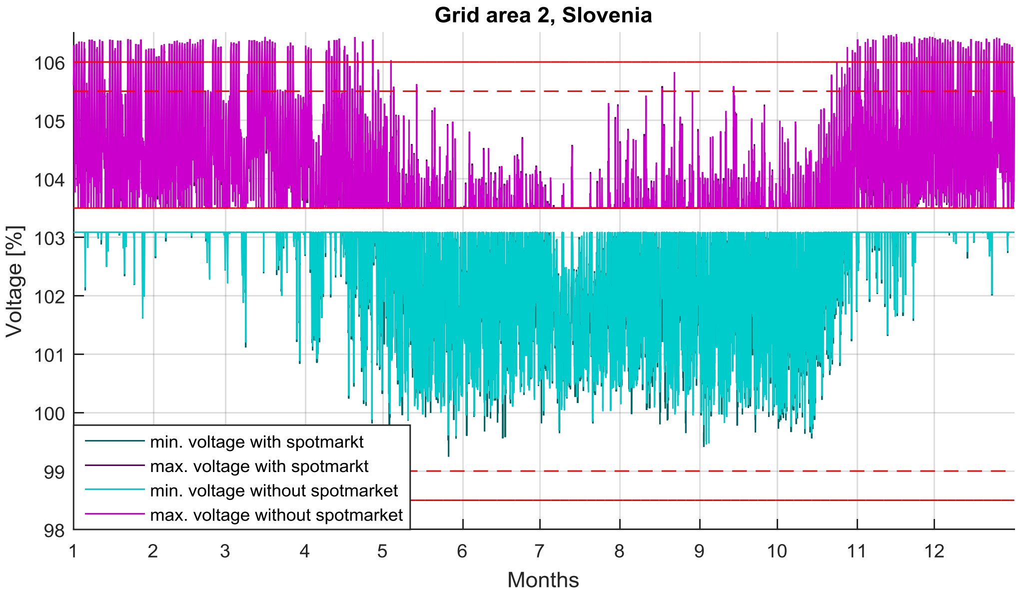

Figure 19: Participation of the hybrid-VPP on the spot market in the Slovenian grid area 2 for the future scenario 2030. The figure shows the minimum and maximum voltage, as well as the voltage band reserved for voltage rise and voltage drop and the set point in red. (The reactive power of the customers was not considered in these simulations, therefore some overvoltage situations occurred.)

2.2.1.b VPP for tertiary reserve market (1b)

Beside the spot market, the participation of the hybrid-VPP on the tertiary reserve market was simulated as well. In the technical simulations, the influence of the market participation on the grids was determined. In order to simulate the maximum possible impact on the grids, it was assumed that the bids of the hybrid-VPP would always be accepted on the market in this analysis.

For the two Austrian grid areas, the analysis was done for the years 2013 and 2030. The results for 2030 are shown in Figure 20: Especially in grid area 2, the influence of the market participation can be seen, resulting in several peaks in the voltage throughout the year. However, the voltage band was not violated in any of the cases, since both grid areas had enough reserve capacities. The results look very similar for the year 2013 and can be found in **Figure 73** in the Appendix.

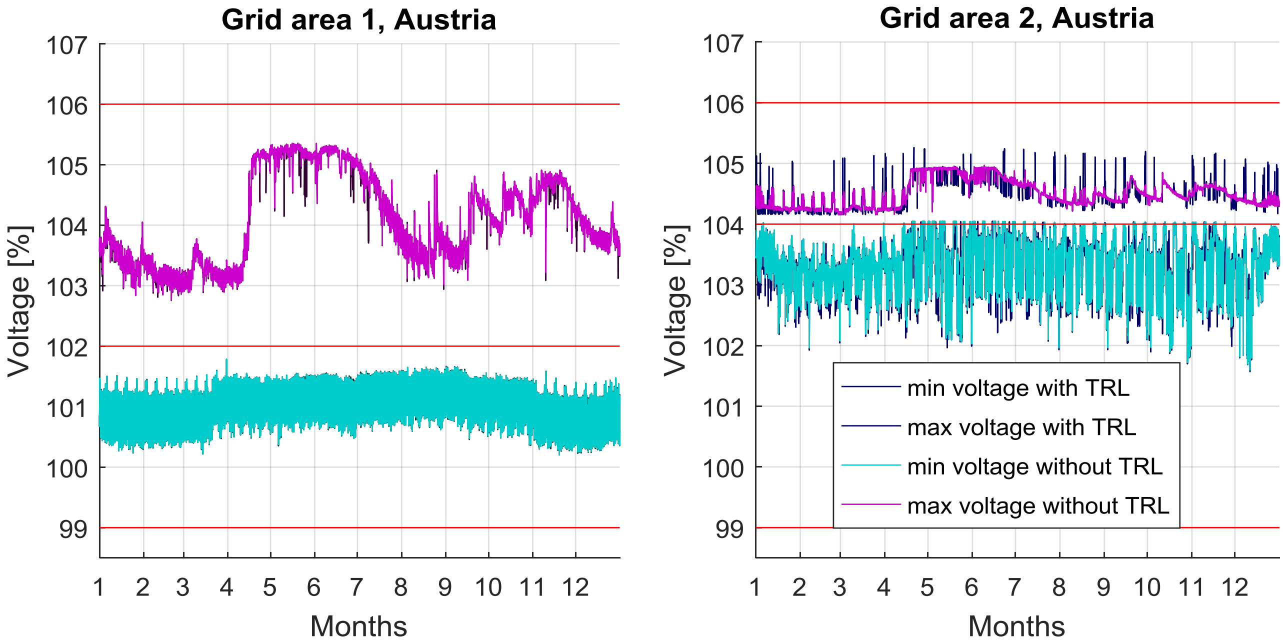

Figure 20: Change of the grid voltages with participation in the tertiary reserve market for the two Austrian grid areas in 2030

The same analysis was done for the two Slovenian grid areas; Figure 21 shows the results for 2030. In the first gird area, the market participation is hardly visible, since the grid has sufficient reserve in the voltage band. In the second grid area, however, the participation of the VPP on the tertiary reserve market would cause some violations of the upper voltage band (marked in green).

According to the European Commission's guideline on electricity transmission system operation [6], the DSO could therefore limit or exclude the customer from participation on the balancing market. However, very often the grid only faces problems during some periods, whilst market participation would not cause any problem during the rest of the year. Therefore, introducing a hybrid-VPP concept allows (more) flexibilities to participate in the market in critical grid areas. If the current grid status was known to the VPP, thus making it a hybrid-VPP, the voltage band violations could have been prevented. This is shown exemplarily for one week in Figure 22 and will be further evaluated in the hybrid use case in chapter 2.2.4.a.

For 2013, the market participation would not cause any grid problems. The detailed simulation results can be found in Figure 74 in the Appendix.

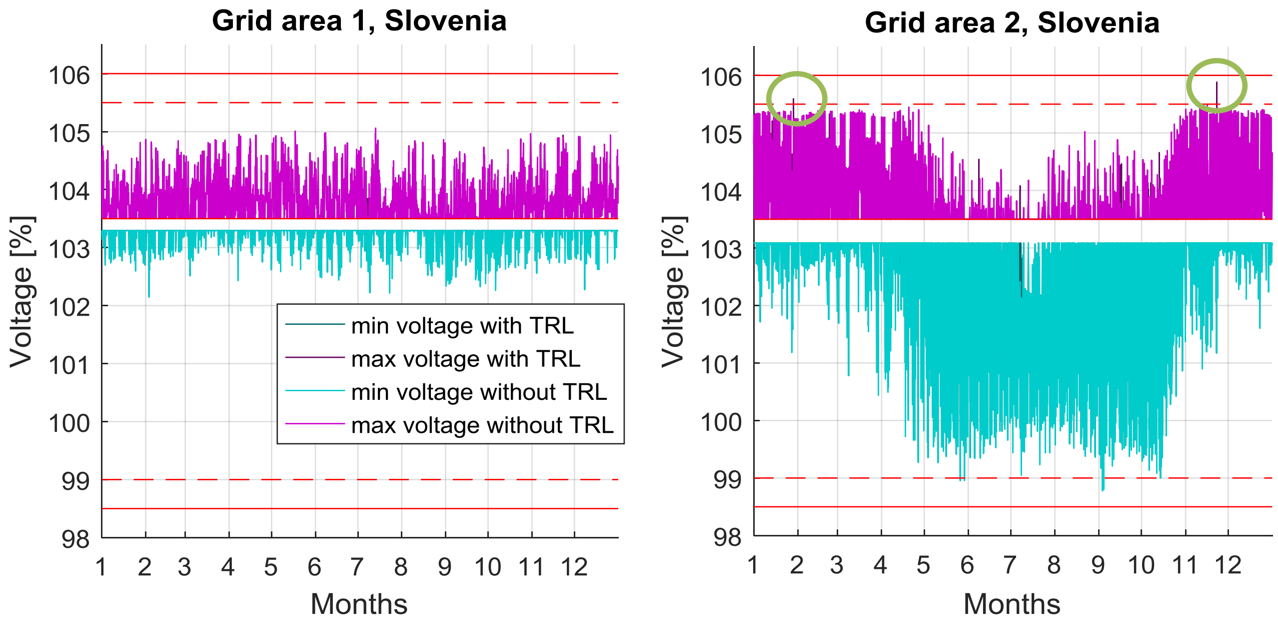

Figure 21: Change of the grid voltages with participation in the tertiary reserve market for the two Slovenian grid areas in 2030. The reactive power of the customers was taken into account in this use case.

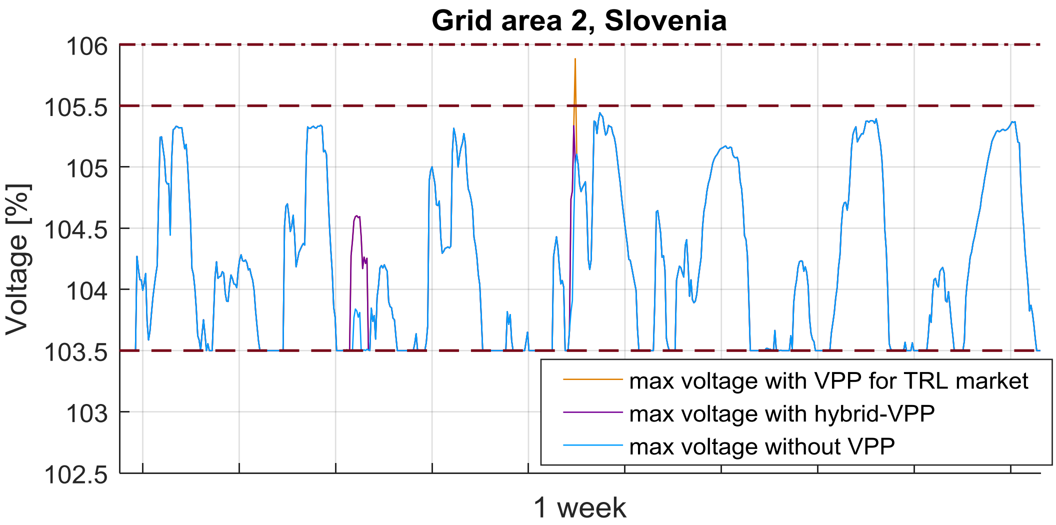

Figure 22: The figure shows the maximum grid voltage in the second Slovenian grid area during one week in 2030. The market participation of a VPP can lead to grid problems (orange). If a hybrid-VPP is used instead, which knows the current situation in the grid, those problems can be prevented (purple).

2.2.2 **Customer use cases** (2)

The customer use cases were analysed in several case studies in the technical grid simulations. The desired connection points for the new customers were chosen in locations already facing certain grid restrictions. For the Austrian case, the focus was on integrating new generators (2a) and for Slovenia the integration of new consumers (2b) was analysed.

2.2.2.a VPP to minimize grid connection cost for new generators (2a)

For Austria, two different case studies were simulated, both for the year 2020. In the first one, a PV plant and in the second one a wind power plant was connected to an area in the grid where the production was already very high. Both power plants had a peak production of 2 MW and participated in the Q(U) reactive power control. As shown in Figure 23 and Figure 24 both power plants would lead to violations of the upper voltage band. According to conventional power system planning they would be required to build a line with a length of 15 km towards the closest suitable connection point. Alternatively, they could participate in the hybrid-VPP. To keep the voltage within the limits, the production of the PV plant would be reduced by 14.85 MWh over the whole year; the wind power plant would be reduced by 31.02 MWh.

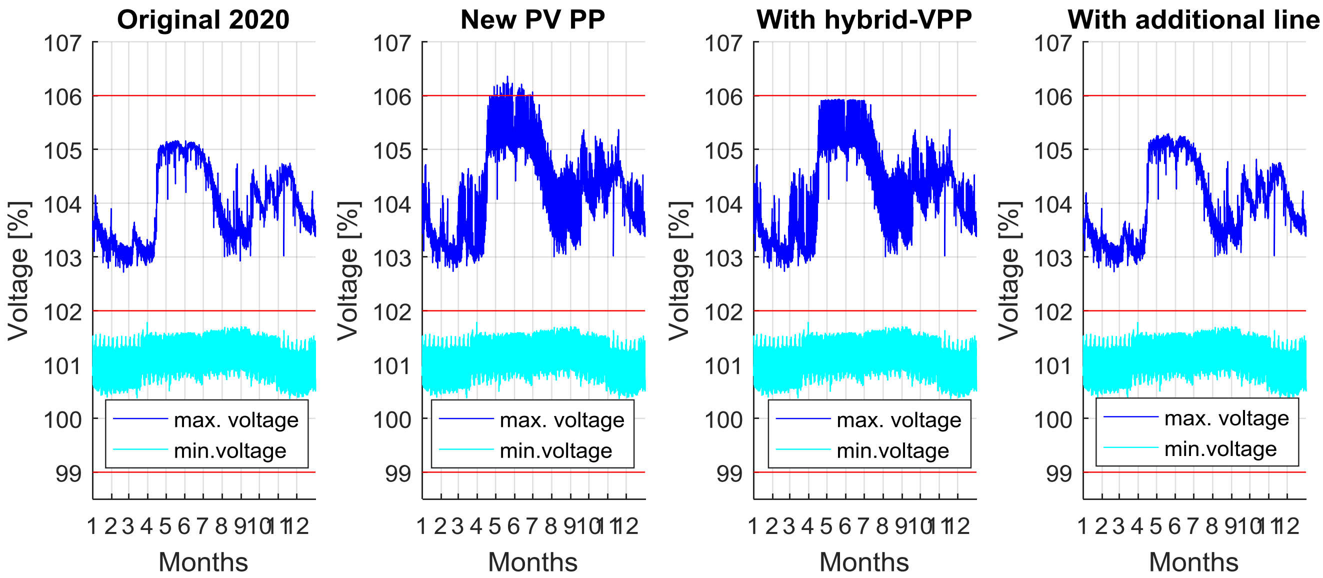

Figure 23: Case study for the use case “Minimizing grid connection costs for the customer” in the Austrian grid area 1; additional PV plant leads to violations of the voltage band (middle left); with participation in the hybrid-VPP (middle right); with new private line (right)

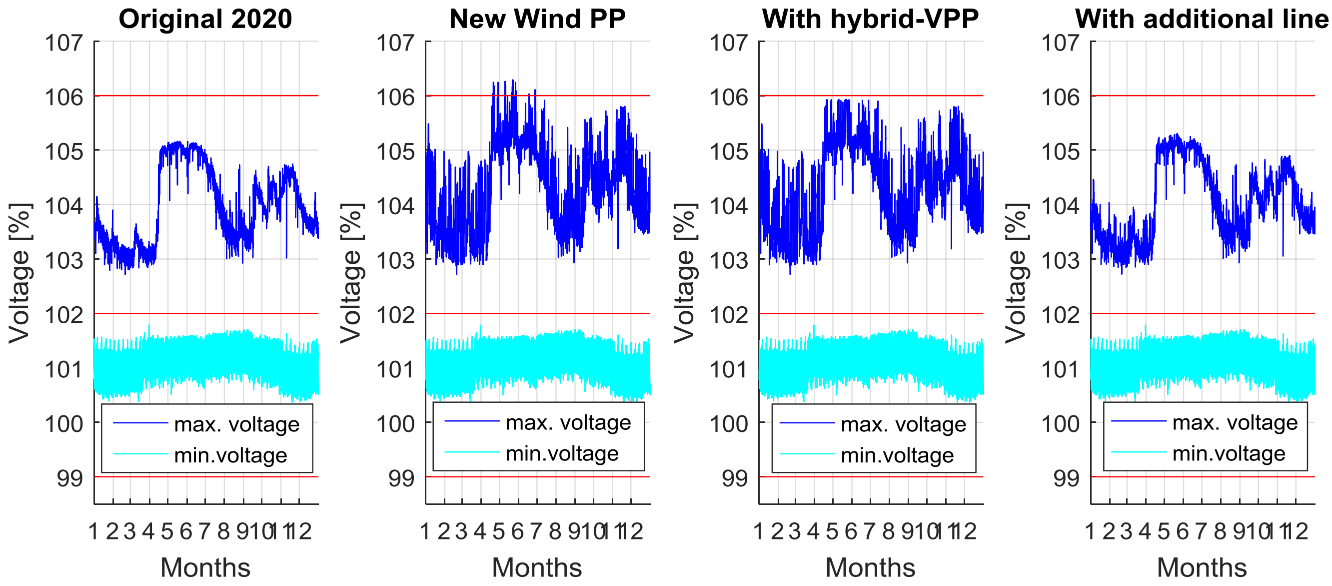

Figure 24: Case study for the use case "Minimizing grid connection costs for the customer" in the Austrian grid area 1; additional wind power plant leads to violations of the voltage band (middle left); with participation in the hybrid-VPP (middle right); with new private line (right)

Additionally, two sensitivity analyses were carried out for this use case. First, the size of the installed capacity was varied, as can be seen in Figure 25 and Table 5. The analysis was done for a wind power plant and its installed power was varied between 1 MW and 6 MW. The higher the installed capacity, the bigger is the share of curtailed energy over the year. At capacities of 6 MW, already more than 20% of the produced energy has to be reduced to keep the grid voltage within the limits.

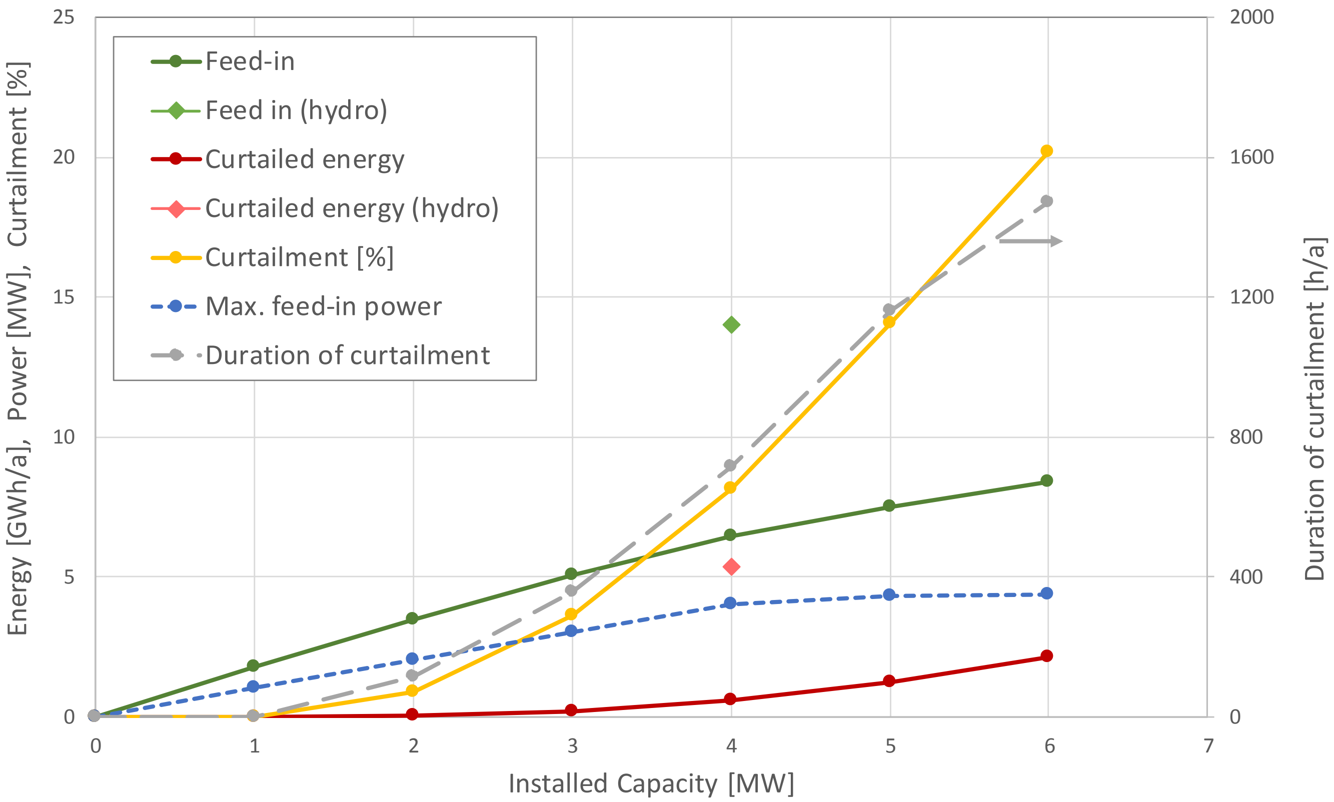

Figure 25: Sensitivity analysis of the installed wind capacity for the customer use case, and comparison with a 4 MW hydropower plant on the same connection point.

Additionally, Table 5 shows that the maximum power, which can be produced at any time during the year, remains at a bit over 4 MW, even if the installed capacity increases. This leads to the conclusion that there is a limit in the reasonable size of installed capacity, where a further increase would not be economic.

Table 5: Sensitivity analysis of the installed wind capacity

Installed capacity [MW]	Energy in-feed (with hybrid-VPP) [MWh]	Reduced energy [MWh]	Time of reduction [h/a]	Reduced energy [%]	Maximum power [MW]
1	1749	0	0	0.0	1.0
2	3467	31	114	0.9	2.0
3	5059	188	357	3.6	3.0
4	6428	568	716	8.1	4.0
5	7516	1230	1162	14.1	4.3
6	8376	2118	1472	20.2	4.4

In a second sensitivity analysis, different production technologies were compared. Figure 26 and Table 6 show the comparison of a wind, a PV and a water power plant, all with a peak power of 4 MW. They were all connected separately at the same chosen point in the grid. As shown, the wind power plant has a bigger total infeed than PV, since wind has more full load hours. The water power plant has the highest full load hours of the analysed technologies.

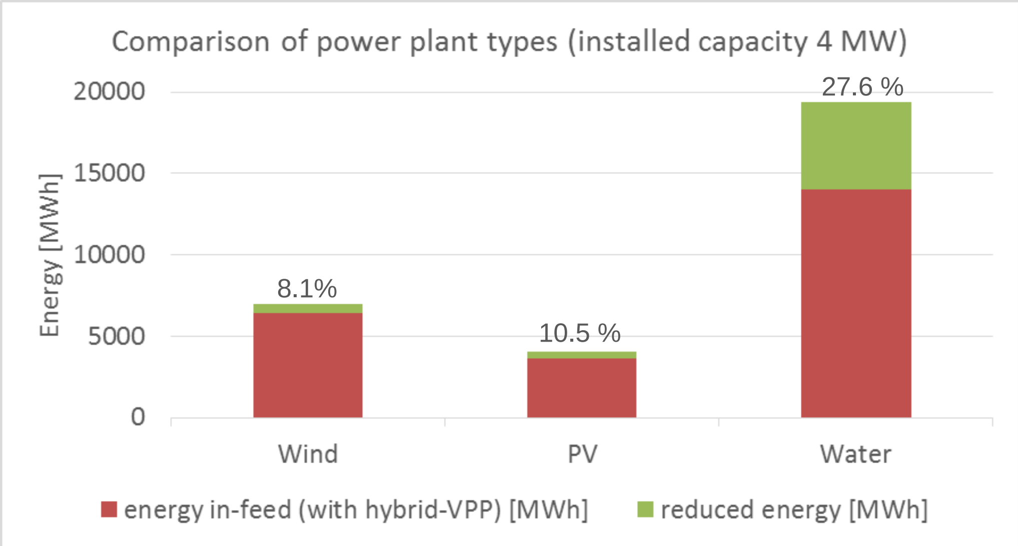

Figure 26: Sensitivity analysis of different production technologies for the customer use case

However, with the water power plant, the reduced energy is also much higher (27.6%), than with the other technologies. The reason for this a correlation effect. Since there is already a lot of waterpower installed in the observed grid, installing another water power plant would increase the voltage at times, were it is already rather high. Therefore, the relatively reduced energy is biggest in this case. The PV power plant ranks second in terms of relatively reduced energy with 10.5%, the wind power plant has the smallest reduced energy with 8.1%. Wind power has a high production especially in winter, were the existing water power plants produce only little energy. Therefore, it does not lead to as much over voltage as PV and water in the chosen grid area.

Table 6: Sensitivity analysis of the production technology

Tech-nology	Installed capacity [MW]	Energy in-feed (with hybrid-VPP) [MWh]	Reduced energy [MWh]	Time of reduction [h/a]	Reduced energy [%]	Maximum power [MW]
Wind	4	6428	568	716	8.1	4.0
PV	4	3596	423	516	10.5	3.6
Water	4	14022	5353	3244	27.6	3.3

The economic analysis of this use case can be found in chapter 3.4, where the conventional method of building a new line and the participation in the hybrid-VPP are compared from economic point of view.

2.2.2.b VPP to minimize grid connection cost for new consumers (2b)

For Slovenia, two case studies were simulated for the base scenario (2014) and for the year 2020. Here a new industrial customer with a nominal power of 1.5 MW was added to a section in the grid, which already had high energy consumption.

The simulation for 2014 showed that the infeed of this new customer would lead to violations of the required lower voltage border during several times in the year (see Figure 27). In the traditional approach, the customer would have to build a new private line of a length of 3 km towards the closest suitable connection point. If the customer would agree to partake in the hybrid-VPP, they could connect at their desired connection point. However, their consumption would be reduced by 20.74 MWh over the whole year, which is equal to 0.25% of the total consumption. Practically, the consumption would be shifted towards non-critical hours.

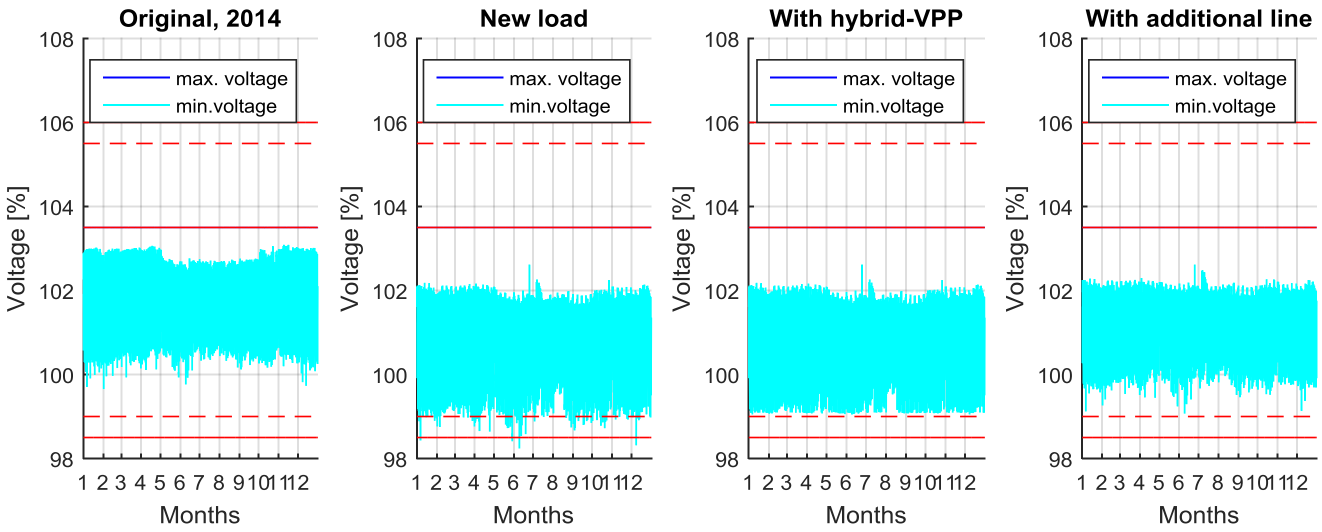

Figure 27: Case study for the use case "Minimizing grid connection costs for the customer" in the Slovenian grid area 2 for the year 2014; additional industrial load leads to violations of the voltage band (middle left); with participation in the hybrid-VPP (middle right); with new private line (right). The reactive power of the customers was not considered in these simulations.

For 2020, the case study showed rather interesting results (see Figure 28): Again, the new load would lead to violations of the lower voltage band, especially in summer. At the same time, however, it would prevent the violations of the upper voltage band, which would otherwise occur due to the high infeed of CHP power plants in winter. If the load would participate in the hybrid-VPP its energy consumption during critical hours would be reduced by 30.26 MWh, which is equal to 0.36% of the total yearly consumption. The alternative additional line of 3 km like in the year 2013 would not be sufficient for this case, as can be seen in the middle right picture of Figure 28. The customer would need to build a line of 5.4 km to the closes suitable connection point, to avoid all violations of the lower voltage band.

However, it is questionable how this case study would be treated in reality, since the customer on the one hand relieves the situation at the upper voltage band but causes new violations of the lower voltage band.

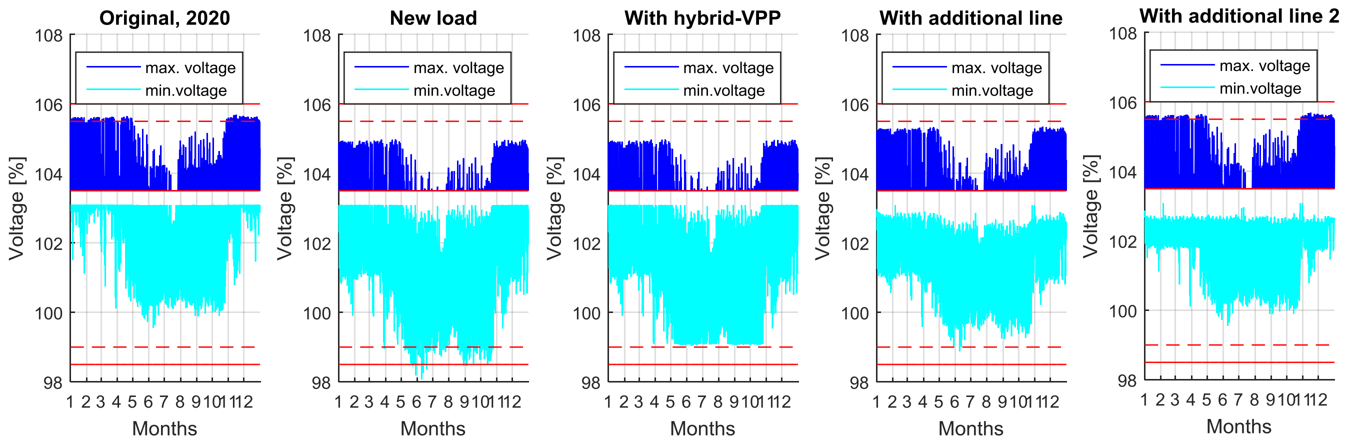

Figure 28: Case study for the use case "Minimizing grid connection costs for the customer" in the Slovenian grid area 2 for the year 2020; additional industrial load leads to violations of the voltage band (middle left); with participation in the hybrid-VPP (middle); with new private line (middle right); with longer private line (right). The reactive power of the customers was not considered in these simulations.

2.2.3 DSO use cases (3)

In this chapter, the two DSO use cases are analysed from a technical perspective. The aim was to provide a first proof of concept in smaller case studies. A more detailed analysis of DSO's benefits of a hybrid-VPP, with simulations of the whole year will be shown in the hybrid use cases in chapter 2.2.4.

2.2.3.a VPP for optimization of grid investments - Slovenia (3a)

The grid-simulations showed that no voltage band problems occur in both Austrian grid areas until the year 2030 with the assumed models. There is enough reserve available in the voltage band and occurring bottlenecks could be solved with the reactive power control and line-drop compensation. Therefore, no expansions of the grid are necessary in any of the three scenarios and this use case cannot be investigated here. In accordance with ENS it was decided against the implementation of another expansion scenario, which would bring the grid to its limits, in order to keep the future scenario as realistic as possible.

In Slovenia however, some violations of the voltage band occurred in both future scenarios. Therefore, a reinforcement of the grid would be necessary in the future. In the course of this use case, this conventional approach will be compared with the usage of a hybrid-VPP.

Several case studies were carried out in the Slovenian grid areas, which were published in [3]. In each one, one week was picked, during which grid constraints occur. It was evaluated via simulations whether those could be lessened with the help of the hybrid-VPP. Figure 29 shows one example case study, for the future scenario 2030. In regular grid operation (blue line) several violations of the desired voltage limit (red dashed line) would occur. With the use of the hybrid-VPP (green dashed line), the voltage did not exceed the desired limit during the whole period. If the complete flexibility of the hybrid-VPP was activated, the total power changed by 800 kW, which resulted in a voltage change of 0.68%.

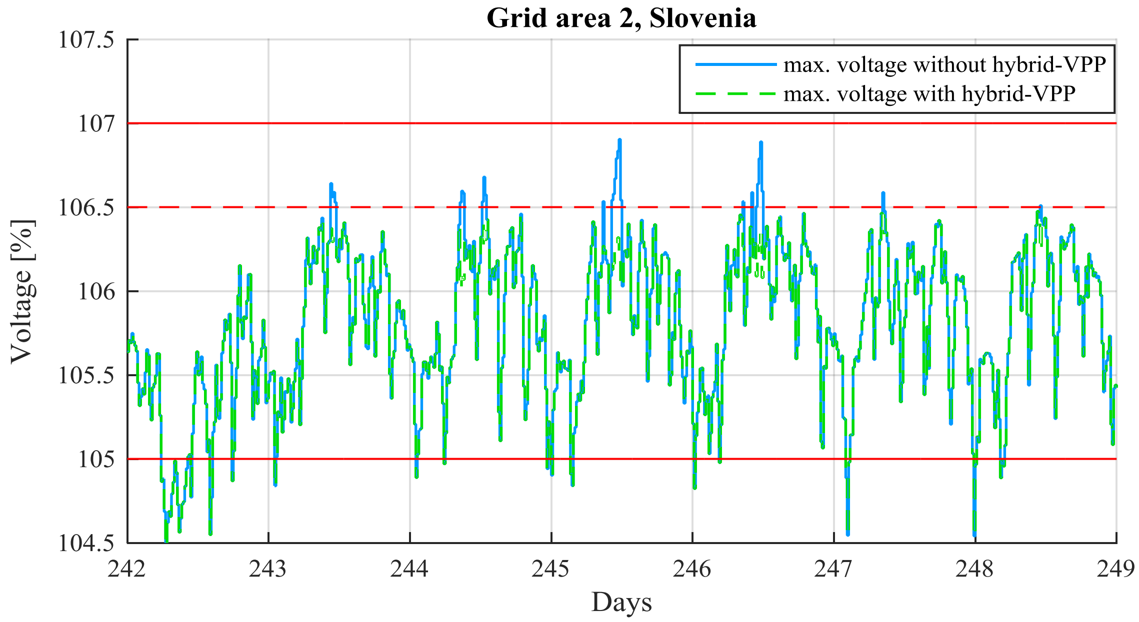

Figure 29: Case study for the use case "Minimizing grid investments for the DSO" in the Slovenian grid area 2, evaluated for one example week[2].

2.2.3.b VPP to support grid operation during maintenance and special switching states - Austria (3b)

This use case was investigated only for the Austrian grid areas. The implementation for Slovenia was not possible, since only one feeder of the MV-grid was available for the simulations, so no reasonable switching or backup supply scenarios could be defined

In a first case study, the Austrian grids are examined during an exemplary week. The outage of one line in the second grid area is simulated. The affected branch has to be switched to the first grid area to prevent a blackout in this section of the grid. Until the error can be resolved, which takes an estimated time of five hours, the first grid area has to supply those additional customers.

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[2] The voltage band limits as well as the set point in this case study are different from the other case studies of this deliverable. The reason is that this case study was done in an earlier stage of the project. The used voltage band limits and set point were slightly adjusted in accordance with ELj at a later point.

If the grid was operated conventionally, this operation results in a voltage rise and thus in a violation of the upper voltage limit (see blue curve in Figure 30). Due to this overvoltage, some of the generation units would be tripped. The amount of curtailed energy is depicted in the first column of Figure 31.

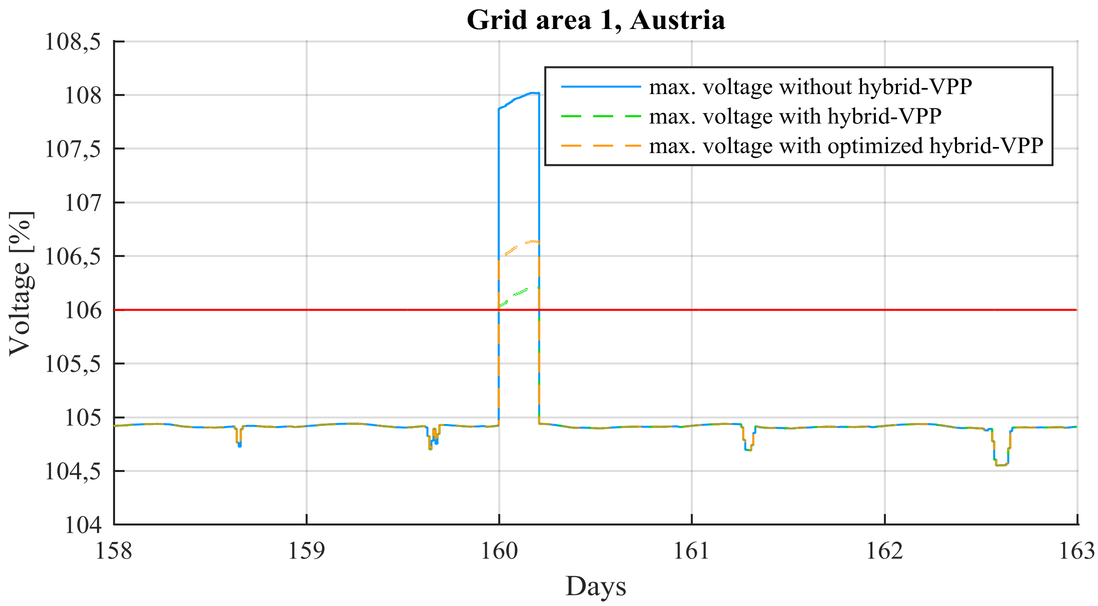

Figure 30: Grid driven operation of hybrid-VPP in the first Austrian grid area during an outage scenario. The outage occurs at the 160th day of the simulated year and can be resolved after five hours. The red line shows the upper limit of the voltage band.

As unregulated tripping of customers is not desired, the hybrid-VPP provides its flexibility to reduce the voltage rise. The green curve in Figure 30 shows the highest voltage in the grid, after activating the hybrid-VPP. The highest grid voltage could be reduced by nearly 2%. However, the upper limit of the voltage band is still violated, which means further measures, like expanding the hybrid-VPP or using a P(U)-control for generation units, would be necessary to prevent tripping of generation units. Furthermore, the total loss of infeed is about three times as high as in the scenario without hybrid-VPP (see second column in Figure 31). Nevertheless, the usage of the hybrid-VPP is still valid: With its support, the loss of infeed due to unregulated overvoltage dripping could be reduced by more than 70%. The majority of curtailed energy now originates from hybrid-VPP control. Such a controlled situation in the grid is generally preferable to an unregulated one, which includes spontaneous tripping of units.

Nevertheless, the total loss of infeed power is rather high in this scenario. The reason is that all flexibilities, which have an influence on the highest voltage, are activated. Since this highest voltage naturally occurs at the end of a branch, flexible units that are located close to the transformer station, only have a very small influence on this voltage. Hence, it would not be economic to activate all possible hybrid-VPP participants. Therefore, a second, economically optimized scenario was created. Here, only those flexibilities are activated which have a significant influence on the highest voltage in the grid. As expected, this leads to a slight increase in the voltage peak, of about 0.5% (see orange curve in Figure 30). On the other hand, the total loss of infeed could be reduced substantially by nearly 70% in comparison to the scenario before (see third bar in Figure 31). The total amount of curtailed energy is even lower than in the first scenario, since the hybrid-VPP only partially curtails some of the power plants.

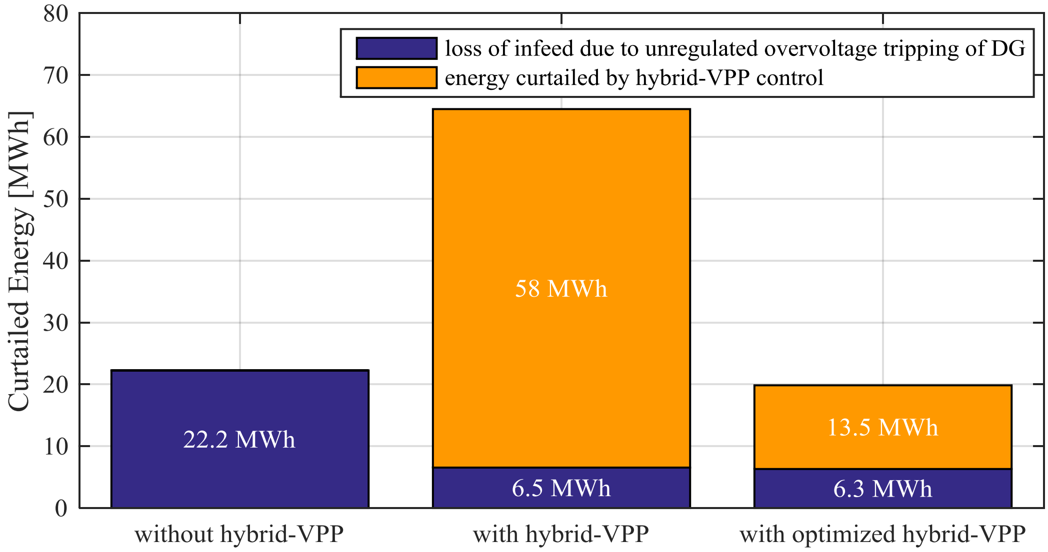

Figure 31: Curtailed energy during outage for the three scenarios: without/with/with optimized hybrid-VPP. The blue bars show the total loss of infeed due to unregulated overvoltage tripping of distributed generation (DG); the orange bars show the energy curtailed by the hybrid-VPP control; the combination of the respective blue and orange bars shows the resulting total loss of infeed.

To sum up, the case study showed that the hybrid-VPP could be used to support the DSO in case of an outage. With its help, unregulated overvoltage tripping of distributed generation units could be reduced significantly in this example. If more flexible units participate in the hybrid-VPP, especially in the relevant grid parts far away from the transformer station, the unregulated tripping of power plants could even be completely prevented. The hybrid-VPP facilitates the curtailment of energy in a controlled manner, which is always preferable to an uncontrolled situation in the grid.

2.2.4 Hybrid use cases

In this chapter, the previously individual use cases should now be combined to hybrid use cases. Thus, synergy effects can be created which benefit all participants. The hybrid use cases were simulated with a co-simulation approach of the market optimization and grid simulation. The simulation procedure for this was already presented in Figure 2. This chapter analyses the co-simulation results from the grid's perspective.

2.2.4.a Market (1b) + DSO (3a) Use Case – Slovenia

This use case was analysed for the year 2030 for the second Slovenian grid area, since this was the simulation scenario with the most severe grid problems. Therefore, it would also be the most interesting to consider for this use case. The hybrid-VPP now tries to support the DSO and solve voltage band problems, whilst also optimizing its flexibilities on the market.

As the analysis of the future scenarios in chapter 2.1 showed, the growing number of new generators and consumers would lead to grid problems in the second Slovenian grid area. As a first step to solve those problems, a Q(U) reactive power control was implemented for all future generators, which could solve all the existing over voltage problems. However, some under voltage problems remain. Therefore, the DSO would need to invest into some new grid infrastructure. In this specific use case, a new cable with a length of about 2.5 km and costs of 180.000 € would have to be built.

Furthermore, the market simulation in chapter 2.2.1.b showed that the participation of a hybrid-VPP on the tertiary reserve market would cause some over-voltage problems (see Figure 21).

When using a hybrid-VPP, both of those issues can be solved with the traffic light model, as described in chapter 1.4: During times of under-voltage problems, the grid is in the red phase and will get actively supported by the flexibilities of the hybrid-VPP. At times where the grid voltage is already close to its limits, i.e. in a yellow phase, the market participation will be restricted. Thus, the potential over-voltage problems due to the balancing market can be prevented as well. Finally, in green phases, when enough reserve is available in the grid, the hybrid-VPP operator can optimize their flexibility on the market, freely. Those three traffic light phases with their different objectives are considered in the hybrid-VPP optimization, which will be described in detail in chapter 4.

Figure 32 shows the results of the grid simulations for this hybrid use case: The light turquoise and light purple curves show the minimum and maximum voltage in the grid in the conventional scenario. The Q(U)-control is already active here, preventing some voltage-problems. With the help of the hybrid-VPP (dark turquoise and dark purple curves), all remaining under voltage problems could be solved (green markings). Furthermore, the participation on the balancing market does not cause any additional grid problems (orange markings), as it was observed in the pure market use case in Figure 21.

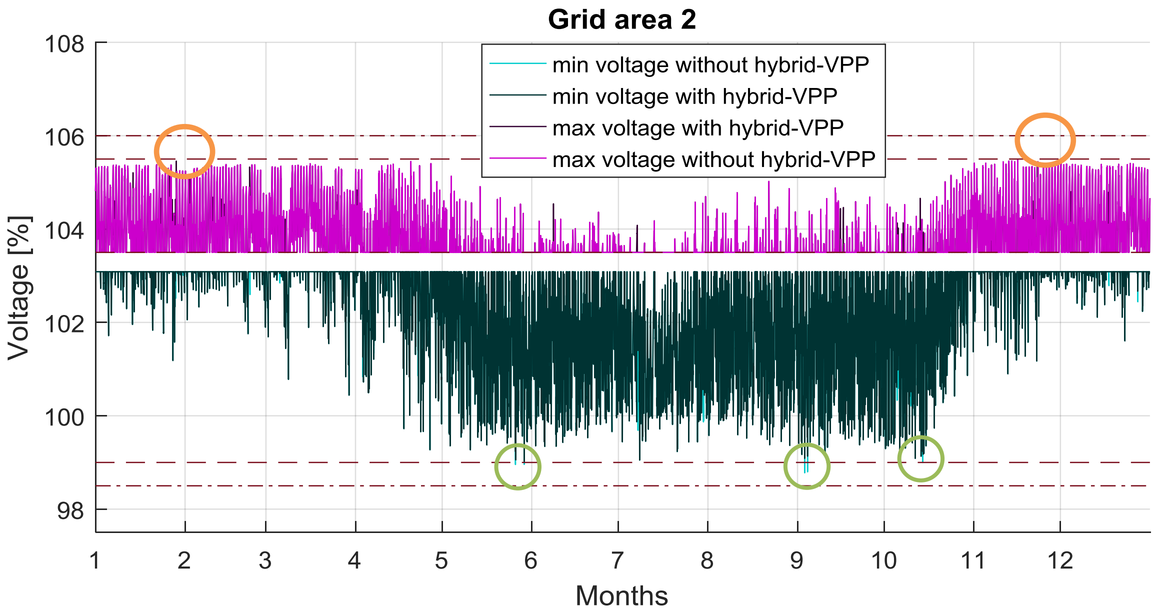

Figure 32: Results of the hybrid use case combining the participation on the tertiary reserve market and the optimization of grid investments. Simulation for the second Slovenian grid area for 2030; the simulation included a constant cos(φ) of the customers as well as a local Q(U)-control for all new generators.

2.2.4.b Market (1b) + Customer (2b) + DSO (3a) Use Case – Slovenia

In the next step, the previous hybrid use case (2.2.4.a) is extended with the customer use case. Again, the simulations were done for the year 2030 for the second Slovenian grid area. As already described in the individual customer use case in 2.2.2.b, a new industrial customer of 1.5 MW wants to connect to the grid at an underdimensioned connection point. It was assumed that the customer can also provide reactive power by means of a Q(U) control.

The starting point for this analysis was the previous hybrid use case, where the hybrid-VPP already supports the DSO, while participating in the market. The new customer would now cause some grid problems if they were connected to the grid conventionally (see light turquoise curve in Figure 33). They would therefore need to invest into a reinforcement of the grid. However, if they participated in the hybrid-VPP, they could save those higher grid connection costs and additionally participate in the market during non-critical times (green phase). During critical times (red phase), their consumption would be reduced to 50% in order to avoid under voltage problems (see dark turquoise curve in Figure 33).

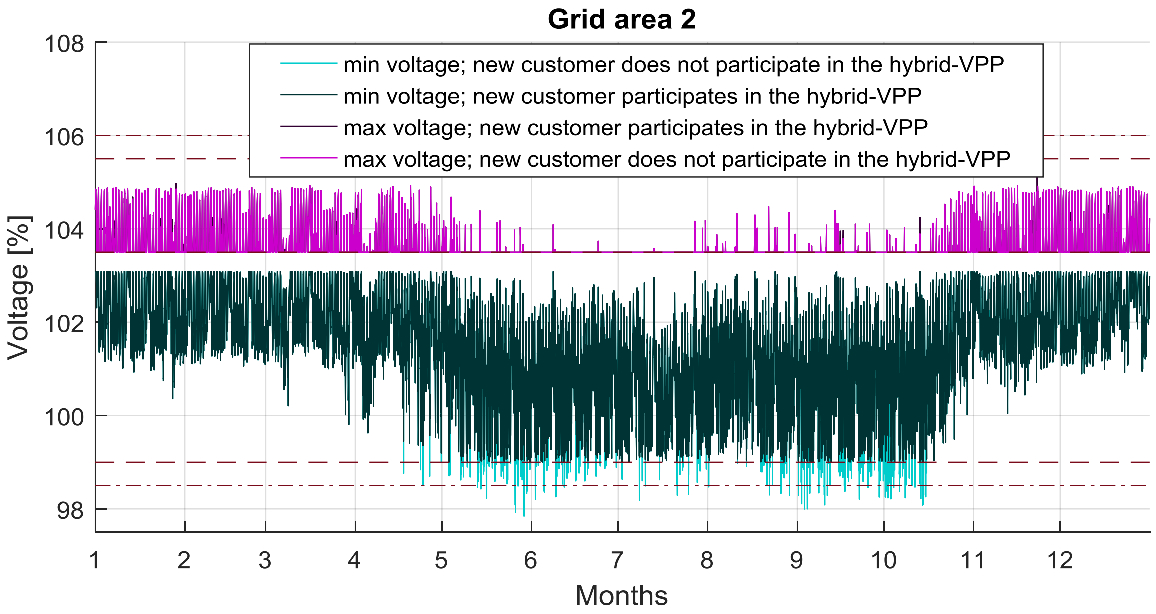

Figure 33: Results of the hybrid use case combining the participation on the tertiary reserve market, the optimization of grid investments and the minimization of grid connection costs for a new consumer. Simulation for the second Slovenian grid area for 2030; the simulation included a constant cos(φ) of the customers as well as a local Q(U)-control for all new generators.

This use case provides benefits for all participants: The customer can save grid connection costs and participate in the balancing market. The VPP can participate on the balancing market in a critical grid area. The DSO can prevent or delay grid investments.

2.2.4.c Market (1b) + DSO (3b) Use Case – Austria

Next, the tertiary control market use case (1b) was combined with the DSO use case (3b) of grid support during maintenance and special switching states. This hybrid use case was analysed for the Austrian grid areas for the year 2030. Here, the hybrid-VPP supports the DSO during some special grid situations and can participate on the market, freely, during the rest of the year.

Nine non-ordinary switching scenarios were defined for the whole year, each lasting for five hours. It should be noted that the number of switchovers would be much lower during a real year. The high number of non-ordinary grid states was selected to be able to investigate the possible impacts of the hybrid-VPP.

Figure 34 shows the simulation results: For each of the 9 switching scenarios, the range of the occurring grid voltages in the investigated sections is depicted with a bar. The upper end of the bar represents the highest occurring voltage and the lower end represents the lowest grid voltage during that time. As can be seen from the blue bars, the voltage band is violated in 8 out of 9 special switching states if the hybrid-VPP is not used. Applying the hybrid-VPP (yellow bars), all voltages band violations could be significantly reduced for nearly all special switching states. The grid voltage in the whole grid section could be kept completely below the required upper limit in 5 out of 7 cases. No improvements were possible in the switching state showing violations of the minimum voltage. In this case, no local flexible units were available to increase the grid voltage by means of load curtailment or increasing generation in the relevant grid sections. Detailed figures of the grid voltages over the whole year can be found in Figure 75 and Figure 76 in the Appendix.

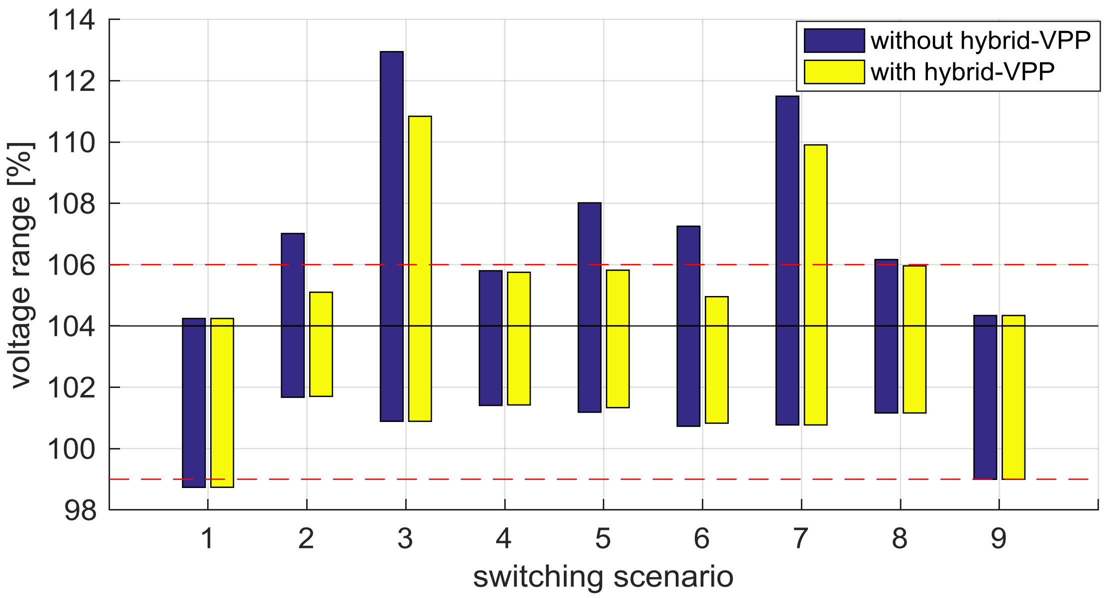

Figure 34: Comparison of the maximum and minimum grid voltages in the 9 simulated special switching states, with and without the hybrid-VPP. The bars show the occurring voltage range in the grid.

In order to avoid all violations of the voltage band, a larger pool of flexible units or higher levels of availability would be necessary. Especially more units capable to decrease demand or increase generation would be needed to be able to avoid under voltage situations, too.

2.2.4.d Market (1b) + Customer (2a) Use Case – Austria

For this hybrid use case, the customer use case was combined with the participation on the tertiary reserve market. The economic analysis of the customer use case showed that the new customer needs to have a size of about 20 MW or more in order to be economic from a VPP operator's perspective (see section 3.4.3). Therefore, the following use case was created: Besides the already added 2 MW wind power plant (see chapter 2.2.2.a), two additional wind parks of 5 MW and 7 MW were added for the year 2030 in the Austrian grids at three different connection points.

The installation of those wind parks would not cause any overloading of grid elements: The cables were loaded at no more than 70% of their maximum capacity; the transformer stations were at 58% and 88% of their maximum loading. However, the new wind parks would lead to some overvoltage situations at peak times in the grid (see Figure 35). In the conventional approach, the customers would therefore have to invest into new lines to connect to a more suitable connection point. The necessary cable lengths and resulting costs are listed in Table 7.

Table 7: Required grid enhancement to connect the new customers

Customer	Cable length	Costs
2 MW	15.124 km	€ 2.268.600
5 MW	6.733 km	€ 1.009.950
7 MW	6.251 km	€ 937.650

Alternatively, the infeed of the wind parks can be reduced by the hybrid-VPP to 40% during peak times. In the rest of the year, the new customers could also use their flexibility to participate in the market for tertiary control, integrated into the pool of the hybrid-VPP.

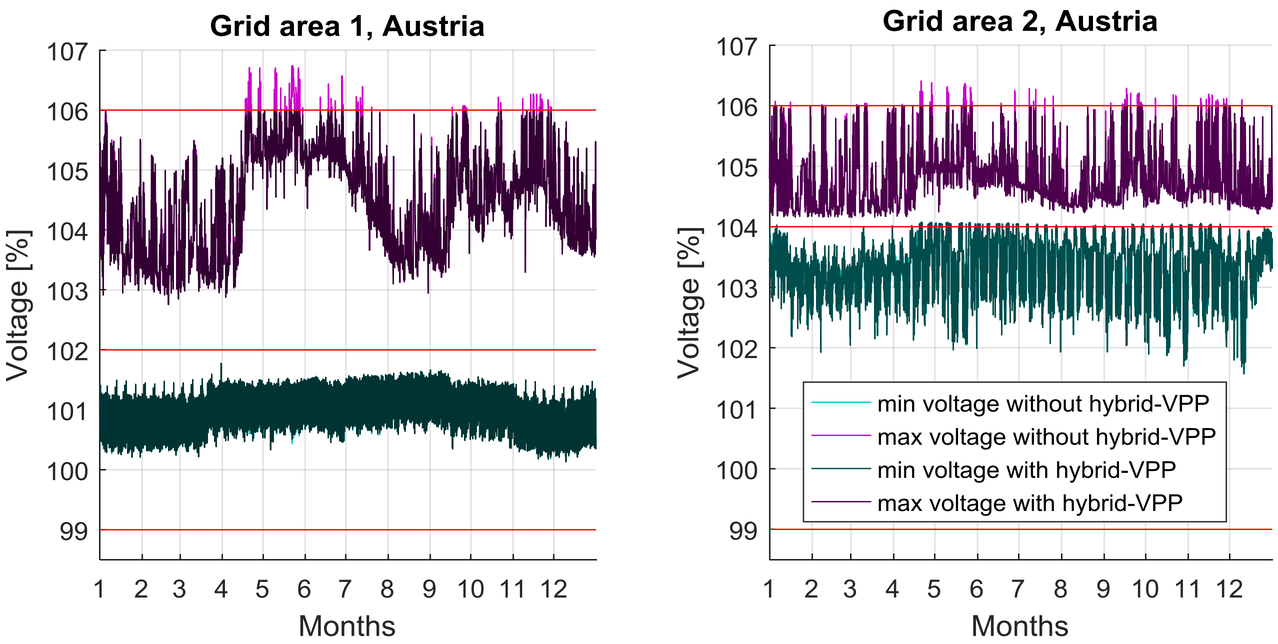

Figure 35: Results of the hybrid use case combining the participation on the tertiary reserve market and the minimization of grid connection costs for new generators. Simulation for the Austrian grid areas for 2030.

Furthermore, the benefit of having a Q(U) control was analysed for this use case. A comparison was made, how much energy of the new customers needed to be reduced by the hybrid-VPP if they had a Q(U) reactive power control (see Figure 4), versus if they only had a constant cos(φ) = 0.95. The results are summarized in Table 8 below for all three new generators. The benefit of having a Q(U) control can be seen very clearly: For the two smaller wind parks, the necessary curtailed energy could be more than halved, for the 7 MW power plant it is even only one sixth in comparison to the fixed cos(φ). Thus, the losses through a reduced infeed could be reduced significantly. Therefore, a Q(U) control should always be the first measurement against voltage band problems. Only in cases where the reactive power control is not sufficient, the hybrid-VPP should be used to curtail active power.

Table 8: Comparison of the curtailed active power in the year 2030 when using a constant cos(φ) vs. a Q(U)-control for the new generators

	cos(φ)		Q(U)	
Customer	Curtailed energy [MWh]	Duration of reduction [h/a]	Curtailed energy [MWh]	Duration of reduction [h/a]
2 MW	299	367	143	196
5 MW	746	367	358	196
7 MW	704	198	114	30

The results in Table 7 and Table 8 also show clearly, how much this use case depends on the specific grid situation and on the requested connection point of the customer: The largest connecting customer (7 MW) had the smallest number of curtailed hours, as well as the shortest required grid enhancement. Their requested connection point is much stronger than the one of the 2 MW customer, which already faces some high voltages during certain peak times. Therefore, this customer would need a disproportionally large grid enhancement of more than 15 km or alternatively have their energy reduced for nearly 200 h/a.

3 Economic analyses of VPP use cases

3.1 Introduction and methods of approach

In this section, results of the economic cost-benefit and stakeholder analyses are presented. The microeconomic analyses for the different use cases introduced in section 1.3 is based on the results of the “technical grid simulations” presented in section 2 as well as the “development and simulation of hybrid-VPP aggregation concepts” in section 4. The goal of the research findings is amongst others to serve as a base for future hybrid-VPP business model development.

In this context, key questions to be answered for different use cases are:

- Identification of key roles and stakeholders and their relationships
- Analyses of cost and cost structures of hybrid-VPPs
- Which revenues can be expected from VPP operation (hybrid and non-hybrid)
- Assessment of minimum sizes of hybrid-VPPs in terms of capacity of controlled flexibilities
- Investment analyses: Profitability of a hybrid-VPP

Answers to these questions were analysed separately for the different use cases and for the two regions Styria (Austria) and Slovenia.

In order to find answers to the above research questions, the following methods of approach have been applied for the different uses cases in Styria, Austria and Slovenia:

- The roles of identified key stakeholders (flexibility providers, VPP operators, flexibility markets, DSOs, suppliers and traders) were analysed with regard to flows of information, flexibilities and cash between them.
- Life cycle cost benefit analyses (LCCBA): 1. Assessment of project/life cycle cost (LCC) for different hybrid-VPP applications and 2. Modelling of revenue streams from participation in different energy markets based on pools of flexibilities from Styria and Slovenia.
- Break-even analyses based on the LCCBA including sensitivity analyses for variations in input parameters.
- Dynamic investment analyses based on LCCBA cash flow modelling including economic and financial key performance indicators (KPIs) for hybrid-VPP use cases.

Throughout the analyses, all monetary numbers are excluding VAT, and tax effects are not considered. Further remarks on the methodologies are provided in the respective subsections. The results are based on an iterative process with the findings from the technical grid simulations and the simulations of hybrid-VPP aggregation concepts in sections 2 and 4.

In the first part of the economic section of the report, VPP project cycle cost and cost structures are presented, followed by an economic appraisal of the different market, customer, grid and hybrid use cases.

3.2 hybrid-VPP project cycle cost and cost structure in Austria and Slovenia

All subsequent economic analyses are based on a life respectively project cycle cost (LCC) assessment of the hybrid-VPP, adapted for different use cases. The analyses accounts for four types of cost categories: Firstly, capital expenditures (CAPEX) are differentiated between a) Fix per VPP system and b) Variable per flexibility connected to the VPP. Secondly, annual operational expenditures (OPEX) are differentiated in c) Fix per year and d) Variable per flexibility connected and per year.

The cost estimates are based on interviews with practitioners and experts in the field and have been reviewed and confirmed by other members of the hybrid-VPP4DSO project consortium. Additional explanations and remarks on individual cost items are provided in the in the right column of Table 9.

Exemplarily for a hybrid use cases (c.f. 3.6), the following table summarizes the VPP cost for all four cost categories in Austria:

Table 9: hybrid-VPP cost: CAPEX: a) Fix, b) Variable per MW; OPEX: c) Fix per year; d) Variable per MW, year - Austria

	unit	cost	Explanations and remarks
a) **CAPEX** (per VPP system <100 MW):	[EUR]	**70.000**	
VPP System	[EUR]	**50.000**	*VPP System installation; Pre-qualification APG; TSO connection*
Connection to DSO NOC	[EUR]	**20.000**	*Network operation center connection (manpower + hardware)*
Trading floor infrastructure	[EUR]	0	*not considered*
Trading license	[EUR]	0	*Softcost not considered*
Balancing group	[EUR]	0	*50.000 EUR Security, refundable*
b) **CAPEX** (per flexibility of ~ ±1MW):	[EUR/MW]	**4.000**	
Per flexibility connected	[EUR/MW]	**3.000**	*Technician + hardware at client*
Transaction cost VPP client	[EUR/MW]	**1.000**	*Sales, marketing, drawing up of contract*
	unit	cost	*Explanations and remarks*
c) **OPEX** (fix per VPP system per year):	[EUR/a]	**99.000**	
VPP-IT operating cost	[EUR/a]	**30.000**	*IT-System hosting, maintenance, support*
IT-communication TSO	[EUR/a]	**6.000**	*IT-communication with TSO*
IT-communication DSO	[EUR/a]	**3.000**	*IT-communication with DSO*
Personal operating cost			
VPP operation incl. trading	[EUR/a]	**60.000**	*24/7: 0,1 person equivalents/a (876 h/a @ 65 EUR/h;)*
d) **OPEX** (variable per client per year):	[EUR/a]	**4.400**	
Software licence VPP (per flexibility of ~ ±1MW)		**3.500**	
TRL only	[EUR/a]	**3.500**	*including day-ahead, intraday ...*
IT-communication clients (per flexibility)	[EUR/a]	**900**	*DSL encrypted*
Average 0,5 + 5 MW	[EUR/a]	**900**	
5 MW	[EUR/a]	**1.200**	*e.g. industrial site (DSL+firewall)*
0,5 MW	[EUR/a]	**600**	*e.g. small hydro (mobile connection)*

For hybrid-VPP application, minor additional investments, e.g. for a connection to the DSO network operation center (NOC) are needed (c.f. 3.6.2).

Figure 36 below presents the total VPP project cycle cost and the cost structure for one year of operation as a function of the capacity of controlled customer flexibilities.

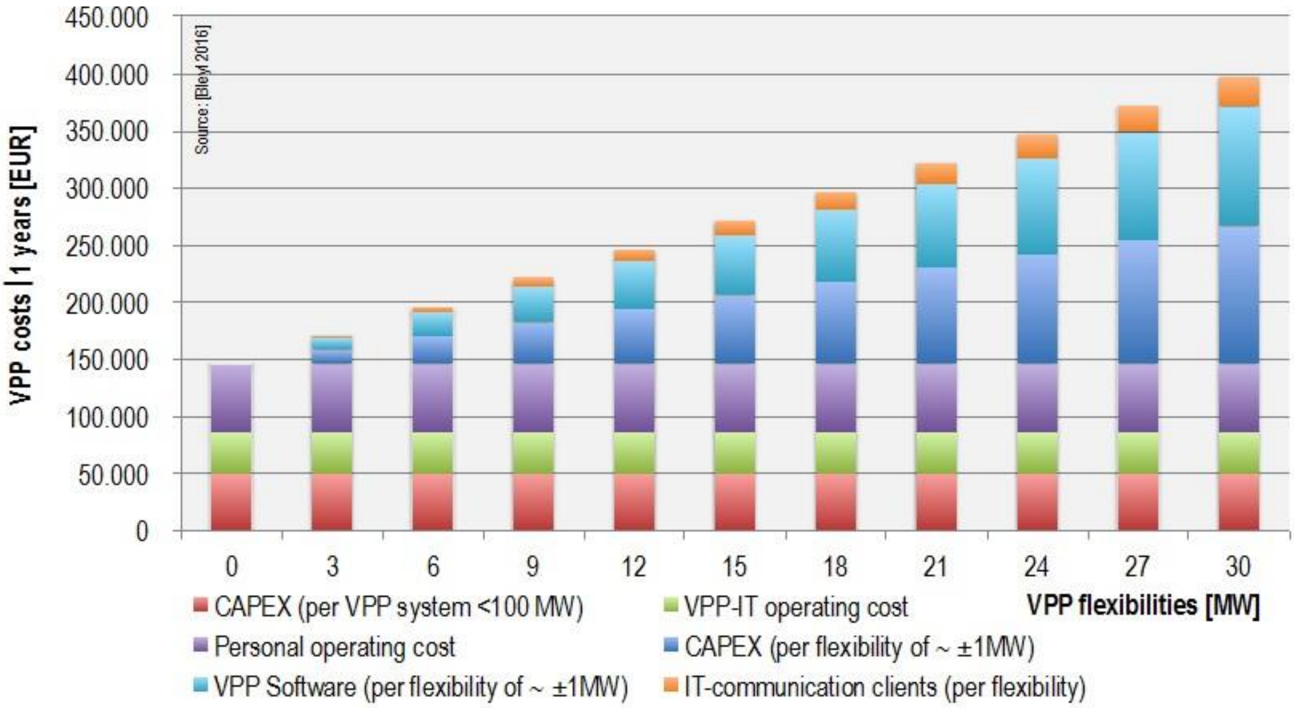

Figure 36: Project cycle cost and cost structure for market driven use cases (1 year operation) – Austria

Fix costs of the VPP account for close to EUR 150.000,-, independent of the capacity of controlled customers (VPP flexibilities). Depending on the size of the VPP, variable CAPEX and OPEX have to be added as displayed in the figure above (for one year of operation). By example of a VPP system with 30 MW of flexibilities, total cost accumulate to EUR 400.000,-, whereas the OPEX share is about 57%.

The CAPEX and OPEX for a VPP in Slovenia are slightly lower for the same VPP functionality, as can be seen in the figure below:

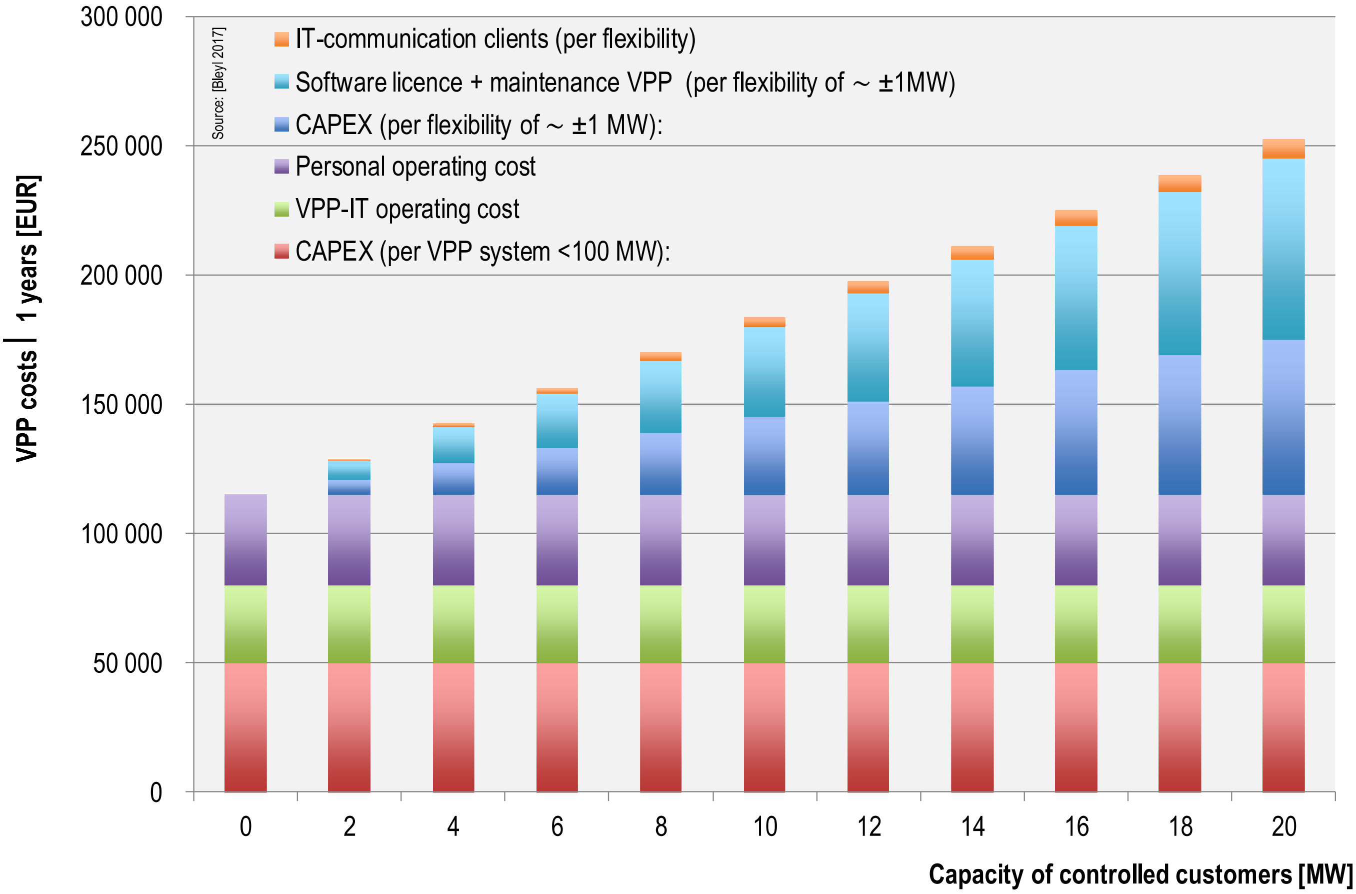

Figure 37: VPP project cycle cost and cost structure for market driven use cases (1 year operation) -Slovenia

Fix costs of the VPP account for close to EUR 115.000,- (for the VPP system, VPP-IT operating and personal cost), independent of the capacity of controlled customers (VPP flexibilities). By example of a VPP system with 20 MW of flexibilities with an average of 1 MW per customer, total cost accumulate to EUR 250.000,-, whereas the OPEX share is 56% (comparable to the Austrian case). To reach the same capacity of controlled customers with smaller flexibility units (e.g. 0,2 MW on average), the total VPP cost increase almost twofold (see Figure 43), due to the fix investment needed per flexibility as well as the higher operational expenditure for the IT communications with each flexibility.

The above hybrid-VPP cost components and structure apply to all investigated use cases subsequently. However, individual VPP cost components are adapted to meet required functionalities for other VPP applications of the different use cases, which will be briefly outlined in the respective use case descriptions. E.g. for the hybrid-VPP DSO use case, additional CAPEX and OPEX are needed for a connection to the DSO network operation center (NOC) and respective IT communications (c.f. section 3.7).

3.3 Market use cases (1)

3.3.1 Stakeholders

Figure 38 displays key roles and stakeholders involved in a market-driven VPP business case without restrictions from network operation. The figure also displays their relationships with regards to flows of information, flexibilities and cash.

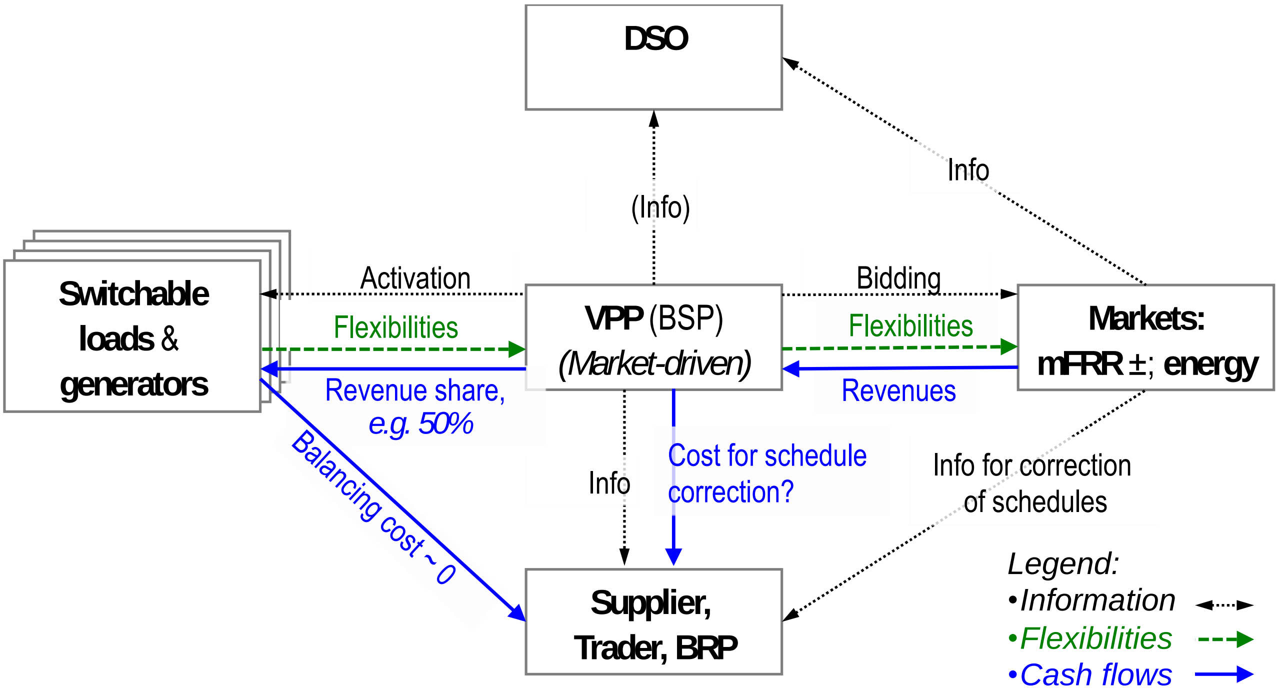

Figure 38: VPP Stakeholders for flexibility markets without restrictions from network operation

In the market driven use cases, the main cash flows are generated on balancing or energy only markets. In return for providing switchable loads or generation capacities to the VPP, the flexibility provider receives a share (e.g. 50%) of the revenues generated by the VPP on the market (revenue sharing model). Depending on the time and predictability of the deviations from the schedule, imbalance cost may have to be paid to the supplier, trader or BRP. Likewise, corresponding information flows are also displayed in the figure above.

3.3.2 Tertiary reserve market use case – Austria (1b)

3.3.2.a Revenues from tertiary reserve market

The revenues earned on the Austrian balancing market are mainly depending on the tradeable capacity of the pool, the market prices and the performance of trading on the pay-as-bid market.

The units available in the investigated area of Styria (Table 2) could provide a tradeable capacity of max. +14 and -12 MW. However, since a VPP is not limited to the regional borders of Styria, a VPP operator could aggregate units from all over Austria and thus there is no limit to be considered for the maximum size of the pool. Practical limits would appear from the size of the market, the tendered volume in 2017 is approx. +280 MW/-170 MW, which is similar to earlier years. A VPP providing more than 25% of the market volume could have a considerable impact on the market prices (highest accepted bid prices). This effect is not considered since the tradeable capacity of the pool is too low to influence the market significantly in average tenders. Therefore, a static market was assumed in the initial break-even analysis explained in the following chapter.

A simple benchmark for revenue expectation of an average market participant in the Austrian balancing market for tertiary reserve was assessed based on total costs published by APG [10].

In 2015 APG had market costs of total 17.82 Mio. EUR for +280MW/-125MW of tertiary reserve, consisting of 4.37 Mio. EUR for capacity reservation and 13.45 Mio. EUR for balancing energy. The general trend showed declining prices of capacity reservation, even going down to 0 EUR/MW/h during many hours. As a conservative approach, the prices for capacity reservation were assumed to be near to zero in the following years while the prices for balancing energy would remain on the same level as in 2015.

The tertiary reserve band is asymmetric and the energy cost for positive and negative reserve are not equal. To deal with this fact, a symmetric tertiary control band was assumed and the average revenues of a symmetric reserve unit were calculated according to Table 10. It is unrealistic that a single unit will permanently participate on the market, since technical unavailability and non-acceptance of the bid in the tender will appear. These conditions were considered by a rate of market participation (hit rate) of 65%.

Table 10: Simple assessment of specific revenues from participation in the Austrian tertiary reserve market

TSO’s costs for tertiary reserve	13,45 Mio	EUR/a
nominal positive reserve	280	MW
nominal negative reserve	125	MW
total nominal reserve band	405	MW
assumed symmetric reserve band	±202,5	MW
TSO’s costs per ±1 MW	**66 420**	**EUR/±1MW/a**
Participation rate of average unit	65	%
Annual revenue of participating unit	**43 173**	**EUR/±1MW/a**

The VPP operator would earn these specific revenues but would have to reimburse the owner of the flexible unit for the participation in the VPP. To consider the reimbursement of the flexible unit a revenue sharing model was assumed, which can frequently be found in the aggregation business. E.g. 40% revenue sharing would mean that the VPP would have to pay 40% of the incoming revenue to the owner of the flexible unit. If not mentioned otherwise, a hit rate of 65% and 50% revenue sharing was assumed in the following chapters.

In the later stage a detailed simulation of market participation in the weekly tenders was performed to deal with the real pool size, asymmetric pool and market volume, also assuming revenue maximizing trading strategies. Results of those simulations are used in the detailed economic analyses of the hybrid use cases in chapter 3.7.

Significantly higher revenues could be earned if the VPP would participate in the market for secondary control. However, secondary balancing markets were not considered in the analysis for Austria and Slovenia due to technical restrictions of the investigated flexibilities in terms of full activation time and availability.

The future evolution of balancing prices and revenues for market participants is mainly influenced by two opposing trends. On the one hand, the increasing share of fluctuating renewable generators will lead to higher demand of balancing reserves and energy, which could increase the prices for balancing reserves. On the other hand, the European TSOs try to reduce costs of balancing by increasing international cooperation, imbalance netting[3] and coupling of balancing markets, which may significantly reduce the number and duration of activations over the year. In 2015 there was already a quite competitive market situation in Austria, meaning that further decreasing prices could discourage owners of flexible units to participate in the market and a self-regulating effect could be observed. Thus, it was assumed that the level and annual profile of prices in 2020 and 2030 would be the same as in 2015.

3.3.2.b Break-even analyses tertiary reserve market

For the break-even analyses, VPP revenues and costs are compared as a function of the capacity of controlled customers. The results for the tertiary market use case are displayed in Figure 39.

[3] Avoidance of simultaneous secondary control activation in opposite directions by taking into account the respective area control errors as well as the activated aFRR and correcting the input of the involved frequency restoration processes accordingly. More details: https://www.entsoe.eu/major-projects/network-code-implementation/electricity-balancing/igcc/Pages/default.aspx

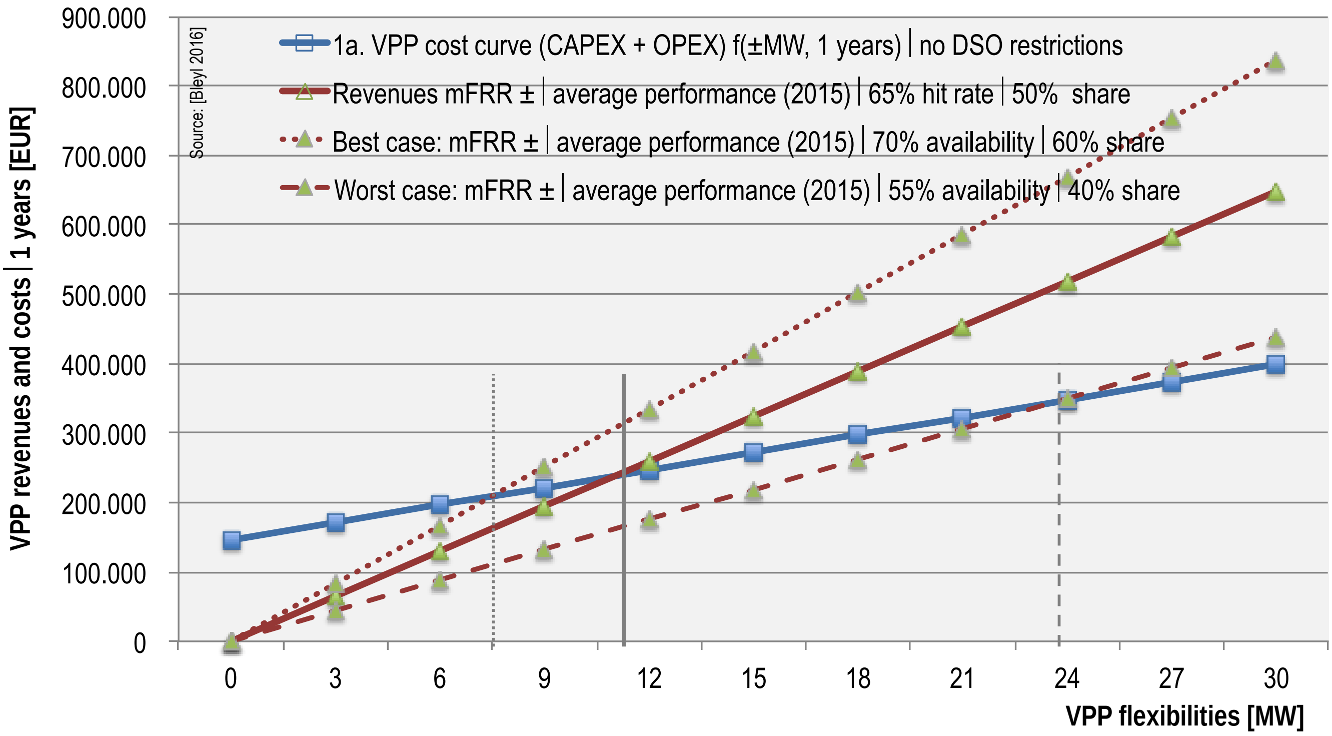

Figure 39: Break-even analyses for the tertiary reserve market: Revenue vs. cost for one year of VPP operation, incl. sensitivity for best and worst cases in Austria. 1 MW of VPP flexibility means ±1 MW of tradeable capacity.

For one year of VPP operation time, VPP revenues and total cost break even at about ±11 MW of tradeable capacity. This figure can be interpreted as a minimum size for a market based VPP. However, for a profitable business case, the capacity of controlled customers will need to be above this value, since break-even analyses do not consider financing cost or expected profits. If the VPP project time is increased to two years, revenues and total cost break even already at about ±8 MW of connected flexibilities.

With regard to a sensitivity analyses, the best-case and worst-case scenarios in the figure above reveal break-evens at ±7.5 MW and ±24 MW. Particularly for the worst case, the parameters "availability" and "revenue share" in the array of curves can serve as threshold values for the risk analyses.

3.3.3 Tertiary reserve market use case – Slovenia (1b)

3.3.3.a Revenues from tertiary reserve market

Same as in the Austrian case, revenues earned on the Slovenian balancing market are mainly depending on the tradeable capacity of the pool and the market prices. Different to Austria, the Slovenian TSO (ELES d.o.o.) currently uses annual auctions and bilateral contracts to guarantee the availability of the required reserves during the entire year. The capacity price and energy price of the contracts is published on the homepage of ELES[4] and shown in Table 11. Only contract for positive reserve are published and statistics show that negative activation appeared only for less than 10h of the year, thus it is assumed that the negative tertiary reserve is negligible. It is remarkable, that ELES has one contract with a VPP considering the special requirement of this technology.

Table 11: Contracts for provision of tertiary reserve published by the Slovenian TSO.

Tender	Supply	Product	Capacity (MW)	Reserve fee (€/MW/y)	Energy fee (€/MWh)
22.11.2013	2014-2018	144 MW	10	55 000	200
11.12.2014	2015	VPP	15	38 900	240
11.12.2014	2015-2018	50 MW	50	47 000	249
11.12.2014	2015	139 MW	139	39 500	260
22.11.2013	2014-2018	144 MW	134	68 300	270

The capacity prices of the Slovenian contracts seem to be significantly higher than Austrian average prices of the same period (cf. APG [10]), which might be related to the limited market liquidity and the duration of the contacts. Additionally, reserve providers in Slovenia face high penalties in case of underperformance during an activation. Penalties in Slovenia were assumed with 4 000 EUR/MW/h. For the following break-even analyses, it was assumed that the VPP would show underperformance for 2 h twice a year and thus have to pay total penalties of 16,000 EUR/MW/a.

The evolution of units available in the investigated area of Slovenia is explained in Table 2. The investigated units could provide a nominal capacity of max. +16 and -15 MW. This resulted in a tradeable capacity of +9 MW/-8 MW (see chapter 4.2.1). In the Slovenian case it was assumed that the VPP would be the contract partner to ELES using a contract with a capacity price of 38 900 EUR/MW/a and an energy price of 199 EUR/MWh, which would be a slightly lower price than in all of the published contracts. Same as in the Austrian case, it was assumed that the reserve price would be identical in 2020 and 2030. Further, it is assumed that the owners of the flexibilities would get a share of 50% of the yearly net revenues. Net revenues are calculated from revenues according to the contracted prices reduced by the penalties. Since a one-year-contract must be fulfilled, the VPP must provide the capacity during the entire year and thus no availability factors have been considered. In fact, the VPP operator must maintain internal backup to cover any outages of the units in the pool to avoid penalties.

3.3.3.b Break-even analyses tertiary reserve market

In Slovenia, the results for the tertiary market use case are displayed in Figure 40:

[4] See www.eles.si

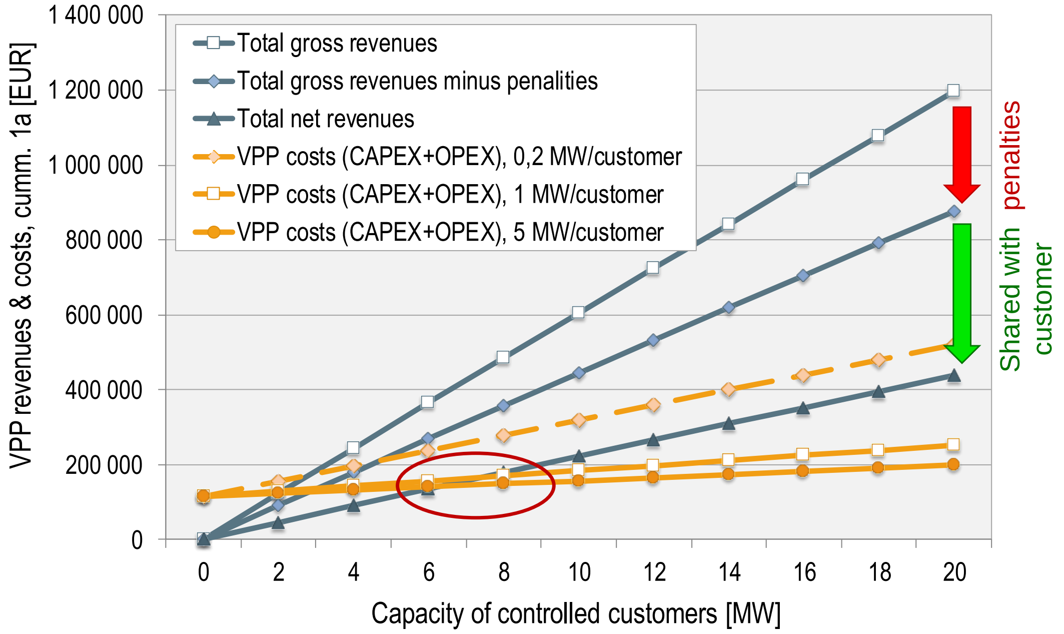

Figure 41: Break-even analyses for the tertiary reserve market: Revenue vs. cost for one year VPP operation time, incl. sensitivity for best and worst cases in Slovenia. Capacity in MW means tradeable positive capacity.

In addition to the Austrian case, the figure also displays the different market rules in Slovenia, which impose substantial penalties in the case of non-delivery. The remaining revenues are assumed to be shared 50:50 between VPP and flexibility providers. For one year of VPP operation time, VPP revenues and total cost break-even at about 7 MW of connected flexibilities. As in the case of Austria, this figure can be interpreted as a minimum size for a market based VPP. However, for a profitable business case, the capacity of controlled customers will need to be at least 25% above this value, since break-even analyses do not consider financing cost or expected profits.

Another important observation relates to the sensitivity of the VPP cost curve as function of the size of customer units. In the case of smaller customers (0.2 MW on average), the capacity of controlled customers needed for break-even is above 30 MW.

3.3.4 Spot market use cases - Austria and Slovenia (1a)

3.3.4.a Revenues from day ahead spot market

The aim of the second market-based use case analysis is to quantify the benefits that can be achieved using the flexible loads of a VPP for arbitrage on day-ahead spot markets. For this investigation only flexible loads have been considered, because the considered generators are volatile, depend on the supply of e.g. water (hydro-power plants) and, thus, lack flexibility.

For the Base scenarios historical spot market price data from the year 2013 for Austria and from 2014 for Slovenia has been used. For the future scenarios results from the EDisON model [7] have been utilized. Two spot market price time series have been employed each for the years 2020 and 2030. The future Base price scenarios are the results of implementing the Ten-Year Network Development Plan 2014[5] from the ENTSO-E into the EDisON model, while for the EnEFF scenarios the energy efficiency targets of Austria are included.

Methodology

The arbitrage business on the day-ahead spot market is modelled as a mixed-integer linear optimization problem (MILP) minimizing the aggregated total cost for energy purchase of all considered loads. The model considers a time frame of one year with a quarter-hourly resolution. With the nomenclature listed in Table 12 the objective function of the optimization problem is given by:

$$\min \sum_{t} \sum_{i=1}^{n} \sum_{j=1}^{n_i} \mathbf{p}_t \cdot (\mathbf{load}_{t,i} + \mathbf{inc}_{t,i,j} - \mathbf{red}_{t,i,j})$$

Table 12: List of model variables and parameters

Parameters	
$t \in \{1, \ldots, 35040\}$	Quarter-hourly time step
$\mathbf{p}_t$	Day-ahead spot market price at time t.
n	Number of loads considered by the VPP model
n_i	Number of flexibility options for load i
$\mathbf{load}_{t,i}$	Original load i at time t
Decision variables	
$\mathbf{inc}_{t,i,j}$	Increase of load i at time t by activation of flexibility option j
$\mathbf{red}_{t,i,j}$	Reduction of load i at time t by activation of flexibility option j
Auxiliary variables	
$\mathbf{inc\_active}_{t,i,j}$	Binary variable indicating whether the increase of flexibility option j and load i is active at time t
$\mathbf{red\_active}_{t,i,j}$	Binary variable indicating whether the reduction of flexibility option j and load i is active at time t
$\mathbf{inc\_start}_{t,i,j}$	Binary variable indicating whether the increase activation of flexibility option j and load i is starting at time t

[5] https://www.entsoe.eu/major-projects/ten-year-network-development-plan/tyndp-2014/Pages/default.aspx

$\mathbf{red\_start}_{t,i,j}$	Binary variable indicating whether the reduction activation of flexibility option j and load i is starting at time t

Each load can have one or more flexibility options, which are characterized by different (optional) constraints. For the implementation of some constraints binary auxiliary variables $\mathbf{inc\_active}_{t,i,j}$, $\mathbf{red\_active}_{t,i,j}$, $\mathbf{inc\_start}_{t,i,j}$ and $\mathbf{red\_start}_{t,i,j}$ are used, which state, whether a load increase or reduction is active or starting at time t.

Let $\mathrm{min\_inc}_{i,j}, \mathrm{min\_red}_{i,j}, \mathrm{max\_inc}_{i,j}$ and $\mathrm{max\_red}_{i,j}$ be the minimal and maximal increase and reduction, respectively for the flexibility option j of load i. Then the foundation of the model is formed by putting the decision variables $\mathbf{inc}_{t,i,j}$ and $\mathbf{red}_{t,i,j}$ in relation with the auxiliary binary variables $\mathrm{inc\_active}_{t,i,j}$ and $\mathrm{inc\_active}_{t,i,j}$:

$$
\begin{aligned}
\mathbf{inc}_{t,i,j} &\le \mathrm{max\_inc}_{i,j} \cdot \mathbf{inc\_active}_{t,i,j} \quad \forall t,i,j \\
\mathbf{red}_{t,i,j} &\le \mathrm{max\_red}_{i,j} \cdot \mathbf{red\_active}_{t,i,j} \quad \forall t,i,j \\
\mathbf{inc}_{t,i,j} &\ge \mathrm{min\_inc}_{i,j} \cdot \mathbf{inc\_active}_{t,i,j} \quad \forall t,i,j \\
\mathbf{red}_{t,i,j} &\ge \mathrm{min\_red}_{i,j} \cdot \mathbf{red\_active}_{t,i,j} \quad \forall t,i,j
\end{aligned}
$$

Furthermore, let $\mathrm{min\_inc\_time}_{i,j}, \mathrm{min\_red\_time}_{i,j}, \mathrm{max\_inc\_time}_{i,j}$ and $\mathrm{max\_red\_time}_{i,j}$ denote the minimal and maximal block length in quarter hours of a load increase and reduction, respectively. Then the binary variables $\mathrm{inc\_active}_{t,i,j}$ and $\mathrm{red\_active}_{t,i,j}$ can be linked to $\mathrm{inc\_start}_{t,i,j}$ and $\mathrm{red\_start}_{t,i,j}$ with the following constraints:

$$
\begin{aligned}
\mathbf{inc\_active}_{t,i,j} &\ge \sum_{\boldsymbol{s}=\boldsymbol{t}-\mathrm{min\_inc\_time}_{i,j}+1}^{\boldsymbol{t}} \mathbf{inc\_start}_{t,i,j} \ \forall t,i,j \\
\mathbf{red\_active}_{t,i,j} &\ge \sum_{\boldsymbol{s}=\boldsymbol{t}-\mathrm{min\_red\_time}_{i,j}+1}^{\boldsymbol{t}} \mathbf{red\_start}_{t,i,j} \ \forall t,i,j \\
\mathbf{inc\_active}_{t,i,j} &\le \sum_{\boldsymbol{s}=\boldsymbol{t}-\mathrm{max\_inc\_time}_{i,j}+1}^{\boldsymbol{t}} \mathbf{inc\_start}_{t,i,j} \ \forall t,i,j \\
\mathbf{red\_active}_{t,i,j} &\le \sum_{\boldsymbol{s}=\boldsymbol{t}-\mathrm{max\_red\_time}_{i,j}+1}^{\boldsymbol{t}} \mathbf{red\_start}_{t,i,j} \ \forall t,i,j
\end{aligned}
$$

These constraints form the basis of the MILP. Further flexibility characteristics can be described by adding additional constraints to the model using the decision or auxiliary variables. To limit flexibility activations on weekdays, for example, $\mathbf{inc\_active}_{t,i,j}$ and $\mathbf{red\_active}_{t,i,j}$ can be set zero for all t belonging to weekends. With this model set-up the following flexibility characterizations can be described:

- Power:
    - Minimal and maximal load increase and reduction in MW
    - Relative minimal and maximal load increase and reduction in percent of current load
- Flexibility availability:
    - Hours per day (e.g. 8 AM – 8 PM)
    - Days per week (e.g. MO – FR)
    - Months, seasons, quarter per year (e.g. May – September)
- Time:
    - Minimal and maximal reduction and increase time per flexibility activation (shifting of minimal/maximal length load blocks)
    - Minimal pause between flexibility activations
    - Maximal time between load increases and reductions
    - Time frames, load changes have to be balanced (sum up to zero) within (e.g. day, week, month, …)
- Number:
    - Maximal flexibility activations per day, week, month, quarter, season and year

In order to illustrate the functionality of the model, consider a load from Styria with flexibility options characterized by the following constraints:

- Maximal load increase and reduction: 0.22 MW
- Load shift block length: 3 hours
- Maximally one flexibility activation per day
- A load reduction (or increase) block immediately has to be balanced with a subsequent load increase (or reduction) block.
- Available only on weekdays

Figure 42 shows the activations of this flexibility option in one week. The upper plot shows the original load, the new load, calculated by the model, and the differences between these loads, which correspond to the flexibility activations. The lower plot shows the spot market prices in the considered week. It can be seen that there is only one activation per weekday. Each load change block lasts for three hours and has a power of 0.22 MW. A load increase is balanced immediately with a subsequent reduction. Thus, the times chosen for the flexibility activations are the ones where the steepest price change gradients occur.

Figure 42: Illustration of flexibility activation of a Styrian load for week 24 of the year 2013.

It is important to mention that this model, being an optimization model with perfect foresight with respect to price and load development, provides an upper bound for the benefits that can be generated on the spot market in real life, where uncertainties and forecast errors have to be dealt with.

Results for Austria

Based on the results from the questionnaires three different loads were considered for the spot market use case in Austria. Their flexibility options and the respective characterizations are listed in Table 13. Empty fields indicate that there is no restriction for the flexibility option with respect to the corresponding category.

Table 13: Flexibility options for the loads in Austria

	Load 1 (with two separate loads)		Load 2	Load 3
Flexibility option	1	2	1	1
Maximum load change	0.4 MW	0.22 MW	0.15 MW	0.25 MW
Load shift block length	2 hours	3 hours		0.5 hours
Maximal activation number	1 per day	1 per day		1 per week
Daily availibility	6 AM - 10 PM			6 AM - 4 PM
Weekly availibility	Mon - Fri	Mon - Fri	Mon - Sat	Mon - Fri
Yearly availibility	Sep - Apr			
Catch-up within	immediately	immediately	1 day	1 day

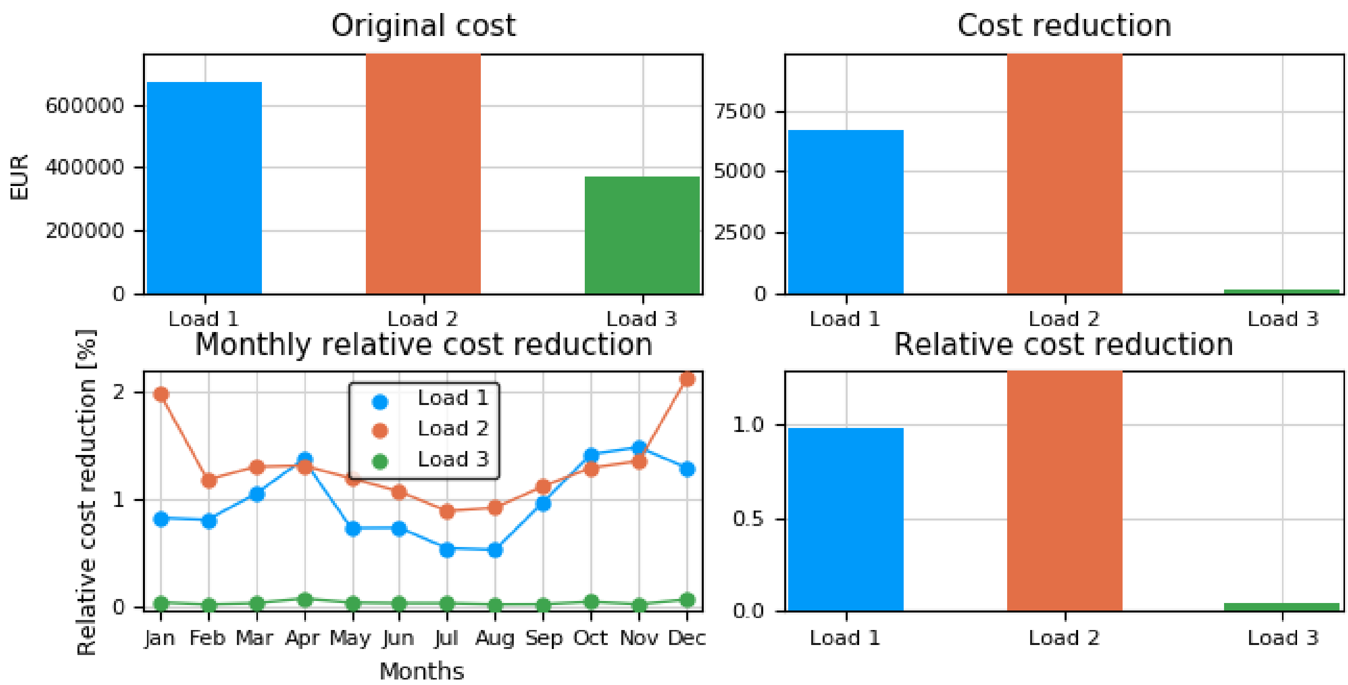

Figure 43: Economic results per load for the Austrian 2013 spot market scenario.

Figure 43 shows the model results per load for the Austrian use case with the 2013 spot market prices. It can be seen that the flexibility option for Load 2 achieves the highest absolute and relative annual benefits, although its load change capacity of 0.15 MW is the lowest. This is due to the fact that the other flexibility options have more temporal restrictions. Load 1, for instance, has a total load change capacity of 0.62 MW. The flexibility options, however, are restricted to one activation per day, they have to last for a certain time and they have to be balanced immediately afterwards. Load 3 may only be changed once per week for half an hour, which significantly limits the flexibility benefits.

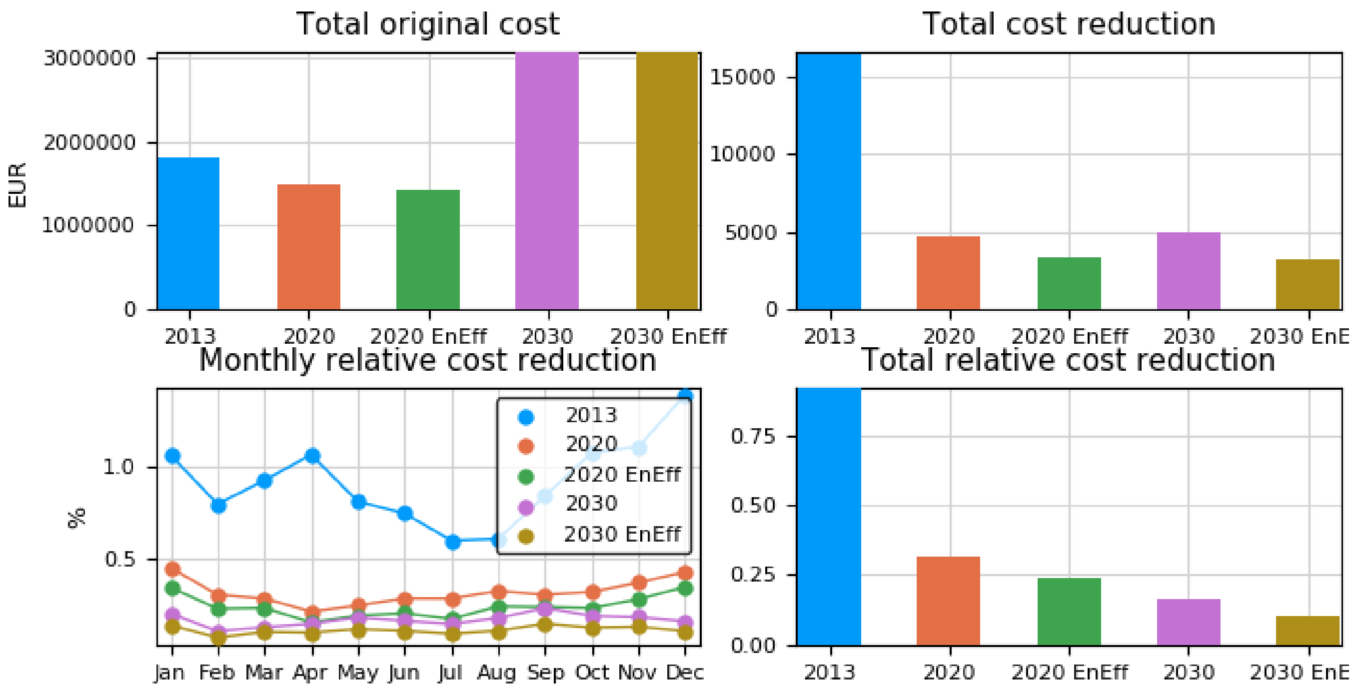

Figure 44: Economic results for all considered Austrian spot market scenarios.

The total annual benefits for different price scenarios are illustrated in Figure 44. The high total cost for the 2030 scenarios are due to CO_2 price assumptions employed in the EDisON model. In all future scenarios both, the absolute and the relative possible cost reduction, are significantly reduced, compared to the 2013 Base scenario. The main reason for this is the reduction in spot market price spreads in the future scenarios.

Results for Slovenia

In Slovenia there was only one load with one flexibility option to be considered for the day-ahead spot market analysis based on the results from the questionnaires in D1 [13]. Its constraints are listed in Table 14. The load is limited by 0.37 MW and the load reduction by 27 % of the current load. A flexibility activation has to last for one hour and the load has to be balanced within the same day. The flexibility is only available between May and September.

Table 14: Flexibility options for the Slovenian load

	Load 1
Maximal load	0.37 MW
Maximal relative load reduction	27%
Load shift block length	1 hour
Yearly availability	May - Sep
Catch-up within	1 day

The results for the Slovenian load are illustrated in Figure 45. Similar to the Austrian use case the benefits of demand response are significantly higher in the baseline year 2014 than in the future price scenarios. The relative cost reduction of up to 5 percent is considerably higher than the relative cost reduction achieved by the Austrian loads. This is due to the high temporal availability of the Slovenian load: Even though flexibility activations are only available between May and September, there is no limit to the number of daily activations.

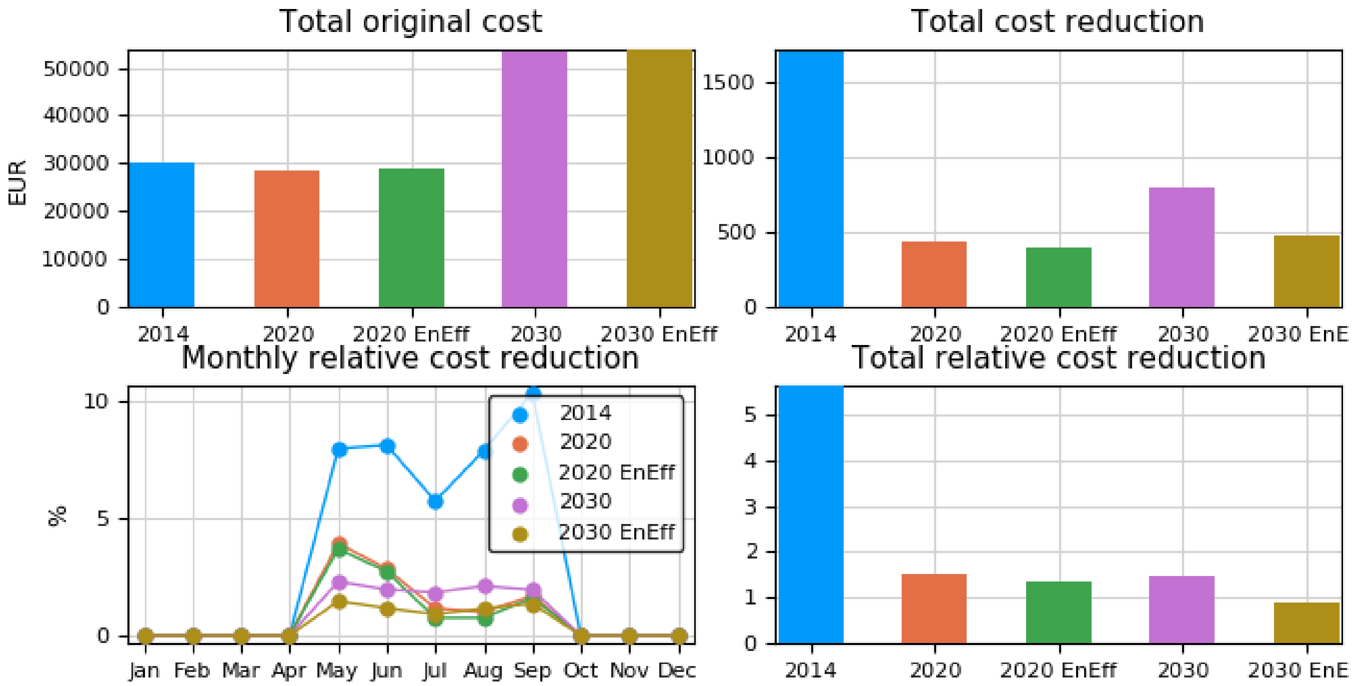

Figure 45: Economic results for all considered Slovenian spot market scenarios.

Further price scenarios:

During the analysis of the spot market use cases for Austria and Slovenia further questions arose. Firstly, it was assumed that a quarter-hourly wholesale market price would allow for higher benefits of demand response compared to an hourly price due to the increased price volatility. In order to examine this assumption, the optimization model with the Austrian loads was solved for the hourly and for the quarter-hourly EXAA spot market prices of the year 2015. The results, illustrated in Figure 46, show that the quarter-hourly prices indeed facilitate more benefits for flexibilities than the hourly prices.

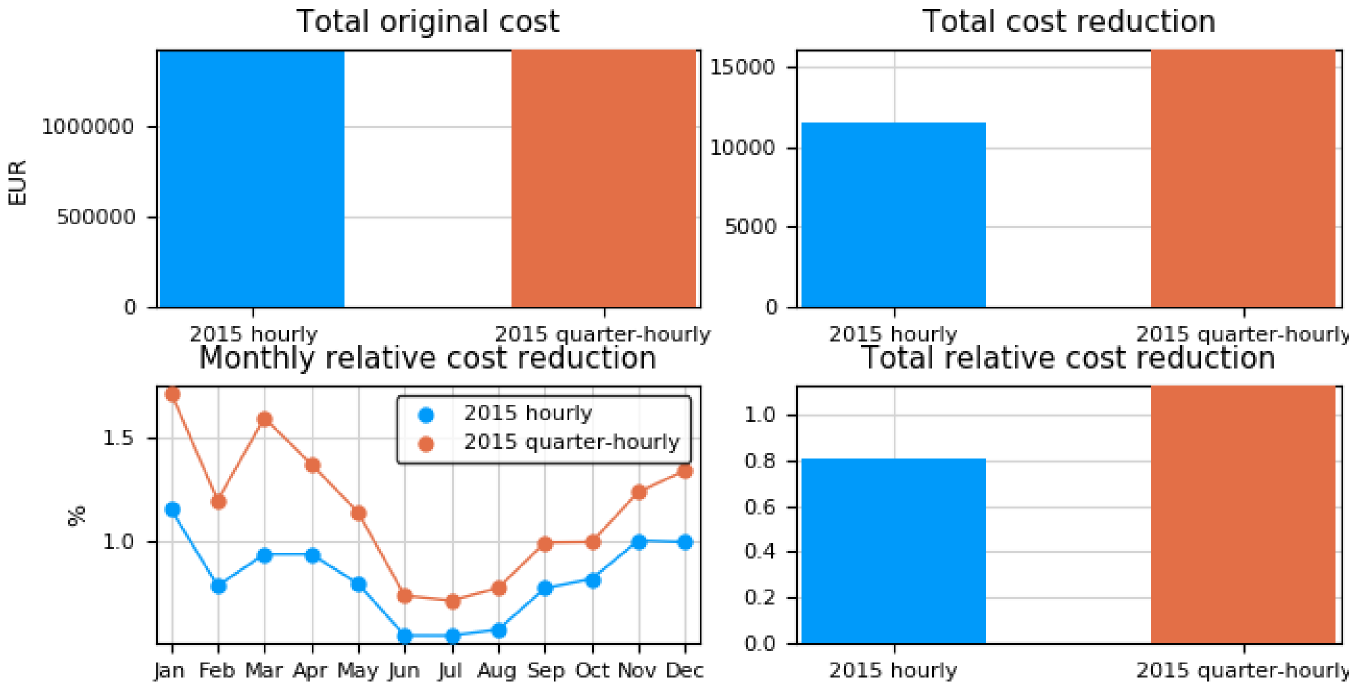

Figure 46: Economic results of hourly and quarter-hourly spot market prices.

3.3.4.b Revenues from intraday spot market

Furthermore, it was investigated, whether more profit could be generated on the intraday market. For this purpose, the model with the Austrian loads was solved for the day-ahead prices and for the average intraday prices on the EPEX spot market in the year 2014. No significant difference in total cost, cost reduction and relative cost reduction was found between these price scenarios, as can be seen in Figure 47. The intraday prices are based on the continuous intraday market. Therefore, the prices are the weighted average price. The realized prices of the market participants could also be higher or lower.

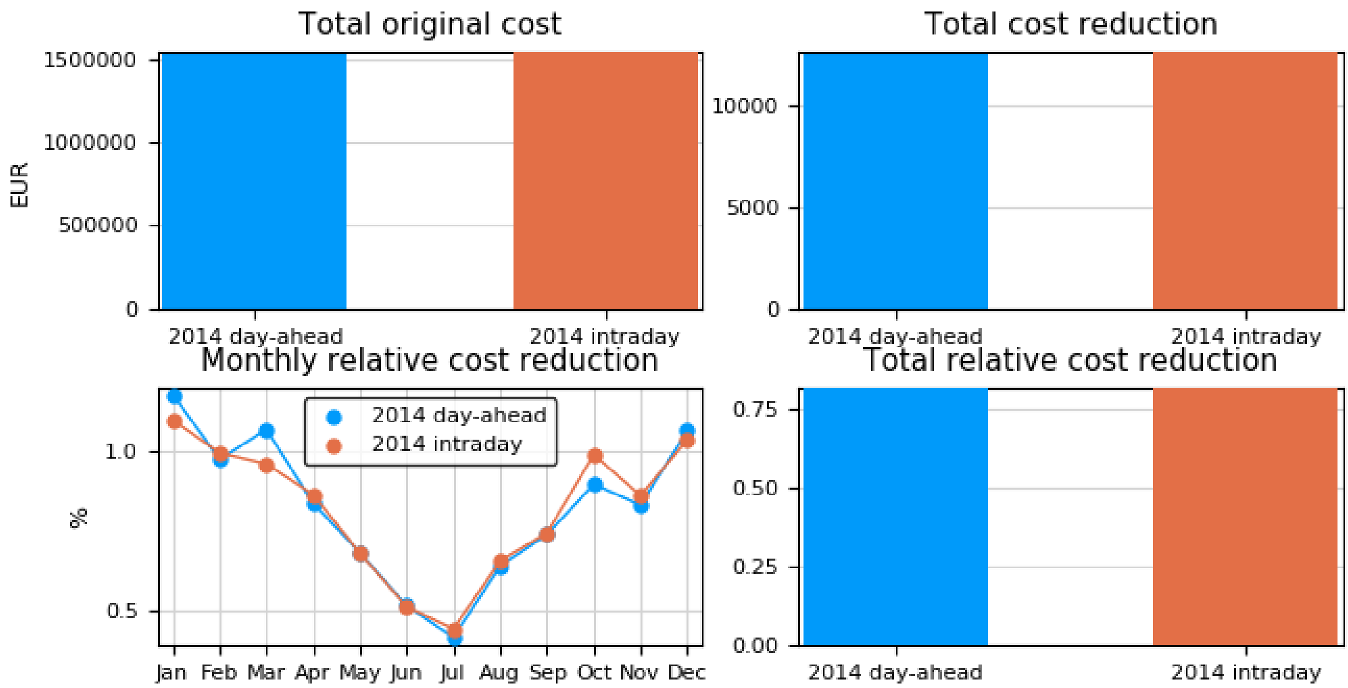

Figure 47: Economic results of day-ahead and intraday prices.

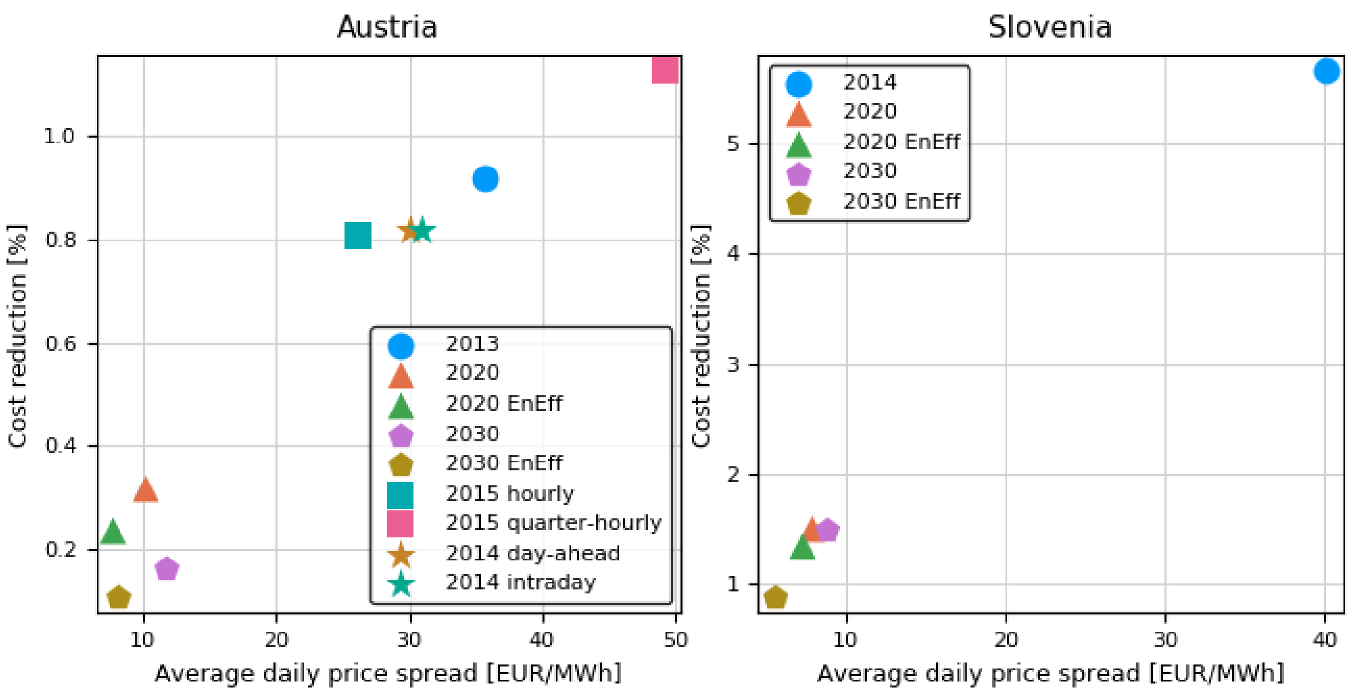

Figure 48: Relation between relative cost reduction and average daily price spread for different scenarios.

Aside from load flexibility availability in terms of power, number of activations and temporal availability, one key parameter for the economic efficiency of demand response is the price spread on the electricity wholesale market. If the total amount of energy consumption may not be changed, but loads may only be shifted in time, the only source for generating profits is the difference between higher and lower price levels. The relation between economic efficiency of demand response and the spread of market prices can be seen in Figure 48, showing the average daily price spread versus the relative cost reduction achieved for different scenarios.

3.3.4.c Break-even analyses day ahead sport market

For the break-even analyses, VPP revenues and cost are compared as a function of the capacity of controlled customers. The results for the sport market use case for a two-year operating period are displayed in the figure below.

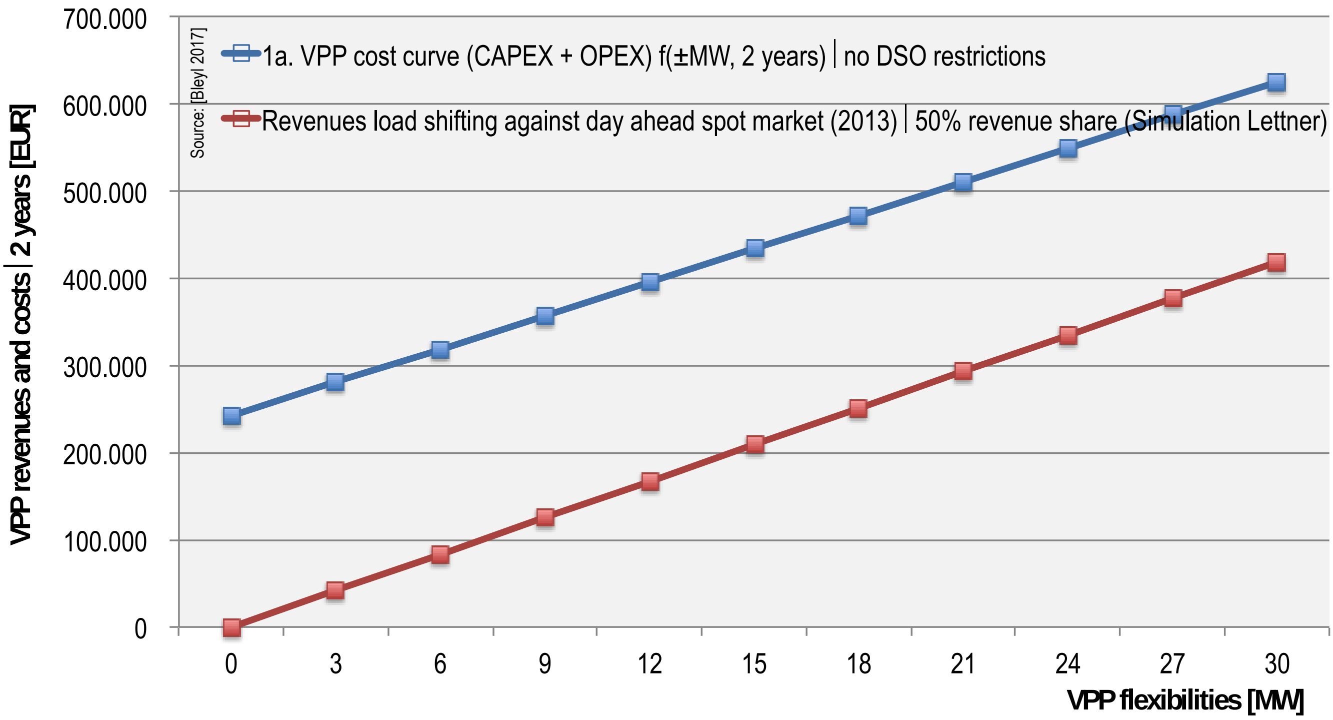

Figure 49: Break-even analyses day ahead sport market: Revenue vs. cost for 2 years VPP operation time

The results show, that VPP revenues from arbitrage on day-ahead spot markets are not sufficient to pay back for the VPP investment during a two-year operation period, not even beyond the scope of 30 MW connected flexibilities. Longer VPP operation periods of more than two years would not substantially accelerate the break-even. However, the variable CAPEX and OPEX can be recovered through the revenues.

In order to reach a break-even at 30 MW connected flexibilities would require a 75% revenue share for the VPP, leaving just 3.500 EUR/MW/year for the flexibility provider on average.

3.4 Customer use cases: VPP to minimize grid connection cost (2)

3.4.1 Stakeholders

In this section the focus is on the customer's perspective. In the analyzed use case in Austria an existing or new grid customer plans to install (additional) renewable[6] generating capacity for feed-in, either wind, PV or water in an already stressed grid section. With the conventional approach, the customer would be required to pay for the needed grid enhancement or build a new power line to the closest "suitable connection point". Alternatively, the customer can connect to the existing infrastructure, if he agrees to be curtailed in critical hours, e.g. in cases of voltage band violations. Here a local P=f(U) feed-in control is the preferred option but may be problematic in some grid topologies, whereas curtailment via a hybrid-VPP, driven by DSO commands (c.f. Figure 50) is a more versatile solution.

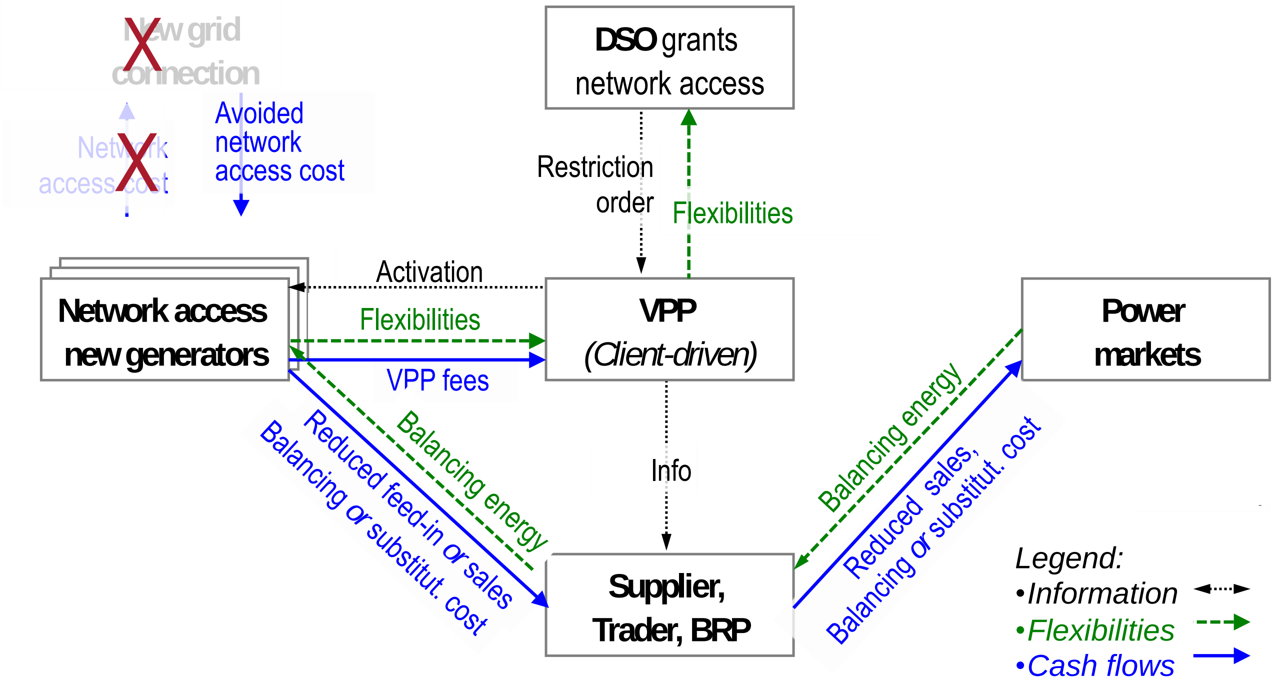

Figure 50: VPP Stakeholders to minimize grid connection cost for new renewable generation capacity

As shown in detail in section 2.2.2, the production of the PV plant would need to be curtailed about 15 MWh over the year, in order to keep the voltage within the limits. This corresponds to 0.74% of the entire production. The wind power plant would need to be reduced by 31 MWh, which corresponds to 0.89% of the entire production.

6 A similar logic would apply for non-renewable supply sources.

In a second customer use case from Slovenia (c.f. 2.2.2.b), an additional industrial load with a nominal power of 1.5 MW was added to a grid section, which was already reaching its limits at certain times. As in the Austrian case the curtailment needed, if the load participated in the hybrid-VPP is rather small: Its energy would be reduced by just 30.26 MWh, which is equal to 0.36% of the total yearly consumption (c.f. Table 15).

3.4.2 Customer cost benefit analyses for new renewable generators - Austria (2a)

From the customer's perspective, the question of an economic comparison between the costs of grid enhancement versus participation in a network-driven VPP arises. For the customer use case this translates into the costs for a new 15 km grid connection versus the cost for the VPP services and the value of the curtailed energy (lost revenues for the customer). The technical background of this case is explained in chapter 2.2.2.a. The key economic calculations parameters are summarized in Table 15. According to the TSO's rules for balancing markets, renewable generators like wind power or PV plants could only participate in the tertiary control if 100% backup of conventional units would be available. Furthermore, in the year 2016 a renewable generator, which receives a feed-in tariff, is not allowed to participate in balancing markets. Therefore, no revenue loss from the tertiary market is to be expected.

Table 15: Customer use case for 2 MW generators: Key economic calculation parameters - Austria

Grid enhancement costs AT		
Cable	150 000 €/km	
Total Grid enhancement costs (15,1 km)	2 268 600 €	
Loss of revenues AT		
	PV (14.85 MWh/a)	Wind (31.02 MWh/a)
Tertiary market	0 €/a	0 €/a
Spot market	399 €/a	808 €/a
Spot market (EnEff)	378 €/a	806 €/a
Feed-in tariff	1 223 €/a	2 777 €/a

As a first indication, a simple pay back analysis is sufficient to demonstrate economic viability of the VPP application instead of the grid enhancement (payback time of the additional grid enhancement cost is several hundred years according to the numbers in Table 15, due to the small revenue losses compared to the grid investment).

Another example for three different cases of potential new wind parks (explained in chapter 2.2.4.d) is shown in Figure 51, comparing avoided investments for grid enhancement cost versus service cost for participation in a VPP and reduced revenues from electricity feed-in due to curtailment (Accounting of differential cost only).

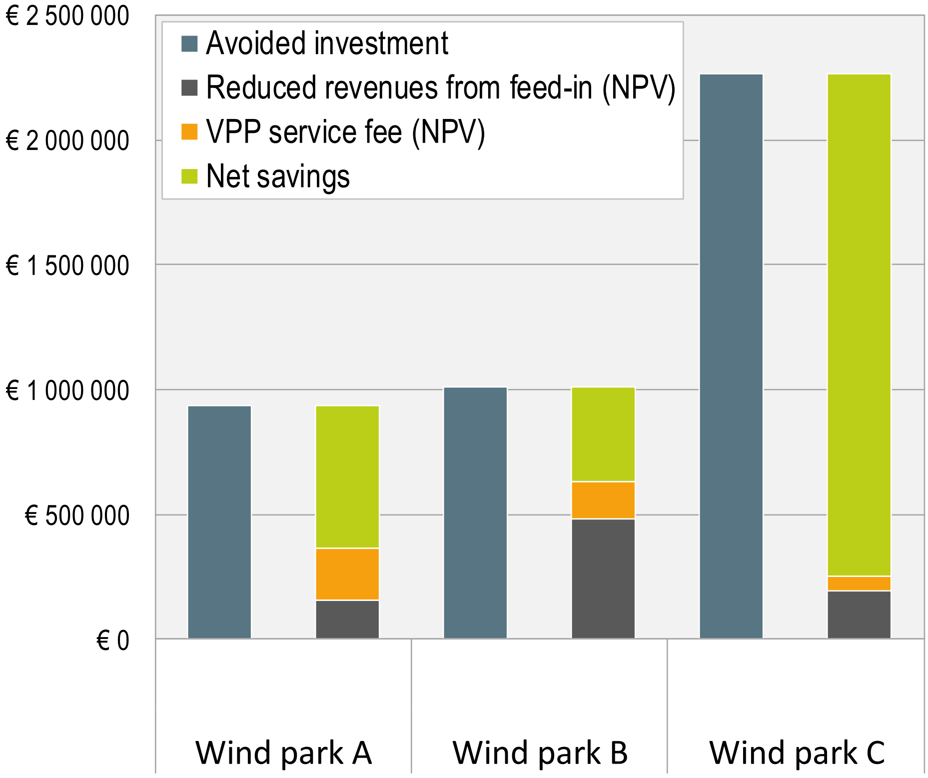

Figure 51: Cost benefit analyses: VPP to minimize grid connection cost for three windparks (A: 7 MW, B: 5 MW, C: 2 MW) – Austria

The NPV (at 3% discount rate) of the VPP service cost over 20 years life cycle of wind park are between 5% and 20%, the reduced revenues are between 10 and 50% of the grid investment cost. As a result, the net savings compared to the avoided grid investments are positive in all cases and range between about EUR 300 000 and more than EUR 2 000 000 in absolute values or between 30% and 90% of the avoided investment. However, it should be noted that these are only theoretical savings. In reality, wind park C, with grid connection costs of EUR 2 000 000, would most likely not be built at all without the hybrid-VPP.

3.4.3 Minimize grid connection cost for new consumers - Slovenia (2b)

Analogue to the Austrian customer use case, the question of an economic comparison between the costs of grid enhancement versus participation in a network-driven VPP arises. This translates into the investment costs of 400.000 EUR for a new 1.3 km cable versus the cost for the VPP services and the internal costs of load shifting (117 MWh/a, 266 h/a). In this case the NPV (at 3% discount rate) of load shifting costs over an assumed life cycle of 20 years is likely to exceed the saved investments because of the more complex nature and higher costs of industrial load shifting compared to curtailment of renewable generators. In the given case, the grid reinforcement would be the better alternative if the average costs of load shifting would exceed 42 EUR/MWh.

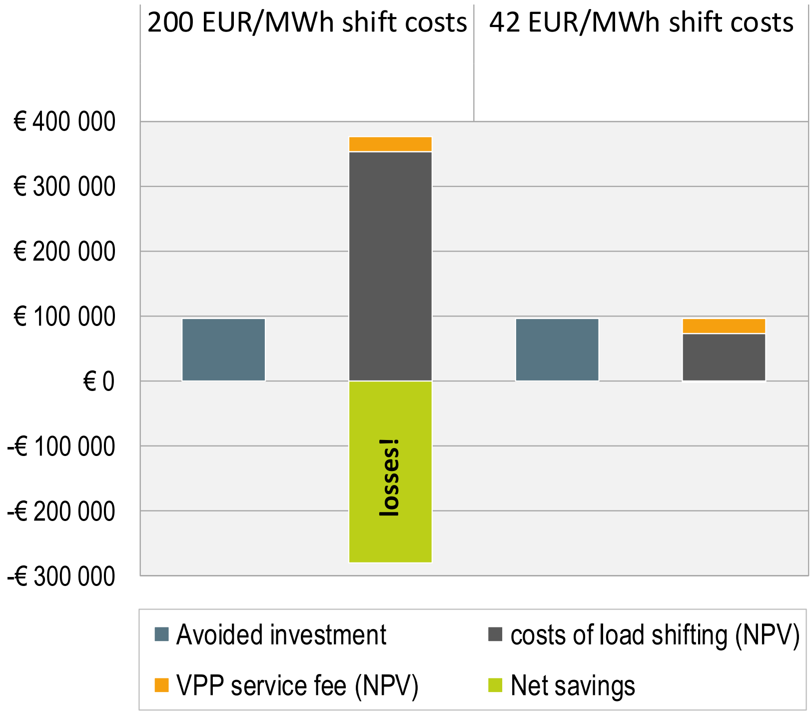

Figure 52: Cost benefit analyses: VPP to minimize grid connection cost for an industrial load of 1.5 MW, avoided cable length 1.3 km; NPV cumulated over a lifetime of 20a, depending on the internal costs of load shifting – Slovenia

In another configuration of a pure customer use case simulated for the same customer (see chapter 2.2.2.b), the grid enhancement would require a new cable of 3 km (situation in 2014) or even 5.4 km length (situation in 2030), but the yearly shifted load would be far lower (Table 16) than in the example shown above.

Table 16 Minimize grid connection cost for new consumers: Key economic calculation parameters - Slovenia

Grid enhancement cost SI		
Scenario year	2014	2020
Cable length	3 km	5.4 km
Cable investment	220 000 €	400 000 €
Loss of revenue SI		
Shifted load (MWh/a)	20.74	30.26
Medium Losses (200 €/MWh)	4 148 €/a	6 052 €/a
High Losses (800 €/MWh)	16 592 €/a	24 208 €/a

Considering the long lifetime of grid investments, the 2020 situation is relevant. Under these conditions, the load-shifting measure of the customer would be much preferable, the maximum allowed costs for load shifting would be above 800 EUR/MWh (considering a 20-years life cycle and 3% interest rate). Both cases show that, from a customer's perspective, an assumed VPP service fee of 2000 EUR/MW/a (see chapter 3.4.4) would be of lower impact compared to costs of load shifting.

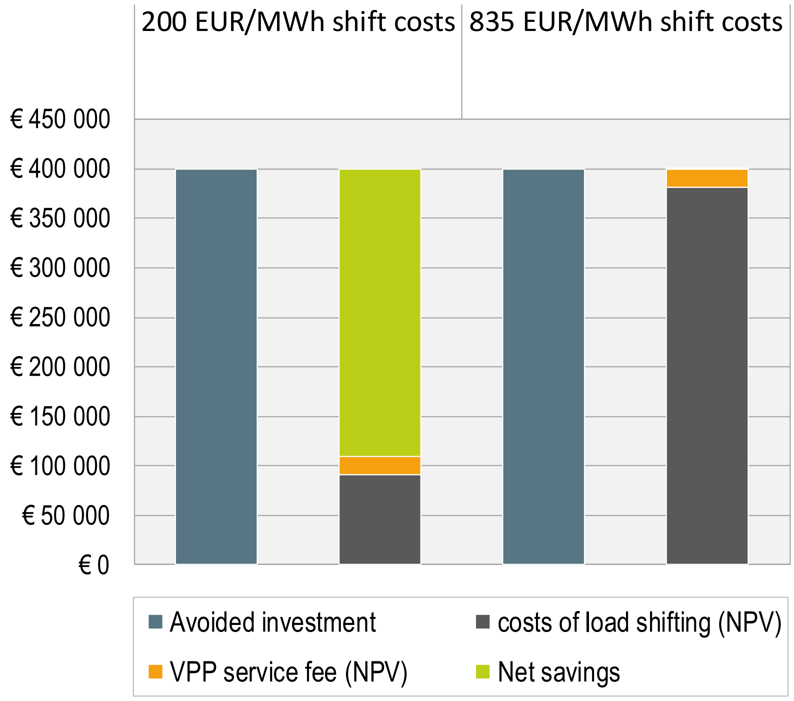

Figure 53: Cost benefit analyses: VPP to minimize grid connection cost for an industrial load of 1.5 MW, avoided cable length 5.4 km; NPV cumulated over a lifetime of 20a, depending on the internal costs of load shifting – Slovenia

3.4.4 Break-even analyses from the VPP operator's perspective

The VPP project cycle cost for this customer use case application is less expensive compared to section 3.2. Main differences are lower OPEX for the VPP system (IT operating cost and personal) as well as per client (software license), which leads to a shallower ascending of the cost curve as a function of an increasing number of flexibilities as depicted in Figure 54 for a 10-year operating period.

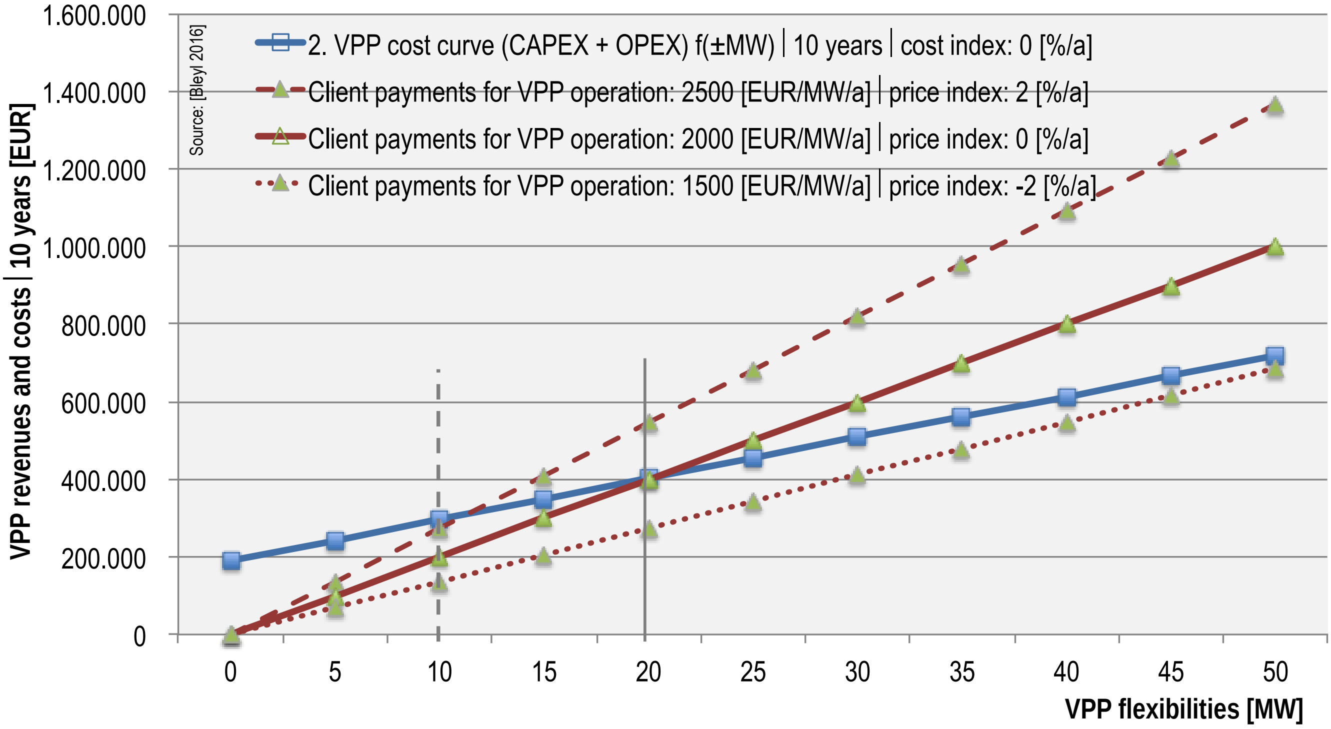

Figure 54: VPP to minimize grid connection cost: Revenues vs. cost = f(MW; Client payments); 10 years operation time

Depending on the VPP service fee ("client payments for the VPP operation"), break-even starts at 10 MW in the case of 2.500 EUR per MW connected for a ten-year operation time. At a service price of 2.000 EUR per MW, break-even is at 20 MW connected. Below 2.000 EUR/MW, the payback time increases significantly due to the small marginal differences between service price and VPP costs.

3.5 DSO use cases (3)

3.5.1 Stakeholders

Figure 69 displays the key roles and stakeholders involved for DSO-driven VPP use cases such as optimization of grid investments (3a) or VPP support during operation and maintenance or special switching states (3b). The figure also displays their relationships with regards to flows of information, flexibilities and cash.

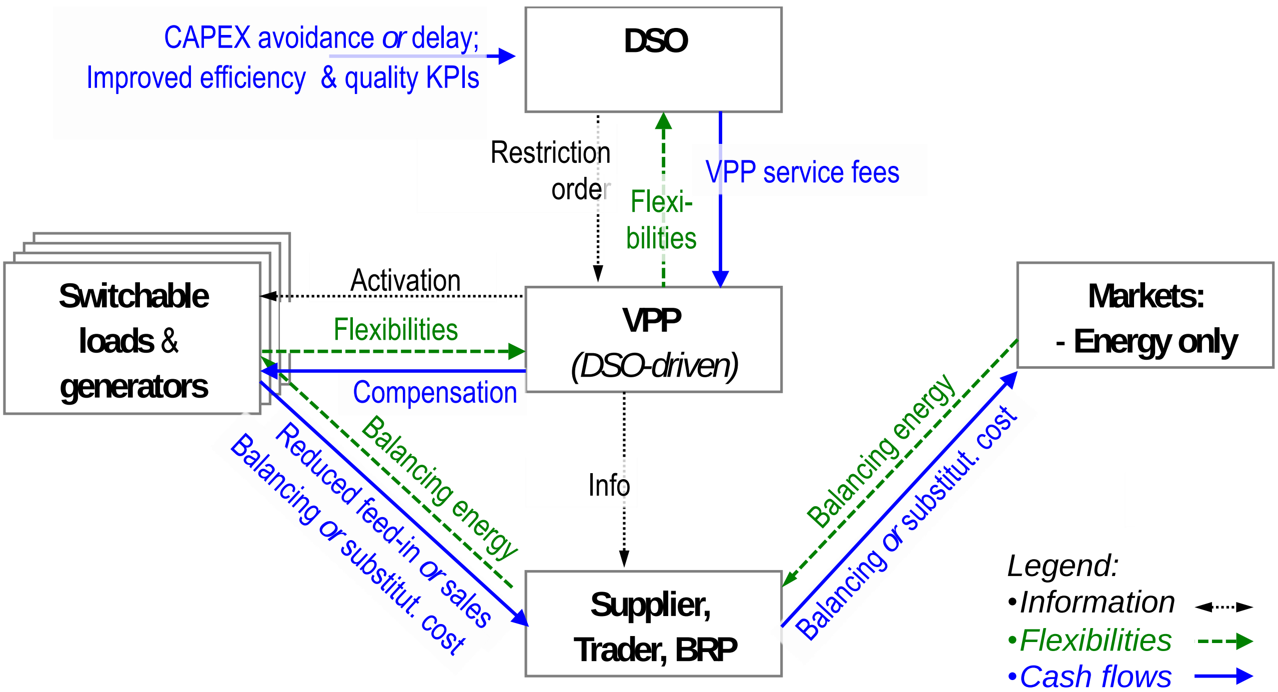

Figure 55: DSO-driven VPP: Stakeholders, information, flexibilities and cash flows

As outlined in section 2.2.3.a for the use case of optimization of grid investments (either delay or avoidance of investments), the grid-simulations showed that *"no voltage band problems occur in both Austrian grid areas until the year 2030"*. Therefore, no expansions of the grid are necessary in any of the three scenarios and this use case could not be investigated further.

3.5.2 VPP for optimization of grid investments (3a) - Slovenia

The technical analysis (see chapter 2.2.3.a) for the Siska region in Slovenia showed that grid reinforcements would be required in order to be able to supply the future demand. The required cable would have a length of 2.45 km and would cause investment costs of approximately 181 000 EUR. As an alternative to the grid reinforcements, a VPP could curtail loads during critical hours. This measure would require load curtailment or load shifting of up to 1 MW but the shifted energy would be only 183 MWh per year. Like in the customer use cases, the VPP service fee is assumed with 2000 EUR/MW/a. Even though the load shifting would only account for ca. 183 full load hours per year, it is still questionable if a VPP purely for that purpose would make sense. If a life cycle of 20 years and a discount rate of 3% is assumed, then the costs for industrial load shifting would need to stay below 54 EUR/MWh, otherwise the grid reinforcement would be the more economical alternative. Considering a real lifetime of mid-voltage cables of 50 years, the cost for load shifting would even need to be below 26 EUR/MWh that the VPP is more beneficial in comparison to the grid reinforcement.

In the given case, the main benefit of the VPP service would be its short-term availability at relatively low initial investments. The VPP service could be used to defer grid investment, or as bridging solution in case of delayed commissioning or expected future reduction of load in the area. However, it would probably not be economic to replace the technical grid reinforcement by a VPP service in the long-term.

A hybrid approach, where the industrial load would primarily be used to solve grid constraints during critical hours and participate in the balancing markets during non-critical hours would be a chance to improve the economic feasibility of the VPP solution because the effort for communication and remote control would be shared between both use cases. This hybrid approach is investigated in chapter 3.6.

3.5.3 VPP to support grid operation during maintenance and special switching states (3b) - Austria

For the use case of a VPP to support DSO grid operation during maintenance and special switching states (3b) described in section 2.2.3.b, the case study showed that the hybrid-VPP can be used to support the DSO in case of an outage. *“As a result, unregulated overvoltage tripping of distributed generation units could be reduced significantly. The VPP facilitates the curtailment of energy in a controlled manner, which is always preferable to an uncontrolled situation in the grid.”*

In the current regulatory framework, economic benefits for the DSO of the above use cases cannot be quantified. However, in the context of a potential future quality-based regulation regime, improved network efficiency will most likely be a significant indicator for quality KPIs, which in return leads to higher regulated returns on investments for the DSO. Based on the stakeholder analyses, the DSO-driven use cases have a potential for a WIN-situation for all stakeholders involved. Valuing the 13.5 MWh of curtailed energy from the DSO use case (c.f. Figure 31) at an average ‚Value of Lost Load’ of 8.1 €/kWh in Austria [8] results in approx. 109 000 EUR, valued at 11.1 €/kWh [9] results in close to 150 000 EUR. Future valuations based on an ASIDI indicator [9] will possibly lead to higher economic incentives for DSO-driven VPP applications according to first estimations. Some further details are provided in the hybrid cases in the next section.

3.6 Hybrid-VPP use cases

3.6.1 Stakeholders

As described in 2.2.4, hybrid use cases combine two or more individual VPP stakeholder functionalities. To perform these hybrid functionalities, a hybrid-VPP requires some additional tasks, flows of information, deployment of flexibilities but also respective cash flows between stakeholders in addition to the single use cases described in the previous subsections. However, the majority of tasks and roles as well as relationships between stakeholders remain similar as can be seen in Figure 56. E.g. a hybrid-VPP can support a DSO during critical grid conditions such as during maintenance and special switching states, while for the rest of the time, the flexibilities can participate in balancing markets without restrictions.

In addition to the stand-alone balancing market use cases presented in section 3.3, the DSO can place restriction orders on the VPP operation in the hybrid-VPP application as displayed in the figure below:

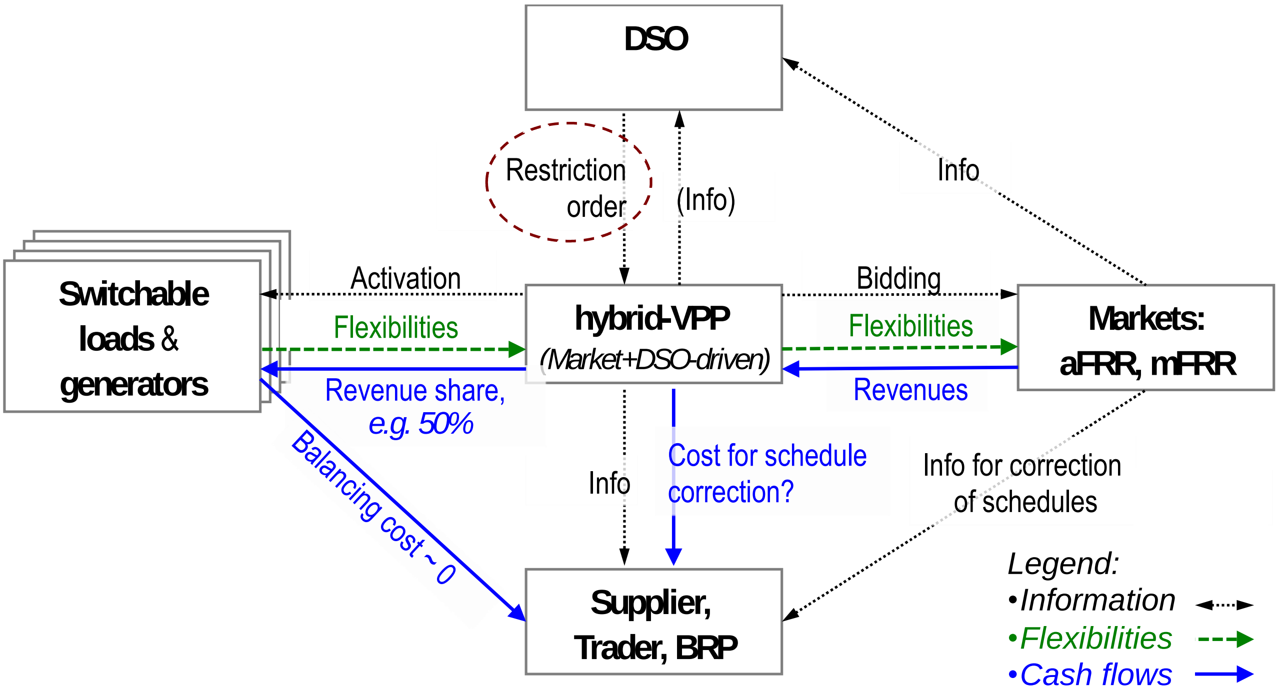

Figure 56: hybrid-VPP Stakeholders for flexibility markets with restrictions from DSO network operation

All other stakeholder roles are similar to the market-driven use case.

In another hybrid use case with VPP curtailment services provided to customers in order to reduce network access cost (c.f. section 3.4), the VPP receives additional revenues from those customers (c.f. Figure 50)

3.6.2 Break-even analyses

From an economic perspective, rather minor additional investments and operating expenditures are required for upgrading to a hybrid-VPP functionality. These are needed mainly for a connection to the DSO network operation center (NOC) and annual cost for respective IT communications. The additional costs are independent of the size of the VPP, as can be seen in the cost graph below. All other VPP costs are similar to section 3.2. However also additional revenues for the hybrid-VPP are rather limited as described in the customer and DSO use case sections 3.4 and 3.5. This will be further described in the investment analyses section below and also discussed in the conclusions section.

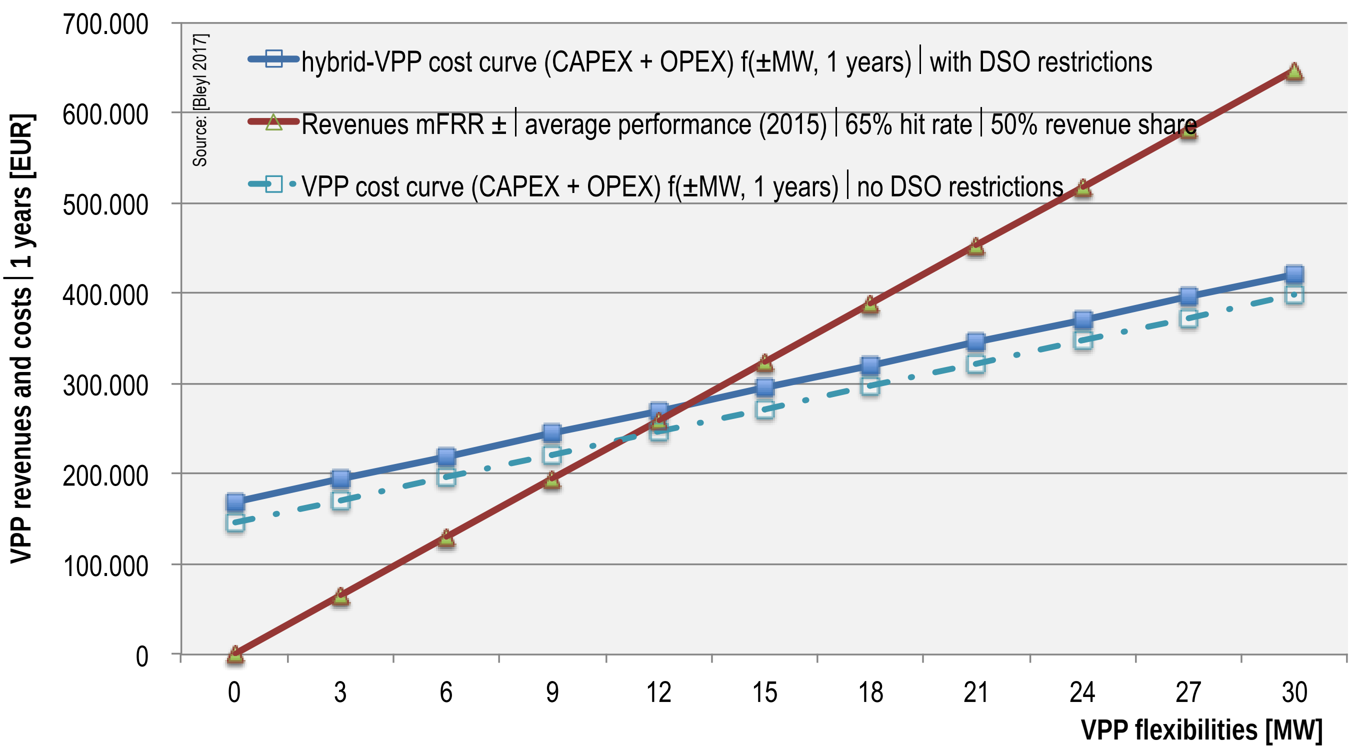

Figure 57: Comparison of break-even analyses for tertiary reserve market with and without DSO restrictions (hybrid-VPP vs. market-based VPP) for one year of operation - Austria

The additional hybrid-VPP costs to facilitate DSO restrictions amount to about EUR 20.000 CAPEX plus 3.000 EUR per year for IT communications with the DSO. With regard to the break-even point, this leads to an increase of about 2 MW to 13 MW of connected flexibilities. It is assumed that the number of DSO interventions is small and has no significant impact on the activation and revenue generation of the flexibilities on the tertiary market. All case study examples investigated in the previous chapters showed less than 270 critical full load hours per year, thus the additional unavailability (due to grid constraints) can be assessed with less than 5% of the year. As a result, the additional hybrid-VPP functionality to support

DSO operations, leads to just a slight increase in the capacity of controlled customers needed in order to break-even, which can be attributed to the rather small increase in LCC for a hybrid-VPP functionality.

In Slovenia, additional costs for an upgrade to a hybrid-VPP functionality are slightly lower (20.000 EUR investment and 1.200 EUR per year for OPEX), which has no significant influence on the results of the break-even analyses of the hybrid-VPP use cases.

3.7 Hybrid-VPP investment analyses for a market and customer use case (1b + 2a)

In this section, an investment analyses for a hybrid-VPP use case as introduced in section 2.2.4.d is presented. The use case demonstrates the combination of tertiary reserve market (use case 1b) and customer grid connection cost optimization (use case 2a).

The use case is based on a pool of flexibilities derived from customer surveys [13] and forecasts of new generators based on DSO's assumptions for long-term grid planning. The nominal flexibility of the pool of 34 units is +14.8/-26.8 MW, according to Table 2. Three additional wind parks (14 MW nominal capacity in total) were considered to require a VPP service for curtailment during critical hours in order to save investments into grid connection, as explained in 3.4.2. This pool was used in the combined grid and market simulations explained in chapter 4. The flexibility available for bidding was assessed on a weekly basis. Due to seasonal dependencies of hydropower and reservation of required backup, the calculations showed a flexibility tradeable on the Austrian weekly market for tertiary control of +(4 … 6) MW and –(2 … 15) MW. The three new customers did only show a minor influence on the tradeable capacity. According the market rules valid in 2016, wind parks can only be used in a weekly market for tertiary control in Austria if conventional backup is available, thus the windparks were mainly used as additional backup.

Planned unavailablilites, e.g. because of traffic light signals were considered in the calculation of the weekly tradeable capacity. This capacity was assumed to be completely accepted on the market. Unplanned unavailablilities do not have a reducing impact any more since the calculation algorithm reserved sufficient internal backup.

A real trader would adapt bid prices for each tender according to the results of the past tender. This process was modelled in a simplified way by the following approach: The capacity price of each week was assumed to be the average capacity price of the reference year (2015). The energy price was kept constant for the entire year, but two parallel simulation were performed to show two extreme cases. In the first case, the energy price was kept on a level, which presented a maximum revenue over the year (presuming a constant energy price over the entire year). Due to the relatively high energy price of the bid the pool was not activated by the TSO every time. This case assumes that a trader would have access to the tendering results of the entire year before placing their own bid, which is not realistic. In the second case, the energy price was chosen just low enough to perform all possible activations of the reference year. This implicated far lower revenues but the maximum impact on the grid. Both cases are summed up in Table 17. The realistic result of an average trader would be between those two cases. The initial assumption of average market performance as used in the breakeven analysis (chapter 3.3.2.a) also shows a reasonable match between those two limits derived from the detailed simulation.

Table 17: Results of the coupled grid & market simulation: annual gross revenues of a hybrid-VPP in Austria

	annual gross revenues			
Case	Capacity positive	Energy positive	Capacity negative	Energy negative
Max. revenues pos: 93 EUR/MWh neg: -15 EUR/MWh	66 190 EUR	197 371 EUR	245 658 EUR	408 223 EUR
Sum:	**917 442 EUR**			
Max. activations pos: 174 EUR/MWh neg: -365 EUR/MWh	66 190 EUR	159 270 EUR	245 658 EUR	67 016 EUR
Sum:	**538 134 EUR**			

Remark: A negative energy indicates that the TSO is paying for the energy which the provider of negative tertiary control is "consuming" from the system and the provider will have a positive revenue from providing "negative energy".

Methodically, the dynamic investment assessment is based on a Life Cycle Cost Benefit Analysis (LCCBA), from the perspectives of potential hybrid-VPP investors and financing institutions. For this purpose, the projected income and expense cash flows of the use case are modelled[7] over an entire project cycle. Economic key performance indicators (KPIs) are the internal rate of return (IRR), the net present value (NPV) and a dynamic amortization period, separately for the project (P-CF) and the equity cash flow (E-CF). On the financing side, the influence of debt financing on the remaining equity CF, as well as liquidity, is examined using the financial KPIs 'Cash Flow Available for Debt Service' (CFADS) and the 'Loan Life Coverage Ratio' (LLCR). Revenue or cost development factors are not considered.

The project cycle investment and operating cost of the hybrid-VPP are based on the cost model as described in section 3.2. CAPEX and OPEX are adapted to the hybrid functionality of the VPP as well as the number of flexibilities connected: From the investment perspective of the VPP, the total CAPEX amounts to EUR 218.000,-, OPEX are at 169.000 EUR per year. No subsidies were accounted for to avoid distorting the results. The net revenues to the VPP from mFRR were simulated in detail with 298.000 EUR/year (max. revenue case, assuming 50% revenue sharing and 65% hit rate). The hit rate of 65% is assumed to reduce the best possible result towards the performance of a real trader. The revenue

[7] with the degree of detail of a pre-feasibility study

contribution from the customer use case for the VPP service of 14 MW connected amount to just 28.000 EUR per year, which is an order of magnitude below the balancing market revenues.

The results of the LCCBA net cash flows are displayed in Figure 58.

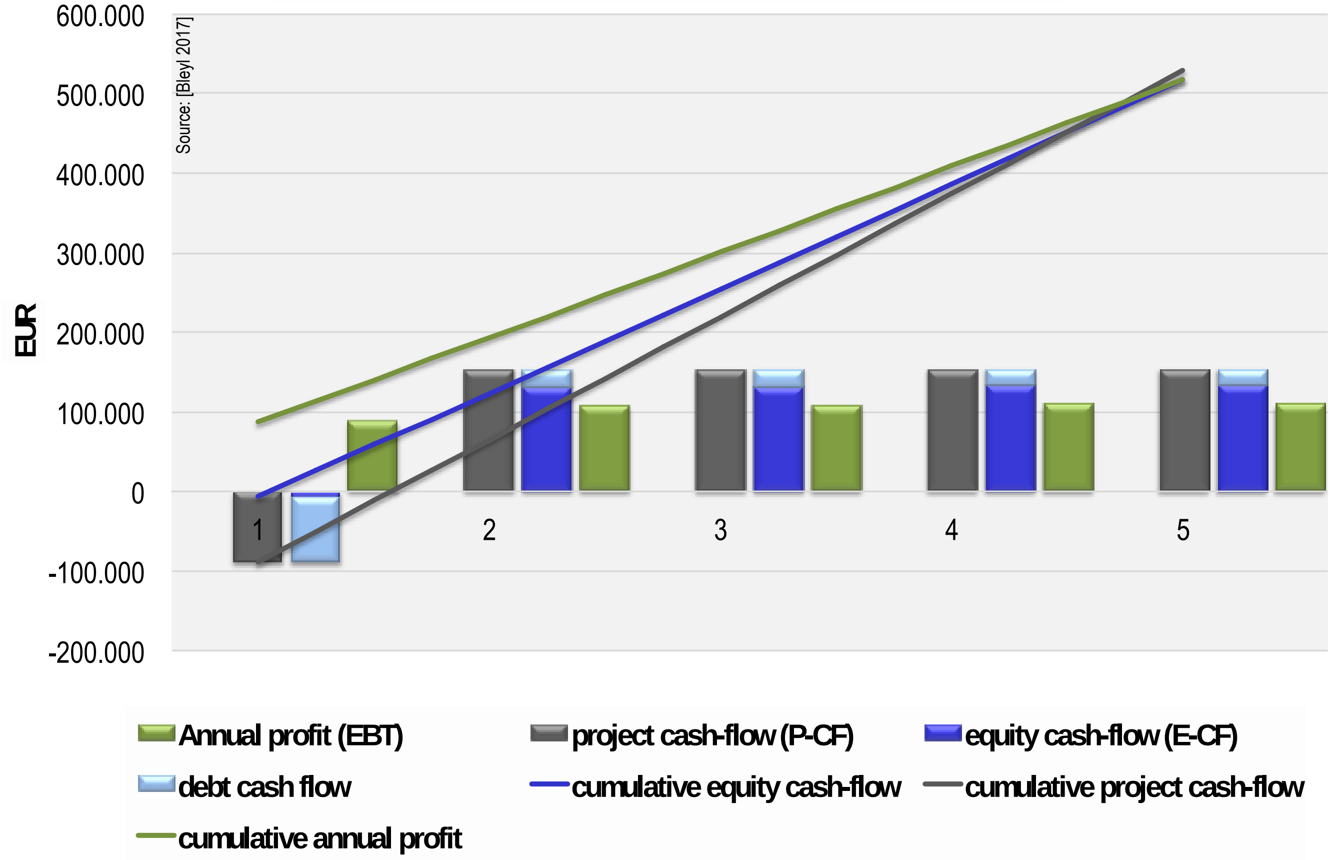

Figure 58: hybrid-VPP investment analyses: Net project and equity cash flows and annual profits – Austria

Over a five-year period, the cumulative project cash flow is positive with 529.00 EUR, whereas total revenues account for 1.561.000 EUR and expenditure for OPEX are 815.000 EUR in addition to the initial investment of 218.000 EUR. Economic KPIs of the net cash flows indicate a very high profitability of this use case: The IRR is very high at 170% (This is because of the high revenues from the balancing market, which is starting to flow in already after two months. This offsets parts of the investment. Furthermore, the payback period is short, with below 2 years.), a NPV of above 400.000 EUR, and a dynamic payback period of 1,6 years. For the equity cash flow, an even shorter payback period of 1 year and the NPV is 370.000 EUR (discounted with an assumed 15% minimum expectation on the return of the equity investment). Table 18 summarizes the key results and KPIs of the LCCBA for the project and equity cash flows.

The Slovenian VPP investment analyses reveals comparable results: The VPP case is a little bit smaller in volume (positive cumulative project cash flow of 325.000 EUR) but yields similar results of the KPIs with a payback time of just 1,3 years and an IRR of above 100% over 5 year project period.

Table 18: hybrid-VPP investment analyses: Summary of results and KPIs – Austria

		project cash-flow	equity cash-flow
project duration	years	5	
total investment	EUR	218.000	
invested equity	EUR	-	109.000
invested debt capital	EUR	-	109.000
interest rate for discounting	%	9,5% (WACC)	15% (equity interest rate)
net present value	EUR	405.797	367.009
internal rate of return (IRR)	%	169,8%	2126,8%
payback period (dynamic)	years	1,6	1,0
Loan Life Cover Ratio	-	5,7	-
		total over project duration	**annual averages**
cumulative project cash-flow	EUR	528.696	105.739
cumulative equity cash-flow	EUR	517.251	103.450
total investment	EUR	218.000	-
revenues	EUR	1.561.210	312.242
expenditure	EUR	1.043.958	208.792
earnings (EBT) (before taxes, accounting)	EUR	517.251	103.450

Financing of the investment is modelled with a mix of 50% debt capital (5 years term with an effective interest rate of 4,0% for a commercial loan) and 50% equity with a typical minimum yield expectation of 15%, which results in a Weighted Average Cost of Capital (WACC) used for discounting of 9,5%.

The analysis also includes a multi-parameter sensitivity analysis of the IRR and NPV with respect to deviations of relevant input parameters, e.g. investment costs (CAPEX), operating costs (OPEX), project duration, interest on debt capital and revenues. The sensitivity analysis in Figure 59 shows the influence of a percentage change of selected input parameters on the project NPV:

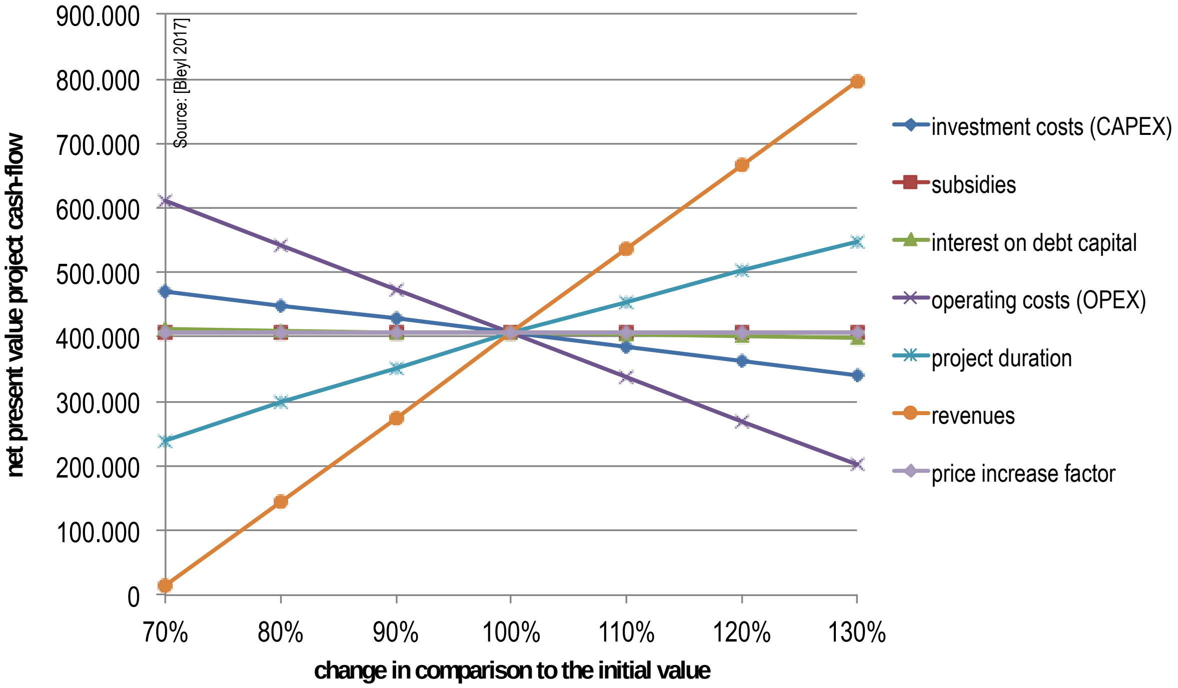

Figure 59: hybrid-VPP investment analyses: Sensitivity of NPV of project cash flow - Austria

Revenues of the VPP (which mainly stem from tertiary market participation, c.f. above) followed by operating expenditures and project duration are the most sensitive to relative changes of input parameters, whereas variations in CAPEX have a relatively small influence on the NPV. In terms of risk assessment, a revenue decrease of up to 30% would be the profitability limit (NPV = 0). In terms of economic risks, also OPEX should be assessed carefully (hybrid-VPP IT and personal operating cost as well as software licences), when preparing for the business case.

4 Development and simulation of hybrid-VPP aggregation concepts

4.1 The hybrid-VPP simulation approach

In the following a brief overview of the simulation procedure is given. The details of each step are explained in the following chapters. The simulation of the hybrid-VPP business was carried out by means of a coupled simulation of power flow in the distribution grid and simulation of the hybrid-VPP behaviour in a tertiary reserve system. The simulation was performed for an entire year with a resolution of 15 min.

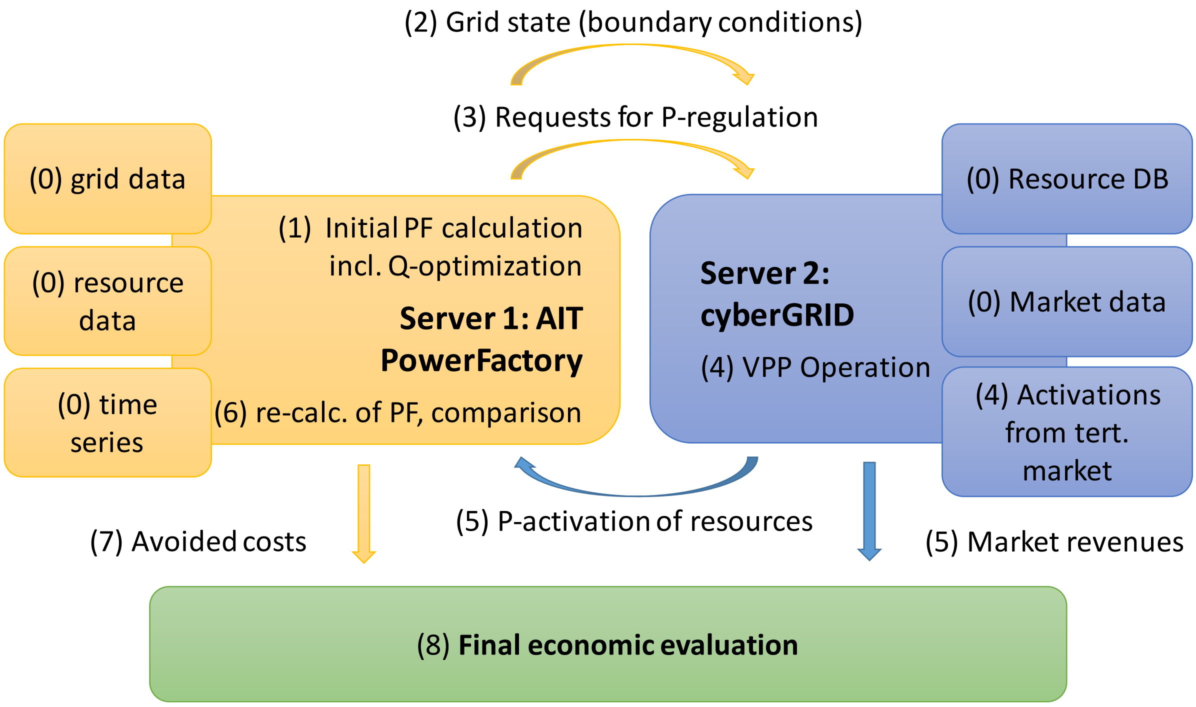

Figure 60: Overview of the simulation procedure for the hybrid-VPP grid, market and business simulation

Figure 71 shows an overview of all required steps. At the beginning, the input data was prepared; this includes data of the distribution grid, the flexible resources and their properties, financial results of the tertiary reserve market in the reference year and technical activations of the tertiary reserve system. In a first step, the operational planning of the DSO is simulated (1). Details of the power flow simulations are explained in chapter 2.1 and 2.2. The technical grid simulations identify issues for the different sections of the grid, which are communicated to the hybrid-VPP (2). The VPP operator has to accept the restrictions of the DSO. Furthermore, the DSO can order activations from the hybrid-VPP to solve grid issues (3).

In the simulation, the DSO can define 6 levels of restrictions for activation of resources in each grid section, which was symbolized by means of a traffic light system:

- full availability (green),
- only positive activation (i.e. increase of generation) allowed (yellow positive),
- only negative activation (i.e. decrease of generation) allowed (yellow negative),
- positive activation ordered by the DSO (red positive),
- negative activation ordered by DSO (red negative), and finally
- no activation allowed (e.g. during maintenance).

The levels of the traffic light system are symbolized in Figure 61. In the simulations, each connection point of a flexible unit was assigned with an individual traffic light status for each 15-min interval.

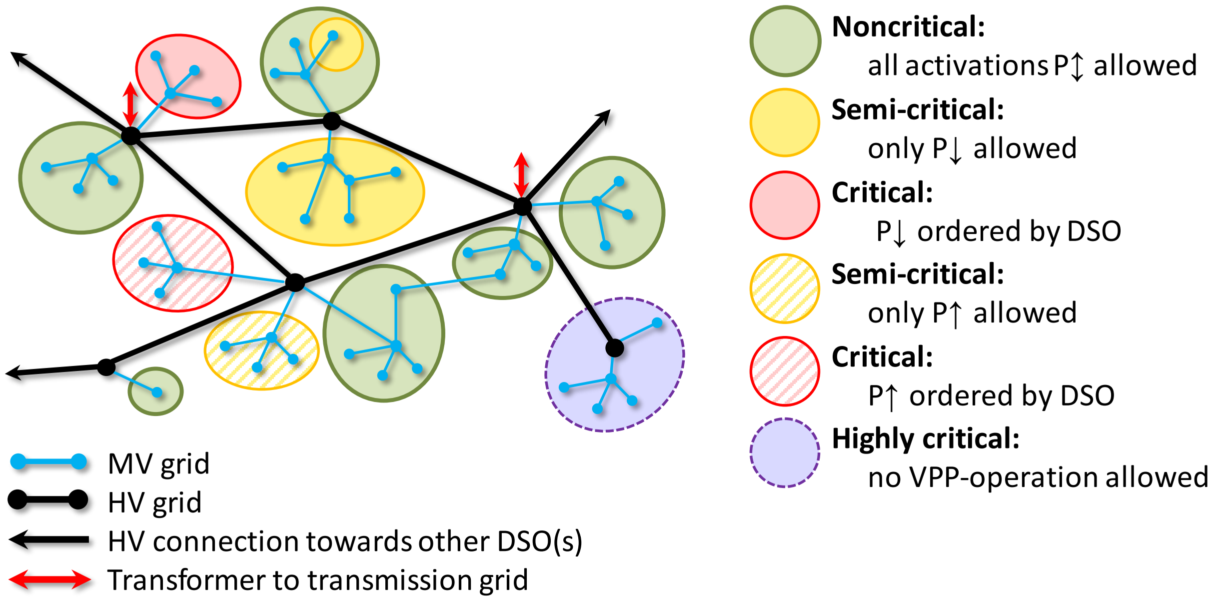

Figure 61: Schematic representation of the traffic light system for the hybrid-VPP

In the second step, the algorithms of the hybrid-VPP primarily solve or reduce the current issues in the local grid to a maximum extent using the locally available flexibilities; whilst the expected revenue from participating in the balancing market is optimized as the secondary objective (4). In the simulation of the VPP operation, the available capacity for the following week was assessed considering also the required internal backup in the pool. This available capacity is offered to the ancillary service market for tertiary reserve with capacity price and energy price. Depending on the energy price of the bids, the activation model determines for each 15 min interval of the simulated year, if and to which extent flexibility has to be activated by the hybrid-VPP. The activation orders from the TSO are sent to the hybrid-VPP simulator in each 15-min interval. The hybrid-VPP dispatches the available flexibilities to fulfil the TSO's activation order. The results of this simulation are the activation profiles of all available flexible units in the pool in intervals of 15 min for an entire year and the corresponding revenues from the tertiary reserve market for capacity reservations and provision of control energy during the year (5).

In the third step, the resulting change of the flexible unit's profiles is sent back to the grid simulation model, which evaluates the impact of the hybrid-VPP operation on the distribution network (6). Whether the grid issues could be solved or minimized is identified by comparing the old and new grid states (e.g. shown in Figure 32). Finally, the avoided grid investment costs are assessed manually and provided to the economic evaluation (7). The results of the final economic evaluation are discussed in chapters 3.3 to 3.7.

4.2 Hybrid-VPP simulation algorithms

4.2.1 Aggregation algorithms and assessment of tradeable capacity of the pools

The surveys of work package 1 [13] provided a first estimate of the number of flexible resources in each grid area. The first indicator to describe a pool of flexibilities is the number of units and sum of nominal flexible capacity of each pool, these figures are shown in Table 2.

A provider of balancing reserve must be able to fulfil the contracted capacity in each moment of the contract duration and in the worst case for the entire duration of the contract. The nominal capacity is only available in the best case and usually only for a limited duration and limited number of activations per day or week. Thus, it is required to transform the nominal capacity and limitations of activation (duration and number) into an equivalent capacity, which could be available for the entire contract duration. The contract duration is equivalent to the duration of the bids, which was assumed to be one week in Austria resp. one year in Slovenia. A simplified method to perform the transformation of capacity, which provides reasonable results for pools with at least 10 units, is to calculate the maximum energy, which each unit could provide during the contract duration. Afterwards, the equivalent capacity is calculated as the quotient of the units' maximum possible energy provision and the contract duration. This calculation was performed separately for the positive and negative flexible capacity of each unit.

$$\overline{P_{f,bid}} = \frac{\sum_{a_{max}} (P_{f,a} \times t_{a,max})}{t_{bid}}$$

$\overline{P_{f,bid}}$ .... average flexibility of a unit during duration of a bid (or contract)

a_{max} .... maximum allowed number of activations during the bid duration

$P_{f,a}$ .... available flexibility; may show daily or seasonal variations

$t_{a,max}$ ..... maximum allowed duration of activation of the unit

t_{bid} .... duration of bid (or contract)

The calculation of the maximum possible energy provision must include the seasonality of available flexibility $P_{f,a}$. In particular for switchable loads and renewable generators the seasonal behaviour of available capacity has to be taken into account. Using the known active power profiles of the reference years, the available capacities can be determined if the following technical limitations are known:

- Upper limit of control range
- Lower limit of control range
- Max. upward flexibility
- Max. downward flexibility

The calculation of the upward (positive) and downward (negative) flexibilities based on the active power time series and the technical limitations is shown in Figure 62.

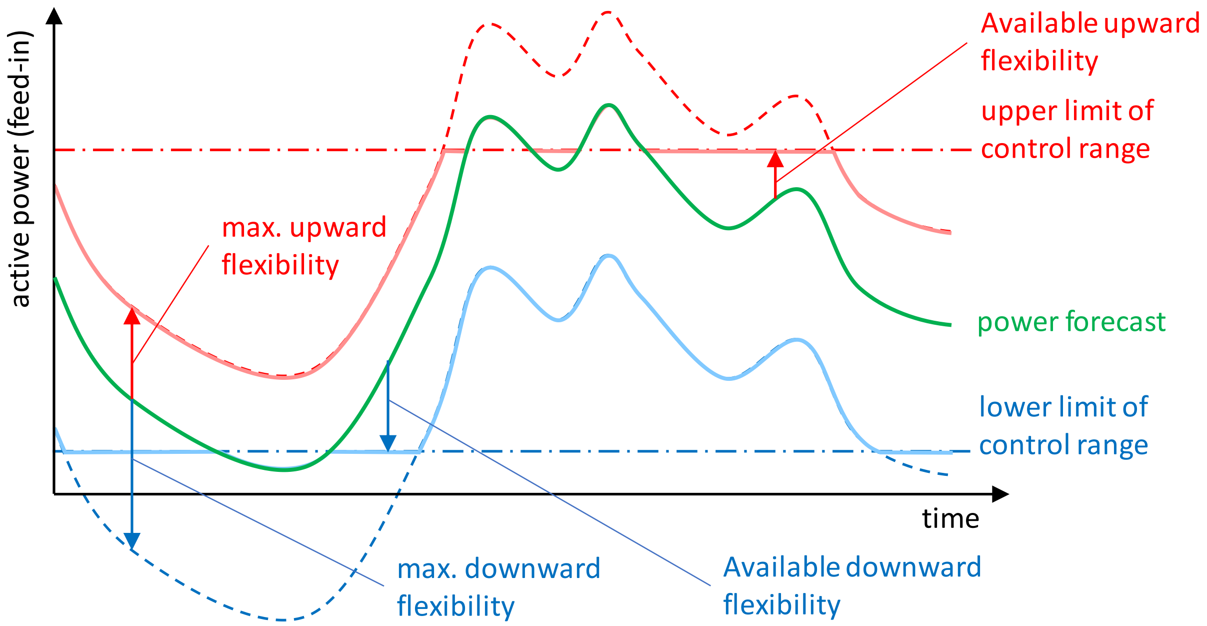

Figure 62: Impact of technical limitations of a flexible unit on the available upward and downward flexibiltiy

These calculations were performed for the entire year for each unit and each 15-min interval. In the next step, the available flexible capacity of each pool was calculated for each interval, using an n-1-1 approach. This n-1-1 means that the highest flexibilities inside and outside of the investigated grid sections were each considered as required as backup and the remaining flexibilities were summed up to the available flexibility of the pool. The pool's flexibility was rounded down to integer values, since the lowest allowed resolution of bids was 1 MW in 2016. This procedure was performed separately for upward and downward flexibility of the pool. There is no binding rule for the calculation of the required backup, the decision to keep 2 units out of a pool of 34 units for backup was taken based on the practical experience of the team.

Finally, the lowest interval value of the pool's flexibility was used to determine the tradeable capacity for each bidding period (contract period). The results for the Austrian use cases are shown in Figure 63. The increase of negative capacity during the summer months is related to run-of-river hydro power, which can only be curtailed in generation. The different use cases showed only minor impact on the tradeable capacity, because the main difference of the scenarios was the number of wind parks, which do not provide much reliably available capacity for the duration of a whole week. The impact would be far higher if the number of hydro power plants or gas turbines would differ between the scenarios. The grid use case reduced the tradeable capacity because of the known curtailment contracts, which have an impact on critical hours.

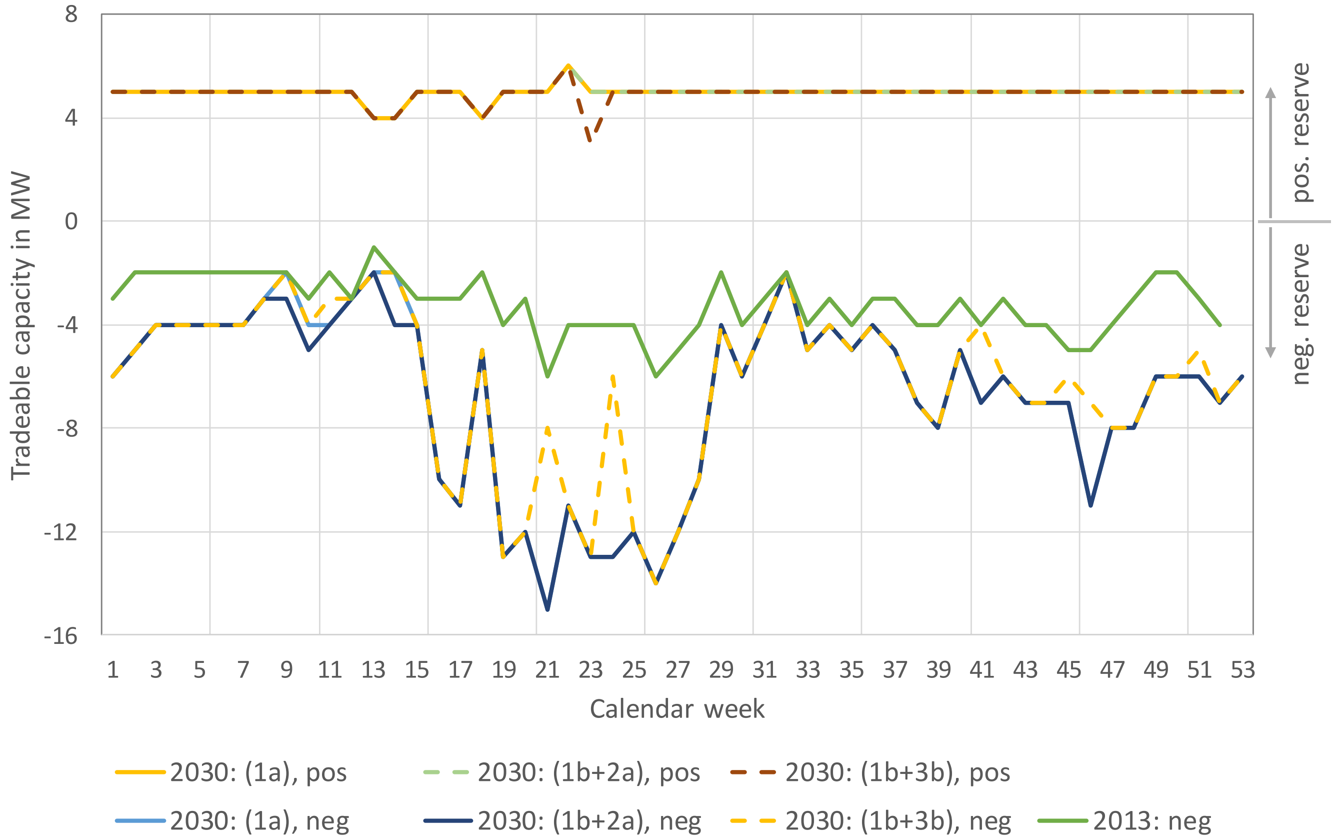

Figure 63: Comparison of simulation results of tradeable capacity in the Austrian use cases

In the Slovenian case a yearly contract was simulated, thus, the pool's lowest available positive flexibility throughout the year needed to be selected. This approach resulted in a tradeable positive capacity of 9 MW and negative capacity of 8 MW. The negative tertiary reserve system in Slovenia was not further analyzed due to the lack of available data for market tenders and activations.

4.2.2 Simulation of participation in the tertiary reserve market

The participation in the tertiary reserve market was simulated in two steps. In the first step, the bid price or contract price was determined based on the reference year. For the simulations until 2030, the reference year of 2015 was chosen, since the most recent time series for auction results and physical activations were available for that year. According to the actual market rules in Austria and Slovenia, the bid price for tertiary reserve consists of two parts: the capacity price and the energy price. The capacity price is paid to the balance supplying party (BSP) for being available for activation during the entire duration of the bid or contract. This price is also relevant for the acceptance of the bid in the pay-as-bid-auction. Bids, which exceed the marginal price of the weekly auction will not be accepted in the market and thus not receive capacity payments. The energy price is used to evaluate the physical provision of reserves. It is only paid for the energy provided by activations of physical units. The energy price is used by the TSO to establish the activation merit order of all bids. The energy price of positive capacity will usually be positive, i.e. the BSP will receive payments from the TSO. In case of negative activations, the energy price can be positive or negative. A positive energy price for negative activations would mean that the BSP would pay to the TSO for the energy consumed from the grid during the negative activation. In case of a negative energy price, the TSO will pay to the BSP to consume the excessive energy from the grid – this is the usual case in balancing markets. Bids, which were not accepted in the weekly capacity auction can be offered in a second auction to provide tertiary reserve without capacity price, only receiving the energy payments in case of activations.

In Slovenia there are only yearly contracts (see Table 11), therefore it was assumed that the hybrid-VPP would fulfil a contract with a capacity price of 38 900 EUR/MW/a and an energy price of 199 EUR/MWh. The capacity price was chosen equivalent to the lowest one in the published contracts. The assumed contract provides the highest possible number of activations in the simulation because the energy price is lower than in all other contracts and the VPP is the first position in the activation merit order. Because of the highest number of activations, this contract also provided the highest revenues from the energy payments. Any higher energy price would result in a significant decrease in the number of activations and loss of revenues, which could not be compensated by the higher energy price.

The approach for the Austrian simulation was more complex. In 2016, APG used weekly and daily auctions to procure the required amount of tertiary reserve. Capacity payments could only be achieved by participation in the weekly market. The weekly market is divided into six products for working days and six products for the weekend. Each product covers a block of 4h to be provided on each day. Since the balancing market is expected to be reorganised by APG and the unit specifications provided by the surveys did not allow a very detailed analysis, it was assumed that only one weekly product would exist, which would cover all 168 h of the week. This assumption led to a reduction of tradeable capacity and lower revenues from capacity payments and thus presents a conservative approach for the following economic analysis. The average price of each product is published by the TSO. The equivalent price for the weekly product was calculated as the average prices of all 12 products. The development of the weekly capacity prices is shown in Figure 64. It is obvious that capacity prices decrease during spring and summer, when much flexible capacity from hydropower units is available in the system. Data of market prices and activations were taken from the homepages of APG [11] and ENTSO-E [12].

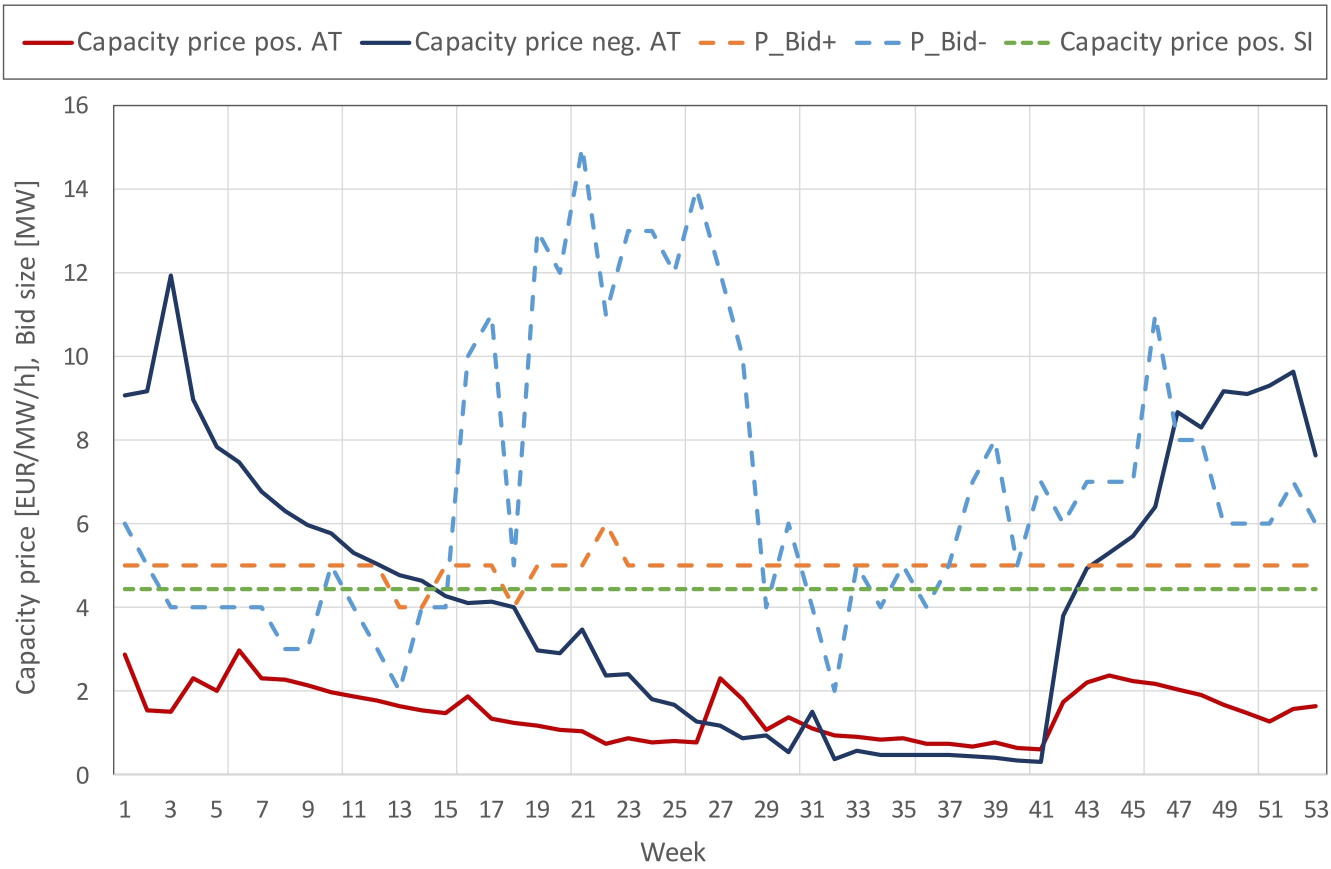

Figure 64: Weekly capacity prices in Austria and Slovenia as used in the simulations; tradeable capacity in the Austrian pool in use case (1a)

As explained in chapter 3.7 two separate cases for the energy price definition were used in Austria. In the first case, the energy price was chosen in way that the pool can participate in the maximum possible number of activations and therefore the pool will receive the lowest marginal activation energy price of all 15-min intervals, i.e. 93 EUR/MWh for positive and -15 EUR/MWh for negative reserve (example based on the data from the year 2015). This case is the worst-case scenario for the distribution grid and it was used to test the functionality of the hybrid-VPP concerning its impact on the grid. In the second case, the energy price of the bid was optimized until the maximum revenues were gained, i.e. 174 EUR/MWh for positive and -365 EUR/MWh for negative reserve. The second case was used to assess the economic performance of the hybrid-VPP. In both cases, it was assumed that the energy price of the weekly bids was kept constant during the entire year.

The simulation of the hybrid-VPP operation was performed for the entire year with a resolution of 15 min. For each interval the tertiary activations of the TSO were analysed, each time when the marginal price of the activation was higher or equal to the hybrid-VPP's energy price, the VPP participated in the activation. The hybrid-VPP internally disaggregated the activation set point according to the available units. The available capacities of the units were calculated based on the units actual feed-in or consumption and the traffic light (TL) status. Activations for the DSO in the red TL status had priority against the market activations. Usually, the disaggregation algorithm follows an internal merit order according to bilateral contracts between the VPP and the units. In order to proof the hybrid-VPP concept and cause the maximum possible grid impact, the internal merit order was adapted to give priority to units inside the investigated grid areas.

4.3 Results of simulations

The main purpose of the investigations was the proof of the hybrid-VPP and the traffic light concept by means of simulations. Thus, the most important results of the coupled simulations of power flow in the distribution grid and the hybrid-VPP system are the feedback of hybrid-VPP operation on the distribution grid. An example of the impact of the market on the unit's profile is shown in the following Figure 65, where the activations of a new windpark with 5 MW_{peak} (use case 2a) are differentiated between market and grid purpose. It was assumed that the lower limit of control range for grid related activations would be 2 MW. The hybrid-VPP can satisfy the DSO's activation order as well as the market.

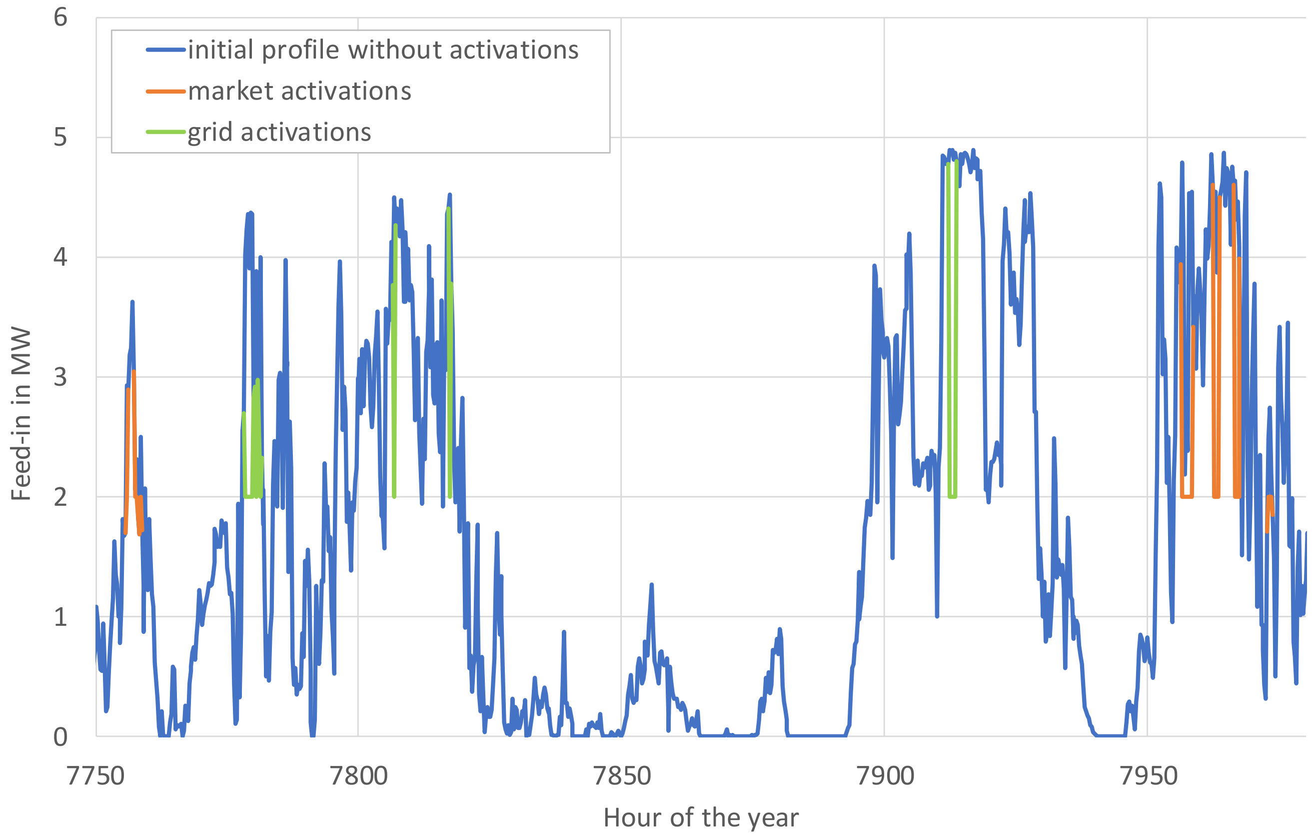

Figure 65: Simulated profile of a wind park with activations in a hybrid use case (1b)+(2a)

The simulations demonstrated the potential of a hybrid-VPP to support local distribution grid operation in parallel to active participation on a national market for tertiary reserve. The traffic light system and hybrid-VPP showed the ability to prevent violations of operative limits in all market (1) and customer (2) use cases. In the DSO use cases (3) the effectiveness of grid support mainly depends on the number and location of available resources. In the use case (3b) 6 of 9 investigated cases could be solved by the hybrid-VPP alone, while 3 cases would have required further measures by the DSO due to lack of available flexibilities.

The details of technical grid simulations can be found in chapter 2. In the following, the results of the hybrid-VPP business operation are summarized.

4.3.1 Revenues of the hybrid-VPP in Austria

After the definition of all simulation rules and the preparation of input data, as shown in the previous chapters, the simulations were performed. In this chapter, the economic results of the simulations are discussed. These results were the input for the following economic analysis, which are discussed in chapter 3.

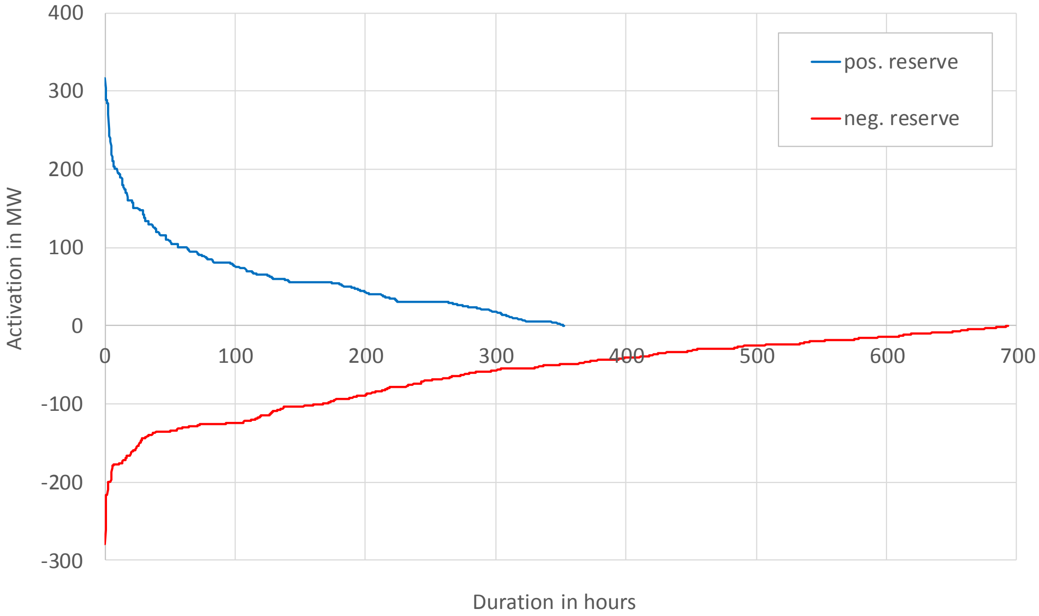

Figure 66: duration curves of tertiary reserve activation in Austria in the reference year

The negative reserve was higher in number and energy of activations as well as in the average price. This can also be seen in the revenues of the hybrid-VPP operation. The evolution of revenues of the hybrid-VPP during a simulated year is shown in Figure 67.

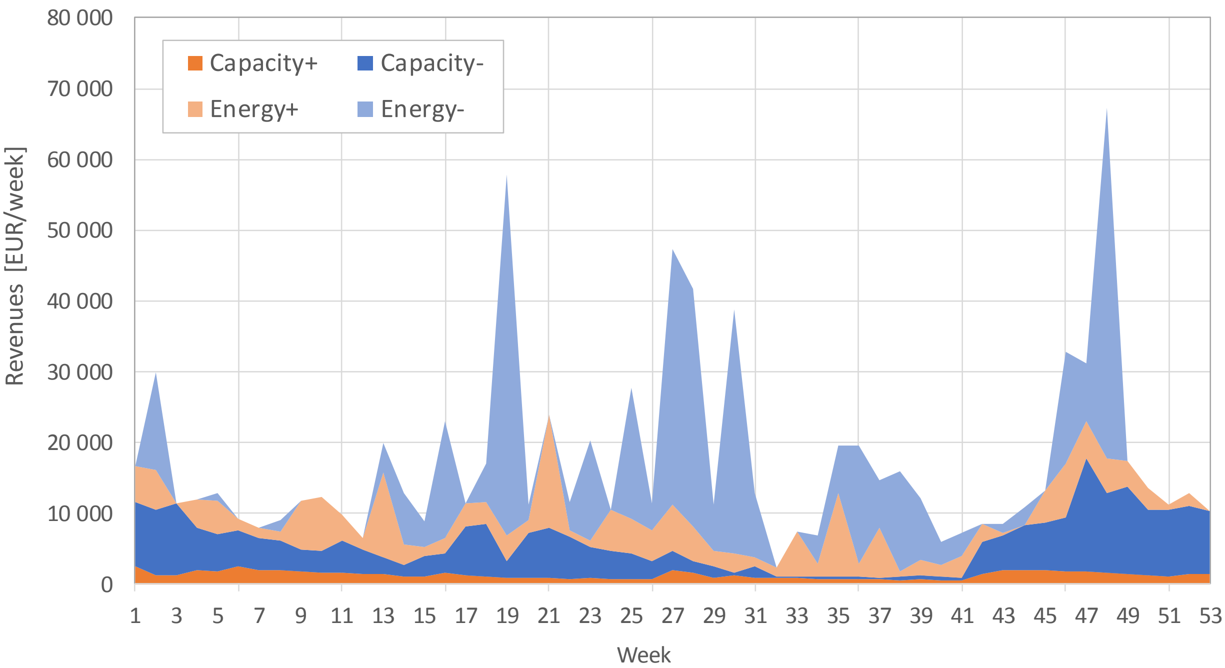

Figure 67: Simulated weekly revenues of the hybrid-VPP operation in Austria in use case (1b)+(2a).

Finally, the values for the entire year were calculated; these are summarized in Table 19. The revenues from the support of the distribution grid have only a low impact on the total gross revenues of the hybrid-VPP. In the customer supporting hybrid use case (1b)+(2a) the tradeable capacity did not increase significantly since all three new users are windfarms which cannot provide reliable capacity during an entire week. The additional service fee, which the customer is expected to pay, will further add 28 000 EUR of revenues (see chapter 3.4.2 and 3.7). The grid supporting hybrid use case (1b)+(3b) shows a slightly worse performance than the market use case. The reason is the reduction of tradeable capacity in case of grid maintenance. The additional benefits for supporting the DSO could be considerable (see chapter 3.5.3), but currently there is no supporting legal framework.

Table 19: Comparison of revenues from the simulated Austrian tertiary reserve market

	Annual gross revenues			
Case	Capacity positive	Energy positive	Capacity negative	Energy negative
(1a)	66 100 EUR	197 400 EUR	239 700 EUR	404 600 EUR
Sum:	**907 700 EUR**			
(1b)+(2a)	66 200 EUR	197 400 EUR	245 700 EUR	408 200 EUR
Sum:	**917 400 EUR**			
(1b)+(3b)	65 800 EUR	197 100 EUR	225 600 EUR	397 500 EUR
Sum:	**886 000 EUR**			

4.3.2 Revenues of the hybrid-VPP in Slovenia

The tertiary reserve market in Slovenia is less dynamic than in Austria, but also the number of activations is far lower in Slovenia. In the reference year, the total duration of tertiary activations in Slovenia did not exceed 115 h (see Figure 68), therefore the grid impact of the market operation was low.

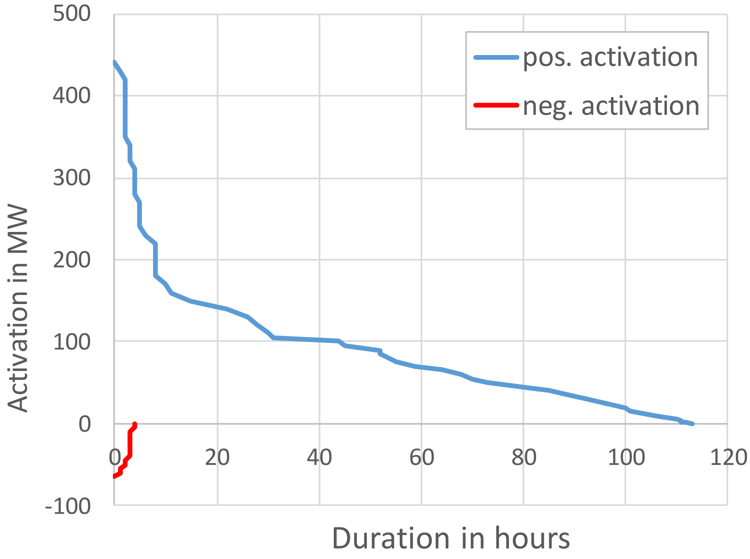

Figure 68: Duration curve of tertiary reserve activations in Slovenia (data source: ENTSO-E [12])

Furthermore, the capacity payments were significantly higher than the energy payments. Because of the strict calculation algorithms and the rule to cover the entire year with one contract (like in the real system), there was no impact of the different scenarios on the tradeable positive capacity. Minor impact was shown on the negative capacity, which was not simulated due to the lack of market data. Therefore, all use case simulations resulted in the same revenues from the tertiary reserve market.

Table 20: Revenues of the hybrid-VPP from the tertiary reserve market in Slovenia

<table>
<tr><th>Use case</th><th colspan="2">Tradeable capacity [MW]</th><th>Capacity payments [EUR]</th><th>Energy payments [EUR]</th><th>Total market revenues [EUR]</th></tr>
<tr><td>2014: (1a)</td><td>+9</td><td>-7</td><td>–</td><td>–</td><td>–</td></tr>
<tr><td>2030: (1a)</td><td>+9</td><td>-8</td><td rowspan="3">350 100</td><td rowspan="3">195 400</td><td rowspan="3">545 500</td></tr>
<tr><td>2030: (1b)+(3a)</td><td>+9</td><td>-8</td></tr>
<tr><td>2030: (1b)+(2b)+(3a)</td><td>+9</td><td>-7</td></tr>
</table>

Remarks: The 2014 use case was only evaluated in terms of the grid impact of VPP operation.
The negative reserve market was not simulated in Slovenia.

5 Conclusion

5.1 Technical results

The simulation scenarios were analysed to identify the type and location of possible grid problems. In those scenarios, no problems occurred in any of the Austrian grid areas in the regular switching state. Therefore, the hybrid-VPP could participate in the market, freely, in case of normal grid operation. However, it could still support the DSO in case of maintenance or special switching states and reduce connection costs for new customers. In the Slovenian grid areas, some voltage band problems occurred in the second grid area in 2020 and in 2030. Here, the hybrid-VPP could help to prevent or delay the necessary investments into the grid.

Another finding from the different scenarios was the strong dependence on the predominant generation technology: In the analysed Austrian grid areas, a hybrid-VPP would only be of limited use for the DSO, since here most producers are hydropower plants. Possible occurring voltage rises and over voltages are relatively constant during spring and summer, for a long period. A thus necessary long running curtailment of generation units by a virtual power plant would not be economical under the current regulatory framework. On the other hand, PV and wind power plants are more volatile and an over voltage occurs only during short peak times. Here a hybrid-VPP could support the DSO during those peak hours.

In the analysis of the spot market participation, no significant influence on the voltage in the chosen grid areas could be found. One reason for this is the small number of flexible loads, participating in the hybrid-VPP (3 in the Austrian grid areas and only 1 in the Slovenian). Furthermore, there was enough reserve in the voltage band available, especially in the second Austrian grid area. This is also the reason, why the balancing market had no negative impact on keeping the voltage limits in Austria. Here, the impact on the grid voltage was clearly visible; however, due to the sufficient reserve in the voltage band, no violations occurred. However, in one of the Slovenian grid areas, the market participation of the VPP would have had a negative impact on the grid, during critical times. Therefore, it is reasonable for a market-driven VPP to consider the current grid state.

The customer use case showed a strong dependency of the curtailed energy on the specific location of in the grid. While the size of the new customer also has a big influence on the amount of reduced energy, what is often more important is the strength of the grid on the chosen connection point. The sensitivity analysis furthermore showed the strong dependence of the amount of curtailed energy on the production technology. Another finding was the importance of having a Q(U) control as a first measurement against voltage band problems, since it can significantly reduce the amount of curtailed energy of the new customers.

In the DSO use case, the hybrid-VPP could help to reduce or eliminate voltage band violations. Moreover, the hybrid-VPP can support the DSO during special switching states. It can reduce unregulated overvoltage tripping of distributed generation units. The hybrid-VPP facilitates the curtailment of energy in a controlled manner, which is always preferable to an unregulated situation in the grid.

The hybrid use cases showed that the combined utilization of the hybrid-VPP for the market and for grid support works well from a technical point of view. It was possible to solve existing voltage band problems, prevent additional grid problems due to market participation, whilst still using the flexibilities on the balancing market during non-critical times. During the special switching states, the hybrid-VPP could help to reduce overvoltage situations, while still participating in the balancing market during the rest of the time. The hybrid combination of the customer and the market use case was technical successful as well. With the participation in the hybrid-VPP, the new generators and consumers could save costs for their grid connection and additionally make profits from participating in the balancing market. Finally, from a technical point of view, the success of the "complete" hybrid case, which combines the market, DSO and grid use case could be demonstrated as well.

To actively support the DSO during special switching and to decrease or defer investment costs, enough flexibility has to be available in the specific grid section and the correlation between the availability of the flexibility in one grid section should be low, as by this the hybrid-VPP is able to solve the problems with flexibility during all times. Furthermore, grid problems which occur over a very long period of time (e.g. seasonal) can likely not be prevented by flexibilities, only. Moreover, due to the nature of the grid problem being a local problem that has to be solved at a specific location and during all times of the year, the DSO needs long contract times with the hybrid-VPP. Currently, the regulatory trend is to decrease the contract times between flexibilities and VPP, but to enable a hybrid-VPP that actively supports the DSO (UC 3a and 3b), the VPP has to be able to bind the flexibility resources for a longer period. In case the contract duration is too short, the DSO would face a high risk to rely on the flexibility and would therefore invest in conventional infrastructure instead. However, for the real implementation, economic and regulatory aspects must be taken into account, too. To sum up, the applicability of the hybrid-VPP depends on the grid topology and the location, capacity and type of available flexibilities. These characteristics must be investigated individually. The simulations showed that a pool with units diverse in location and type of generation is recommended in order to be able to support the distribution grid operation throughout the entire year.

5.2 Economic results

From an economic perspective the following summary and conclusions can be drawn, based on the use cases analysed. For the individual uses cases, a market-based VPP can be operated economically, if at least 15-20 MW of flexible capacity can be offered to the tertiary reserve markets for a project period of 1-

2 years. For a project period of 5 years, this appears to be a very attractive investment. A stand-alone customer-driven use case would require at least 25 MW of controlled capacity over a 10-year project period. Economic benefits for the DSO use cases cannot be quantified in the current regulatory framework apart from deferral of grid development projects. However, in the context of a possible future quality-based regulation regime, improved network efficiency will most likely be a significant indicator for quality KPIs, which in return leads to higher regulated returns on investments for the DSO.

For a combination of different use cases, a hybrid-VPP can deliver a multiple task optimization for different VPP use cases as has been shown in the technical analyses in section 2.2.4. To achieve these hybrid functionalities, some additional flows of information, deployment of flexibilities but also respective cash flows are needed, however the majority of interactions between stakeholders remain similar to the single use cases. Accordingly, additional CAPEX and OPEX for an upgrade of a VPP to a hybrid-VPP functionality to support customers (network access cost reduction) or DSO services are rather small and amount to just 10-15% compared to a purely market-based VPP system. In other words, there are high synergies for a hybrid-VPP on the technical and cost side between different VPP applications.

On the revenues side, the majority of incomes for the hybrid-VPP use cases stem from participation in balancing markets. Additional revenues from either customer (use cases 2) or DSO (use case 3) services are about one order of magnitude below in the use cases analysed. As a bottom line in terms of a break-even analyses, this leads to just a slight increase of the capacity of controlled customers needed in order to pay back the investments.

From a multiple stakeholder perspective, the most promising use cases for a hybrid-VPP identified are customer-driven, where (new) grid customers can save substantial connection costs in exchange for accepting minor temporary curtailment of their loads in cases of critical network situations. Practical applications of customer-driven through hybrid-VPPs are repowering of existing wind parks, efficient grid development for renewables, and deferral of grid development for DSOs.

Based on the stakeholder analyses, a hybrid use cases with customer and DSO applications can be a WIN-situation for all stakeholders involved. From an economic perspective, hybrid-VPP applications can be integrated as add-ons into existing market-based VPPs and thus facilitate a multiple WIN situation for the key stakeholders involved. However, the rather small revenues from DSO or customer use cases do not justify stand-alone VPP systems for these purposes in the current regulatory framework.

Abstract

The hybrid-VPP concept combines a commercial operation of the VPP with technical support of distribution grid operation. The analysis of this concept showed that there are three significant types of use cases, (1) the purely market oriented VPP operation, (2) customer use cases, where the VPP provides curtailment services to new customers to avoid customer related investment into technical grid enhancement, and (3) DSO use cases, where the VPP supports the grid operation to save investment or operative costs of the DSO. These use cases can be combined to exploit synergies in VPP infrastructure and operation.

Based on the use cases identified and analysed in the hybrid-VPP project, it could be shown that the utilization of the hybrid-VPP for the market, the customer and for grid support works well from a technical point of view. The applicability of the hybrid-VPP depends on the grid topology and the location, capacity and type of available flexibilities. These characteristics must be investigated individually. The simulations showed that a pool with units diverse in location and type of generation is recommended in order to support the distribution grid operation throughout the entire year.

Additional cost for upgrading to a hybrid-VPP functionality are rather low, because of the high system synergies between different VPP functionalities. At the same time, its additional revenue generation from hybrid-VPP services for customer and DSO services is about one order of magnitude lower compared to the market-based revenues from balancing markets. In conclusion, hybrid-VPP applications can be integrated as add-ons to existing market-based VPPs, however the rather small revenues from DSO or customer use cases do not justify stand-alone VPP systems for these purposes in the current regulatory framework.

From a multiple stakeholder perspective, the most promising use cases for a hybrid-VPP identified are customer-driven, where (new) grid customers can save substantial connection costs in exchange for accepting minor temporary curtailment of their loads in cases of critical network situations. Practical applications of customer-driven through hybrid-VPPs are repowering of existing wind parks, efficient grid development for renewables, and deferral of grid development for DSOs.

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Appendix

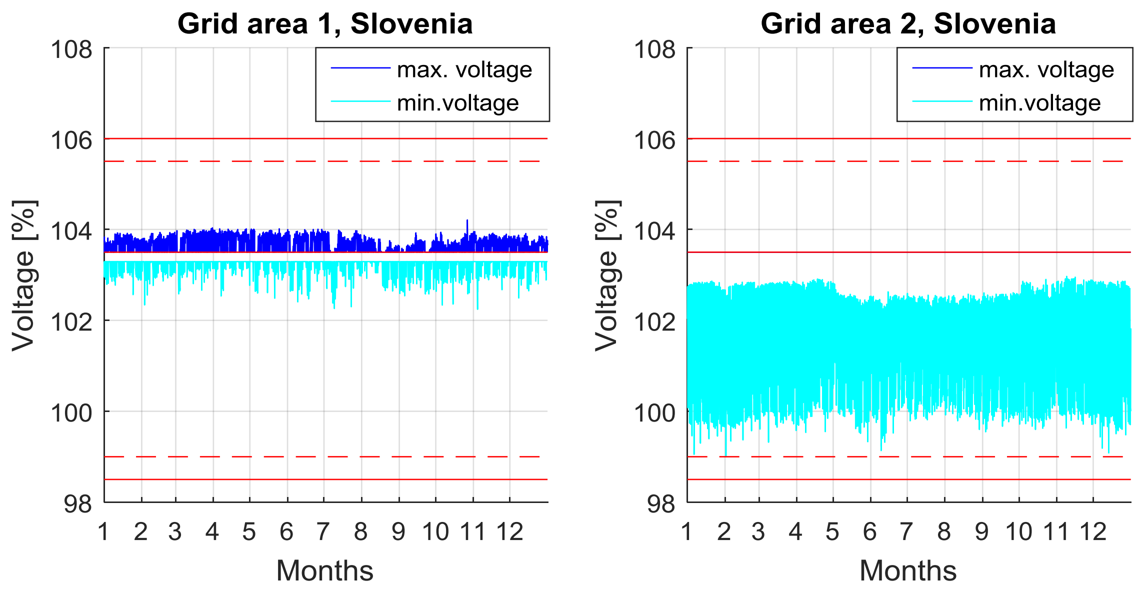

Figure 69: Minimum and maximum voltage in the two Slovenian grid areas in the base scenario, with a constant cos(φ) for all loads and generators. (The red lines show the voltage band reserved for voltage rise (top) and voltage drop (bottom), as well as the set-point (middle) and the reserve area (dashed).

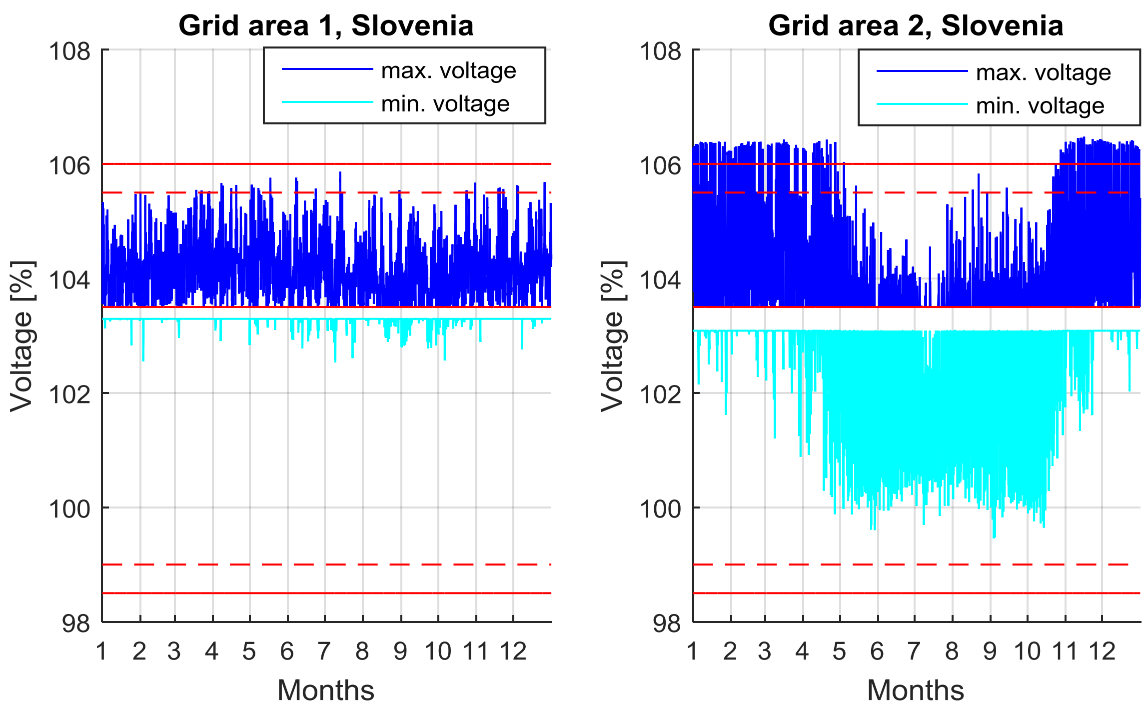

Figure 70 Minimum and maximum voltage in the two Slovenian grid areas in the future scenario 2030, without considering the reactive power of the customers.

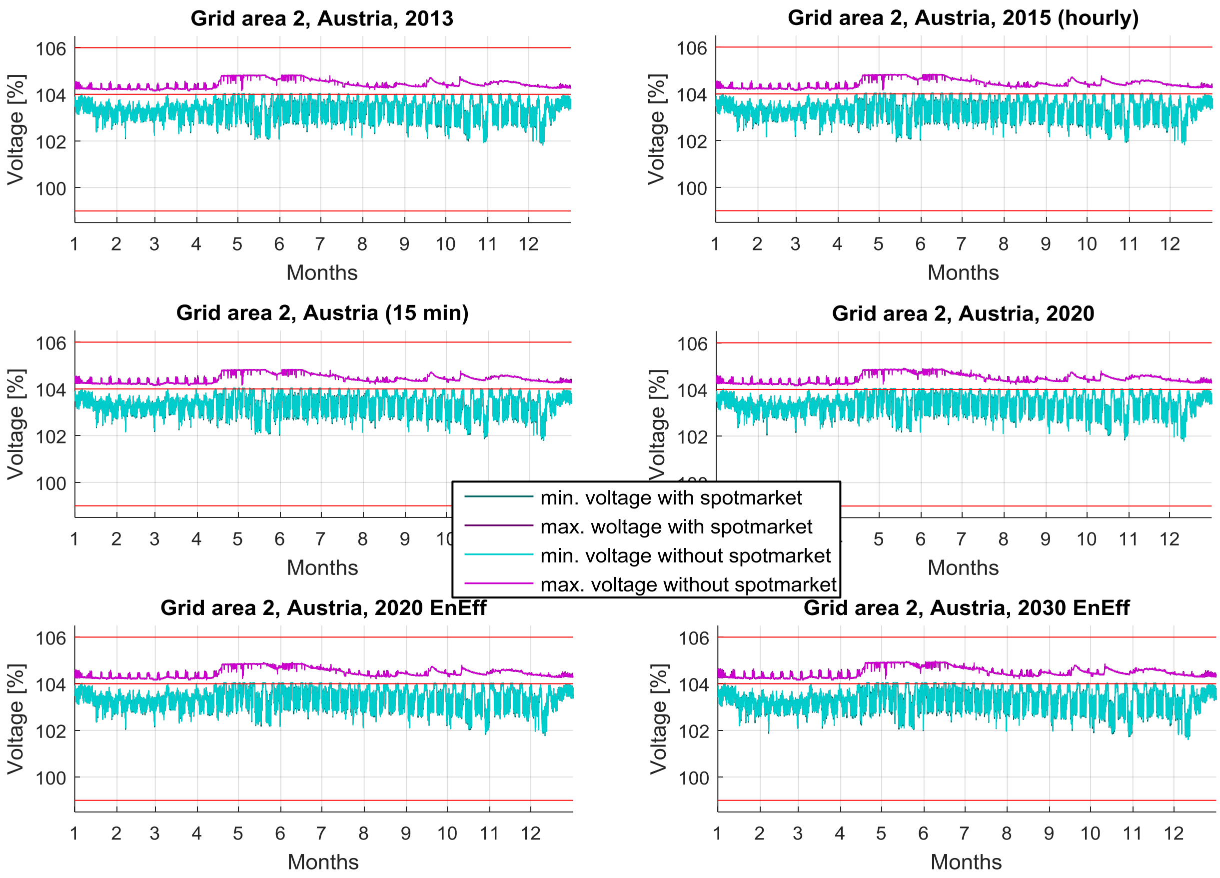

Figure 71: Participation of the hybrid-VPP on the spot market in the Austrian grid area 2; 2013 (top left); 2015 with hourly prices (top right); 2015 with quarter hourly prices (middle left); middle right: 2020; 2020, Energy Efficiency (bottom left); 2030 Energy Efficiency (bottom right).

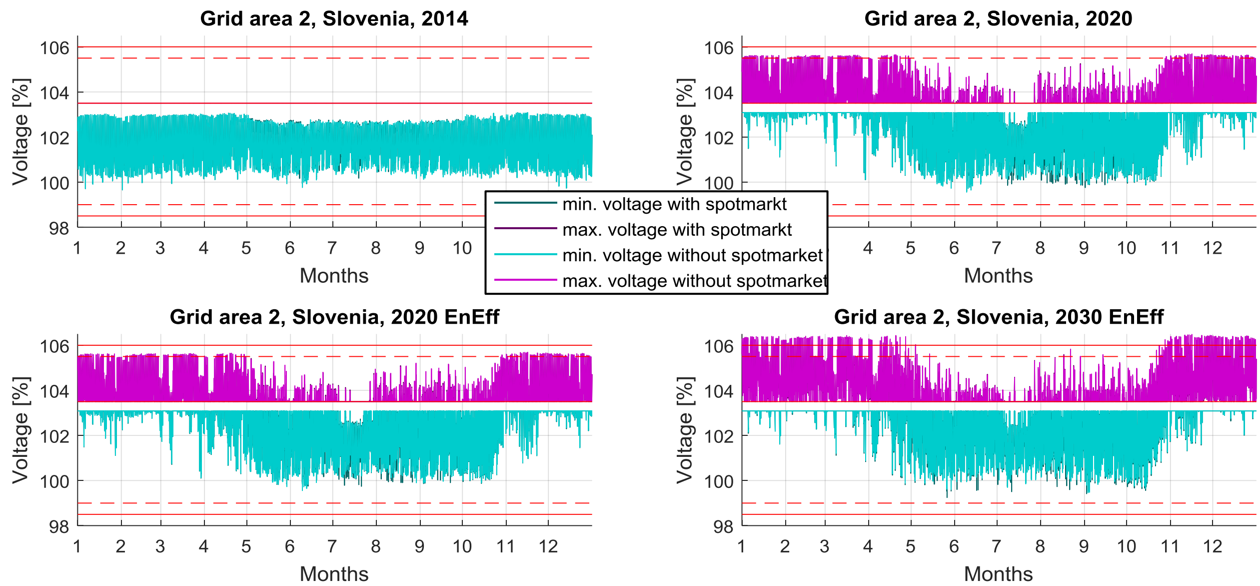

Figure 72: Participation of the hybrid-VPP on the spot market in the Slovenian grid area 2; 2014 (top left); 2020 (top right); 2020, Energy Efficiency (bottom left); 2030 Energy Efficiency (bottom right). (The reactive power of the customers was not considered in these simulations, therefore some overvoltage situations occurred.)

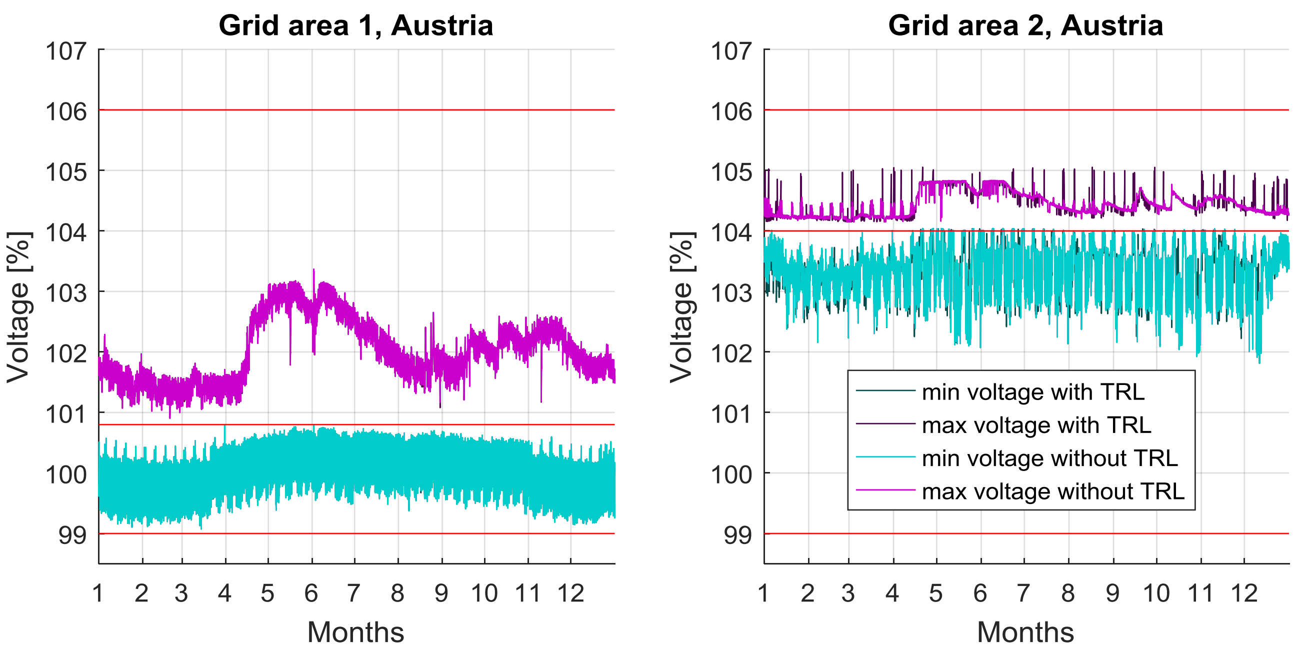

Figure 73: Change of the grid voltages with participation in the tertiary reserve market for the two Austrian grid areas in 2013

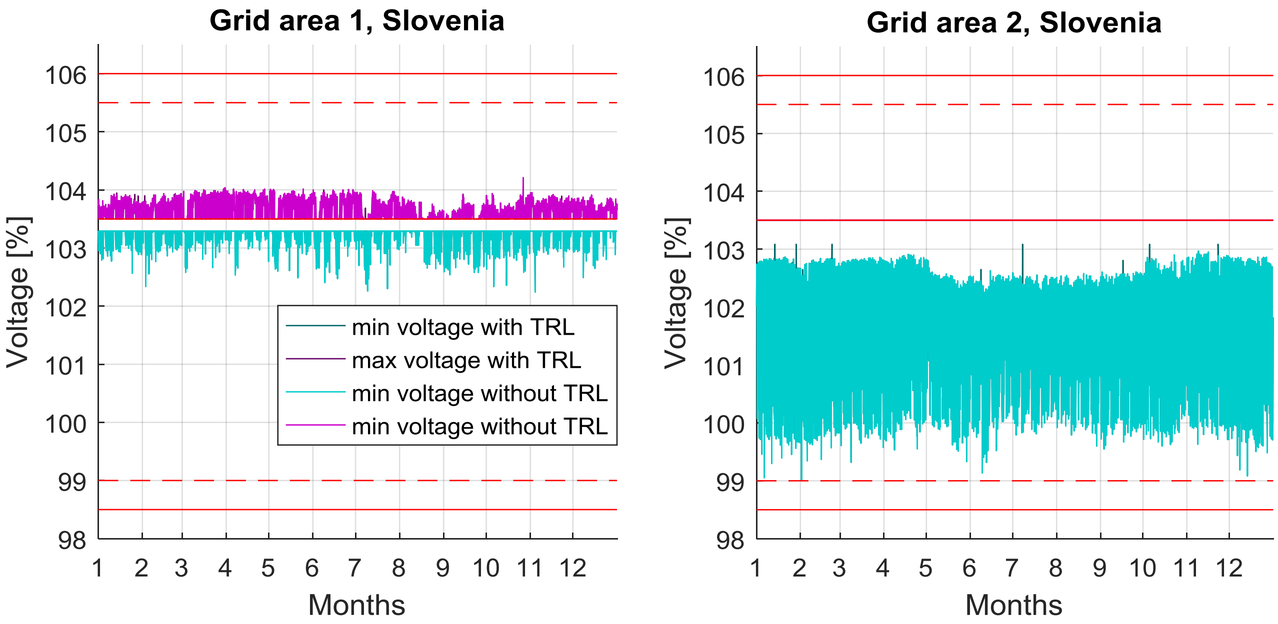

Figure 74: Change of the grid voltages with participation in the tertiary reserve market for the two Slovenian grid areas in 2014. The reactive power of the customers was taken into account in this use case.

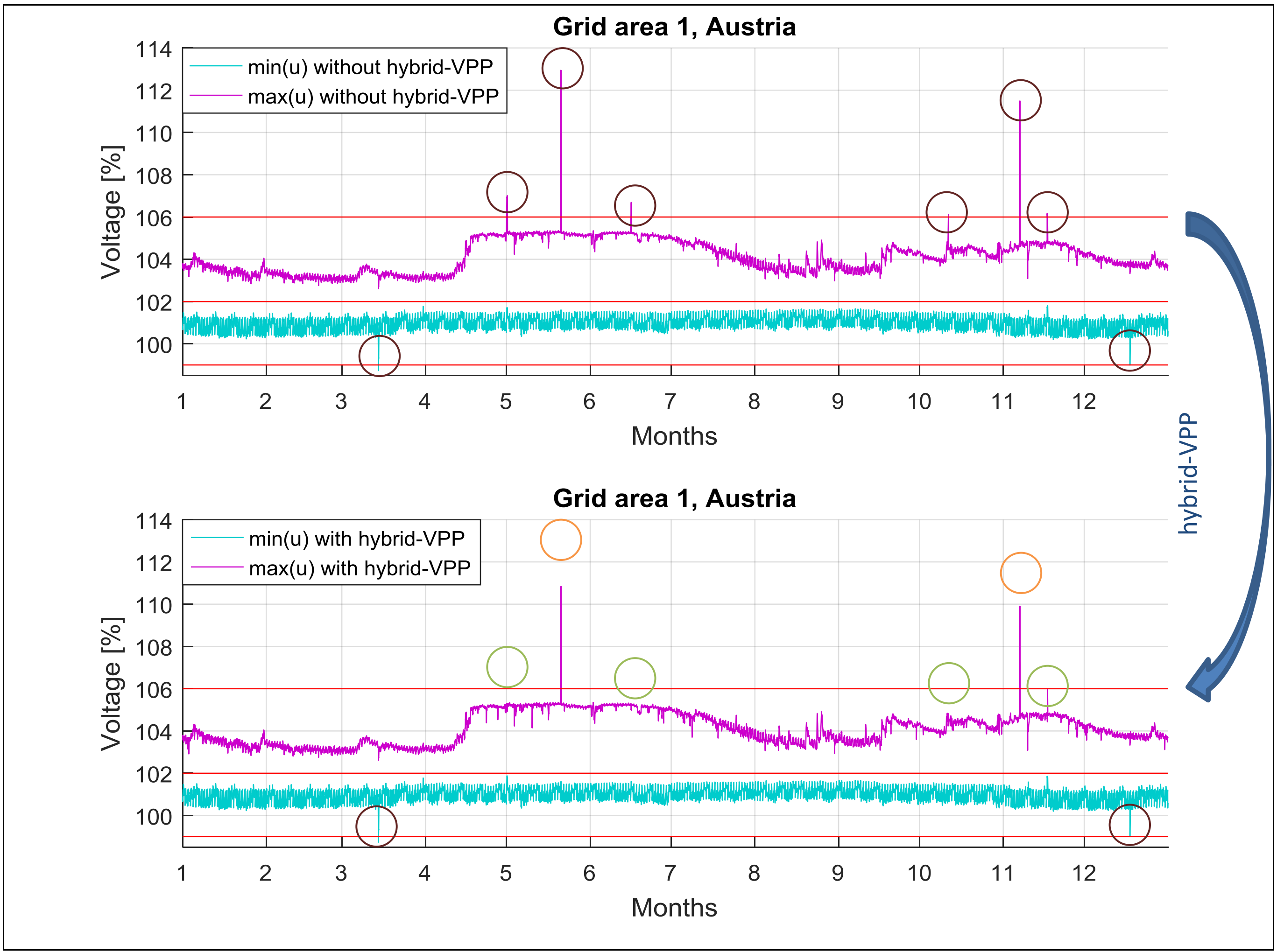

Figure 75: Results of the hybrid use case combining the participation on the tertiary reserve market and the support of the DSO during maintenance and special switching states. Simulation for the Austrian grid area 1 for 2030. The upper graphic shows the grid state with the special switching states, the lower graphic shows the same situation, but with the hybrid-VPP.

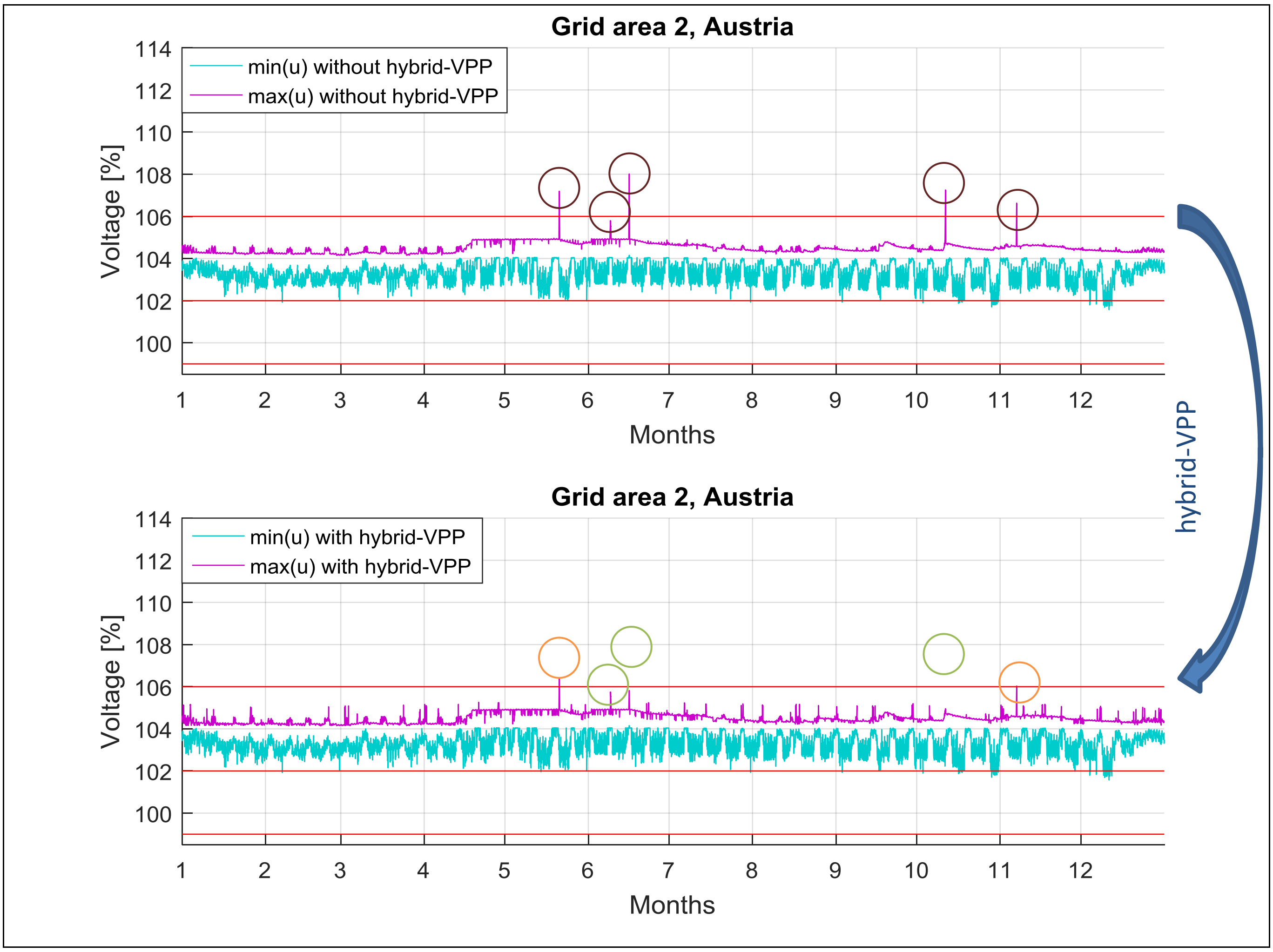

Figure 76: Results of the hybrid use case combining the participation on the tertiary reserve market and the support of the DSO during maintenance and special switching states. Simulation for the Austrian grid area 2 for 2030. The upper graphic shows the grid state with the special switching states, the lower graphic shows the same situation, but with the hybrid-VPP