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Towards positive energy districts: assessing the contribution of virtual power plants and energy communities

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***Abstract*— The concept of positive energy districts (PED) encompasses a range of policies and strategies in response to climate protection targets in urban areas. Due to the limited potential of renewable energy in urban neighborhoods, broader definitions of PED are proposed that allow for energy exchange through the grid infrastructure. This study evaluates demand side management in combination with a virtual power plant (VPP) to assess the impact on the design of PED. In particular, the optimal customer behavior in response to flexible electricity tariffs is analyzed. A techno-economic energy system model is proposed for an urban area in Germany that optimizes the customer cost and the VPP's margin. This includes electrical energy generation, storage, demand, and access to the short-term electricity market. Based on economic analysis, a dynamic market-based tariff allows the VPP to maximize profit margins. Consumers benefit when the local balances of renewable energy supply and demand are integrated into the dynamic tariff.**

***Index Terms*—Demand response, Virtual power plants, Mixed integer linear programming, Cost benefit analysis, Consumer behavior**

I. INTRODUCTION

To address the issue of load fluctuations and to provide flexibility for renewable-based energy systems, Demand Response (DR) and Virtual Power Plants (VPP) have been discussed as countermeasures. Such concepts are seen as approaches that can offer aggregation potential in the electricity system [1]. DR is used as a technology to control energy consumption, e.g., to manage grid stress and congestion. One way to achieve effective consumption using DR is by load shifting. This means that the load of certain appliances is shifted to other periods without affecting the consumer's comfort [2]. A VPP is described as virtual entity that is composed of physical devices such as Renewable Energy Sources (RES), gas turbines, energy storage, and flexible loads using advanced information technology and software systems. The VPP is set to participate in managing the power system and respective electricity markets [3]. While a VPP ensures efficient control of distributed generation facilities in particular, the concept of Positive Energy Districts (PED) aims to bundle measures and strategies for the holistic transformation to sustainability of urban areas [4]. Various PEDs have already been implemented across Europe. As defining elements of PED (1) a geographical boundary; (2) a state of interaction with an energy grid; (3) an energy supply method; and (4) a balancing period must be considered. The state of interaction with other energy grids determines the type, whether it is an autonomous, dynamic, or virtual PED [5]. For this study, the framework conditions for the establishment of a virtual PED are analyzed.

In parallel to the modeling exercise presented in this study, a platform-based technical infrastructure is developed and implemented by the municipal utility in Leipzig that illustrates the relevance of the research [6]. The main objective of the platform is to promote the interaction between energy generation, storage capacity and consumers into a virtually connected community. It sets the stage for peer-to-peer energy trading, energy communities, a citywide decentralized VPP, and connectivity to the heat and power sectors. Consequently, the platform has implemented real-time forecasting and optimization methods. To improve interaction with household customers, externally controlled "smart plugs" will be installed in various residential units during the project. This solution enables customers to actively participate in the energy market and thereby increase the share of RES in their energy consumption [6]. Moreover, the reliable integration of DR is considered as a potential business case for a successful transformation of the

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municipal energy system. Although the platform is not yet operational, this study aims to provide insights into the impact of active customers on the power system through a modelling approach, and thus, contributes to the assessment of the technical and economic potential of DR in residential building.

DR is defined “as the changes in electricity usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time” [7]. Any deliberate adjustment in end-use electricity consumption patterns that are intended to change the timing, level of demand, or overall consumption may be considered as part of DR. In addition, there are two approaches to changing consumption behavior that customers can use, namely load curtailment and load shifting [8]. Both procedures involve some inconvenience for customers, as the energy service cannot be consumed as planned. Since customer acceptance of DR programs is critical to the success of demand-side flexibility, the inconvenience to residential customers posed by DR must be reduced as much as possible. Accordingly, this study assumes that DR is provided solely by load shifting, as it has less impact on customer convenience.

DR strategies aimed at encouraging end users to participate are divided into price-based (implicit provision) and incentive-based programs (explicit provision) [7, 9]. Incentive-based programs are divided into classical and market-based programs. For the inconvenience of providing flexibility on demand, program participants receive payments. Of course, the extent of external control of the load must be specified in a contract between the two parties [7, 10]. The other main category of DR programs are the price-based plans associated with this study. In these programs, the variable (wholesale) electricity price is transferred to residential customers through fluctuating variable electricity tariffs based on the spot market prices. In contrast to the fixed time blocks in time-of-use (TOU) pricing, in dynamic pricing, the hourly tariff is fixed in the short term and reflects the spot market price, but optionally also the grid situation.

So far, few projects on positive and zero energy concepts have investigated the economic potential of residential DR in the context of PEDs [11, 12]. To fill this gap, this work aims to (1) develop a model of a virtual PED (including market players) for two timesteps; (2) evaluate the technical and economic potential of DR to facilitate the establishment of PEDs; and (3) determine the benefits for different actors in the energy system, e.g., the energy community, and the VPP. Thus, the results contribute to energy providers’ efforts to develop innovative business models based on active management of the demand side. In addition, grid operators can benefit, as the model results also include high-resolution load flows.

This study is structured as follows. Sec. II is devoted to scenario modelling, illustrating the framework of the model, and describing the model setup. Within the framework of the model, the design of the energy system is outlined, and the optimization approach explained. Sec. III presents the results for the main scenarios, followed by a comparison of the effects of a sensitivity analysis. The technical and economic results are briefly discussed in Sec. IV. Finally, Sec. V presents the conclusion.

II. Material and Methods

A key component of this study is the application of a techno-economic model to evaluate the potential of DR in combination with a virtual power plant. First, the methodology is described in detail, which includes the energy system design and the optimization approach of the modelling framework *Integrated Resource Planning and optimization* (IRPopt). The model setup embraces underlying data, scenario design, and sensitivity analysis.

IRPopt represents an integrated techno-economic mixed- integer optimization framework for assessing complex energy systems. An introduction into the mathematical and software engineering design of IRPopt is given in [13–15]. Using this optimization framework, various integrated optimization problems are solvable based on a generic objective function. An energy process graph represents the technical foundation of the framework. This approach supports a flexible configuration of sectors, processes, and interconnections. The energy flow in megawatt hours is endogenously determined at each timestep. This optimal operation policy is dependent on monetary flows which are exchanged between commercial actors. IRPopt has been applied for different case studies at different spatial levels [8, 16, 17]. The mathematical formulation of the shifting mechanism relies on the work of [18]. Thus, the model decides whether a certain amount of the load can be increased or decreased per time step. The constraints guarantee that only a maximum share of the load is shifted (load shift potential). Moreover, a load shift must be compensated for within a given period (load shift horizon).

A. Model framework

A municipal energy system is modelled with IRPopt for two moel years that represent the system development. The relevant model elements are shown in Tab. 1. For this study, the model includes generation, storage, demand, the electricity market, a VPP as layer of control, and their interconnections. In the first model year, electrical energy is generated mainly by rooftop solar power, whereas it is assumed that the VPP widely covers the municipal energy system in year 2. Consequently, the sources for the generation of electrical energy include also wind power. In the second year, the model contains a cumulative energy storage in the form of a battery system to represent a local flexibility option.

The final energy demand for electricity is split into two different groups. These customer groups exemplify the cumulative demand of different residential consumption patterns.

TABLE 1: Main elements of the model and representation in IRPopt.

Model element	Modeling concept in IRPopt
Electricity market	Exogeneous time series for the hourly spot market price.
Customer groups	Exogeneous time series for the hourly load profile and parameters for the load shift potential. The actual hourly demand is endogenously determined.
RES	Exogeneous time series for the hourly wind and PV generation.
Battery storage	The techno-economic model determines hourly energy flows for the storage and withdrawal of electricity.
Virtual power plant	Entity, which purchases electricity from the spot market or RES to serve the customer loads in a profit-maximizing way.

Lastly, the VPP is implemented as the managing unit for commencing DR actions. Therefore, the VPP is the centerpiece of information and control, and thus, responsible for the adequate management of the energy flows within the system. A graphical depiction of this energy system including the interconnections drawn is provided in Fig. 1. Depending on the scenario design, the mixed-integer problem is modelled via an objective function that maximizes the gross margin of the individual actors. Subsequently, the model optimizes in two steps, firstly for the individual customer and secondly, for the VPP.

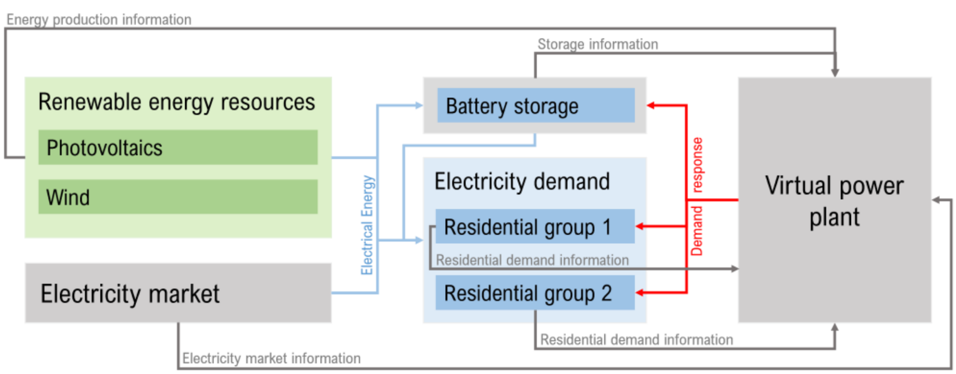

Figure 1: Main elements of the energy system model, and its interdependencies.

B. Scenario design

The DR scenarios are categorized with a distinction made between the load shift potential (LSP) and the load shift horizon (LSH). LSP is defined as percentage of the hourly electricity demand that can be shifted to another timestep within the LSH. Both parameters are averages that consider the distinct shares and characteristics of all DR-capable devices. For the “No DR” scenario the parameters LSP and LSH are set to zero. Thus, it determines the baseline for comparing the modeling results. The scenario “DR low” is characterized by noticeable resistance to the use of new technologies in the private sector. Hence, the LSP is limited. Finally, in the “DR high” scenario, behavioral changes influence larger parts of the customers, resulting in a noticeable participation in DR programs. The varying LSP and LSH for the different scenarios are presented in Tab. 2.

TABLE 2: Scenario-based assumptions of the load shift parameters.

Year	Model parameter		Residential customer group 1		Residential customer group 2	
	DR Scenario	No DR	DR low	DR high	DR low	DR high

1	Load shift potential	-	10 %	20 %	35 %	70 %
	Load shift horizon	-	1.5 h	2.5 h	1.5 h	2.5 h
2	Load shift potential	-	10 %	20 %	35 %	70 %
	Load shift horizon	-	1.5 h	2.5 h	**2.5 h**	**4 h**

In addition, the demand side is split into two customer groups. The size of the customer groups depends on the penetration level of electric heating systems in the building stock. It is projected that the share of electric heating systems is increasing from approximately 10 % in year 1 to around 40 % in year 2 [19]. In model year 1, 1,000 households are connected to the VPP, of which 900 are part of residential customer group 1 (RL1) and 100 are assigned to group 2 (RL2). While the model year 1 describes a more experimental phase, the VPP is assumed to have increased significantly in the second year of analysis. Therefore, the total number of households within the VPP amounts to 50,000 in the second step.

C. *Model data*

1) *Demand side:* Data of the demand side represent climate conditions in Germany. The group RL1 is based on a standard load profile of an average household living in an apartment building, while the second group RL2 lives in single-family homes where heating and hot water are provided by an electrical heat pump with a thermal buffer storage [20]. The load profile for RL1 is up-scaled to 2,500 kWh p.a., compared to 6,500 kWh p.a. for RL2, including a profile for the heat pump system [21].

2) *Tariff design:* Four different electricity tariffs are proposed, ranging from static to dynamic ones. Nonetheless, the simple average of all tariffs have the same value. The calculation can be taken from the Appendix. The dynamic tariffs consist of a fluctuating price component and a constant surcharge. The tariff designs is summarized in Tab. 3. Accordingly, the “Flat tariff” (FT) offers customers a fixed price for each time step in the year. The FT is derived from the yearly average spot market prices plus a fixed surcharge. The second tariff (HD) is a highly dynamic pricing scheme where the fluctuating price component reflects the electricity spot market price per time step. As a result, the electricity tariff for the customer changes hourly, based on the spot market price for that time step and the fixed margin. The tariff VPP_{TOU} is a time-of-use pricing scheme. To reflect the local PV generation, two tariff zones were recognized. The first one is the low-cost period, ranges from 8 am to 4 pm and the second one, the high-cost period, ranges from 4 pm to 8 am. The tariff VPP_{HD} is a highly dynamic pricing scheme with a fluctuating price component. However, the price variation is not directly related to the hourly changing spot market prices over the year. Instead, the electricity production of the local generation units per time step are balanced with the residential demand of both customer groups before DR is applied. These values indicate periods where demand initially exceeds the local supply or vice versa. The calculated ratios are linked to spot market prices to ensure comparability with the other tariffs. In concrete, the hourly market prices are ordered and the highest price is matched with the highest demand-supply ratio. The matching is executed for each time step according to the function *f* (see Appendix), which leads to a new market price-based time series that reflects changes in the local demand-supply ratio.

TABLE 3: Design of the electricity tariffs.

Tariff	Description
FT	Constant electricity tariff based on the yearly (simple) average spot market price and a surcharge.
HD	Dynamic tariff based on hourly spot market price and a surcharge.
VPP_{TOU}	Tariff with two price zones per day, considering local PV supply: low-cost (8am to 4pm) and high-cost period (4pm to 8am) based on zonal average of spot market price and a surcharge.
VPP_{HD}	Dynamic tariff based on hourly local demand-supply ratio related to hourly spot market price and a surcharge.

3) *Supply side:* In model year 1, the energy community can be supplied with local PV generation. The installed capacity of PV amounts to 1.5 MWp. In year 2, the energy community increased substantially, and therefore, the installed capacity of PV is raised to 50 MWp. Due to the rising electricity demand, a diversification of RES is anticipated. Hence, an installed capacity of 25 MW of wind power is available. In addition, a battery storage complements the technical configuration with a capacity of 15 MWh.

III. RESULTS

The optimization results are analyzed for the basic scenarios from a technical, economic, and ecological point of view. Finally, a sensitivity analysis is performed, and the results are evaluated.

A. Basic scenarios

1) Energy flows: At first, the impact of DR on purchases from the spot market is analyzed. The absolute change in electricity purchased and sold by the VPP compared to the FT is illustrated in Tab. A 1 (see Appendix). In year 1, the changes in purchases and sales are evenly split. In year 2, the quantities differ due to the use of the battery storage in combination with self-generation capacity. The market demand declines in both DR scenarios in year 1. For comparison, the initial purchases from the spot market total 2,034 MWh (year 1) and 113,862 MWh (year 2) while sales sums up to 730 MWh (year 1) and 13,846 MWh (year 2). When DR is implemented in year 1, the decreasing market demand reaches the lowest value with the VPP_{HD} tariff. As expected, the figures for the “DR low” scenario are noticeably lower across all tariffs. In contrast, market interactions in year 2 are increased for scenario “DR high” in combination with the HD and VPP_{HD} tariffs. In this case, the VPP optimizes the use of the battery storage given these dynamic tariffs. In contrast to the highly dynamic tariffs, the VPP_{TOU} electricity tariff led to a significant decrease in market interactions. The static structure of this tariff, with two price tiers based on own RES generation, resulted in less interaction with the spot market. Similar market dynamics are observed in a weakened form in the scenario combinations of the “DR low” scenario.

2) Key performance indicators of the local energy system: The “On-site Energy Ratio” (OER) describes the relation between the annual energy supply from local RES and the annual energy demand [22]. Accordingly, the OER is not dependent on load flexibility. Thus, it remains constant across all scenarios and tariffs. Based on the definition, the OER is calculated with 0.55 in year 1, and 0.51 for year 2. In addition to Sec. III.A.1, the Annual Mismatch Ratio (AMR) is calculated that summarizes the impact of DR on energy flows and characterizes the state of the PED [22]. The AMR represents the average amount of imported energy into the system compared to the local energy demand. It is composed of the relative mismatches per hour over the year. This highlights periods when demand exceeds the supply from RES. Smaller numbers for the AMR mean that the supply of RES is more in line with demand. In year 1, the AMR is 0.7 for the “No DR” scenario, which is slightly reduced to 0.69 with DR measures. Tab. 4 displays the AMR in year 2. All dynamic tariffs can reduce the AMR compared to the reference. Due to the lower LSP, the AMR is only slightly reduced in the “DR low” scenario. In general, the high dynamic tariffs (HD, VPP_{HD}) offer the strongest incentive to improve the AMR.

TABLE 4: Annual Mismatch Ratio (AMR) in model year 2 per unit (pu).

	No DR	**DR high**			**DR low**		
	FT	HD	VPP_{TOU}	VPP_{HD}	HD	VPP_{TOU}	VPP_{HD}
AMR [pu]	0.54	0.47	0.48	0.46	0.52	0.53	0.52

B. Economic potential of demand side management

The study focuses on the incremental impacts of DR. Therefore, it is assumed that the investment costs for the VPP generation units are the same in all scenarios. The relative change in electricity costs per customer is calculated for each customer group in Tab. A 2 (see Appendix). As expected, the highest cost reduction is achieved with the VPP_{HD} tariff. Customer group 2 can exploit the higher initial DR potential. The cost savings differ significantly between the various tariffs. Fig. A 1 (see Appendix) depicts the range of the yearly cost reduction for all DR tariffs compared to the FT per customer group. It can be derived that the potential cost savings of RL1 (up to 12 € in year 2) are noticeably smaller than for RL2 (up to 114 € in year 2). The smaller monetary outcome is related to the lower amount of shifted load of these households. This study assumes that the load shifting of the households is controlled automatically by smart systems. The associated costs of this equipment need to be covered additionally. For the utilization of the necessary smart devices, meters, and controllers, additional investment and operating costs are required. The annually fixed recurring costs for smart metering are ranging between 30 € and 90 € [23, 24].

To assess the economics of DR for the VPP, several impacts of DR tariffs must be considered, e.g.,

- revenue losses due to changes in the electricity consumption behavior of the customers, and
- profits generated by an optimization of the purchasing strategy (cost reduction).

Based on the assumptions of this study, the net effect for the VPP is negative in all scenarios. The sharpest drop in profits is recorded for the VPP_{HD} tariff with 6 % (year 1) and 9 % (year 2). From the systemic perspective, the calculated cost reduction of customers is equal to the loss in revenues for the VPP. In parallel, the VPP can improve its purchasing strategy and reduce the decrease in revenue. However, given the rational behavior of customers and the perfect foresight of the model, the overall effect for the VPP remains negative.

C. Reduction of CO_2 emissions

If the electricity sector is not fully decarbonized, a carbon footprint for the electricity delivered to the municipal energy system must be considered. DR measures can reduce carbon emissions if they result in direct consumption of local RES that would otherwise be curtailed. If the load is then shifted to hours with a higher share of self-generation, the supply on the spot market can be reduced and consequently the (local) CO_2 emissions decrease. Given the current specific emissions of the electricity mix in Germany, exemplary savings in CO_2 emissions are calculated with 8.4 t (HD) and 38.1 t (VPP_{HD}) in the "DR high" scenario in model year 1.

D. Sensitivity analysis

Additional constraints are introduced for the sensitivity analysis. First, RES curtailment is not allowed when spot prices are negative (Sensitivity 1). Then, a larger battery storage is installed in model year 2 (Sensitivity 2). Lastly, the installed RES capacity (Sensitivity 3) is increased to match the yearly residential demand, so that the OER is equal to one. The results of the sensitivity analysis are discussed in terms of import requirements to the local energy system. Fig. A 2 (see Appendix) illustrates the percentage decrease in market supply compared to the base case. The absolute values of market purchases are shown in Fig. A 3 (see Appendix). In year 1, the reduction is between 6 % and 13 %. The non-curtailment condition reduces the single effect of sensitivity 3. This is related to the already higher share of onsite generation. In year 2, the decline in market purchases reaches values between 22 % and 38 %. The higher battery capacity is mainly used to exploit the spot market volatility. In year 1, an AMR of 0.61 is observed across all four tariffs. Due to the restricted load shift horizon, the demand in the evening and night cannot be balanced with PV generation, which limits a further improvement of AMR. In contrast, mixed generation from wind and PV in year 2 can further optimize AMR, resulting in values of 0.24 with DR and 0.32 without DR.

IV. Discussion

According to the design of the modeling approach, on the supply side only the interaction of the VPP with the short-term electricity market varies between the DR scenarios. Subsequently, the model determines the impact of different electricity tariffs on market supply for customers and the VPP. Assuming simplified cost accounting, FT or HD tariffs offer the best options if the VPP's goal is to maximize profit margins. However, if the VPP seeks a higher self-sufficiency and wants to establish a PED, a VPP_{HD} based rate system is preferable. Since DR is also a flexibility option for the VPP to replace conventional power plants to serve the residual load, further economic evaluations of the additional benefits are needed. However, the available potential and deployment are limited by time availability and technical constraints, which limits competitiveness of DR compared to other flexibility options. Nevertheless, it complements and replaces them in some use cases. Thus, DR plays a central role in the design of decarbonized energy system and for the integration of renewable energies [25]. The future economic potential of DR unfolds in customer groups that operate electric heating systems and electric cars. The higher electricity consumption and the longer load shift horizon of those technologies have a positive effect on the economics, especially with dynamic tariffs. Furthermore, tariffs that are based solely on spot market prices reduce the independence of the local energy system. In contrast, the degree of energy self-sufficiency can be increased through electricity tariffs based on both the electricity demand patterns and local RES generation profiles.

V. Conclusion

In the initial model design, DR and variable tariffs lead to fewer market purchases than a fixed tariff. The structure of the tariffs HD, VPP_{TOU} and VPP_{HD} incentivized households to shift their consumption from high-cost periods to low-cost periods, especially in scenarios with VPP_{HD} tariff. Moreover, the model results for year 1 can yield a decreasing market dependence of the local power system when a non-curtailment restriction (Sensitivity 1) and a higher generation capacity (Sensitivity 3) are introduced. Through these measures, onsite RES generation and use is increased, and thus, improve the criteria for PEDs. While the HD tariff focuses exclusively on the spot market and follows its dynamics, the two VPP tariffs also consider the generation of local RES that contributes to covering additional load. Since the VPP_{HD} is a dynamic tariff, it has a higher potential for load shifting than the static VPP_{TOU} tariff. The clear trend toward market independence changes in the second model year with the introduction of battery storage. Now the FT tariff no longer had the highest market purchases across all settings. In addition, VPP_{TOU} had the fewest market interactions, due to the static structure of the tariff, which resulted in less exploitation of market price fluctuations and thus fewer market purchases. Furthermore, the increase in battery capacity (sensitivity 2) increased market interactions for dynamic tariffs compared to the reference.

Regarding the PED criteria, the model results show that the relationship between OER and AMR is reciprocal. It stands to reason that the AMR decreases when the OER increases but has not yet reached the value of one. However, increasing onsite generation to achieve OER values above one does not automatically reduce the AMR value, as the variable RES profiles limit further improvements in the AMR value. This is observed in model year 1. While the increase in onsite generation generally reduced AMR, load shifting had little impact on AMR compared to the reference scenario. This is due to the specific generation profile of PV, which is limited to the daytime, and to the non-shiftable demand in the evening and at night (household appliances with non-shiftable load). This finding changed in year 2. Although the initial OER is lower than in year 1, the average AMR is better due to the diversified generation sources from wind and PV. Based on the complementary RES profiles, the potential to meet the hourly demand increases automatically. The diversified overall generation profiles also allowed for a reduction in AMR within the various system settings. Thus, the scenario combinations with load shifting capability decreased their AMR compared to the reference scenario for all system settings, with the VPP_{HD} tariff showing the strongest improvements. This highlights the potential of DR to improve self-sufficiency and enhance PED criteria.

As part of thorough economic analysis, the impact on consumers and the VPP must be considered. Under the limited consideration of costs and revenue sources, FT produced the highest profit for the VPP. Since the VPP must purchase notably more electricity on the spot market than it could sell from local RES, net procurement costs are negative across all scenario combinations, except for sensitivity 3 with increased generation capacity, where sales and purchases balance. Nonetheless, net procurement was largely negative in this case as well, since surplus power generation must be sold also at lower market prices, while power was purchased at expensive hours. On the other hand, the dynamic electricity tariffs that induce customers to shift their loads can reduce the VPP's procurement costs. But residential customers can also reduce their electricity costs through load shifting – the optimized trading balance of the VPP cannot outweigh this loss in revenues. The avoided costs to consumers exceed the lost profits across all scenario combinations. Accordingly, the net effect is found to be positive for the DR scenarios when compared to the reference without DR.

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APPENDIX

I. Calculation of the electricity tariffs

- Flat tariff (FT)

$$FT = \sum_{t=1}^{8760} \frac{Spotprice(t)}{8760} + Margin$$

- Highly dynamic tariff (HD)

$$HD_t = Spotprice_t + Margin \quad \forall t \in \{\}$$

- Time-of-use tariff (VPP_{TOU})

$$VPP_{TOU}^{low} = \sum_{d=1}^{365} \sum_{tt=9}^{16} \frac{Spotprice_{tt}}{365 * 8} + Margin \qquad \forall tt \in \{1 \dots 24\}, d \in \{1 \dots 365\}$$

$$VPP_{TOU}^{high} = \sum_{d=1}^{365} \sum_{tt=1}^{8} \sum_{tt=17}^{24} \frac{Spotprice_{tt}}{365 * 16} + Margin \qquad \forall tt \in \{1 \dots 24\}, d \in \{1 \dots 365\}$$

- Dynamic tariff (VPP_{HD}) based on hourly local demand-supply ratio (RL)

$$RL_t = Electricity\ demand_t - PV_t - Wind_t \qquad \forall t \in \{\}$$

$$VPP_{HD_t} = f(RL_t)\ , f : RL_t \rightarrow Spotprice_t \quad \forall t \in \{1 \dots 8760\}$$

II. Model results

TABLE A 1: Model results – change in energy flows due to demand response compared to the scenario “No DR”.

	DR high			DR low		
Year 1	**HD**	**VPP_{TOU}**	**VPP_{HD}**	**HD**	**VPP_{TOU}**	**VPP_{HD}**
Change in electricity purchases [MWh]	-18.74	-53.36	-85.11	-2.60	-2.54	-23.07
Change in electricity sales [MWh]	-18.74	-53.36	-85.11	-2.60	-2.54	-23.07
Year 2	**HD**	**VPP_{TOU}**	**VPP_{HD}**	**HD**	**VPP_{TOU}**	**VPP_{HD}**
Change in electricity purchases [MWh]	2,590.19	-4,214.89	1,966.37	-69.92	-1,845.16	-614.66
Change in electricity sales [MWh]	2,606.26	-4,202.51	1,871.67	-53.84	-1,845.23	-707.63

TABLE A 2: Change in electricity costs per customer group with demand response compared to the reference scenario (“No DR”).

	DR high			DR low		
Year 1	**HD**	**VPP_{TOU}**	**VPP_{HD}**	**HD**	**VPP_{TOU}**	**VPP_{HD}**
Customer group 1	-1.77%	-0.65%	-3.15%	-0.59%	-0.17%	-1.40%
Customer group 2	-6.45%	-2.27%	-8.84%	-2.29%	-0.59%	-2.66%
Year 2	**HD**	**VPP_{TOU}**	**VPP_{HD}**	**HD**	**VPP_{TOU}**	**VPP_{HD}**
Customer group 1	-3.93%	-1.26%	-4.25%	-2.25%	-0.32%	-2.22%
Customer group 2	-14.73%	-8.77%	-15.40%	-5.00%	-2.23%	-5.45%

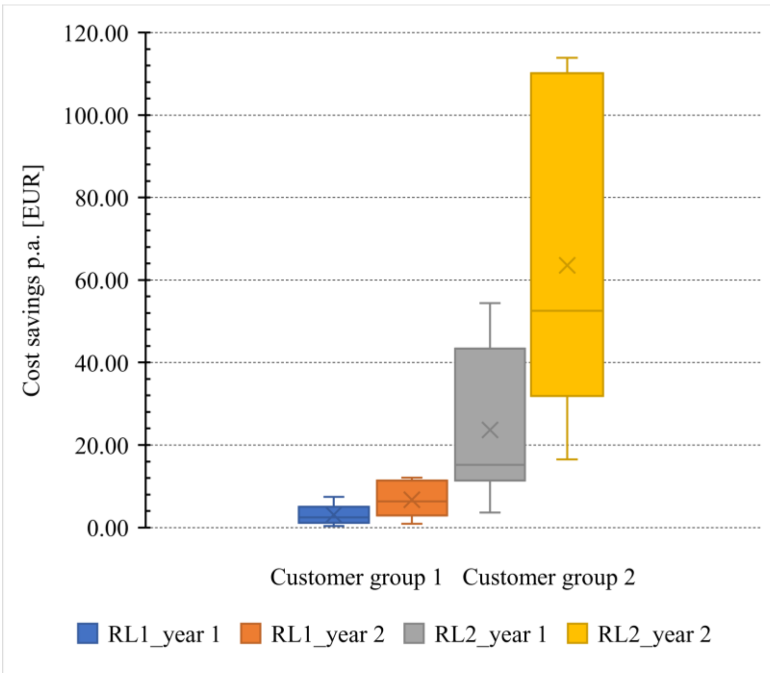
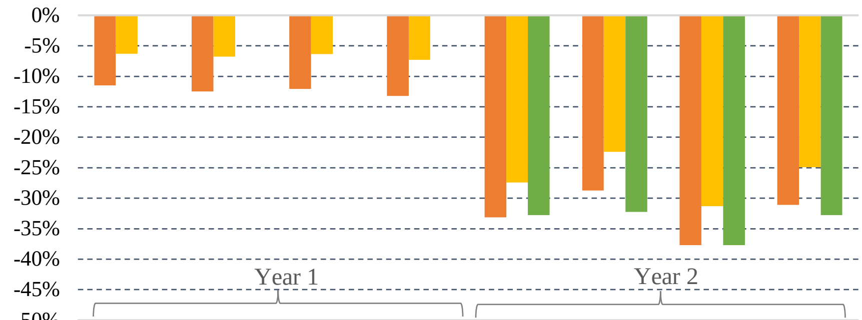


Figure A 1: Economic potential – annual cost savings per customer group and model year with demand response tariffs.



	FT	HD	VPP (TOU)	VPP (HD)	FT	HD	VPP (TOU)	VPP (HD)
Change in market supply compared to original scenario settings	-11%	-12%	-12%	-13%	-33%	-29%	-38%	-31%
Change in market supply compared to Sensitivity 1	-6%	-7%	-6%	-7%	-27%	-22%	-31%	-25%
Change in market supply compared to Sensitivity 2	0%	0%	0%	0%	-33%	-32%	-38%	-33%

Figure A 2: Sensitivity analysis – increase in RES capacity to OER=1 reduces electricity imports to the local energy system. Results are shown for scenarios “No DR” and “DR high”. The effect is weaker when combined with a non-curtailment condition (Sensitivity 1). Sensitivity 2 shows an increase in battery storage capacity in addition.

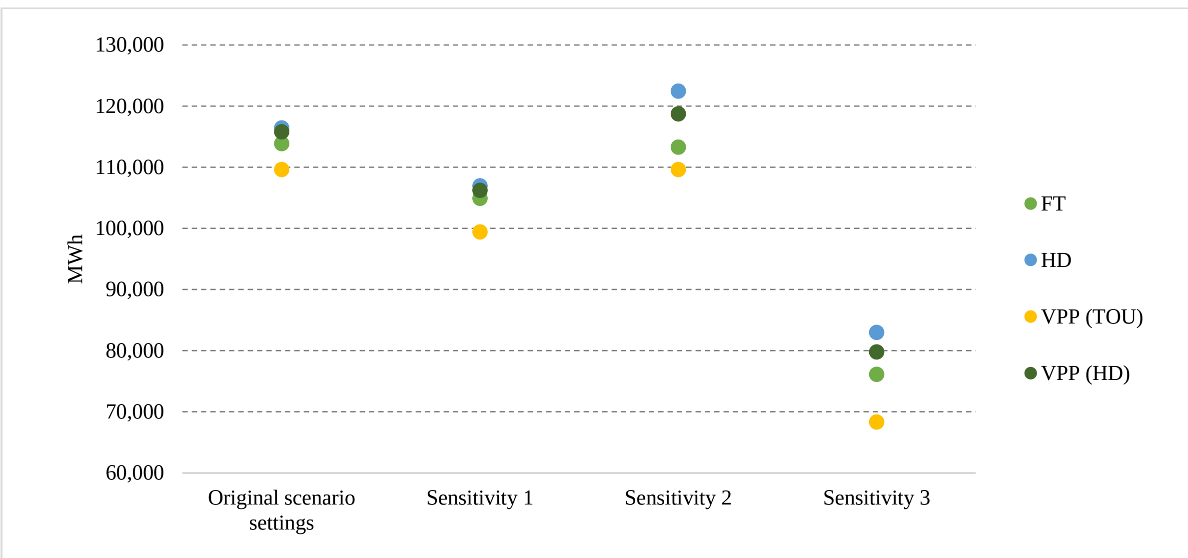


Figure A 3: Model results – total market supply for the original scenario setting, sensitivity 1 (non-curtailment condition), sensitivity 2 (increased battery storage), and sensitivity 3 (increased RES capacity and battery storage) in model year 2.