Modeling Demand Flexibility of RES-based Virtual Power Plants

Oluwaseun Oladimeji, Álvaro Ortega, Lukas Sigrist, Pedro Sánchez-Martín, Enrique Lobato, Luis Rouco
Institute for Research in Technology, Comillas Pontifical University, Madrid, Spain

***Abstract*—In this paper, an approach to evaluate the benefits of demand flexibility for Virtual Power Plants (VPPs) is presented. The flexible demands chosen in this study are part of a renewable energy source-based VPP that participates in Day-Ahead Market (DAM) and Intra-Day Market (IDM) and has dispatchable and non-dispatchable assets. A demand model with bi-level flexibility is proposed: the first level is associated with DAM, whereas the second level is related to IDM sessions. Simulations are carried out considering a 12-node network to ascertain the eventual impacts of modeling demand flexibility on VPP operation. The market structure considered in the case study resembles the different trading floors in the Spanish electricity market. Results obtained show that the proposed demand flexibility scheme increases the overall profit of the VPP, as well as the revenues of the demand owners without disrupting the consumer's comfort.**

***Index Terms*—Day Ahead Market, Flexible Load, Intra-Day Market, Renewable Energy Sources, Virtual Power Plant**

I. Introduction

Demand Side Management (DSM) for mutual benefits of consumer and the utility has been around for several decades. The definition, constituent parts and strategies for managing consumer's load have also evolved through this time [1]. These strategies have included peak clippings, valley filling, load shifting, strategic conservation, strategic load growth, and flexible load shape, among others [2], [3]. Today, popular loads that have been included in DSM studies comprise electric vehicles (EVs) and large thermal-storage air-conditioning systems. These have been chosen largely due to their possession of storage and/or inertia provision capabilities. In many studies of load management however, a main challenge with DSM models is the absence of appropriate measures of benefits for consumers that provide such flexibility actions.

In [4], two types of load, flexible and non-flexible, were presented but assigning prices to this flexibility provision was not addressed. In a study with multiple Distributed Energy resources (DERs), EVs serving as controllable electrical loads were used as a source of flexibility for load shifting. The objective here was increasing profitability of the DER assets [5]. Similar to the previous study, authors of [6] proposed the utilization of flexible loads to absorb the variable renewable generation during the day instead of simply doing load shifting from peak demand periods to times of low prices in the middle of the night. Moreover, communication systems are increasingly permeating the power system with the usage of more Internet of Things devices. Thus, an information-rich energy system with flexible and responsive electrical loads that have storage capabilities can be built to respond to variable Renewable Energy Sources (RESs) [7].

While these advancements are noteworthy, less attention has been given to load owners having full control over what value they assign to flexibility provision. This question can be coupled with seeking a solution for market participation of stochastic nondispatchable RESs. Aggregating RESs within a VPP seeks to provide a better controlled output and to make RES more competitive in electricity markets [8]. In contrast to our present work, VPPs with flexible demands and who offer prices to those demand owners for their flexibility provision have not been taken into account in previous literature. Additionally, discussions with European utilities have revealed that demands participating in VPPs have to be modeled, for electricity market participation, differently from the standard assumption of generators with negative power input.

To fill this gap, a RES-based VPP incorporating flexible demand for flexibility provision while participating in energy markets is presented. We propose a demand model with bi-level flexibility associated with different energy market sessions. The demand owner maintains high level of control over its own consumption by setting different profiles which the VPP manager can choose from in DAM at a cost. Moreover, the demand owner allows tolerances around the chosen profile at IDM at no cost. A network-constrained unit commitment model is formulated to submit VPP DAM auctions and then subsequently IDM bids to correct for deviations.

In this study, we consider that the VPP participates in the Spanish energy market. The energy market in Spain is well tailored for the studies carried out in this work and the authors have extensive knowledge of its market structure. The methodology proposed can be readily applied in other energy markets with similar structure and trading sessions.

II. VPP Modelling

This section presents the formulation of the VPP model used in this paper. The VPP comprises flexible demands (industrial, airport and residential loads), Dispatchable Renewable Energy Source (D-RES) (hydro), Non-dispatchable Renewable Energy Sources (ND-RESs) (wind power plant, solar PV) and Solar Thermal Unit (STU) with storage capability. These assets are distributed across the electrical network and connected to the main grid through one or more Points of Common Coupling (PCC). The VPP components and electrical network were presented in [8]. The business model considered for the VPP is the maximization of its aggregated profit by optimally scheduling the generation and demand assets in its portfolio.

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 883985 (POSYTYF project).

The formulation for each asset class is discussed in the remainder of this section. D-RESs are modeled like conventional power plants [9] with linearized operation costs of the dispatchable assets. Network constraints are formulated by using a DC power flow approximation [10]. D-RESs and DC power flow constraints are well-known and not discussed here due to space limitations. In addition, the STU model is adopted from [11]. The objective function of the VPP, and other constraints are presented in the following subsections.

A. Nomenclature

This subsection presents the notation and nomenclature used in this section and in Section III.

Indexes and Sets

$b \in \mathcal{B}/\mathcal{B}^m$	Network Buses / Network buses Connected to Main Grid	
$c \in \mathcal{C}/\mathcal{C}_b$	D-RES / D-RES connected to bus b	
$d \in \mathcal{D}/\mathcal{D}_b$	Demand / Demand connected to bus b	
$k \in \mathcal{K}$	IDM sessions	
$\ell \in \mathcal{L}$	Network lines	
$p \in \mathcal{P}$	Demand profiles	
$r \in \mathcal{R}/\mathcal{R}_b$	ND-RES / ND-RES connected to bus b	
$t \in \mathcal{T}$	Time periods	
$\theta \in \Theta/\Theta_b$	STU / STU connected to bus b	

Parameters

C_c^0/C_c^1	Shut-down/start-up cost of D-RESs	[€]
C_c^{V}	Variable production cost of D-RESs	[€/MWh]
$C_{d,p}$	Cost of load profile p of demand	[€]
$\underline{E}_d$	Min energy consumption of demand d throughout the planning horizon	[MWh]
$\underline{P}_{d,t}/\bar{P}_{d,t}$	Lower/upper bound variations of the power consumption of demand d in time t	[%]
$\underline{P}_{r,t}$	Min production of ND-RES in time t	[MW]
$P_{d,p,t}$	Max hourly consumption of profile p of demand d	[MW]
$\check{P}_{r,t}$	Available production of ND-RES in time t	[MW]
$\bar{P}_b^m$	Maximum power that can be traded with the main grid at bus b	[MW]
$\underline{R}_d/\bar{R}_d$	Down/up ramping limit of demand d	[MW/h]
Δt	Duration of time periods	[h, min]
λ_t^{DA}	DAM price in time t	[€/MWh]
$\lambda_{k,t}^{\mathrm{ID}}$	Price of IDM session k in time t	[€/MWh]

Variables

$p_t^{\mathrm{DA}}/p_{k,t}^{\mathrm{ID}}$	Total power traded in the DAM/IDM in time t	[MW]
$p_{\ell,t}$	Power flow through network of line ℓ in time t	[MW]
$p_{\theta,t}$	Electrical power generation of STU in time t	[MW]
$p_{b,t}^m$	Power scheduled to be bought from/sold to the DAM and IDM markets at bus b in time t	[MW]
$p_{c,t}$	Power generation of D-RESs in time t	[MW]
$p_{d,t}$	Power consumption of demand in time t	[MW]
$p_{r,t}$	Power generation of ND-RES in time t	[MW]
$u_{d,p}$	Binary variable to select demand profile	[0/1]

B. Profit Maximization Objective

Due to small volumes and low liquidity of energy traded in the IDM relative to DAM and modest price differences between these markets in the Spanish system [12], the objective functions in DAM and IDM are decoupled in this work. Each IDM further has associated constraints to cater for updates or changes in forecasts of stochastic sources. In DAM, the objective function (1) is the maximization of the obtainable profit by the VPP assets calculated as the revenue from power trades minus cost of operating D-RES and cost of selecting a particular load profile. $c_{c,t}^0$ and $c_{c,t}^1$ in (1) are auxiliary variables used to dynamize shut-down and start-up costs, C_c^0 and C_c^1, of D-RES c in time period t. Operation cost of ND-RES are not considered in the objective function due to their relative low value when compared to costs of dispatchable sources. For different IDM sessions, the benefit (2) is calculated over changes in traded power $\Delta p_{k,c,t}$ between: (i) DAM and first IDM trading period and (ii) other subsequent IDM sessions. Cost of choosing a specific load profile is not included while computing objective of IDM because this choice is made during DAM participation and must be accounted for only once.

$$\max_{\Xi^{\mathrm{DAM}}} \sum_{t \in \mathcal{T}} \left[\lambda_t^{\mathrm{DA}} p_t^{\mathrm{DA}} \Delta t - \sum_{c \in \mathcal{C}} \left(C_c^{\mathrm{V}} p_{c,t} \Delta t + c_{c,t}^0 + c_{c,t}^1 \right) \right] - \sum_{d \in \mathcal{D}} \sum_{p \in \mathcal{P}} C_{d,p} u_{d,p} \tag{1}$$

$$\max_{\Xi_k^{\mathrm{IDM}}} \sum_{t=\tau_k}^{|\mathcal{T}|} \left[\lambda_{k,t}^{\mathrm{ID}} p_{k,t}^{\mathrm{ID}} \Delta t - \sum_{c \in \mathcal{C}} \left(C_c^{\mathrm{V}} \Delta p_{k,c,t} \Delta t + c_{k,c,t}^0 + c_{k,c,t}^1 \right) \right], \quad \forall k \in \mathcal{K} \tag{2}$$

C. Energy Balance

Energy balance constraints common to both market stages are modeled in (3) whereas those specific to DAM and IDM are formulated in (4) and (5) respectively. Equation (3a) gives energy balance at the PCC with the main grid, while (3b) is the balance for all other buses in the VPP network at every time period [13]. The difference between both equations is presence of $p_{b,t}^m$ at the main grid representing scheduled power to be traded with other market participants. This power available for trading (buy or sell) is set within prespecified bounds in (3c).

$$\sum_{c \in \mathcal{C}_b} p_{c,t} + \sum_{r \in \mathcal{R}_b} p_{r,t} + \sum_{\theta \in \Theta_b} p_{\theta,t} - \sum_{\ell | i(\ell)=b} p_{\ell,t} + \sum_{\ell | j(\ell)=b} p_{\ell,t} = p_{b,t}^m + \sum_{d \in \mathcal{D}_b} p_{d,t} , \quad \forall b \in \mathcal{B}^m, \forall t \in \mathcal{T} \tag{3a}$$

$$\sum_{c \in \mathcal{C}_b} p_{c,t} + \sum_{r \in \mathcal{R}_b} p_{r,t} + \sum_{\theta \in \Theta_b} p_{\theta,t} - \sum_{\ell | i(\ell)=b} p_{\ell,t} + \sum_{\ell | j(\ell)=b} p_{\ell,t} = \sum_{d \in \mathcal{D}_b} p_{d,t} , \quad \forall b \in \mathcal{B} \setminus \mathcal{B}^m, \forall t \in \mathcal{T} \tag{3b}$$

$$-\bar{P}_b^m \leq p_{b,t}^m \leq \bar{P}_b^m , \quad \forall b \in \mathcal{B}^m, \forall t \in \mathcal{T} \tag{3c}$$

1) DAM Formulation: Equation (4) ensures that summation of traded power at all PCCs is equivalent to the total power available for trading by VPP.

$$p_t^{\mathrm{DA}} = \sum_{b \in \mathcal{B}^m} p_{b,t}^m , \quad \forall t \in \mathcal{T} \tag{4}$$

2) IDM Formulation: For IDM sessions, the IDM offers/bids do not substitute those submitted in the DAM, but rather, they are *adjustments* of the DAM offers/bids as reflected in (5). The rationale behind such adjustments can be due to unplanned maintenance of generators, changes in ND-RES outputs, demand changes and/or line faults.

$$p_t^{\mathrm{DA}^*}+\sum_{\kappa=1}^{k-1} p_{\kappa,t}^{\mathrm{ID}^*}+p_{k,t}^{\mathrm{ID}}=\sum_{b\in\mathcal{B}^m} p_{b,t}^{m} \ , \qquad \forall k\in\mathcal{K},\forall t\geq\tau \qquad (5)$$

where $p_t^{\mathrm{DA}^*}$ and $p_t^{\mathrm{ID}^*}$ are solutions of the DAM and previous IDMs respectively. Note that the only difference with respect to (3) is the time index, $\forall t\in\mathcal{T}$, which is replaced with $\forall t\geq\tau$, where τ is the first delivery period of current IDM session.

D. Non-dispatchable Renewable Energy Sources

The ND-RESs modeled in (6) comprise mainly wind power and solar PV plants. The lower bound represents the asset technical minimum while the output is bounded above by the available stochastic source. Forecasting techniques for the ND-RES units were not modeled since the focus of the work is on demand modelling. However, input parameters were chosen after careful analysis of realistic power plant data.

$$\underline{P}_{r,t}\leq p_{r,t}\leq\check{P}_{r,t} \ , \qquad \forall r\in\mathcal{R},\forall t\in\mathcal{T} \qquad (6)$$

III. Flexible Demands

This section presents the model of the demand flexibility in a VPP participating in energy markets that is proposed in this work. The model comprises two levels of flexibility, each associated with DAM and IDM market sessions respectively.

A. DAM Formulation

An optimal load profile is selected during DAM as the first flexibility level. For each demand d, (7a) and (7b) guarantees the choice of a single profile p out of all the available ones. Prior to market participation, various profiles are prepared by the demand owners/aggregators and communicated to the VPP manager. A particular profile might serve as the *default*, i.e., the consumption profile that will be followed by the demand if no market participation is considered. Additional profiles which the load owner can follow but might be operationally costly can be presented. However, compensation will be required from the VPP if those are chosen. Take an instance of residential demands; the default profile might feature double peaks at 09:00 and 20:00 whereas another profile features a shift of these load peaks to 07:00 and 21:00 respectively. If the second profile is selected as optimal by the VPP, the cost of *operational inconvenience* must be paid to the load owner.

$$p_{d,t}=\sum_{p\in\mathcal{P}} P_{d,p,t}u_{d,p} \ , \qquad \forall d\in\mathcal{D},\forall t\in\mathcal{T} \qquad (7a)$$

$$\sum_{p\in\mathcal{P}} u_{d,p}=1 \ , \qquad \forall d\in\mathcal{D} \qquad (7b)$$

B. IDM Formulation

The second level of demand flexibility is provided during different IDM sessions, formulated in (8). At IDM, the load profile selected from DAM cannot be changed. However, the demand owner allows the VPP manager to vary the consumption within predefined threshold (symmetric or not) around that selected profile ($P^*_{d,p,t}$) as presented in (8a). Equations (8b) and (8c) define the ramps of the demand profile from one period to the next. Finally, (8d) ensures that, over the total duration of the current IDM session plus the periods covered in previous sessions, a minimum amount of energy is consumed.

$$\begin{aligned}(1-\underline{P}_{d,t})\,P^*_{d,p,t}&\leq p_{d,t}\\ &\leq\left(1+\bar{P}_{d,t}\right)P^*_{d,p,t} \ , \qquad \forall d\in\mathcal{D},\forall t\geq\tau \qquad (8a)\end{aligned}$$

$$p_{d,t}-p_{d,(t-1)}\leq\bar{R}_d\Delta t \ , \qquad \forall d\in\mathcal{D},\forall t\geq\tau \qquad (8b)$$

$$p_{d,(t-1)}-p_{d,t}\leq\underline{R}_d\Delta t \ , \qquad \forall d\in\mathcal{D},\forall t\geq\tau \qquad (8c)$$

$$\underline{E}_d\leq\sum_{t=1}^{\tau-1}p^*_{d,t}\Delta t+\sum_{t=\tau}^{|\mathcal{T}|}p_{d,t}\Delta t \ , \qquad \forall d\in\mathcal{D} \qquad (8d)$$

IV. Case Study

This section presents the case studies considered to test and validate the RES-based VPP model proposed in this paper. The VPP topology considered and input data are outlined in Sections IV-A and IV-B.

A. VPP Description

The VPP assets are distributed across a 12-node network connected to a main grid through the PCC (bus 5) as shown in Fig. 1. The demands considered are industrial, airport and residential loads (buses 3, 9 and 12) with minimum daily consumption of 800, 580, and 600 MWh respectively. Three profiles are associated with each demand and total consumption for each profile is the same. Capacity of hydro (bus 6) is 111 MW. Wind power plant (bus 4), solar PV (bus 8) and STU (bus 1) each have capacities of 50 MW.

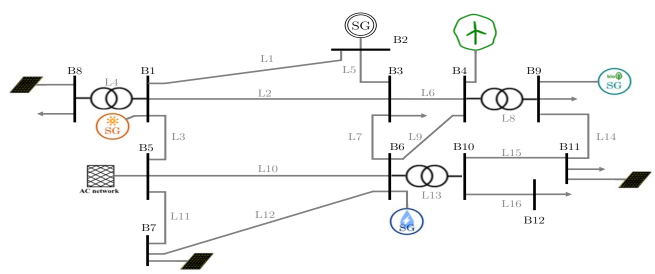

Fig. 1. 12-node network for test cases

Load profiles have been discretized because of the market requirements where bids are submitted on an hourly basis. The demand owners can prepare continuous load profile curves and on an hourly basis, the average is computed and submitted.

B. Input Parameters

A time horizon of 24 hours with an hourly resolution is utilized during DAM, while a subset of the 24 hours is used for each IDM session (see [12]). Figure. 2 shows the three profiles considered for each of the loads. Load profiles have been discretized because of market requirements with hourly bids submission. The demand owners can prepare continuous load profile curves and on an hourly basis, the average is computed and submitted. The basecase profile simulates *default activities* of electricity consumers (see Section III-A). The other two profiles (early and late peaks) are designed to perform load shifting around the basecase. During IDM, the demand owner

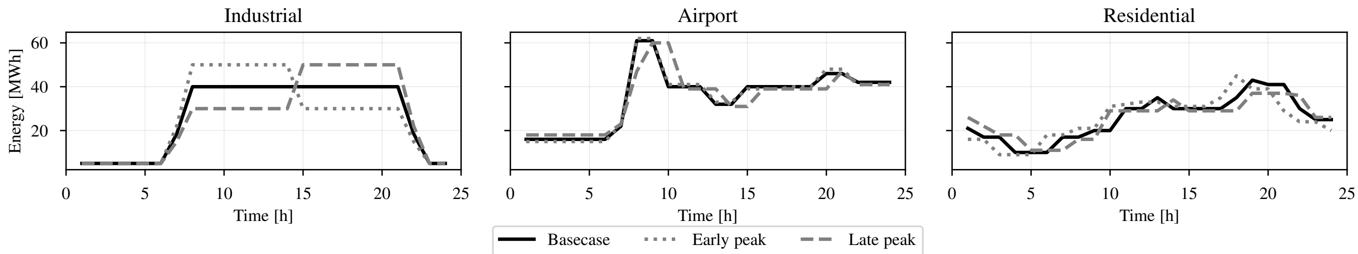

Fig. 2. Demand profiles

allows a percentage of tolerance for demand movement over the selected profile at DAM. In this case study, symmetric tolerances from $10-50\%$ over the total demand are considered. Note that the highest tolerance values considered serve only as an illustrative study, as likely no demand owner would allow such variations in a short notice (sometimes as short as 1 hour).

V. Results

To test the effectiveness of our model, two distinct operation days are identified: a clear sunny day and a day with intermittent cloud covers. Two aspects are thoroughly discussed for each day, namely: a) optimal price to be offered by the VPP to the demand owners and b) effect of the flexibility provided by demand on the profits accrued and operation of the VPP.

A. Optimal Price Offered by VPP to Demand Owners

First, we provide a solution to the benefits for demand owners and show that there is a maximum daily total and a price per MWh ($C_{d,p}$) that the VPP is prepared to pay demand owners such that it is still profitable. The default load profile has zero cost because the demand owner follows it regardless of other events. VPP then decides what price to pay demand owners for other profiles such that it's benefits are not eroded.

1) Clear day: The optimal choices of demand profiles obtained for VPP operation on a clear day is shown in Table I. These are obtained when $C_{d,p}$ for every other profile is set to zero. Industrial and residential loads have the early peak and late peak as optimal profiles respectively. To determine the cut-off costs before the basecase is selected, costs for other demand profiles are then gradually increased (simultaneously for all demands). It was then observed that the VPP manager is only willing to pay up to €320/day to the industrial load owner. If the demand owner has set the cost of the industrial early peak profile at $C_{d,p}$ = €325/day, then the VPP would have selected the default load as the optimal. The €320 is thus the maximum offering for the early peak industrial load profile, after which it is no more profitable for VPP. Industrial late peak and residential early peak profile are not-optimal (✘) for the operation horizon. In another trading day with different prices and other demand profiles, this might not be the case. With airport load, there are more options for both the airport demand owner and the VPP manager. The early peak profile is profitable for the VPP manager as a cost up until €500/day while the late peak profile is only profitable until €305/day.

As observed in Fig. 2, the different airport profiles have only subtle differences. Additionally, the load profiles have a benefit-inducing relationship with the evolution of the market price on this clear day. Indeed, the first profile peaks (periods 8-10) correspond to lower electricity prices and thus account for the higher costs which the VPP is prepared to pay. When the demand cost per MWh of the optimal profiles are computed, proof of the hypothesis is further demonstrated. For the airport profiles, $C_{d,p}$ = €10.42/MWh for 48 MWh shifted and €7.44/MWh for 41 MWh shifted of the early and late peak profiles respectively. Contrast this with industrial early peak profile where $C_{d,p}$ = €4.35/MWh for 73.5 MWh shifted. Thus, the €/day offer from VPP depends a little less on the magnitude of energy shifted and more on the load profile shape with respect to market price. Finally, these costs per MWh associated with DAM represent lower bounds on the price that VPP is willing to pay demand owners. With the tolerances allowed in IDM, VPP benefits increase and the prices paid to demand owners are expected to follow the same trend.

TABLE I
DEMAND PROFILE CHOICE AT NON-ZERO COSTS ON A CLEAR DAY

Demand	Basecase	Early peak	Late peak
Industrial	chosen when cost>€320/day	optimal	✘
Residential	chosen when cost>€180/day	✘	optimal
Airport	chosen when cost>€500/day	optimal	suboptimal - chosen when cost>€305/day

2) Cloudy day: On a cloudy day, it is observed that for all demands, the late peak profile is not optimal for the VPP operation. Additionally, the VPP manager is unwilling to pay amounts as high as the clear day case. Only €90/day and €260/day is offered to the industrial and airport load respectively. For the residential load, the deviations from the default load are not optimal at all and the VPP manager thus, offers no price to the residential load owner.

TABLE II
DEMAND PROFILE CHOICE AT NON-ZERO COSTS ON A CLOUDY DAY

Demand	Basecase	Early peak	Late peak
Industrial	chosen when cost>€90/day	optimal	✘
Residential	optimal	✘	✘
Airport	chosen when cost>€260/day	optimal	✘

B. Effects of Demand Flexibility on VPP Profits

This section discusses effects of: 1) demand flexibility on VPP profitability and 2) flexibility amount allowed by demand.

On a clear day, the VPP manager can realize a profit of €68259 from participating in the DAM (first demand flexibility level). However, at the end of the operation horizon (i.e. final IDM session), this profit can increase by up to 14% attributable to the second demand flexibility level alone beyond its DAM objective. The relationship between second-level flexibility allowance and the associated effect on profits is shown in Fig. 3. Beyond 40%, profits do not show any considerable additional increase and any allocation on load movement beyond this percentage only leads to more saturation on the profits curve.

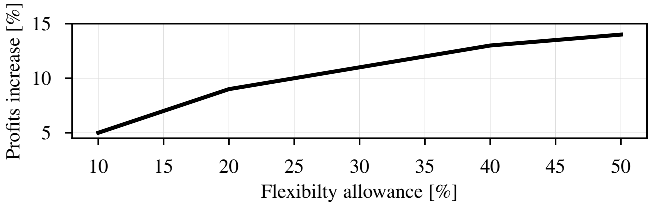

Fig. 3. Demand profile flexibility on VPP profits on a clear day

Figure. 4 shows the impact of demand flexibility on total power traded in DAM and total traded after all IDM sessions. It is observed that increasing flexibility provision reduces the valley in DAM offer around the instant h = 8 and leads to an increase in offers in the energy market while at the same time flattening the curve in the straight section from periods 9 to 19 but keeping total energy consumption constant.

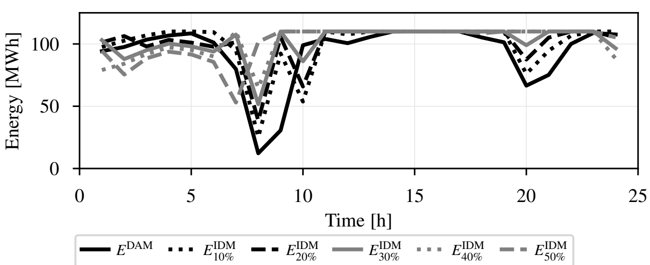

Fig. 4. Scheduled and final traded power based on demand flexibility

Final demand output relative to DAM offer is shown in Fig. 5. Up to 20% flexibility allowance on demands, the variations are smooth and would not necessarily alter normal system operation. However, from 30% and upwards flexibility, higher consumption pattern is observed in demand as evidenced in the industrial and residential demands at periods 10-13 and 17-19. Increasing flexibility allowance gives rise to more of this peaks that might affect system performance. Demand owners would likely not allow such percentages anyway and we simply show a proof of concept here.

VI. Conclusion

This paper presents a model for evaluating the impacts of flexibility provision by demands that are part of an RES-based VPP that participates in energy markets. The flexible demand model proposed has two levels of flexibility associated with different market sessions. The business model of the VPP is such that it maximises its profit by dispatching its generators, carrying out self supply of the demands within its portfolio and utilizing the flexibility actions provided by said demands.

Case studies were then analysed to determine the optimal price the VPP is ready to offer demand owners. Impact of the flexibility provided on operation of VPP and profits accrued at the end of the operation day is also discussed. Based on the studies carried out, it is concluded that there is a maximum price offering from VPP to demand owners for each demand profile. Beyond this price, the default load will be selected. A sensitivity analysis showed that beyond 40% flexibility allowance for the demands studied, there is a saturation of the profit and added flexibility might not be anymore profitable.

References

[1] C. W. Gellings, “The concept of demand-side management for electric utilities,” *Proceedings of the IEEE*, vol. 73, no. 10, pp. 1468–1470, 1985.

[2] G. Strbac, “Demand side management: Benefits and challenges,” *Energy policy*, vol. 36, no. 12, pp. 4419–4426, 2008.

[3] P. Palensky and D. Dietrich, “Demand side management: Demand response, intelligent energy systems, and smart loads,” *IEEE transactions on industrial informatics*, vol. 7, no. 3, pp. 381–388, 2011.

[4] A. De La Nieta et al, “Local economic dispatch with local RES and flexible load management,” in *2018 SEST Conf.* IEEE, 2018, pp. 1–6.

[5] M. Georgiev, R. Stanev, and A. Krusteva, “Flexible load control in electric power systems with distributed energy resources and electric vehicle charging,” *PEMC 2016*, pp. 1034–1040, 2016.

[6] Z. Hungerford, A. Bruce, and I. MacGill, “The value of flexible load in power systems with high RES penetration,” *Energy*, vol. 188, 2019.

[7] J. Taneja, K. Lutz, and D. Culler, “Flexible loads in future energy networks,” in *ICFE 2013*, 2013, pp. 285–286.

[8] B. Marinescu, O. Gomis-Bellmunt, F. Dörfler, H. Schulte, and L. Sigrist, “Dynamic virtual power plant: A new concept for grid integration of renewable energy sources,” *arXiv preprint arXiv:2108.00153*, 2021.

[9] L. Baringo and M. Rahimiyan, “Virtual power plants and electricity markets,” in *e-Book*. Springer, 2020.

[10] A Kargarian et al, “Toward distributed/decentralized DC optimal power flow implementation in future electric power systems,” *IEEE Trans on SG*, vol. 9, no. 4, pp. 2574–2594, 2016.

[11] O. Oladimeji et al, “Optimal participation of heterogeneous, RES-based VPP in energy markets [manuscript submitted for publication to PSCC 2022],” *IIT, Comillas Pontifical University*, 2021.

[12] J. P. Chaves-Ávila and C. Fernandes, “The Spanish intraday market design: A successful solution to balance renewable generation?” *Renewable Energy*, vol. 74, pp. 422–432, 2015.

[13] K. Van den Bergh, E. Delarue, and W. D’Haeseleer, “DC power flow in unit commitment models,” *Energy and Environment*, vol. 240, 2014.

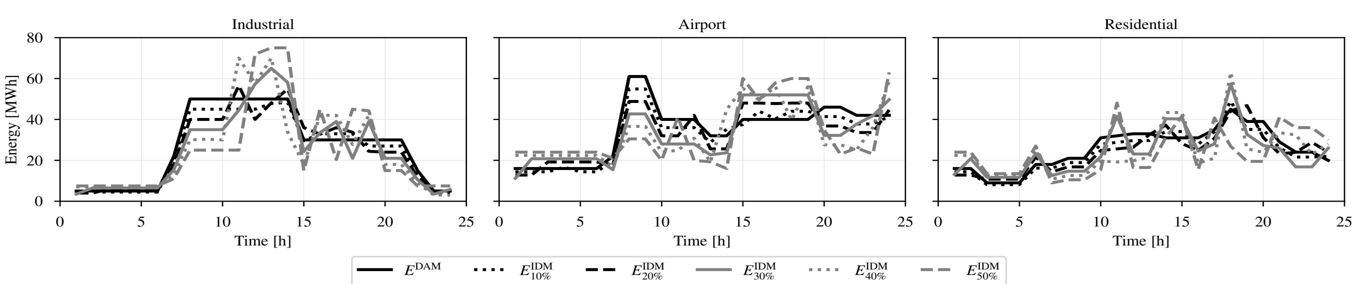

Fig. 5. Scheduled and final demand outputs on a clear day