# A virtual power plant optimal dispatch model with large and small-scale distributed renewable generation

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**Abstract**

Volatility and sharp increases in the price of electricity are serious economic problems in the primary sector because they affect modernization investments for irrigation systems in Spain. This paper presents a new virtual power plant (VPP) model that integrates all available full-scale distributed renewable generation technologies. The proposed VPP operates as a single plant in the wholesale electricity market and aims to maximize profit from its operation to meet demand. Two levels of renewable energy integration in the VPP were considered: first, a wind farm and six hydroelectric power plants that inject the generated electricity directly to the distribution network, and second, on-site photovoltaic plants associated with each of the electricity supply points in the system that are designed to prioritize self-consumption. The proposed technical-economic dispatch model was developed as a mixed-integer optimization problem that determines the hourly operation of distributed large-scale renewable generation plants and on-site generation plants. The model was applied to real data from an irrigation system comprising a number of water pumping stations in Aragon (Spain). The results of the VPP model demonstrate the importance of the technical and economic management of all production facilities to significantly reduce grid dependence and final electricity costs.

**Keywords**: optimization, renewable power sources, distributed generation, self-consumption, management.

## Nomenclature

*Indexes*

| | |
|---|---|
| $i$ | index for number of hours |
| $j$ | index for pumping stations |

*Variables*

| | |
|---|---|
| $P^{i}_{exp}$ | energy exported to the grid (MWh) |
| $P^{i}_{imp}$ | energy imported from the grid (MWh) |
| $P^{i}_{W}$ | wind power generated (MW) |
| $P^{i}_{H}$ | hydroelectric power generated (MW) |
| $P^{i}_{in\,j}$ | energy input from general bus $A$ to a pumping station $j$ (MWh) |
| $P^{i}_{out\,j}$ | energy output from a pumping station $j$ to general bus $A$ (MWh) |
| $I^{i}_{exp}$ | binary variable equal to 1 if energy is delivered to the grid; otherwise, it is equal to 0 |
| $I^{i}_{imp}$ | binary variable equal to 1 if the pumping station $j$ imports energy from the grid; otherwise, it is equal to 0 |
| $I^{i}_{in\,j}$ | binary variable equal to 1 if energy is received by the pumping station $j$ from general bus A; otherwise, it is equal to 0 |
| $I^{i}_{out\,j}$ | binary variable equal to 1 if energy is delivered from the pumping station $j$ to general bus A; otherwise, it is equal to 0 |

*Data*

| | |
|---|---|
| $\rho^{\mathrm{i}}_{\mathrm{exp}}$ | hourly energy sales price (€/MWh) |
| $\rho^{\mathrm{i}}_{\mathrm{imp}}$ | hourly energy purchase price (€/MWh) |
| $\mathrm{f_W}$ | operation and maintenance cost of wind farm technology (€/MWh) |
| $\mathrm{f_H}$ | operation and maintenance cost of hydroelectric technology (€/MWh) |
| $\mathrm{f_{PV}}$ | operation and maintenance cost of photovoltaic technology (€/MWh) |
| $\mathrm{P^{i}_{D\,j}}$ | hourly load of each pumping station $j$ (MW) |
| $\mathrm{P^{i}_{PV\,j}}$ | photovoltaic power generated hourly (MW) |

| | |
|---|---|
| $P^{i}_{W\,max}$ | hourly available wind power generation (MW) |
| $P^{i}_{H\,max}$ | hourly available hydroelectric power generation (MW) |
| $P^{i}_{exp\,max}$ | hourly maximum power exported to the grid (MWh) |
| $P^{i}_{imp\,max}$ | hourly maximum power imported from the grid (MWh) |

## 1. Introduction

Electricity is one of the most costly elements in the operation of an agricultural irrigation water pumping station. Until 2008, the Spanish government set regulated electricity rates, but since then, farming communities have had to purchase electricity from a deregulated market at much higher prices. As a result, the survival of many recently modernized facilities has been threatened due to higher electricity prices; these prices also exhibit volatility and uncertainty throughout the year. Farming communities paid prices above 15 c€/kWh in 2014, compared to an average of 7.7 c€/kWh in 2007. The future of the current scenario of volatility and steep increases in wholesale electricity market pricing is uncertain.

Countries worldwide rely on their energy policy strategies to develop renewable energy to address global warming, reduce their dependence on fossil-fuel-based electricity, improve the security of energy supply and promote industry and development in a region where renewable energy technology is installed. Introducing renewable energy to an increasingly competitive electricity market requires new technologies and operating systems to address new technical and economic challenges arising from the optimal integration of available resources. Smart grids, virtual power plants and digital transformation are keys to this integration.

Most of the studies reviewed in this paper have focused on the growing importance of the management capabilities of different types of virtual power plants. A virtual power plant can be defined as a cluster of distributed generation units, controllable loads and storage systems that are aggregated to operate as a single power plant without the need for a physical connection by direct power lines [1]. In virtual power plants, an energy management system is integral to coordinating power flow between generators, loads and storage. Communication between units may be bidirectional, which means that the virtual power plant (VPP) can send control signals to the components that constitute the virtual plant as well as receive information on the current status of each unit.

The main objective of previous studies has been optimizing the operation of the VPP to maximize profit, using techniques for typical technical and economic dispatch problems, which leads to scheduling different power generation sources [2].

Researchers have proposed different solving methods for the dispatch problem (see Table 1). In [3], the problem of optimal energy management has been solved with an imperialist competitive algorithm. The study in [4] has proposed a fully distributed dispatch algorithm without a centralized controller. The authors of [5] have used a combined optimization method based on interval and deterministic optimization to solve an economic dispatch problem related to VPPs and to manage the uncertainties associated with renewable energy. In [6], the “Big Bang Big Crunch” optimization method has been used to minimize the annual purchase of electricity in unbalanced distribution networks. Other works have applied stochastic optimization ([7], [8]) and non-linear optimization programming ([9], [10]). However, the most frequently applied optimization technique has been mixed-integer linear programming since it suits the characteristics of dispatch problems ([11]–[17]).

One must also consider the economic aspects of the dispatch problem. Virtual power plants can participate in different electricity markets to purchase and sell power. Different approaches can be found in the literature that consider energy markets in relation to VPPs. Reference [11] has maximized the weekly profit of a VPP under long-term bilateral contracts. In [12], a coalition-forming scheme has been developed for a commercial virtual power plant based on weekly bilateral contracting and futures market as well as day-ahead markets. Reference [13] has used several interregional energy contracts to model a cooperation system among neighbouring VPPs. In [18], a methodology to coordinate different VPP agents and electricity market operators has been presented.

Electricity can also be purchased and sold in real-time. Several papers have aimed to determine an optimal bidding strategy for a VPP using different optimization methods. In [19], an optimal offering strategy for a commercial virtual power plant has been obtained by using stochastic optimization. The study in [7] has provided a combination of adaptive robust and stochastic optimization for VPP models that participate in day-ahead and real-time electricity markets. In [9], the distributionally robust optimization approach has been proposed to determine the optimal values of parameters for the bidding strategy, such as capacity or cost curve. The authors of [10] have presented a fuzzy optimization technique to address the bidding problem and have achieved lower computation times with this method than with other deterministic and probabilistic methods.

In order to reduce the range of the problem’s uncertainties, some papers have incorporated an initial statistical contribution in which electricity market pricing and renewable power generation intermittency are the most influential variables. Different methods have been proposed to manage the uncertainty of these parameters in VPP scheduling. References [14] and [19] have considered different demand response programs and have used stochastic programming to manage uncertainty. The point estimate method has been used in [15], while the studies [7] and [8] have proposed a stochastic robust optimization method. References such as [16] and [20] have applied the Conditional Value at Risk (CVaR) method to risk management in the VPP model. Reference [21] has presented a multi-objective programming model that incorporates the uncertainty management and carbon dioxide emissions of VPP. In the mentioned study, the Conditional Risk at Value (CVaR) method and robust optimization theory have been used to model uncertainty. In [22], a method has been provided for profit allocation among different distributed energy resources that constitute the VPP. This method has been shown to reduce computation time through cooperative game theory methods.

Very few papers have studied and analyzed the virtual power plant concept in real cases. In [23], the integration of VPPs in the German energy market has been economically assessed, while the study [17] has analyzed the technical-economic impact of the implementation of the VPP concept in the Spanish electricity system. In [24], the economic feasibility of VPPs in Chongming Island (China) has been studied by calculating the net present value (NPV) and analyzing the life cycle cost.

| Ref. | Objective | Solving method | Wholesale markets | Uncertainty management | Storage | Case study | Real case study |
|---|---|---|---|---|---|---|---|
| **[3]** | Energy management | Imperialist competitive algorithm | | ✓ | ✓ | ✓ | |
| **[4]** | Profit maximization | ADMM and consensus optimization | | | | ✓ | |
| **[5]** | Economic dispatch | Combined interval and deterministic optimization | | ✓ | | | ✓ |
| **[6]** | Energy management | Big Bang Big Crunch | ✓ | | ✓ | ✓ | |
| **[7]** | Bidding strategy | Stochastic adaptive robust optimization | ✓ | ✓ | | | |
| **[8]** | Self-scheduling | Stochastic adaptive robust optimization | ✓ | ✓ | | ✓ | |
| **[9]** | Bidding strategy | Second-order cone program | ✓ | | ✓ | | |
| **[10]** | Bidding strategy | MINLP | ✓ | ✓ | | ✓ | |
| **[11]** | Mid-term dispatch scheduling | MILP | ✓ | ✓ | ✓ | ✓ | |
| **[12]** | Medium term coalition | MILP | ✓ | | | ✓ | |
| **[13]** | Interregional cooperation | MILP | ✓ | ✓ | | ✓ | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **[14]** | Electrical/thermal energy scheduling | MILP | ✓ | ✓ | ✓ | | |
| **[15]** | Electrical/thermal energy scheduling | MILP | ✓ | ✓ | ✓ | | |
| **[16]** | Risk aversion scheduling | MILP | | ✓ | | ✓ | |
| **[17]** | Profit maximization | MILP | | | | | ✓ |
| **[18]** | Congestion management, | Rolling horizon method | ✓ | ✓ | | ✓ | |
| **[19]** | Bidding strategy | Mathematical programming model with equilibrium constraints | ✓ | ✓ | | ✓ | |
| **[20]** | Energy management | MINLP | ✓ | | | ✓ | |
| **[21]** | Multi-objective profit maximization/risk minimization/carbon emissions minimization | Robust optimization | | ✓ | | | |
| **[22]** | Profit allocation | Two-stage stochastic programming/ game theory | ✓ | ✓ | | | |
| **[23]** | Economic feasibility | Scenario method | | | | | ✓ |
| **[24]** | Economic feasibility | NPV/life cycle cost | | | | | ✓ |

**Table 1**. Classification of the reviewed VPP studies

In summary, the reviewed studies have generally proposed models that do not include all the control variables of the different types of renewable generation. In addition, these models have not integrated the management of large- or medium-scale power generation plants (which are mainly designed to export all the electricity produced to the grid) with small-scale photovoltaic self-consumption facilities. Furthermore, the VPP concept has rarely been applied to real cases. These aspects are all considered in our research.

The goal of this paper is to develop a new optimal operation model that incorporates the electricity generation and consumption of irrigation systems. This model incorporates both renewable generation sources and the hourly electricity demand through a virtual power plant mathematical model. As a new feature, the model proposes that the pumping stations' demand is supplied by their own system's power generation sources (for example, wind or hydro) but also by renewable distributed generation sources at each pumping station (photovoltaic), to reduce both its dependence on the grid and the final electricity cost. When necessary, electricity from the grid can be purchased to meet demand. The proposed model is a mixed-integer linear programming model that aims to maximize the profit of the operation of the VPP for each hourly period over one year of study.

In summary, the most innovative contributions of this research are as follows:

- The design of an optimal VPP management model with two levels of integration of renewable energy: on the one hand, wind and hydroelectric power generation injected directly to the grid, and on the other, on-site photovoltaic self-consumption facilities.
- The application of this model to the operation of a power control centre of a 135,000 ha irrigation system in Aragon (Spain) with an electricity consumption of 39 GWh per year and a power generation of 180 GWh per year.

The rest of this article is organized as follows. Section 2 explains the proposed optimal dispatch model. Section 3 details the case study with actual demand and renewable power generation data. Section 4 presents the main results of the model. Next, Section 5 provides a sensitivity analysis of various model parameters. Finally, Section 6 presents the main conclusions of this study.

## 2. Optimal dispatch model

The irrigation system of Riegos del Alto Aragon, one of the largest in Europe, comprises a group of irrigation communities spanning an area exceeding 135,000 ha and with an annual water consumption of 800 $Hm^3$. This system is located in Aragon (Spain), where climatic conditions make irrigation a key determinant of production diversification and of labour and land productivity. Therefore, irrigation is a key influencer of farm income and of the living standards of farmers, which is reflected in the territorial distribution of farm employment.

In recent years, irrigation communities in Riegos del Alto Aragon have invested significantly in their own renewable power generation facilities (wind, hydro). These communities are also large consumers of electricity due to their water pumping stations; therefore, it is essential to jointly manage consumption and power generation to reduce energy costs and improve environmental sustainability. This paper proposes the design and implementation of a VPP that incorporates the electricity consumption of pumping stations and power generation plants. The proposed VPP operates as a single plant in the wholesale electricity market and maximizes the profit of the systems involved. Fig. 1 depicts the location of the electricity generation facilities and the irrigated areas of the Riegos del Alto Aragon irrigation system.

The system under study consists of 27 irrigation water pumping stations that are connected to the electric distribution network and have a total annual electricity demand of 39 GWh. This demand is partially supplied by on-site photovoltaic generation facilities, by other sources from within their own generation system or by the purchase of electricity from the electricity market.

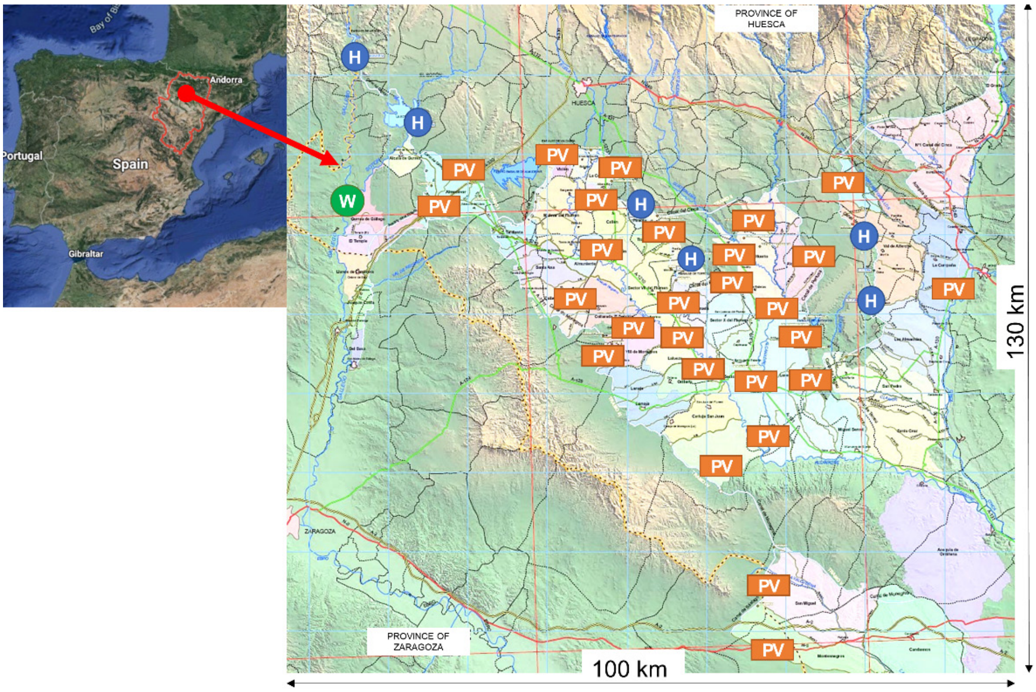



Fig. 1. Map of the irrigation communities of Riegos del Alto Aragon and the location of their renewable power generation facilities

This research proposes a mathematical model of optimal hourly dispatch to incorporate the technical and economic management of all the consumption and generation facilities into a VPP model. The mathematical problem of the VPP profit maximization was formulated as a mixed-integer linear programming model. On the one hand, the problem has binary variables associated with the decision to import or export energy in each subsystem for each hour. On the other hand, the optimum values of the power generation and the imported energy were calculated, both at each pumping station and by the system overall. Equations (1) to (13) formulate the objective function and the technical constraints that model the system behaviour.

Hourly demand and renewable electricity generation forecasts are available the day before for the dispatch model, as well as electricity market prices for purchasing and selling energy from the day-ahead market [25]. However, the decision-making process was performed hourly for one year in order to analyze the system operation and the effective generation and demand coupling during the year 2017.

Fig. 2 schematically presents the VPP agents. The electricity generation plants distributed in the region are connected hourly to attempt to meet the pumping station demand. There are two levels for connecting the generated power: (i) the wind farm and the six hydroelectric power plants send the generated electricity directly to the distribution network, and (ii) the on-site photovoltaic plants (PV) are designed to prioritize meeting the demand of each pumping station and inject any surplus power into the distribution network. These self-consumption facilities are obliged to meet first the local demand in accordance with the provisions of article 9.1 of Spanish Law 24/2013 [26]. Fig. 2 presents the load $\mathrm{P}^{\mathrm{i}}_{\mathrm{D\,j}}$ and produced solar power $\mathrm{P}^{\mathrm{i}}_{\mathrm{PV\,j}}$, and the input $P^{i}_{in\,j}$ and output $P^{i}_{out\,j}$ power in each subsystem. These variables do not represent the power line flows, but rather, the power to connect hourly in the integrated economic VPP model.

If the demand of the pumping stations is not met, energy $P^{i}_{imp}$ will be purchased from the electricity market by a pass-through contract indexed to the OMIE wholesale market prices of Spain [25]. Conversely, if excess energy $P^{i}_{exp}$ is produced, it will be sold to the grid each hour at the price stated by the OMIE day-ahead market, minus generation taxes and fees. The model assumes that purchasing and selling energy transactions cannot occur simultaneously (Eq. 6).

The objective function presented in Eq. 1 maximizes the hourly profit of joint operation of the power generation and consumption facilities of the VPP, expressed as the difference between income and costs of all the system agents. The income results from selling the hourly excess in generated power ($\rho^{\mathrm{i}}_{\mathrm{exp}} \cdot P^{i}_{exp}$) to the electricity market, while the costs are from the power generated hourly by each wind and hydro generation facility ($\mathrm{f_W} \cdot P^{i}_{W}$, $\mathrm{f_H} \cdot P^{i}_{H}$), the cost of PV surplus power sent out from the pumping station ($\mathrm{f_{PV}} \cdot P^{i}_{out\,j}$) and the hourly cost of purchasing energy if generation does not meet demand ($\rho^{\mathrm{i}}_{\mathrm{imp}} \cdot P^{i}_{imp}$).

As mentioned above, the PV plants meet the demand of each pumping station first, so the demand supplied by the PV plants does not need to be purchased from the electricity market. Only the cost of the extra energy generated by each PV plant and injected into the distribution network is considered in the dispatch model.

The technical constraints considered for modelling the system are defined below.

The overall power balance of the system that ensures the supply of the demand at all times is stated in Eq. 2. Furthermore, Eq. 3 defines the power balance at each pumping station and ensures that all available photovoltaic power is used every hour.

Eq. 4 and 5 establish that wind and hydroelectric power generation ($P^{i}_{W}$, $P^{i}_{H}$) must each be equal to or greater than 0 and are limited by their maximum available power.

Next, the constraints related to the energy imported from and exported to the distribution network are presented. The transactions of purchasing and selling energy in the electricity market cannot occur simultaneously every hour; therefore, Eq. 6 states that the sum of the integer decision variables ($I^i_{imp}$,$I^i_{exp}$) must be less than or equal to 1. The limits of energy imported from the grid are defined by Eq. 7; the minimum value must be greater than or equal to 0, while the maximum value depends on the product of the maximum demand of the system (Eq. 9) and the associated integer variable. If energy is imported, $I^i_{imp} = 1$, and the imported energy will be less than or equal to the maximum demand, $\mathrm{P}^{\mathrm{i}}_{\mathrm{imp\,max}}$. A similar situation exists for energy exported to the grid (Eqs. 8 and 10). The maximum system energy that can be generated, and therefore exported to the grid, $\mathrm{P}^{\mathrm{i}}_{\mathrm{exp\,max}}$, is stated in Eq. 10.

Lastly, the constraints related to the photovoltaic generation plants in each pumping station were established. Electricity can only be exchanged in one direction between a subsystem B and the virtual bus of system A each hour (that is, it can only be imported from A to B or exported from B to A (see Fig. 2)); As stated by Eq. 11, the sum of the integer decision variables ($I^i_{out\,j}$, $I^i_{in\,j}$) must be less than or equal to 1. The limits of the energy output of each pumping station is indicated by Eq. 12; it must be greater than or equal to 0, and the upper limit depends on the integer decision variables $I^i_{out\,j}$ and $I^i_{in\,j}$. If energy is delivered to the general bus $A$, $I^i_{out\,j} = 1$, and the upper limit of the energy output of each pumping station will correspond to the available hourly photovoltaic power generated. Otherwise, if the energy is received, $I^i_{in\,j} = 1$, and the maximum value of the energy input of the pumping station will coincide with its hourly demand (Eq. 13).

- Objective function

$$\max\left\{\sum_{i=1}^{8760}\left(\rho^{\mathrm{i}}_{\mathrm{exp}}\cdot P^i_{exp} - \rho^{\mathrm{i}}_{\mathrm{imp}}\cdot P^i_{imp} - \mathrm{f_W}\cdot P^i_W - \mathrm{f_H}\cdot P^i_H - \sum_{j=1}^{27}\mathrm{f_{PV}}\cdot P^i_{out\,j}\right)\right\} \quad (1)$$

- Constraints

$$P^i_{imp} - P^i_{exp} + P^i_W + P^i_H = -\sum_{j=1}^{27}P^i_{out\,j} + \sum_{j=1}^{27}P^i_{in\,j} \quad (i = 1..8760) \quad (2)$$

$$P^i_{out\,j} - P^i_{in\,j} = P^i_{PV\,j} - \mathrm{P}^{\mathrm{i}}_{\mathrm{Dj}} \quad (j = 1..27,\ i = 1..8760) \quad (3)$$

$$0 \le P^i_W \le \mathrm{P}^{\mathrm{i}}_{\mathrm{W\,max}} \quad (4)$$

$$0 \le P^i_H \le \mathrm{P}^{\mathrm{i}}_{\mathrm{H\,max}} \quad (5)$$

$$I^i_{imp} + I^i_{exp} \le 1 \quad (6)$$

$$0 \le P^i_{imp} \le I^i_{imp}\cdot \mathrm{P}^{\mathrm{i}}_{\mathrm{imp\,max}} \quad (7)$$

$$0 \leq P^{i}_{exp} \leq I^{i}_{exp} \cdot \mathrm{P}^{\mathrm{i}}_{\mathrm{exp\,max}} \tag{8}$$

$$\mathrm{P}^{\mathrm{i}}_{\mathrm{imp\,max}} = \sum_{j=1}^{27} \mathrm{P}^{\mathrm{i}}_{\mathrm{D\,j}} \tag{9}$$

$$\mathrm{P}^{\mathrm{i}}_{\mathrm{exp\,max}} = \mathrm{P}^{\mathrm{i}}_{\mathrm{W\,max}} + \mathrm{P}^{\mathrm{i}}_{\mathrm{H\,max}} + \sum_{j=1}^{27} P^{i}_{PV\,j} \tag{10}$$

$$I^{i}_{out,j} + I^{i}_{in,j} \leq 1 \tag{11}$$

$$0 \leq P^{i}_{out\,j} \leq I^{i}_{out\,j} \cdot P^{i}_{PV\,j} \tag{12}$$

$$0 \leq P^{i}_{in\,j} \leq I^{i}_{in\,j} \cdot \mathrm{P}^{\mathrm{i}}_{\mathrm{D\,j}} \tag{13}$$

As indicated by the equations of the formulated optimization problem, the model is of a mixed-integer linear programming type (MILP) because there are decision variables related to the import or export of electricity and continuous variables for the values of energy exchanged. An appropriate solving method involves obtaining the optimal management of energy resources integrated into a VPP, as seen in Section 1. The integer variables are used to carry out the decision-making process for each hourly period during a year. Thus, an optimal hourly solution to the problem can be obtained. MATLAB software was used to solve the mathematical problem because its optimization toolbox includes an efficient solver for mixed-integer linear programming (MILP). The computation time was 6.64 minutes for the dispatch problem of 8760 hours using a computer with an Intel®Core i7 processor, 2.5 GHz CPU and 12 GB of RAM.

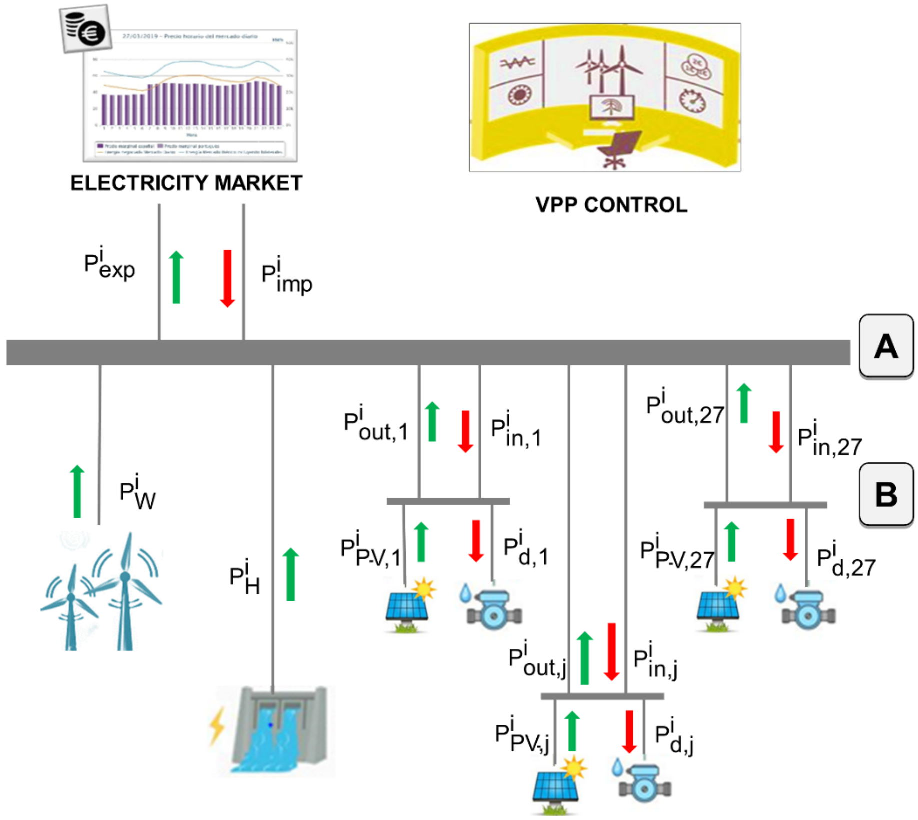



**Fig. 2.** Agents involved in the proposed VPP

## 3. Case study: data

### 3.1. Demand

The hourly load curves of the pumping stations in 2017 are available for integrating demand into the VPP dispatch model. Electricity consumption is highly seasonal since the area's crop irrigation season mainly occurs during the summer months (see Fig. 3).

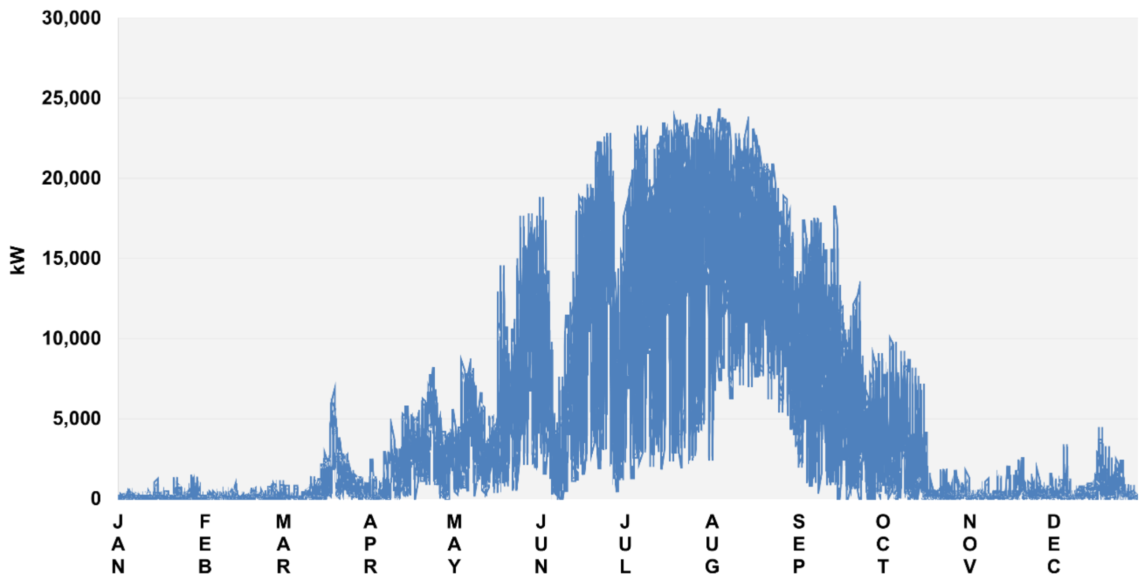


**Fig. 3.** Annual demand curve of the irrigation communities under study

Table 2 presents the electricity consumption per year for each pumping station. The total annual consumption of the analyzed system was 39 GWh.

| Pumping station | Energy (MWh) | Pumping station | Energy (MWh) |
|---|---|---|---|
| **PS1** | 746 | **PS15** | 450 |
| **PS2** | 2,223 | **PS16** | 622 |
| **PS3** | 965 | **PS17** | 3,732 |
| **PS4** | 4,419 | **PS18** | 278 |
| **PS5** | 2,112 | **PS19** | 656 |
| **PS6** | 2,555 | **PS20** | 900 |
| **PS7** | 843 | **PS21** | 1,615 |
| **PS8** | 530 | **PS22** | 1,592 |
| **PS9** | 2,036 | **PS23** | 2,688 |
| **PS10** | 284 | **PS24** | 2,014 |
| **PS11** | 1,011 | **PS25** | 1,053 |
| **PS12** | 1,282 | **PS26** | 192 |
| **PS13** | 1,045 | **PS27** | 801 |
| **PS14** | 2,361 | | |
| **Total energy (MWh)** | | **39,003** | |

**Table 2.** Annual electricity consumption of the pumping stations

The final cost of electricity to a consumer in Spain is the sum of the cost of generating electricity in the wholesale market plus the cost of access tariffs for grid use and other minor fees.

The irrigation communities are under a six-period access tariff contract, meaning there are six different periods with different grid usage costs that depend on the month and time of day. Period P1 is the most expensive and period P6 is the cheapest; therefore, the irrigation communities try to minimize consumption in period 1 and concentrate it in cheaper periods. Fig. 4 shows the distribution of the different periods of the time-of-use access tariffs throughout the year.

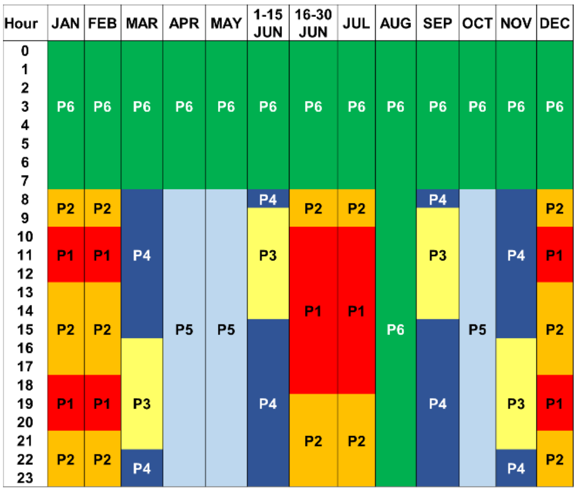



**Fig. 4.** Time-of-use access tariff schedule

Table 3 presents the distribution of electricity consumption for each of the six periods of the high voltage access tariffs. An analysis of the energy distribution indicates that most electricity consumption occurs in period P6 when the energy price is lower; this corresponds to nights, weekends and the month of August.

| Period | Energy consumed (MWh) | Percentage (%) |
|---|---|---|
| **P1** | 1,124 | 2.88% |
| **P2** | 2,432 | 6.23% |
| **P3** | 405 | 1.04% |
| **P4** | 1,334 | 3.42% |
| **P5** | 1,676 | 4.30% |
| **P6** | 32,032 | 82.13% |
| **Total energy (MWh)** | **39,003** | **100.00%** |

**Table 3.** Electricity consumption distribution by pricing period

## 3.2. Hydroelectric generation

The system has six hydroelectric power plants, geographically scattered throughout the region, with a total output power of 14.7 MW. These plants use dammed water and water flowing through channels to produce electricity. Table 4 describes the power distribution of each hydroelectric power plant. The hourly hydropower generation data are available for 2017. Fig. 5 depicts the monthly generation of the system's six hydroelectric plants.

| Hydroelectric power plant | Installed capacity (MW) |
|---|---|

| | |
|---|---|
| **H1** | 4.4 |
| **H2** | 0.9 |
| **H3** | 1.2 |
| **H4** | 1.1 |
| **H5** | 5.0 |
| **H6** | 2.1 |
| **Total power (MW)** | **14.7** |

**Table 4.** Installed capacity of the hydroelectric facilities

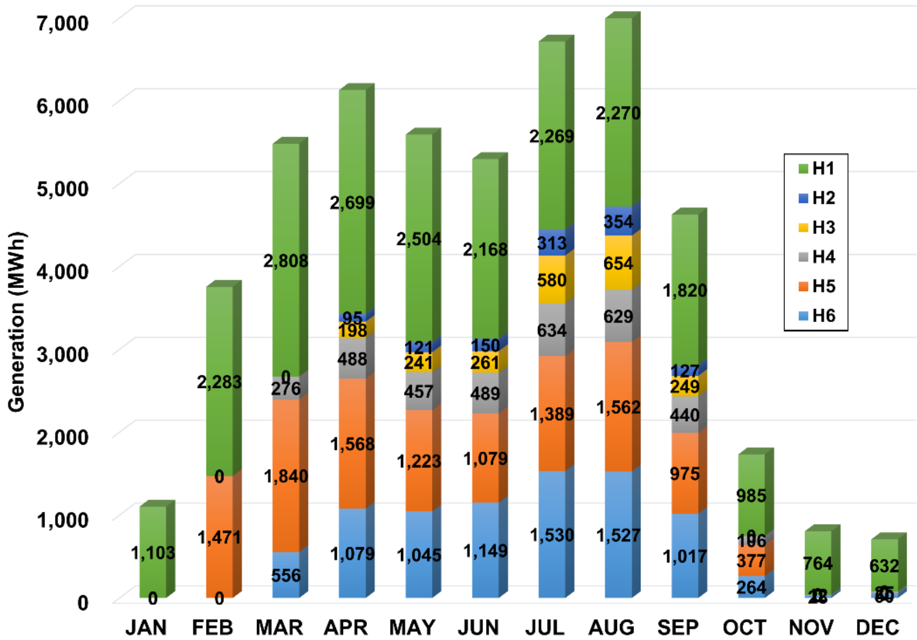



**Fig. 5.** Monthly power generation of the hydropower plants

As indicated in Fig. 5, only one plant operates for the whole year because its dam is fed by a river. The remaining five plants generate power mainly during the irrigation season, when there is an increased amount of water flowing through the transport channels. Table 5 describes the distribution of generated power by pricing period. The total amount of energy generated by the hydropower plants is 48.9 GWh/year.

| Periods | Energy produced (MWh) | Percentage (%) |
|---|---|---|
| **P1** | 3,206 | 6.55% |
| **P2** | 3,841 | 7.85% |
| **P3** | 2,416 | 4.94% |
| **P4** | 4,007 | 8.19% |
| **P5** | 6,239 | 12.75% |
| **P6** | 29,226 | 59.72% |
| **Total energy [MWh]** | **48,934** | **100.00%** |

**Table 5.** Distribution of hydropower generation by pricing period

As previously stated, 60% of the power generation occurs during period P6. However, 80% of the yearly pumping station demand is concentrated in the hours of the same pricing period, P6; therefore, a complete temporal match between hydropower generation and power demand does not exist.

## 3.3. Wind farm

The system has a wind farm consisting of nine wind turbines with an installed capacity of 30 MW. The hourly generation data of the wind farm are available. Fig. 6 visualizes the power generated per month.

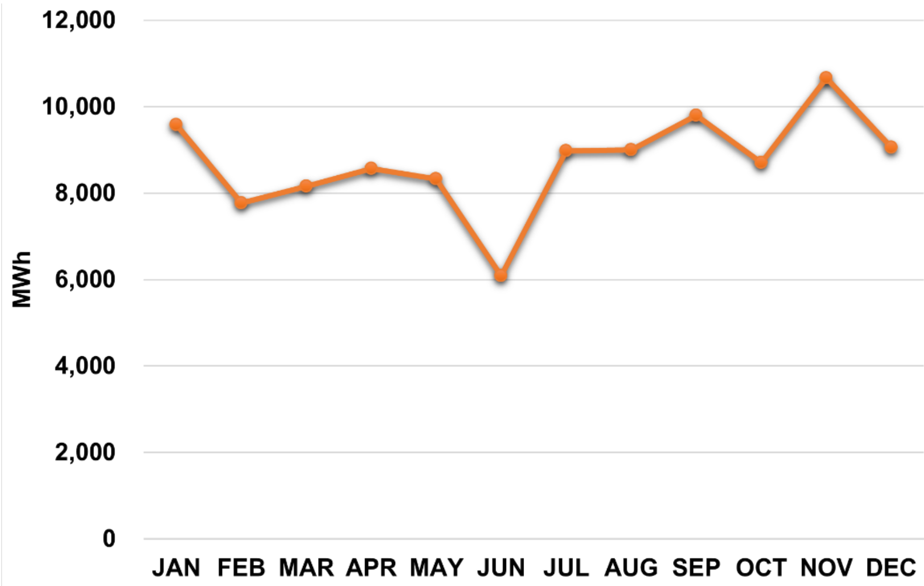



**Fig. 6.** Wind power generation per month

Table 6 presents the power generation distribution by pricing period. Again, the largest power generation occurs during period P6, which is relevant for system power management because it coincides with the period of highest consumption by the irrigation communities.

| Period | Energy produced (MWh) | Percentage (%) |
|---|---|---|
| **P1** | 6,806 | 6.50% |
| **P2** | 10,684 | 10.20% |
| **P3** | 4,879 | 4.66% |
| **P4** | 9,224 | 8.81% |
| **P5** | 10,014 | 9.56% |

| | | |
|---|---|---|
| **P6** | 63,096 | 60.26% |
| **Total energy (MWh)** | **104,703** | **100.00%** |

**Table 6.** Distribution of wind power generation by pricing period.

## 3.4. Distributed photovoltaic generation

Each pumping station has a self-consumption photovoltaic (PV) system. The total installed PV capacity is 15.5 MW. Table 7 lists the installed capacity of each pumping station. Fig. 7 presents the total power generation of the 27 PV plants for each of the 24 hours of every day over the 365 days of study.

| Pumping station | Installed PV capacity (kW) | Pumping station | Installed PV capacity (kW) |
|---|---|---|---|
| **PS1** | 325 | **PS15** | 575 |
| **PS2** | 700 | **PS16** | 230 |
| **PS3** | 300 | **PS17** | 1.005 |
| **PS4** | 975 | **PS18** | 230 |
| **PS5** | 941 | **PS19** | 255 |
| **PS6** | 1,106 | **PS20** | 350 |
| **PS7** | 367 | **PS21** | 750 |
| **PS8** | 301 | **PS22** | 750 |
| **PS9** | 1,000 | **PS23** | 715 |
| **PS10** | 225 | **PS24** | 815 |
| **PS11** | 400 | **PS25** | 445 |
| **PS12** | 420 | **PS26** | 877 |
| **PS13** | 230 | **PS27** | 585 |
| **PS14** | 600 | | |
| **Total power (MW)** | | **15.5** | |

**Table 7.** Installed capacity of photovoltaic facilities

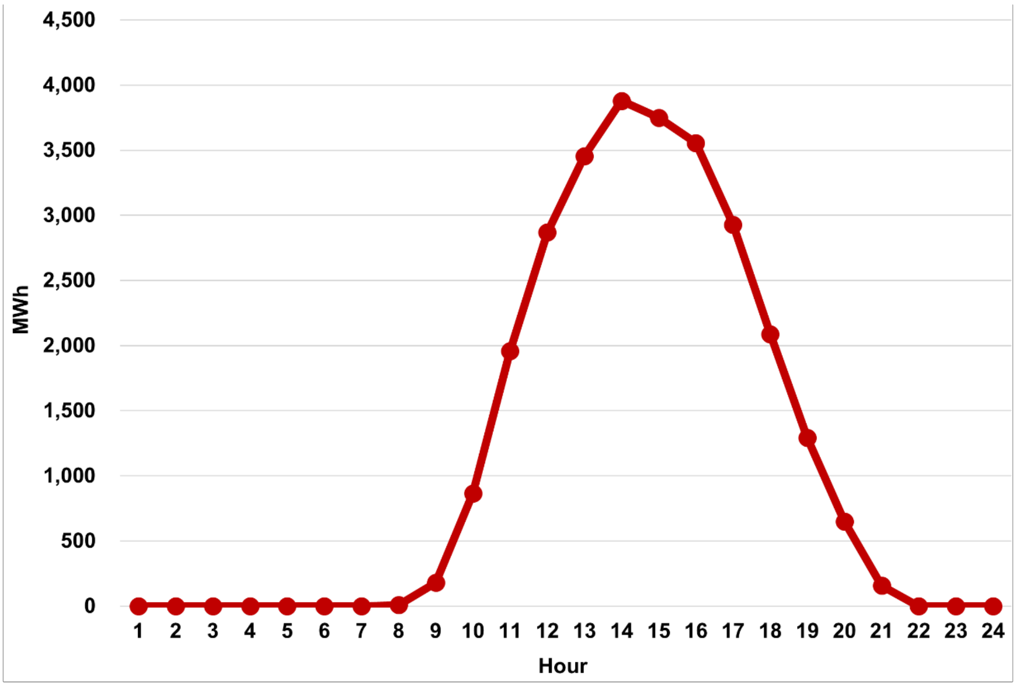



**Fig. 7.** Total energy generated by the photovoltaic plants

As expected, power generation is concentrated in the hours when there is solar radiation, and the maximum generation values are obtained between 12:00 and 17:00.

Additionally, Table 8 presents the distribution of the energy generated by pricing period. The highest power generation occurs in period P6, but this amount is less than that of the wind farm and the hydropower plants.

| Period | Energy generated (MWh) | Percentage (%) |
|---|---|---|
| **P1** | 3,874 | 14.02% |
| **P2** | 2,473 | 8.95% |
| **P3** | 2,057 | 7.44% |
| **P4** | 3,099 | 11.21% |
| **P5** | 5,588 | 20.21% |
| **P6** | 10,553 | 38.17% |
| **Total energy (MWh)** | **27,645** | **100.00%** |

**Table 8.** Distribution of the total photovoltaic generation by pricing period

## 3.5. Generation costs

This research considered variable generation costs, including the renewable technologies' operating and maintenance costs that determine the study model behaviour (see Table 9).

| TECHNOLOGY | OPERATING AND MAINTENANCE COSTS (€/MWh) |
|---|---|
| **Wind** | $f_W = 16.49$ |
| **Hydroelectric** | $f_H = 16.19$ |
| **Distributed photovoltaic** | $f_{PV} = 7.40$ |

**Table 9.** Operating and maintenance costs of renewable technologies [27],[28]

### 3.6. Cost of purchasing electricity

The demand of the pumping stations is met first by on-site photovoltaic plants and secondly by the system generators. In the event that the generation does not fully meet the demand, additional energy $P^i_{imp}$ will be purchased from the electricity market through an indexed contract. In the standard format of a pass-through electricity supply contract, the calculation of the hourly price of purchasing electricity $\rho^{\,i}_{imp}$ must incorporate other terms in addition to the energy price term of the OMIE day-ahead market (see Eq. 14).

$$\rho^{\,i}_{imp}(€/MWh)=\left[\left(C^i_{OMIE}+C^i_{const}+C^i_{procSO}+C^i_{int}+C^i_{cap}+C_{MO}+C_{SO}\right)\cdot\left(1+k^i_{loss}\right)\cdot Cf\right]+Fee+NT^i \qquad (14)$$

The terms of Eq. 14 are defined as follows:

- $C^i_{OMIE}$: hourly electricity price from the OMIE day-ahead market
- $C^i_{const}$: hourly technical constraints on the market price
- $C^i_{procSO}$: hourly market price of ancillary services of the system operator
- $C^i_{int}$: interruptible service cost
- $C^i_{cap}$: capacity cost
- $C_{MO}$: market operator cost
- $C_{SO}$: system operator cost
- $k^i_{loss}$: grid loss coefficient
- Cf: coefficient that varies according to the supplier (usually from 1.15 to 1.18)
- Fee: management cost that depends on the supplier
- $NT^i$: regulated energy term for the grid access tariff

### 3.7. Income from selling electricity

In the proposed model, surplus energy generated in the system is sold at the marginal hourly price recorded by the OMIE wholesale market during 2017. The generation tax (7%) and the generation grid access tariff (0.5 €/MWh) are considered in the final energy sales price (see Eq. 15).

$$\rho^{\,i}_{exp}\ (€/MWh) = \left[C^i_{OMIE}\cdot(1 - 0.07) - 0.5\right] \qquad (15)$$

## 4. Case study: results

The optimization model, which maximizes the hourly profit generated by the system, calculates the optimum value of 114 variables over the 8,760 hours of a year. The main optimization problem variables are those related to the power generated by each of the technologies included in the model and the amount of energy imported or exported hourly, both at each pumping station and by the whole system overall. In addition, the model includes 56 integer variables that have a value of 0 or 1 depending on the most profitable option for the system every hour.

Fig. 8 displays the hourly results obtained to meet the demand of all pumping stations for a week in July, which is typically the month of maximum annual demand.

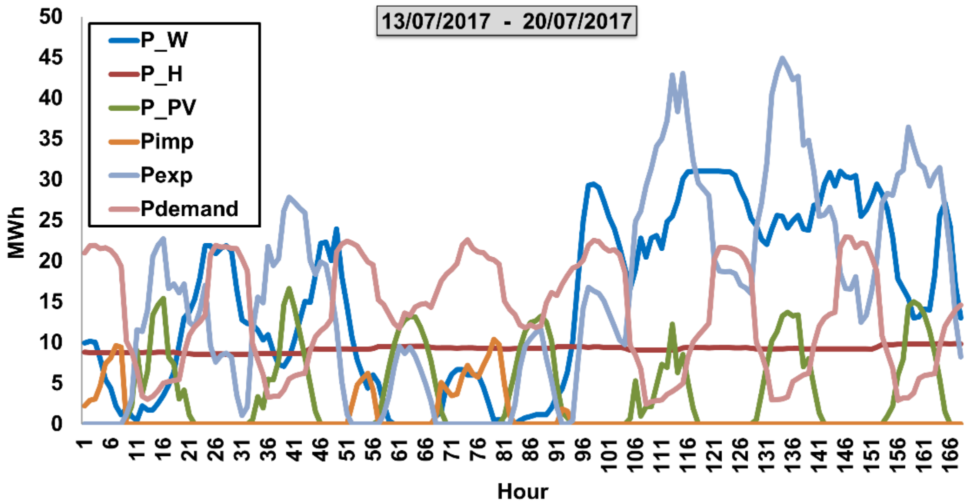



**Fig. 8.** Hourly optimum results for a week in July

In the optimal VPP solution for the hours in July, hydropower generation remains almost constant, since hydroelectric plants depend on water flow into the irrigation communities through the supply channels, and in this month the pumping stations are in full operation.

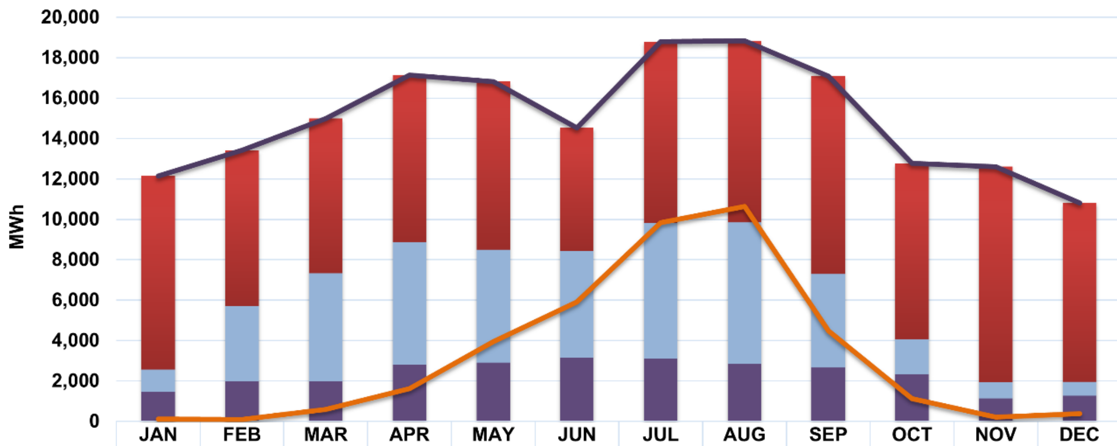
In contrast, the variability of wind power generation is apparent and leads to some full demand coverage situations but also to some periods with a lower contribution to the energy system. When maximum wind power generation is reached, there is no need to buy electricity from the grid, and excess power is exported to the grid; conversely, if wind power generation decreases, the system usually needs to purchase energy from the grid to meet demand.

Lastly, according to the design specifications, the photovoltaic plant's power is self-consumed as much as possible. However, energy consumption patterns are different for each pumping station, and the on-site photovoltaic generation does not perfectly match the load profile of each pumping station. For that reason, some of the stations obtain very small self-consumption rates since they barely connect their pumps during the day when there is substantial photovoltaic generation, while other pumping stations reach self-consumption percentages of around 50%. In the winter months, there is almost no demand, and solar generation is exported to the grid; therefore, the system income increases due to the sale of surplus power.

Fig. 9 shows the optimal power generated monthly by each technology included in the model. As expected, the hydropower plants produce electricity according to the seasonality of the water flowing through the transport channels to the pumping stations, that is, generation is more concentrated in months of the irrigation season. The variation in the electricity generated by the photovoltaic plants follows the typical solar irradiance cycle during the year. However, wind energy production exhibits greater variability than solar energy production due to its stochastic nature, as later discussed in Section 5.2.

Fig. 9 also demonstrates that the demand follows a seasonal pattern and is mainly concentrated in the summer months. However, for the overall system, monthly production is greater than monthly demand throughout the year.

Furthermore, a very high percentage of the available wind and hydroelectric power production is scheduled (98.98% and 99.53%, respectively) (Table 10), but for some hours it is more profitable to purchase energy from the electricity market instead of generating it using renewable power generation plants (see Fig. 11). Electricity production from on-site photovoltaic plants reaches 100% since these plants produce energy whenever the solar resource is available. This information illustrates the usefulness of the optimal dispatch model in maximizing the profit of an integrated VPP operation.




| | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| P_W | 9,583 | 7,706 | 7,661 | 8,257 | 8,327 | 6,093 | 8,978 | 8,997 | 9,796 | 8,702 | 10,663 | 8,869 |
| P_H | 1,103 | 3,742 | 5,349 | 6,061 | 5,591 | 5,296 | 6,715 | 6,995 | 4,628 | 1,732 | 804 | 686 |
| P_PV | 1,462 | 1,971 | 1,987 | 2,817 | 2,906 | 3,148 | 3,105 | 2,846 | 2,670 | 2,333 | 1,139 | 1,262 |
| Pgen | 12,148 | 13,419 | 14,997 | 17,135 | 16,824 | 14,538 | 18,798 | 18,838 | 17,094 | 12,767 | 12,607 | 10,818 |
| Pdemand | 125 | 102 | 601 | 1,617 | 3,945 | 5,910 | 9,849 | 10,647 | 4,480 | 1,128 | 210 | 391 |

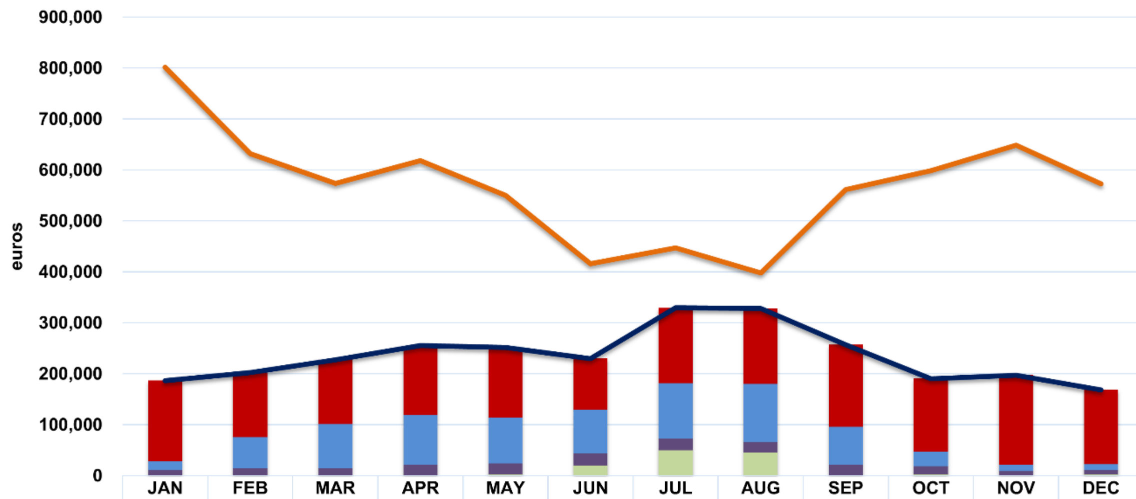
**Fig. 9.** Monthly aggregation of optimal hourly power generation

| | Energy production (MWh) | Demand coverage (%) | Scheduled generation (%) |
|---|---|---|---|
| $P_W$ | 103,634 | 54.5% | 98.98% |

| | | | |
|---|---|---|---|
| **$P_H$** | 48,703 | 25.6% | 99.53% |
| **$P_{PV}$** | 27,645 | 14.5% | 100.00% |
| **TOTAL** | 179,982 | 94.6% | |

**Table 10.** Percentage of annual demand supplied by the system's generators and scheduled generation of each technology

Fig. 10 depicts the monthly generation costs of each technology as well as the income from the sale of surplus power to the electricity market. As indicated, the income throughout the year is greater than the system costs. In the months when the system demand is minimal, surplus power is generated, and high income results from its sale. Conversely, in the irrigation season months, self-consumption increases, and energy must be purchased from the electricity market ($C_{imp}$) to meet demand, resulting in higher costs.




| | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| C_W | 158,031 | 127,070 | 126,332 | 136,165 | 137,313 | 100,480 | 148,047 | 148,363 | 161,538 | 143,497 | 175,839 | 146,257 |
| C_H | 17,854 | 60,581 | 86,601 | 98,124 | 90,520 | 85,748 | 108,716 | 113,247 | 74,924 | 28,046 | 13,023 | 11,113 |
| C_PV | 10,817 | 14,584 | 14,701 | 20,844 | 21,504 | 23,294 | 22,980 | 21,059 | 19,757 | 17,264 | 8,432 | 9,340 |
| Cimp | 0 | 0 | 0 | 0 | 2,293 | 20,385 | 49,927 | 45,483 | 946 | 1,774 | 87 | 1,809 |
| COSTS | 186,702 | 202,235 | 227,634 | 255,134 | 251,630 | 229,907 | 329,670 | 328,152 | 257,165 | 190,581 | 197,380 | 168,519 |
| INCOME | 801,424 | 632,305 | 573,514 | 618,696 | 550,517 | 415,770 | 447,213 | 398,148 | 561,503 | 598,923 | 649,045 | 572,775 |

**Fig. 10.** Monthly costs and income

The pumping station demand is entirely met by the power generation plants for 8,247 hours per year (see Fig. 11). In addition, the power plants produce no power for 36 hours a year. During those hours it is necessary to purchase all the energy required from the electricity market to meet demand, a situation that occurs most often during the peak demand summer months (see $C_{imp}$ in Fig. 10).

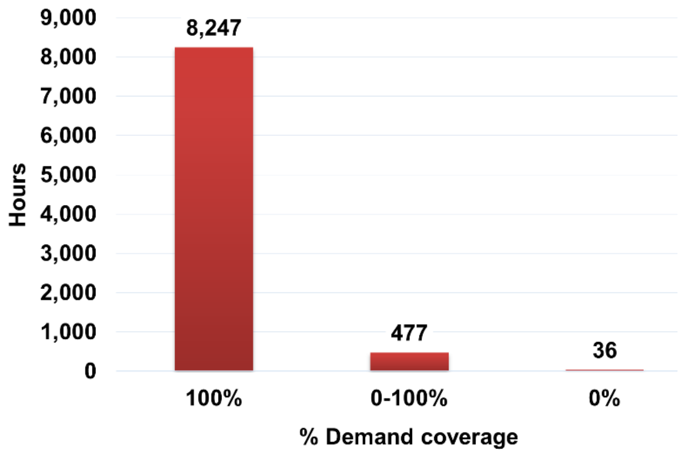



**Fig. 11.** Number of hours and percentage of demand supplied by the VPP

Table 11 presents the main results obtained, in terms of both energy and cost. The power generation plants cover 94.6% of the annual pumping station demand, which considerably reduces the dependence on the grid and aids system sustainability. The remaining 5.4% of demand is purchased from the electricity market either because there is not enough internal generation in the VPP or because purchasing energy is more profitable.

From the results in Table 11, an annual average generation cost of the electricity production of 15.01 €/MWh can be calculated. The annual average remuneration obtained from the sale of electricity is 47.67 €/MWh, and the average cost of the electricity purchase is 58.65 €/MWh. As explained in Section 3, the purchase cost is the sum of the wholesale market price and the network access tariffs.

For the system to maximize its profit, the electricity generation must occur at the same time as consumption, that is, the quantity of energy produced must match the energy demand as closely as possible. However, it depends not only on the available generation resources but also on whether the generation costs are competitive compared to the prices set in the day-ahead electricity market.

| | Energy (MWh) | Demand coverage (%) | Costs / Income (€) |
|---|---|---|---|
| $P_{demand}$ | 39,003 | 100% | |
| $P_{gen}$ | 179,982 | | -2,702,004 |
| $P_{exp}$ | 143,071 | | 6,819,833 |
| $P_{imp}$ | 2,092 | 5.4% | -122,704 |
| $P_{self\text{-}cons}$ | 36,912 | 94.6% | |
| **Total cost** | | | -2,824,708 |
| **Total income** | | | 6,819,833 |

**Table 11.** Optimal annual results of the VPP

## 5. Sensitivity analysis

This section presents a sensitivity analysis of various model parameters to evaluate their corresponding economic impact on the VPP.

### 5.1. Wholesale electricity market prices

This section analyzes the sensitivity of the optimal dispatch model in different electricity market price scenarios. Variation in these prices affects both the income from the sale of surplus generation to the wholesale market and the costs of purchasing energy during certain months of the year. Using the OMIE average 2017 wholesale market price in Spain as a reference, between 2006 and 2017 there are differences that range from -40% to +20% of the 2017 price [25], [29]. Six scenarios of sensitivity analysis have been performed for market prices ranging from -40% to +20%.

Table 12 describes the evolution of the annual generation, import and export of power in relation to the variation in the average electricity market price. Energy imported from the grid remains constant since it is difficult to compete against renewable power generation costs, even when electricity market prices drop by 40%. However, when the market price increases, generation and surplus power sales increase slightly (0.2%) because the price paid by the market renders power generation more profitable. Conversely, when the market price drops, power generation decreases between the reference case and the OMIE -40% case (-1.6%) because generating power is not as profitable if the power is sold at a price below the generation cost.

| | **OMIE -40%** | **OMIE -30%** | **OMIE -20%** | **OMIE -10%** | **OMIE ref** | **OMIE +10%** | **OMIE +20%** |
|---|---|---|---|---|---|---|---|
| **$P_{gen}$ (MWh)** | 177,069 | 178,861 | 179,720 | 179,853 | 179,982 | 180,144 | 180,306 |
| **$P_{imp}$ (MWh)** | 2,092 | 2,092 | 2,092 | 2,092 | 2,092 | 2,092 | 2,092 |
| **$P_{exp}$ (MWh)** | 140,157 | 141,949 | 142,808 | 142,941 | 143,071 | 143,232 | 143,394 |

**Table 12.** Evolution of the annual generation, import and export of power according to OMIE prices

Fig. 12 presents the evolution of system costs and income depending on the electricity market price. In general, the income is greater than system costs for all cases analyzed and always yields a positive operating profit. Changes in electricity market prices have a greater impact on income because they are directly related to the power sales price set by the market, while costs barely change with decreases or increases in the OMIE market price. For example, in the OMIE +20% case, income increases by 20%

compared to the 2017 reference case and 61% compared to the OMIE -40% case; however, costs only increase 1% and 4% for each case, respectively.

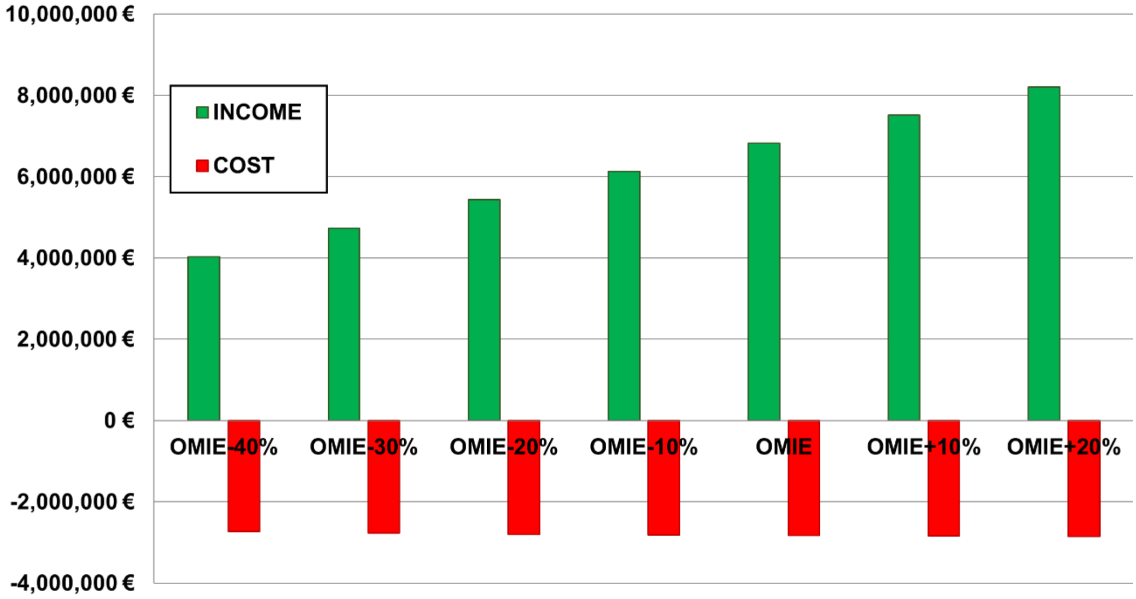



**Fig. 12.** Evolution of annual system cost and income versus OMIE day-ahead market prices

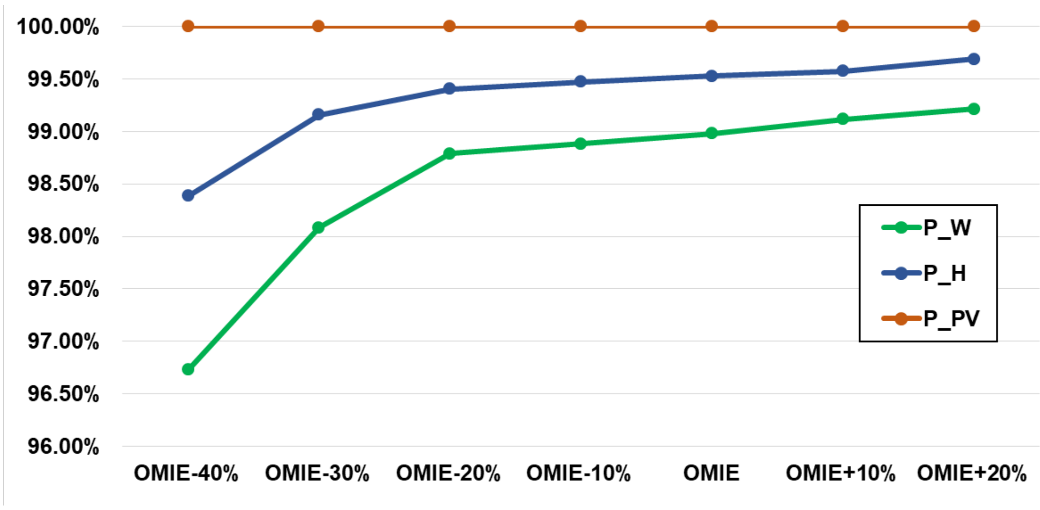



**Fig. 13.** Optimal power production of each generation technology for different market prices

Fig. 13 represents the optimal scheduling of power generation according to the variation in electricity market prices. The photovoltaic energy always reaches 100% due to design specifications. The wind and hydropower generation curves follow a similar trend, but wind energy is used less than hydropower in all the cases studied. This disparity arises mainly because wind power has a higher generation cost; furthermore, the hours of hydroelectric generation and the hours of demand are more similar than those of wind power. Fig. 13 also demonstrates that as market prices increase, producing more electricity with the wind farm and hydropower plants becomes increasingly profitable.

### 5.2. Wind power generation

Wind power technology has the greatest influence on the VPP model. Section 4 validated the model with actual production data from the wind farm in 2017, and this section studies the influence of other wind power generation profiles on the model. For this sensitivity analysis, the 2013–2017 average monthly generation in Spain was applied to the hourly generation profile used in Section 4 (see Fig. 14).

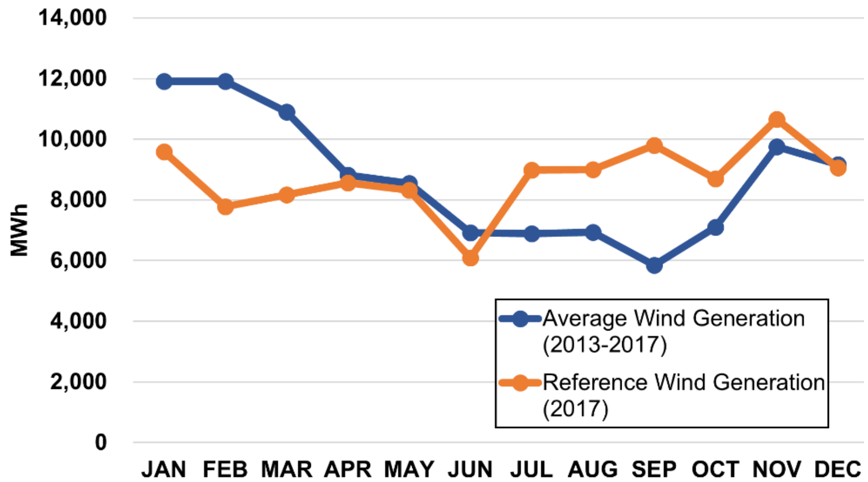



**Fig. 14.** Monthly wind power generation

The new wind power generation values were applied to the VPP optimal dispatch model. Tables 13 and 14 present the main results obtained by changing wind power generation. As a result of wind power generation reduction in the highest-demand months of the irrigation communities (May to September), power import from the grid increases and causes a slight decrease in the use of wind power (-0.22%) and a small increase in system costs (+0.93%). However, the income increases due to excess generation in lower-demand months (+0.73%), and a higher operating profit is achieved compared to the base case in Section 4 (+0.59%). These results demonstrate that the seasonal variations in wind generation do not excessively influence the economic profit of the VPP model.

| | Energy (MWh) | Demand coverage (%) | Demand coverage Δ | Scheduled generation (%) | Scheduled generation Δ |
|---|---|---|---|---|---|
| $P_W$ | 103,407 | 53.7% | -1.47% | 98.76% | -0.22% |

| | | | | | |
|---|---|---|---|---|---|
| **$P_H$** | 48,703 | 25.3% | -1.17% | 99.53% | - |
| **$P_{PV}$** | 27,645 | 14.4% | -0.69% | 100.00% | - |

**Table 13.** Percentage of annual demand supplied by system generators and scheduled generation of each technology, compared with previous results from Table 10

| | **Energy (MWh)** | **Demand coverage (%)** | **Costs / Income (€)** | **Δ** |
|---|---|---|---|---|
| **$P_{demand}$** | 39,003 | 100% | | |
| **$P_{gen}$** | 179,755 | | -2,698,256 | -0.14% |
| **$P_{exp}$** | 143,359 | | 6,869,826 | +0.73% |
| **$P_{imp}$** | 2,608 | 6.7% | -152,986 | +19.79% |
| **$P_{self\text{-}cons}$** | 36,396 | 93.3% | | |
| **Costs** | | | -2,851,242 | +0.93% |
| **Income** | | | 6,869,826 | +0.73% |

**Table 14.** Optimal annual results depending on the annual wind power generation profile, compared with previous results from Table 11

## 6. Conclusions

The development of new power management tools for irrigation systems is essential to improve farm profitability. In addition, the adoption of distributed generation in power systems and the development of more competitive electricity markets require new operation models to optimally integrate the available resources. The proposed technical-economic dispatch model supports VPP management, which is essential for such integration.

With the available renewable-source power generation facilities in the Riegos del Alto Aragon irrigation system, the VPP is able to meet almost 95% of the demand, greatly reducing the system's dependence on the grid and the final cost of power supply. Power is purchased from the electricity market when the hours or quantities of generation and consumption do not match or when purchasing energy is more profitable than generating it with internal renewable-source generation plants. In the latter case, wind and hydroelectric power generation are not 100% scheduled, while photovoltaic generation is completely utilized due to the model design.

A sensitivity analysis of the impact of changes in the wholesale electricity market price on the optimal dispatch model of the VPP was performed. Higher electricity market prices yield higher income from the energy exported to the grid, and increasing power generation and sale to the wholesale electricity market is more profitable. However, a variation in the annual wind power generation profile only slightly changes the results.

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