

Solar PV and self-consumption, drivers of more affordable electricity and of Spain's competitiveness

The price and cost of the day-ahead market with and without utility-scale PV and self-consumption, January 2025 to June 2026



Executive summary

The average price of the Spanish day-ahead market was 60.2 €/MWh between January 2025 and June 2026, and without utility-scale PV or self-consumption it would have been 112.0 €/MWh. The estimate comes from clearing OMIE's day-ahead market again, period by period and with each day's offers, after removing the utility-scale plants, buying the output of PV self-consumption in the day-ahead market and letting France, combined-cycle plants and hydropower respond to the new price.

- **With solar PV and self-consumption, the day-ahead price is 46% lower.** In 2025 the average price was 65.29 €/MWh and without them it would have been 113.9 €/MWh, **48.6 €/MWh higher**, and in the first half of 2026 it was 49.83 €/MWh against 108.1 €/MWh, **58.2 €/MWh higher**.
- **National demand saved €17,021 million in the day-ahead market over 18 months, of which €14,230 million corresponds to utility-scale plants and €2,791 million to self-consumption.** This amounts to **€10,863 million in 2025** and **€6,158 million in the first half of 2026**, about €5,340 million of it since the start of the conflict in Iran on 28 February 2026. The savings are split between the two in proportion to the energy each one produces, 90.5 TWh from utility-scale plants and 17.7 TWh from self-consumption.
- **Combined-cycle plants would have covered 39% of the energy left by solar PV and self-consumption.** Over 18 months they would have matched **34.8 TWh more** in the day-ahead market, 5.7 times what they actually matched, and most of the rest of the gap would have been covered by imports from France and by wind offers that had previously gone unmatched.

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1. Introduction

1.1. Marginal pricing and the pass-through of gas prices to the day-ahead market

Every day, OMIE's day-ahead market matches electricity supply and demand in Spain and Portugal for the following day, by hour until 30 September 2025 and by quarter-hour since 1 October. Sale offers are ranked from the cheapest to the most expensive, and every matched offer receives the price of the last one needed to cover demand, so when that last offer belongs to a combined-cycle plant the price of gas reaches all the energy matched in that period, including energy that burns no gas.

In 2019 and 2020 gas cost an average of 15.45 €/MWh and 10.23 €/MWh on MIBGAS, the organised Iberian gas market, and the average day-ahead price was 47.68 €/MWh and 33.96 €/MWh. In 2021 gas rose to 47.31 €/MWh and the day-ahead price to 111.93 €/MWh, and in 2022, after the invasion of Ukraine, gas reached an average of 99 €/MWh and the day-ahead price 167.52 €/MWh, the highest value in the series (Figure 1).

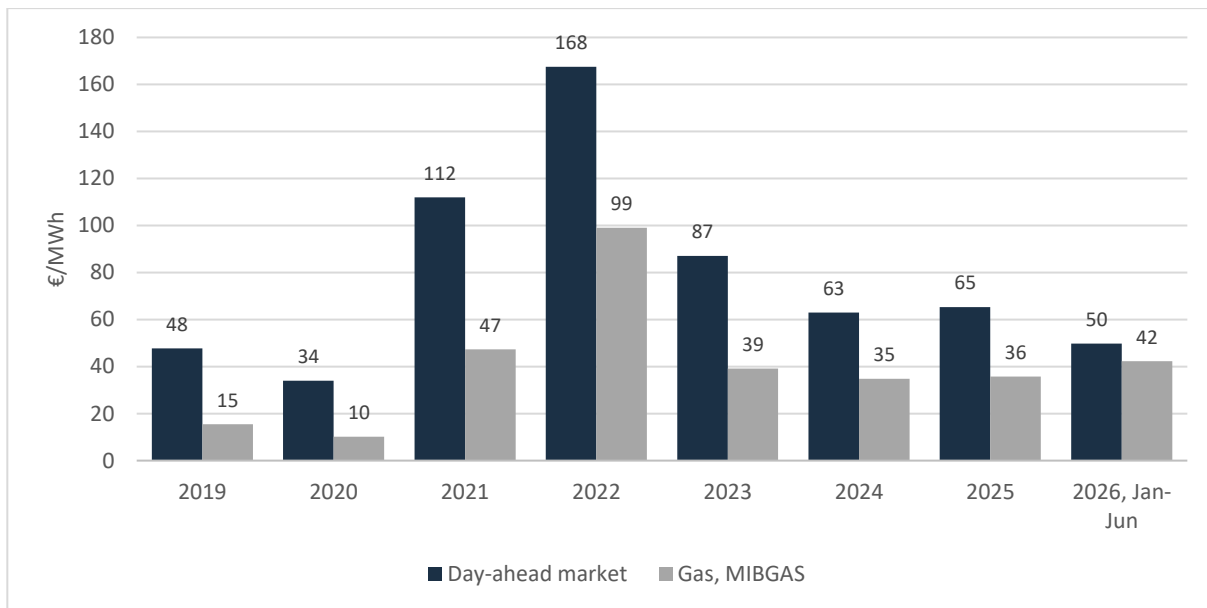


Figure 1. Annual average price of the Spanish day-ahead market and of gas on MIBGAS, 2019 to 2026, in €/MWh. 2026, January to June. Prepared by UNEF with data from ESIOs (indicator 600), the CNMC annual reports on the wholesale gas market and MIBGAS.

From 15 June 2022 until the end of 2023, the gas price cap of Royal Decree-Law 10/2022 compensated gas-fired plants for the difference between the gas price and a cap, initially 40 €/MWh, so that they would offer at lower prices in the day-ahead market, and this adjustment was paid separately from the market price, so the 2022 figure does not include it. In 2023 and 2024 gas fell to 39.12 €/MWh and 34.76 €/MWh and the day-ahead price to 87.10 €/MWh and 63.04 €/MWh, and in 2025 both remained at similar levels, 35.82 €/MWh for gas and 65.29 €/MWh for the day-ahead market.

Installed solar PV capacity in Spain, including utility-scale plants and self-consumption, grew from an average of 7.0 GW in 2019 to 54.4 GW in the first half of 2026, almost eight times more, and over the same period the average day-ahead price returned to levels close to those of 2019, 49.83 €/MWh against 47.68 €/MWh (Figure 2). Day-ahead volatility, the standard deviation of hourly prices within each month, followed a different path, rising from an average of 8.13 €/MWh in 2019 to 46.82 €/MWh in 2022 and 42.57 €/MWh in the first half of 2026, more than five times the 2019 level.

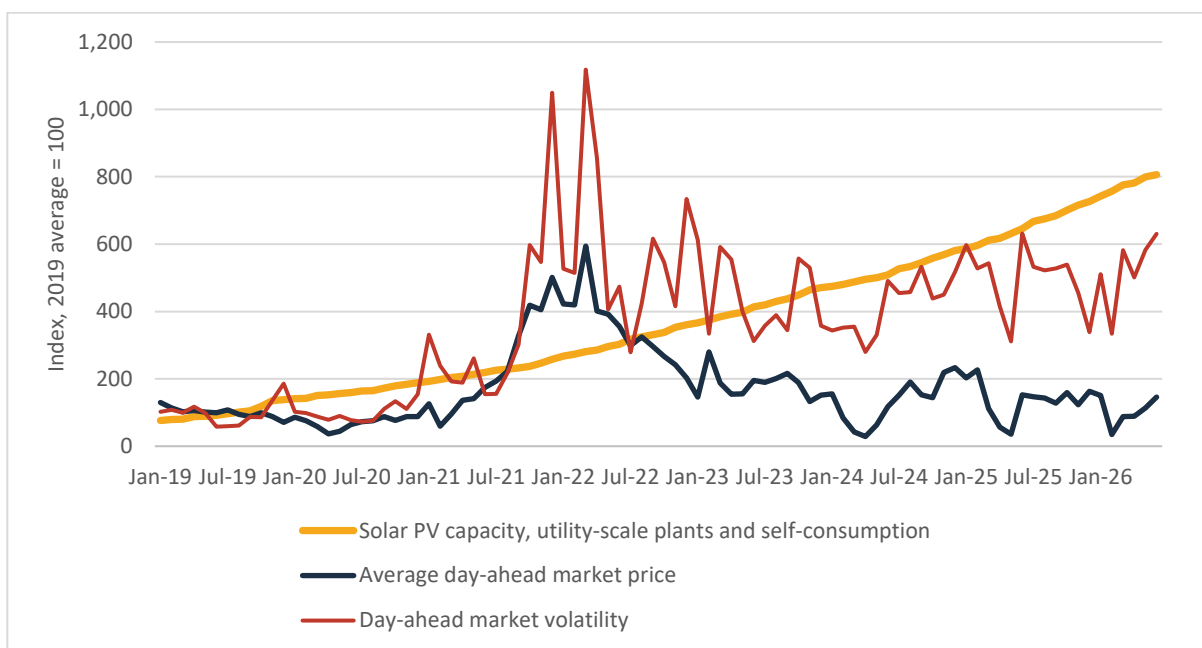


Figure 2. Installed solar PV capacity, utility-scale plants and self-consumption, monthly average price of the Spanish day-ahead market and its volatility, the standard deviation of hourly prices within each month, January 2019 to June 2026, as an index with the 2019 average equal to 100. Prepared by UNEF with data from ESIOS (indicators 600, 1486 and 1945) and UNEF.

In 2019 and 2022 the average hourly profile explained 26% and 28% of the variation in hourly prices within each month, and the rest came from day-to-day price changes. In 2025 it explains 49% and in the first half of 2026 52%, because the average price from 12:00 to 16:00 fell from 48.26 €/MWh in 2019 to 28.95 €/MWh in 2025 and 13.62 €/MWh in the first half of 2026, while the price from 20:00 to 23:00 went from 52.34 €/MWh to 105.27 €/MWh and 92.03 €/MWh. There were 797 hours at zero or negative prices in 2025, and none in 2019, so today's volatility is above all the gap between the sunlight hours, when a large volume of solar PV is matched, and the evening and night hours, when gas still enters the market.

1.2. The gas shock of the conflict in Iran and its dampened pass-through to electricity prices in 2026

Between 1 January and 27 February 2026 gas cost an average of 33.40 €/MWh on MIBGAS, and from the start of the conflict in Iran, on 28 February, until 30 June, 46.44 €/MWh, with 51.34 €/MWh in March, the month in which the Strait of Hormuz was closed (Figure 3).

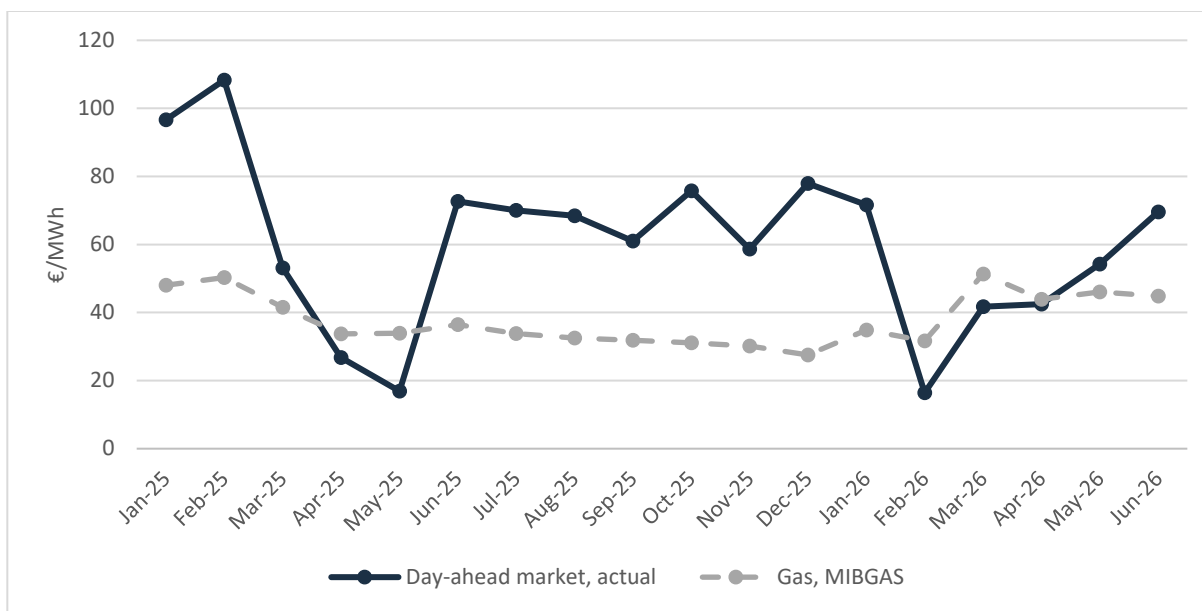


Figure 3. Monthly average price of the Spanish day-ahead market and of gas on MIBGAS, January 2025 to June 2026, in €/MWh. Prepared by UNEF with data from OMIE and MIBGAS.

With gas at these higher prices, the average day-ahead price in the first half of 2026 stood at 49.83 €/MWh, below the 65.29 €/MWh of 2025, and in March the day-ahead price was 41.77 €/MWh, less than gas itself. In 2022 gas at 99 €/MWh pushed the day-ahead price above 160 €/MWh, and in 2026 the rise in gas barely reached the electricity price because in many hours of the day the last matched offer is already wind, hydropower or, above all at midday, solar PV.

Renewable energy has thus dampened in Spain the effect of a crisis that originates abroad, and this document focuses on solar PV, both the utility-scale plants that sell their energy in the market and PV self-consumption, which does not go through it. To measure their effect, the day-ahead market has been simulated without them, and this simulation is used to calculate how much the price would have risen, how much national demand would have paid in the day-ahead market and which energy would have taken their place.

2. How the estimate was made

2.1. Reproduction and validation of day-ahead market clearing

Every day OMIE publishes the supply and demand curves of the day-ahead market, with each sale and purchase step of each unit, and the files with the conditions of the complex offers of combined-cycle and nuclear plants. With these offers the market has been cleared again period by period, using the same criterion as OMIE, over the 547 days from 1 January 2025 to 1 July 2026, 32,855 periods in total.

With all solar PV in place, the simulated price deviates from the price published by OMIE by 0.04 €/MWh on average in 2025 and by 0.02 €/MWh in the first half of 2026, and 99.7% of periods are within 1 €/MWh of it. This simulation with the full fleet is the reference from which solar PV is then removed, so the difference between the two prices captures only the effect of removing it.

2.2. Counterfactual scenario: withdrawal of utility-scale PV offers and addition of self-consumption to demand

Utility-scale PV plants sell their energy in the day-ahead market or through bilateral contracts. In the simulation their sale offers are withdrawn, which shifts the supply curve to the left, and whoever bought from them under contract has to buy that energy in the market, so the energy of their bilateral contracts is added to demand at the highest purchase price offered in every period of the day, which in practice is equivalent to buying it at any price.

PV self-consumption, which does not go through the day-ahead market, is represented by the hourly series with which Red Eléctrica estimates PV self-consumption generation, adjusted month by month to the self-consumption capacity recorded by UNEF. Without self-consumption this energy would be bought in the day-ahead market, so it is added to demand in the same way as the bilateral energy, at any price, which shifts the demand curve to the right (Figure 4).

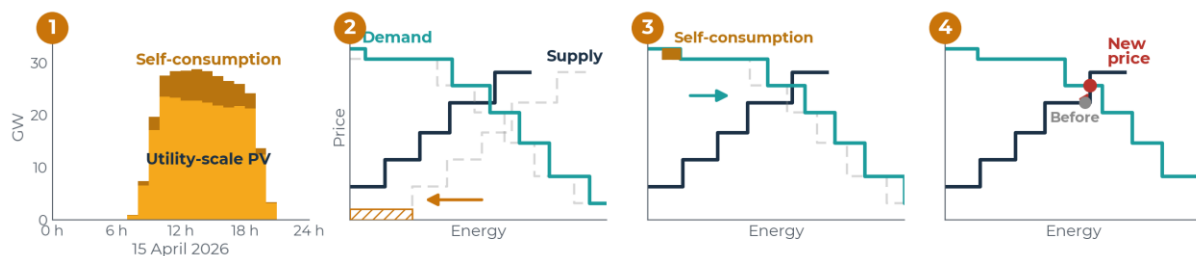


Figure 4. The method in four steps, in a schematic market with no figures except the profile in step 1, that of 15 April 2026. Prepared by UNEF with data from OMIE, Red Eléctrica and UNEF.

In 2025 self-consumption produced 11.5 TWh with about 8.4 GW of capacity, about 1,370 full-load equivalent hours, and on 15 April 2026 it reached about 6 GW at midday. All of its output is added, including the share fed into the grid and offset on the bill, and the only possible overcount is the surplus that installations above 100 kW sell in the market, which no public data source separates.

2.3. Application of the method to an actual clearing period

On 15 July 2025, from 13:00 to 14:00, the day-ahead price was 45.00 €/MWh with all solar PV and self-consumption. Without utility-scale PV or self-consumption, 30,030 MW in that hour between the sale offers withdrawn and the energy that is now bought in the day-ahead market, the supply curve shifts to the left, the demand curve to the right and the intersection reaches 280.00 €/MWh (Figure 5). That intersection is the one for the hour without any response from the rest of the system, and with the response of France, combined-cycle plants and water the same hour stands at 220.62 €/MWh, which is the calculation on which all the figures in this document are based.

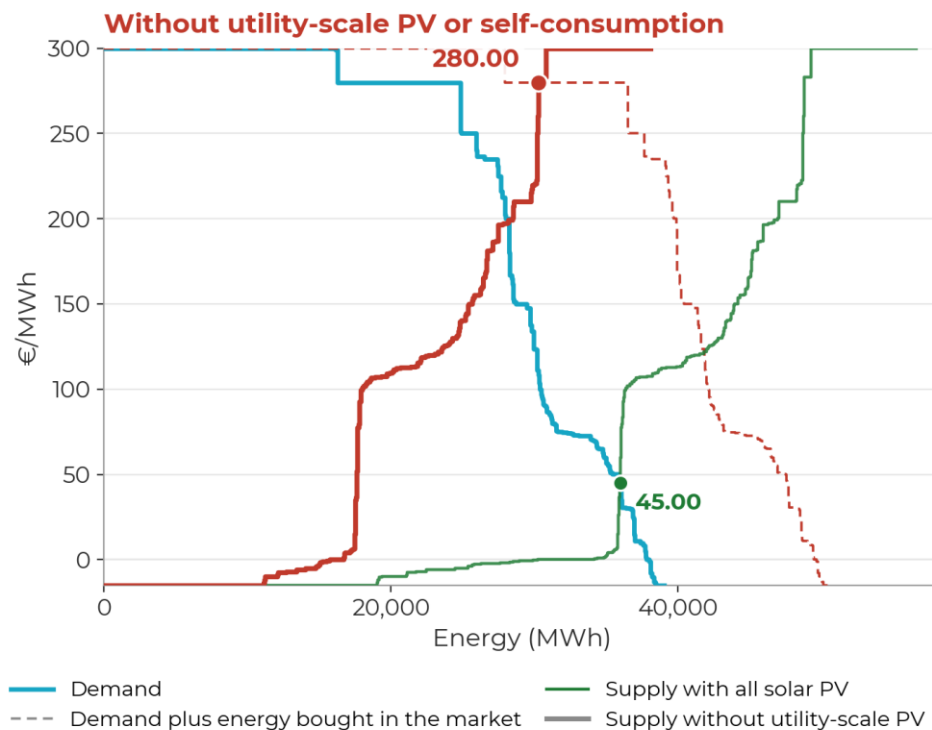


Figure 5. The day-ahead market on 15 July 2025, from 13:00 to 14:00, with all solar PV and without utility-scale PV or self-consumption, before the response of the rest of the system. Prepared by UNEF with data from OMIE, Red Eléctrica and UNEF.

2.4. System response: interconnections, combined-cycle plants and water management

Removing solar PV while nothing else changes overstates the price increase, because the rest of the system responds to higher prices. France sells more to Spain when the Spanish price exceeds the French one and capacity remains available on the interconnection, and Portugal does the same in the hours in which its price decouples from the Spanish one.

Combined-cycle plants whose offers the market rejected re-enter if the new prices cover the income condition of their offer, and hydropower can shift its output from some hours to others but cannot produce more energy over the day than it did, because the water in the reservoirs is the same.

No market participant changes its offers and the French price remains as it was, so the result is a short-term effect with the offers actually submitted. If the French price rose as France sold more to Spain, or if combined-cycle plants offered at higher prices knowing they were indispensable, the price without solar PV would be even higher.

2.5. From the marginal price to the cost of demand and technology substitution in the mix

National demand is the energy bought in each period by units in the Spanish zone, namely suppliers, direct consumers, pumping and storage, plus self-consumption once it is bought in the day-ahead market. Its share of purchases in each period is estimated with the simulation without the response of the rest of the system, and its cost is that energy multiplied by the price of the period. The savings of national demand in the day-ahead market are the difference between its cost without utility-scale PV or self-consumption and its actual cost, and do not include technical constraints or ancillary services, which are paid separately.

The same simulation yields the energy matched by each technology, both the actual figure and the figure that would be matched without solar PV, and the annex sets out the full method with its equations.

3. The price and cost of the day-ahead market

3.1. Magnitude and seasonality of the effect on prices

Between January 2025 and June 2026 the average day-ahead price was 60.2 €/MWh, and without utility-scale PV or self-consumption it would have been 112.0 €/MWh, 86% higher, which means that with them the price is 46% lower. In 2025 the increase would have been 48.6 €/MWh, from 65.29 €/MWh to 113.9 €/MWh, and in the first half of 2026 58.2 €/MWh, from 49.83 €/MWh to 108.1 €/MWh (Figure 6).

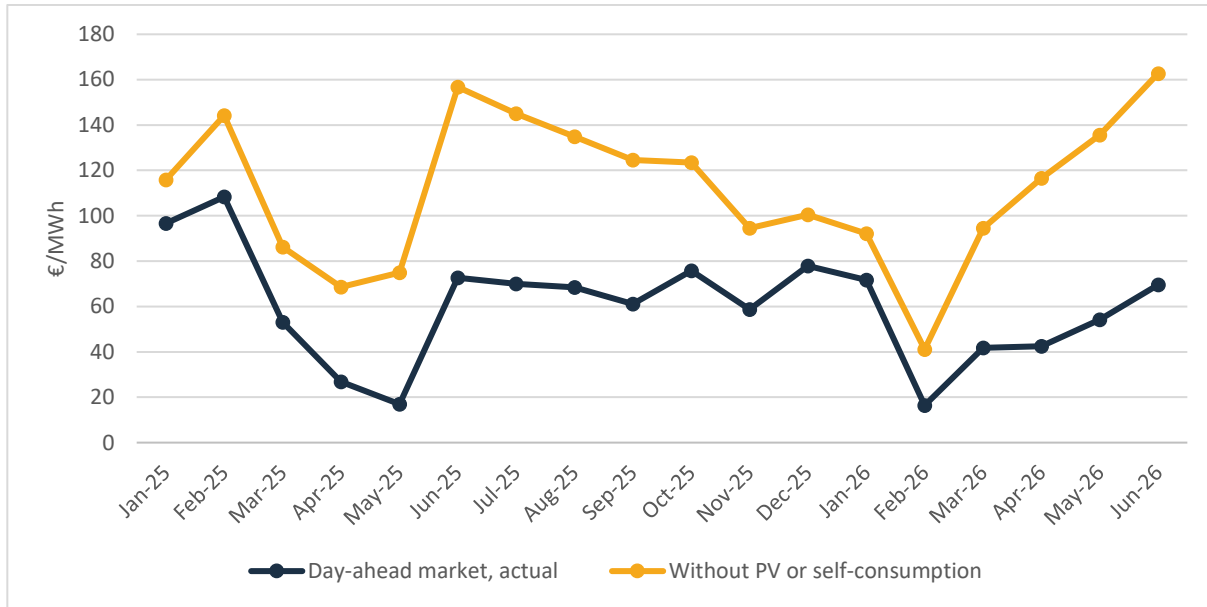


Figure 6. Monthly average price of the day-ahead market, actual and simulated without utility-scale PV or self-consumption, with the response of France, combined-cycle plants and water, January 2025 to June 2026, in €/MWh. Prepared by UNEF with data from OMIE, Red Eléctrica and UNEF.

The price without solar PV is above the actual price in all eighteen months, from 19.2 €/MWh higher in January 2025 to 93.2 €/MWh higher in June 2026. May 2025, the cheapest month of that year at 16.9 €/MWh, would have reached 75.0 €/MWh, and June 2026 would have been the most expensive month in the series, at 162.7 €/MWh against an actual price of 69.6 €/MWh.

The gap widens in spring and summer, when solar PV output is highest, and is larger in 2026, with more expensive gas since the start of the conflict. In the first half of 2025 the increase would have been 45.3 €/MWh, from 61.8 €/MWh to 107.1 €/MWh, against 58.2 €/MWh in the same half of 2026, and from 28 February to 1 July 2026 the price would have risen from 51.7 €/MWh to 126.6 €/MWh. Each MWh of solar PV removed is largely replaced by a combined-cycle plant or by a more expensive import, and the more gas costs, the more valuable the energy that solar PV brings to the market.

3.2. Avoided cost and its split between utility-scale plants and self-consumption: savings for national demand

National demand bought 167.2 TWh in the day-ahead market in 2025 and paid €10,442 million. Without utility-scale PV or self-consumption it would have paid €21,305 million for 178.3 TWh,

2.0 times its actual cost, so national demand saved €10,863 million in the day-ahead market (Figure 7).

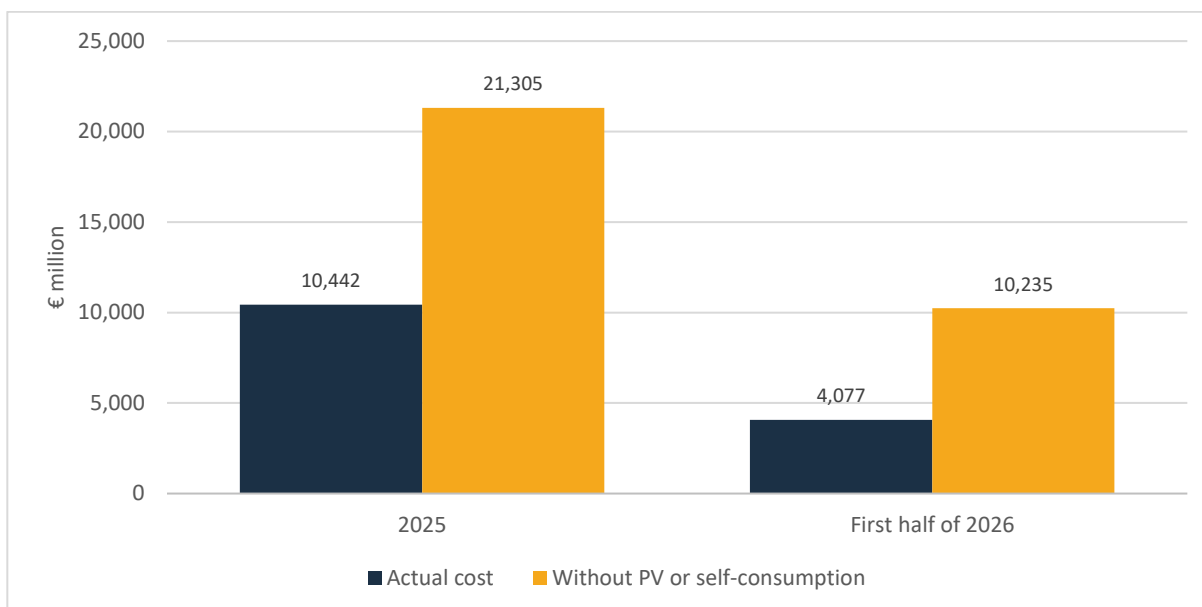


Figure 7. Cost of the energy bought by national demand in the day-ahead market, actual and without utility-scale PV or self-consumption, in € million. The difference between the two bars is the saving of national demand in the day-ahead market. The first half of 2026 runs from 1 January to 1 July. Prepared by UNEF with data from OMIE, Red Eléctrica and UNEF.

In the first half of 2026 it bought 89.4 TWh and paid €4,077 million, and without utility-scale PV or self-consumption it would have paid €10,235 million for 92.7 TWh, 2.5 times its actual cost, with savings for national demand in the day-ahead market of €6,158 million.

Over the 18 months the actual cost was €14,519 million and without utility-scale PV or self-consumption it would have been €31,540 million, and the savings of national demand in the day-ahead market came to €17,021 million, about €5,340 million of them since the start of the conflict in Iran. The simulation removes utility-scale plants and self-consumption at the same time, and the saving is that of both together.

Split in proportion to the energy each one produces, 90.5 TWh from utility-scale plants and 17.7 TWh from self-consumption, €14,230 million of the €17,021 million corresponds to utility-scale plants and €2,791 million to self-consumption, a split that does not depend on the order in which each one is removed.

4. Energy mix that takes the place of solar PV

Without utility-scale PV or self-consumption, 55.4 TWh would be missing in 2025, 43.9 TWh from utility-scale plants and 11.5 TWh from self-consumption, and 88.2 TWh over the 18 months. In 2025 combined-cycle plants in Spain and Portugal would cover 24.6 TWh of that gap, 44%, and would go from matching 6.4 TWh to 31.0 TWh, almost five times more.

The rest of the 2025 gap would be covered mainly by imports from France, with 14.9 TWh, 27%, the response of Portugal in the hours in which its price decouples from the Spanish one, with 4.2 TWh, wind offers that previously went unmatched, with 4.0 TWh, and Portuguese renewables, with 2.3 TWh. With higher prices, the demand that bids in the market would also match 3.6 TWh less, because part of pumping and consumption stops buying at those prices.

Over the 18 months combined-cycle plants would cover 34.8 TWh, 39% of the gap, France 22.8 TWh, 26%, and wind 8.5 TWh, 10% (Figure 8). These are the combined-cycle plants of both countries that are matched in the Iberian day-ahead market, because those that enter through technical constraints to support the grid do not go through the clearing and the simulation does not change them.

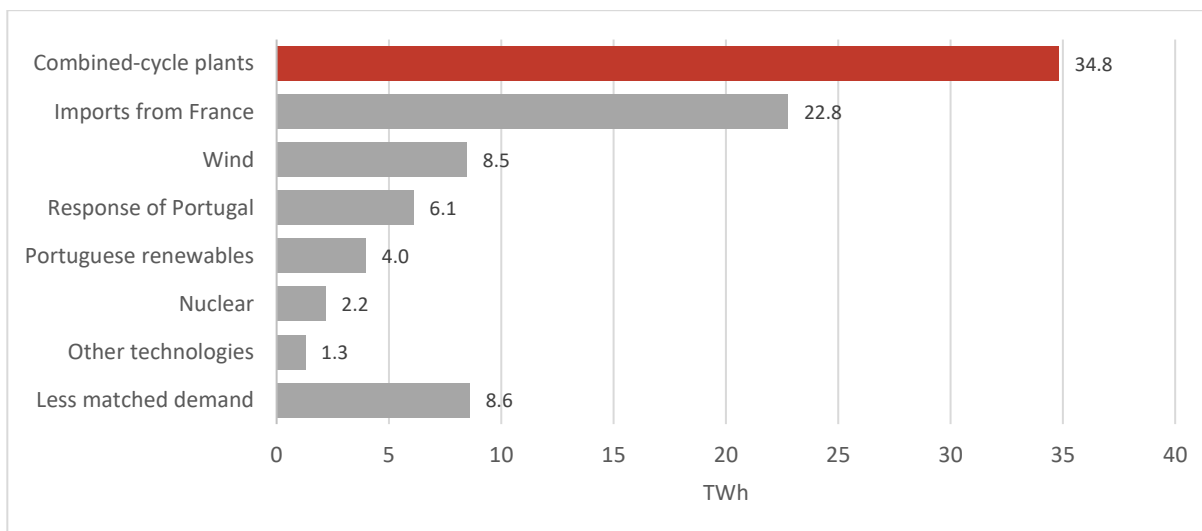


Figure 8. Energy that replaces in the day-ahead market the energy left by utility-scale PV and self-consumption, January 2025 to June 2026, in TWh. Prepared by UNEF with data from OMIE, Red Eléctrica and UNEF.

5. Conclusions

- **Solar PV has cushioned the gas crisis in Spain.** With gas on MIBGAS at 46.44 €/MWh since the start of the conflict in Iran, the average day-ahead price in the first half of 2026 was **49.83 €/MWh**, and without utility-scale PV or self-consumption it would have been **108.1 €/MWh**.
- **Solar PV and self-consumption lower the day-ahead price by 46%.** Over 18 months the average price was 60.2 €/MWh, against the 112.0 €/MWh it would have reached without them, and national demand saved **€17,021 million** in the day-ahead market, **€10,863 million in 2025** and **€6,158 million in the first half of 2026**. Of this total, **€14,230 million** corresponds to utility-scale plants and **€2,791 million** to self-consumption.
- **For every euro of solar PV revenue in the day-ahead market, national demand saved 8.** Between January 2025 and June 2026 solar PV obtained €2,127 million in revenues in the day-ahead market, and national demand saved €17,021 million thanks to utility-scale PV and self-consumption. These revenues are those from its sales in the day-ahead market according to Red Eléctrica's I3 file, excluding bilateral contracts and regulated remuneration.
- **Without solar PV, almost five times as much combined-cycle generation would be matched in the day-ahead market.** The plants in Spain and Portugal would cover 39% of the gap over 18 months, **34.8 TWh**.

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Annex. Methodology

A.1. Data and periods

The simulation covers the 547 days from 1 January 2025 to 1 July 2026. Each day has 24 hourly periods until 30 September 2025 and 96 quarter-hours from 1 October, with 23 or 25 hours, or their quarter-hours, on the days of the clock change, 32,855 periods in total. From OMIE the simulation takes the supply and demand curves of each period, the header and detail files of the offers, with the conditions of the complex offers, and the free exchange capacity at each border. The price in France and Portugal is ESIO indicator 600, gas is the MIBGAS daily index and self-consumption is ESIO indicator 1981.

$$\Delta_t = 1 \text{ h until 30 September 2025, } \Delta_t = 0.25 \text{ h from 1 October} \quad (1)$$

- t , clearing period of day d .
- Δ_t , duration of period t , in h.

A.2. Market clearing

Each period has a set of sale steps and another of purchase steps, each with its power and its price. The supply curve adds up the power of the sale steps priced at or below a given price, and the demand curve that of the purchase steps priced at or above it.

$$S_t(p) = \sum_{i \in V_t, p_i \leq p} q_i \quad (2)$$

$$D_t(p) = \sum_{j \in C_t, b_j \geq p} d_j \quad (3)$$

- p , price, in €/MWh.
- $S_t(p)$ and $D_t(p)$, supply and demand curves of period t , in MW.
- V_t and C_t , sets of sale and purchase steps of period t .
- q_i and p_i , power, in MW, and price, in €/MWh, of sale step i .
- d_j and b_j , power, in MW, and price, in €/MWh, of purchase step j .

The clearing price is the one at which the two curves meet. Sales are ranked from the lowest to the highest price and purchases from the highest to the lowest, and the clearing finds the largest volume at which the sale price is still below the purchase price. If the two marginal steps are matched in full at the same time, at a vertical intersection, the price is undetermined between two values and the midpoint is taken.

$$p_t^* = \frac{p_t^{\min} + p_t^{\max}}{2} \quad (4)$$

- p_t^* , clearing price of period t , in €/MWh.
- $p_t^{\min}$ and $p_t^{\max}$, bounds of the price interval in which the two curves intersect when the intersection is vertical, in €/MWh.

Complex offers with an income condition are accepted or rejected for the whole day. Those that the market accepted are kept, with the minimum power they declare in the detail file matched as a price-taking quantity and the rest of their steps as simple offers, and those that it rejected are excluded. In the periods in which Spain and Portugal cleared together the curve of the two zones is crossed, and in those in which they decoupled, the curve of the Spanish area with the flow to Portugal fixed as it cleared.

The simulation with the full fleet reproduces the OMIE price, and the gap is measured with the mean absolute error, 0.04 €/MWh in 2025 and 0.02 €/MWh in the first half of 2026.

$$MAE = \frac{1}{N} \sum_{t=1}^N |p_t^{\text{sim}} - p_t^{\text{OMIE}}| \quad (5)$$

- MAE, mean absolute error of the simulation, in €/MWh.
- N , number of periods.
- p_t^{sim} and p_t^{OMIE} , price simulated with the full fleet and price published by OMIE in period t , in €/MWh.

A.3. Withdrawal of utility-scale PV and self-consumption

The sale power of all Spanish PV units, identified with OMIE's list of units, is withdrawn, and the energy of their bilateral contracts, together with self-consumption output, is added to demand at the highest purchase price offered in every period of the day.

$$q'_i = 0 \text{ for } i \in \text{PV} \quad (6)$$

$$D'_t(p) = D_t(p) + B_t + A_t \text{ for } p \leq \bar{b}_d \quad (7)$$

- PV, set of sale steps of Spanish utility-scale PV units.
- q'_i , power of sale step i after the withdrawal, in MW.
- $D'_t(p)$, demand curve with the bilateral energy and self-consumption added, in MW.
- B_t , bilateral energy of utility-scale PV in the period according to Red Eléctrica's I3 file, in MW.
- A_t , PV self-consumption output in the period, in MW.
- $\bar{b}_d$, highest purchase price offered in every period of day d , in €/MWh.

Self-consumption output is Red Eléctrica's hourly series, which lags behind the installed fleet, rescaled each month to the capacity recorded by UNEF.

$$A_t = g_t^{\text{REE}} \frac{p_m^{\text{UNEF}}}{p_m^{\text{REE}}} \quad (8)$$

- g_t^{REE} , PV self-consumption generation estimated by Red Eléctrica in period t , ESIOS indicator 1981, in MW.
- p_m^{UNEF} and p_m^{REE} , self-consumption capacity in month m according to UNEF and to Red Eléctrica, in MW.

A.4. Response of France, Portugal, combined-cycle plants and water

France is modelled as an additional sale offer at the French price, for the import capacity that remained free in that period, taking into account the exports already matched. The offer is placed at the higher of two prices, the French price and the upper bound of the reference price interval plus one cent, so that nothing is matched in the reference. Portugal receives the same treatment in the periods in which it decouples, with its border and its price.

$$q_t^{\text{FR}} = K_t^{\text{free}} \text{ at } p_t^{\text{FR}} = \max(p_t^{\text{France}}, p_t^{\text{ref,max}} + 0.01) \quad (9)$$

- K_t^{free} , free import capacity from France in period t , in MW.
- p_t^{France} , French day-ahead market price, ESIO indicator 600, in €/MWh.
- $p_t^{\text{ref,max}}$, upper bound of the reference price interval, in €/MWh.

A complex combined-cycle offer that the market rejected re-enters if, at the scenario prices, it covers its fixed term and earns more than it earned at the reference prices. Offers are added one at a time, from the one that earns most to the one that earns least, and the day is cleared again after each one.

$$\sum_{t \in d} (p'_t - \pi_k) q_{k,t} \Delta_t \geq \max(F_k, U_k) \quad (10)$$

- p'_t , scenario price in period t , in €/MWh.
- π_k and $q_{k,t}$, price, in €/MWh, and power that would be matched, in MW, of the steps of offer k .
- F_k , fixed term of the income condition of offer k , in €.
- U_k , surplus of offer k at the reference prices, in €.

Hydropower and pumped-storage generation in each zone cannot sell more energy over the day than in the reference, but they can shift that energy from some hours to others. This is modelled with a water value per day and per zone, a minimum price below which they do not sell, which is raised until the day's energy fits within that of the reference.

$$\sum_{t \in d} h_{z,t}(\lambda_{d,z}) \Delta_t \leq \sum_{t \in d} h_{z,t}^{\text{ref}} \Delta_t \quad (11)$$

- z , zone, Spain or Portugal.
- $\lambda_{d,z}$, water value of day d in zone z , in €/MWh.
- $h_{z,t}$ and $h_{z,t}^{\text{ref}}$, hydropower matched in the scenario and in the reference, in MW.

A.5. Average price, cost and savings

The average price over a long period is the mean of the clearing prices weighted by the duration of each period, which is equivalent to the arithmetic mean of hourly prices.

$$\bar{p} = \frac{\sum_t p_t^* \Delta_t}{\sum_t \Delta_t} \quad (12)$$

The cost for national demand is the energy it buys in each period multiplied by the price of that period. The simulation is Iberian and its Spanish part is estimated with the share of buyers in the Spanish zone in each period of the simulation without the response of the rest of the system, and the added self-consumption counts entirely as Spanish.

$$C = \sum_t p_t^*(w_t(Q_t - A_t) + A_t)\Delta_t \quad (13)$$

$$\text{Saving} = C^{\text{no PV}} - C^{\text{act}} \quad (14)$$

- C , cost of national demand in the day-ahead market, in €.
- Saving, savings of national demand in the day-ahead market, in €.
- Q_t , energy matched in the area in period t , in MWh.
- w_t , share of buyers in the Spanish zone in the energy matched in the period, between 0 and 1.
- $C^{\text{no PV}}$ and C^{act} , cost without utility-scale PV or self-consumption and actual cost, in €.

The savings are split between utility-scale plants and self-consumption in proportion to the energy each one produces, year by year, using the energy that the simulation removes, the energy that utility-scale plants sold in the day-ahead market and through bilateral contracts and the energy generated by self-consumption. The two parts are rounded to millions of euros so that they add up to each year's savings, and amount to €9,038 million and €1,825 million in 2025 and €5,192 million and €966 million in the first half of 2026, with 56.9 TWh and 11.5 TWh in 2025 and 33.5 TWh and 6.2 TWh in the half-year.

$$\text{Saving}_k = \text{Saving} \frac{G_k}{G_{\text{PV}} + G_{\text{SC}}} \quad (15)$$

- Saving_k , saving attributable to utility-scale plants, $k = \text{PV}$, or to self-consumption, $k = \text{SC}$, in €.
- G_k , energy of utility-scale plants or of self-consumption in the year, in MWh.

A.6. Mix

The energy of each technology is the sum of what its steps match in each period, with self-consumption as a separate row outside the market in the actual case, so that both cases cover the same demand.

$$E_k = \sum_t x_{k,t}\Delta_t \quad (16)$$

- E_k , energy matched by technology k , in MWh.
- $x_{k,t}$, power matched by technology k in period t , in MW.

A.7. Evolution of the day-ahead market and of solar PV capacity

The solar PV capacity of each month is that of utility-scale plants plus that of self-consumption. Utility-scale capacity is obtained by subtracting from ESIO indicator 1486, installed solar PV capacity by autonomous community, the self-consumption estimated by Red Eléctrica,

indicator 1945, which is included in it, and self-consumption capacity is the UNEF year-end figure, interpolated linearly between months. The price of each hour is ESIO indicator 600 for Spain, with the average of the four quarter-hours from 1 October 2025, so that the measure is the same throughout the series.

$$P_m = P_m^{1486} - P_m^{1945} + P_m^{\text{UNEF}} \quad (17)$$

$$\sigma_m^2 = \frac{1}{H_m - 1} \sum_{h \in m} (p_h - \bar{p}_m)^2 \quad (18)$$

$$I_m^x = 100 \frac{x_m}{\bar{x}_{2019}} \quad (19)$$

- P_m , solar PV capacity installed in month m , utility-scale plants and self-consumption, in MW.
- P_m^{1486} and P_m^{1945} , ESIO indicators 1486 and 1945 in month m , in MW.
- P_m^{UNEF} , PV self-consumption capacity according to UNEF in month m , in MW.
- p_h , average price of the Spanish day-ahead market in hour h , in €/MWh.
- $\bar{p}_m$ and σ_m , average price and standard deviation of hourly prices in month m , in €/MWh.
- H_m , number of hours in month m .
- I_m^x , index of variable x in month m , capacity, average price or volatility, with the 2019 average equal to 100.

The share of volatility due to the hourly profile is the share of the variance of hourly prices in each month explained by the average profile by hour of the day in that month, and is reported as the average of the months of each year.

$$R_m = \frac{\sum_{h \in m} (\bar{p}_{m,k(h)} - \bar{p}_m)^2}{\sum_{h \in m} (p_h - \bar{p}_m)^2} \quad (20)$$

- $k(h)$, hour of the day of hour h , from 0 to 23.
- $\bar{p}_{m,k}$, average price of hour of the day k in month m , in €/MWh.
- R_m , share of the variance of hourly prices in month m explained by the profile by hour of the day, between 0 and 1.

A.8. What the simulation does not capture

It is a short-term effect with the offers actually submitted. No market participant modifies its offers, the French price does not move when France sells more to Spain and the MIBGAS price does not rise with higher gas demand, and all three would push the price without solar PV higher. Nor does the simulation model technical constraints, which in reality would change with more combined-cycle plants committed through the market, or the investments that would have been made in a different generation fleet.