Post-Delivery Control of Renewable Energy Production

Market Compliance and Imbalance Analysis for a Three-Park Aggregated Portfolio

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Context
Case study on post-delivery market compliance
for a French renewable energy aggregator

Abstract

Renewable aggregators must reconcile day-ahead volumes sold on the SPOT market with actual production, accounting for regulatory signals such as negative SPOT prices and TAO adjustment orders issued by the French TSO. We analyse 864 fifteen-minute intervals (17–25 March 2026) of actual production, forecasts, SPOT/PREP/PREN prices, and 16 TAO orders for a three-park portfolio (PARC_1: 15 MW solar, PARC_2: 13 MW wind, PARC_3: 85 MW wind), quantifying compliance during the 108 timesteps (27 hours, 12.5%) with negative SPOT prices and across all TAO windows. PARC_3 produced 139.8 MWh during negative-SPOT intervals and 237 MWh during TAO orders, versus 1.5 MWh and 1.44 MWh respectively for PARC_2, resulting in a net imbalance of -874 MWh and a total imbalance cost of $-115{,}914$ € concentrated on two days (18/03 and 25/03). Relative forecast errors are nearly identical on both wind parks ($\sim$54%), confirming that PARC_3's financial impact is driven by non-compliance with shutdown signals rather than by forecast quality. PARC_3's control infrastructure requires urgent inspection; PARC_1 and PARC_2 operate within normal margins.

Contents

1 Introduction

Renewable aggregators such as Agregio Solutions sell the forecasted production of their client portfolios on the day-ahead SPOT market the day before delivery. Because the forecast is built on imperfect weather information and because the real-time grid is subject to operational constraints, every aggregator faces a recurring question once the delivery day has passed: did the portfolio actually produce what was sold, and at what financial cost?

Two regulatory signals modify the baseline rule that "volumes sold on SPOT = forecasted production". First, when SPOT prices are negative, the French *complément de rémunération* scheme is not paid and plants are expected to curtail production to zero. Second, RTE, the French TSO, can issue TAO (*Ordres d'Ajustement*) orders forcing a specific plant to shut down within a defined time window, typically to relieve local grid congestion. Failing to respect either signal generates imbalances that are settled at the PREP (positive imbalance) or PREN (negative imbalance) price, both of which can be extreme during renewable-heavy, low-demand regimes.

This paper analyses the week of 17–25 March 2026 for a three-park portfolio (one solar, two wind) operated by Agregio Solutions. Using 15-minute actual production, the associated forecasts, SPOT/PREP/PREN price series, and the 16 TAO orders issued by RTE during the week, we quantify three distinct compliance dimensions: shutdown during negative SPOT prices, execution of TAO orders, and resulting imbalances with their financial cost. A dedicated focus on PARC_3 and a forecast-quality comparison between the two wind parks isolate the root cause of the portfolio's largest imbalance.

2 Methodology

2.1 Data

The dataset comprises four files provided for the delivery week. Three of them are 15-minute time-series with 864 timesteps each (9 days × 96 intervals per day): actual production per park (MW), forecasted production per park (MW) used as the volume sold on SPOT, and market prices (SPOT, PREP, PREN) in €/MWh. The fourth file lists the 16 TAO orders with start and end timestamps and the affected park.

Park	Type	Installed capacity
PARC_1	Solar	15 MW
PARC_2	Wind	13 MW
PARC_3	Wind	85 MW

Table 1: Portfolio composition. PARC_3 alone represents approximately 75% of installed capacity.

Figure 1 shows the SPOT price over the week. Prices range from approximately −4 €/MWh to ∼250 €/MWh, with the typical morning/evening peak structure and midday troughs. Negative SPOT prices affect 108 timesteps (12.5%, 27 hours), concentrated around midday on high-renewable days. PREP and PREN are more volatile than SPOT, reaching +2,219 €/MWh and −1,738 €/MWh respectively; 222 timesteps (25.7%) have negative PREP/PREN values, which amplifies the cost of imbalances during surplus periods. Figure 2 plots the three series on a shared axis: SPOT remains within a narrow band near the x-axis, whereas PREP and PREN show isolated tail excursions around 20/03, 23/03, and 25/03 that later drive the costliest settlement events.

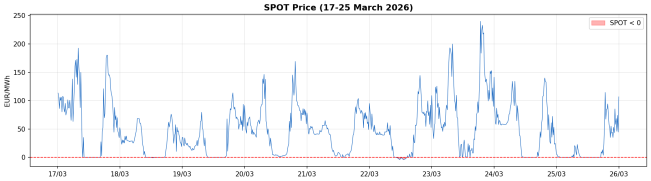

Figure 1: SPOT price over the delivery week. Red shading marks negative-SPOT intervals (12.5% of the week).

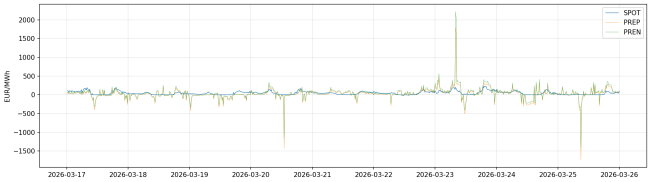

Figure 2: SPOT (blue), PREP (orange), and PREN (green) on a common scale. The PREP spike at +2,219 €/MWh on 23/03 and the PREN trough at −1,738 €/MWh on 25/03 lie more than an order of magnitude outside the SPOT range.

2.2 Imbalance and cost model

For each park $p \in \{1, 2, 3\}$ and each 15-minute timestep t, the volume sold on the SPOT market is defined as

$$V^{\text{sold}}_{p,t} = \begin{cases} P^{\text{prev}}_{p,t} & \text{if } \pi^{\text{SPOT}}_t \geq 0 \\ 0 & \text{if } \pi^{\text{SPOT}}_t < 0 \end{cases} \tag{1}$$

where $P^{\text{prev}}_{p,t}$ is the day-ahead forecast and π^{SPOT}_t is the SPOT price. The imbalance in energy terms is

$$E^{\text{imb}}_{p,t} = \left(P^{\text{real}}_{p,t} - V^{\text{sold}}_{p,t}\right) \cdot \Delta t \tag{2}$$

with $\Delta t = 0.25$ h. The corresponding settlement cost uses PREP for positive imbalances (overproduction) and PREN for negative imbalances (underproduction):

$$C_{p,t} = \begin{cases} E^{\text{imb}}_{p,t} \cdot \pi^{\text{PREP}}_t & \text{if } E^{\text{imb}}_{p,t} > 0 \\ E^{\text{imb}}_{p,t} \cdot \pi^{\text{PREN}}_t & \text{if } E^{\text{imb}}_{p,t} \leq 0 \end{cases} \tag{3}$$

A negative $C_{p,t}$ represents a net payment from the operator. TAO periods are flagged per park through a Boolean mask constructed from the 16 RTE orders and their start/end timestamps, then used to separate TAO-driven imbalances from normal-operation ones.

2.3 Compliance definitions

A park is considered compliant with the negative-SPOT rule if its production does not exceed a 0.01 MW sensor-noise tolerance during $\{t : \pi_t^{\mathrm{SPOT}} < 0\}$. A TAO order is considered respected if the maximum production during the order window is below 0.1 MW. Both thresholds are set to distinguish genuine non-compliance from measurement noise and residual ramp-down inertia.

3 Results

Figure 3 overlays actual and forecasted production for all three parks over the week, with red shading marking negative-SPOT intervals and purple shading marking TAO windows. A first visual inspection already distinguishes the three parks: PARC_1 and PARC_2 track their forecasts closely and visibly drop to zero during most regulatory signals, whereas PARC_3 remains at 60–80 MW inside several red and purple zones.

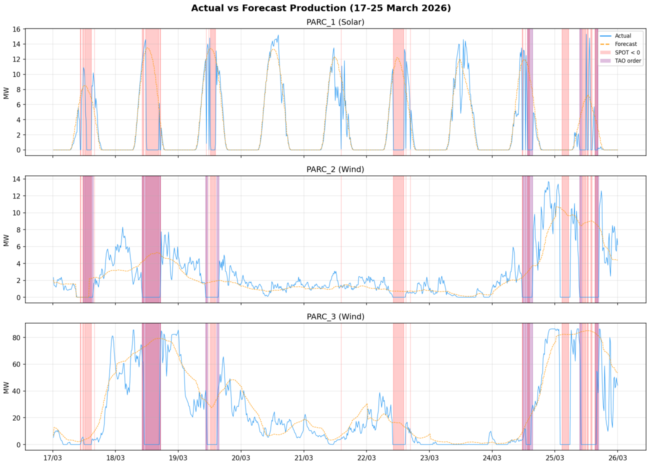

Figure 3: Actual (blue) vs forecasted (orange dashed) production for the three parks. Red zones: negative SPOT; purple zones: TAO orders.

3.1 Shutdowns during negative SPOT prices

We apply Equation (1) and aggregate the energy produced by each park across the 108 timesteps with $\pi_t^{\mathrm{SPOT}} < 0$. Table 2 reports the resulting totals alongside the maximum instantaneous power and a qualitative verdict.

Park	Type	E (MWh)	$P_{\max}$ (MW)	Verdict
PARC_1	Solar	25.6	14.6	Acceptable
PARC_2	Wind	1.5	1.9	Good
PARC_3	Wind	139.8	78.7	Poor

Table 2: Energy produced during negative-SPOT intervals. Target value is ∼0 MWh.

The solar plant produced 25.6 MWh during negative-SPOT windows, with a peak of 14.6 MW. This behaviour is largely explained by the physical inertia of photovoltaic curtailment: a solar plant cannot be switched off instantaneously when midday negative-SPOT windows open, and the production profile mechanically coincides with the hours when SPOT is most likely to become negative. PARC_2 shows near-perfect compliance (1.5 MWh, peak 1.9 MW), confirming that remote curtailment of wind turbines is technically achievable on the same portfolio.

PARC_3's 139.8 MWh over negative-SPOT intervals, with a peak of 78.7 MW, cannot be attributed to curtailment lag: the park is wind-powered and shares the same aggregator infrastructure as PARC_2. The total is concentrated on two days: 76 MWh on 18/03 and 41 MWh on 25/03, both of which coincide with high-wind regimes and extended negative-SPOT episodes.

3.2 TAO order compliance

RTE issued 16 TAO orders during the week: 3 on PARC_1, 6 on PARC_2, and 5 on PARC_3 (two additional orders on PARC_1 and one on PARC_2 are counted if overlap windows are considered individually; the totals reported here follow the per-park flag masks). Table 3 summarises the cumulative TAO time per park and the energy produced during those windows.

Park	Hours	Orders	E (MWh)	Verdict
PARC_1	4.5	3	0.10	Excellent
PARC_2	19.8	6	1.44	Good
PARC_3	15.8	5	237.0	Not respected

Table 3: TAO compliance per park. Target production inside a TAO window is 0 MW.

Figure 4 zooms in on the TAO windows and reveals a more nuanced pattern than the aggregate table suggests. All three parks drop to 0 MW within a few 15-minute steps of the TAO start, confirming that the leading edge of each order is correctly received and executed. Compliance then diverges at the trailing edge: PARC_1 remains at zero until the window closes (0.10 MWh total), whereas PARC_2 and PARC_3 resume production *before* the TAO end time. The premature restart is visible in Figure 4 as the blue line rising back inside the purple zones—most clearly on PARC_3 around 18/03 and

24/3. On PARC_2 the early-restart interval coincides with moderate wind conditions and limits the accumulated energy to 1.44 MWh. On PARC_3 the same pattern occurs during the two high-wind episodes of 18/03 and 25/03, where the early restart releases 60–80 MW of output while the order is still active; the resulting 237 MWh is two orders of magnitude above PARC_2.

The pattern rules out a failure to receive the TAO start signal on the wind parks—both respond correctly to the leading edge of each order. It points instead to a duration-handling issue between the TAO start and end times, consistent with several non-exclusive hypotheses: a SCADA-level issue in the aggregator-to-controller chain, where the TAO may be propagated as a momentary setpoint rather than as a time-bounded hold (possible culprits include lost hold-command propagation, watchdog timeouts that revert the setpoint to its default, or timestamp handling at the park boundary); a fixed-duration timer in the local curtailment controller that expires before the TAO end time; or an operator override that re-enables production early. The magnitude gap between PARC_2 and PARC_3 is driven by installed capacity (12×) combined with the high-wind timing of the two major PARC_3 restart events.

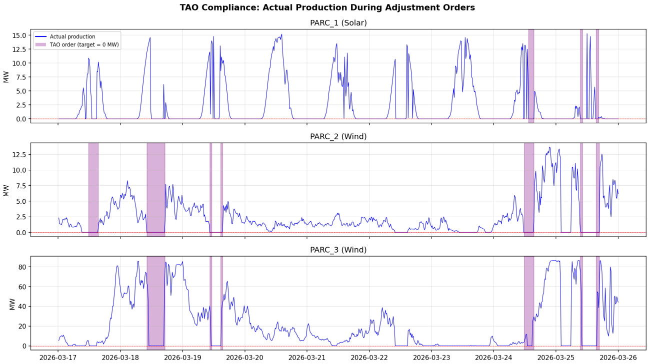

Figure 4: Actual production during TAO windows (purple shading). All three parks drop to 0 MW at the TAO start; PARC_2 and PARC_3 then resume production before the TAO end (premature restart), visible as the blue line rising back inside several purple zones—most clearly on PARC_3 around 18/03 and 24/3.

3.3 Imbalances and costs

Applying Equations (1)–(3) across the full week yields the aggregate indicators in Table 4. Net imbalance is the signed sum of quarter-hour imbalances; absolute imbalance is the sum of their absolute values, which better reflects the operational dispersion.

Figure 5 plots actual production against volume sold and makes Equation (1) visually explicit: wherever $\pi_t^{\text{SPOT}} < 0$, the orange (sold) series drops to zero while the actual production (blue) may continue. The gap is small and transient on PARC_1 and PARC_2; on PARC_3 the two series separate structurally on 18/03 and 25/03, with the actual line remaining at 60–80 MW while the sold line is flat at zero.

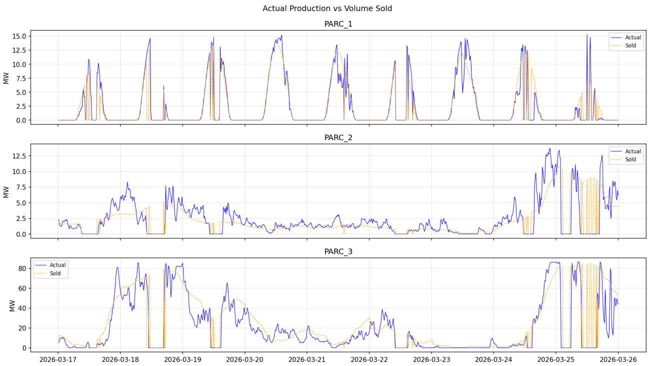

Figure 5: Actual production (blue) versus volume sold on SPOT (orange dashed). The sold series is forced to zero during negative-SPOT intervals per Equation (1).

PARC_1 and PARC_2 remain within normal operational margins, with absolute imbalances below 5% of their weekly sold energy and costs of a few thousand euros. PARC_3 generates a net imbalance of −874 MWh and a cost of −115,914 € over seven days, more than fifty times the cost of the other two parks combined.

The daily breakdowns in Figures 6 and 7 show that PARC_3's annual-scale cost is not uniformly distributed. A single day (25/03) concentrates −467 MWh of net imbalance and approximately −67,000 € of cost—roughly 60% of the weekly total. On that day, PARC_3 produced at near-capacity during an extended negative-SPOT episode, with PREN reaching deeply negative values that amplified the settlement cost.

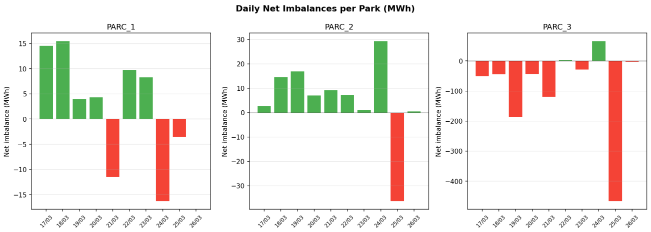

Figure 6: Daily net imbalance per park (MWh). Green: overproduction; red: underproduction. Note the axis-scale difference between parks.

Park	Net (MWh)	Absolute (MWh)	Total cost (€)	Assessment
PARC_1	+25	146	−2,101	Small, well managed
PARC_2	+52	230	+1,946	Acceptable
PARC_3	−874	1,949	−115,914	Critical

Table 4: Weekly imbalance indicators. A negative total cost represents a net payment from the operator to the balancing mechanism.

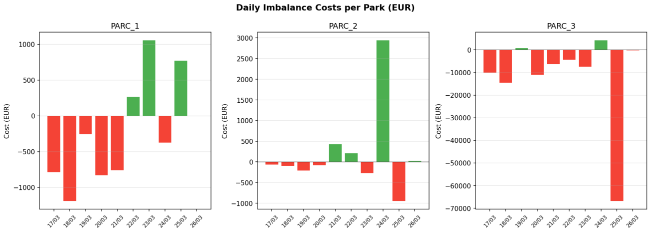

Figure 7: Daily imbalance cost per park (€). PARC_3 dominates with −67,000 € on 25/03 alone.

Separating TAO from normal operations gives further resolution: PARC_3's imbalance *outside* TAO windows is −825 MWh, which implies that 94% of the park's net imbalance volume accumulates during non-TAO hours—that is, during normal-operation hours in which the park simply failed to curtail during negative-SPOT intervals. TAO non-compliance alone accounts for only −49 MWh of net imbalance volume.

3.4 Focus on PARC_3

Figure 8 overlays PARC_3's actual and forecasted production with the SPOT price on a dual axis. The chart makes the compliance gap visually explicit: on 18/03 and 25/03, production remains at 60–80 MW (blue line) exactly when the SPOT price plunges below zero (grey line, red fill). The forecast (orange dashed) tracks the actual production reasonably well outside regulatory windows, which rules out a systematic forecast bias as the driver.

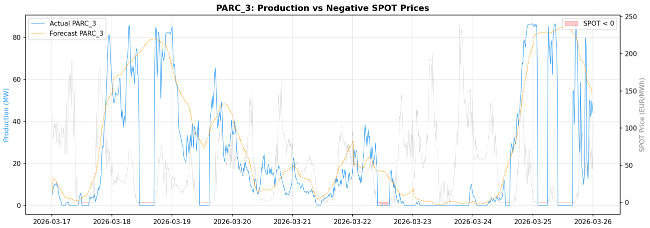

Figure 8: PARC_3 production (left axis, blue/orange) overlaid with SPOT price (right axis, grey). Red fill marks negative-SPOT intervals.

3.5 Forecast quality comparison

To isolate forecast quality from compliance, we restrict the comparison to the two wind parks under normal operation: $\pi_t^{\text{SPOT}} \geq 0$, no active TAO order, and forecast $P_{p,t}^{\text{prev}} > 0.1$ MW. We report the mean absolute error (MAE) in MW, the mean relative error defined per timestep as $|P^{\text{real}} - P^{\text{prev}}|/P^{\text{prev}}$, and a normalised error defined as MAE divided by mean production.

Park	$\overline{P}$ (MW)	MAE (MW)	Rel. (%)	Norm. (%)
PARC_2	2.29	1.12	54.0	48.8
PARC_3	27.69	8.86	53.3	32.0

Table 5: Forecast quality on the two wind parks, restricted to normal operation.

The relative errors are nearly identical across parks (54.0% vs 53.3%), which is the signature of a shared forecast model. PARC_3's larger absolute error (8.86 MW vs 1.12 MW) is mechanical: the park is approximately 12× larger than PARC_2, and absolute error scales with installed capacity under constant relative error. The normalised error is actually better for PARC_3 (32.0% vs 48.8%), indicating that if anything the forecast is more accurate relative to average output on the larger park. The critical financial gap identified in Section 3.3 is therefore not driven by forecast quality.

4 Discussion

4.1 Root cause and trade-off framing

The three analyses converge on the same conclusion: PARC_3's −115,914 € weekly imbalance cost is driven by failures in the local curtailment chain, not by a worse forecast. The failure takes two distinct forms. The negative-SPOT non-compliance is a complete absence of response: the park continues at near-full output through the 27 hours of negative SPOT ($\sim$ 100× more prohibited energy than PARC_2). The TAO non-compliance is a premature restart: the park correctly drops to zero at the TAO start but resumes production before the window closes ($\sim$ 165× more energy than PARC_2 during TAO periods). The forecast model is shared with PARC_2 and performs comparably, and the dispatch infrastructure is operated by the same aggregator, which localises both failures to the PARC_3 boundary.

The trade-off worth noting here is between operational simplicity and financial exposure in large-park portfolios. PARC_3 alone represents roughly 75% of the portfolio's installed capacity: even a small proportional compliance gap translates into disproportionate euro losses when PREN prices drop deeply negative during renewable-surplus regimes. The two days 18/03 and 25/03 together account for most of the weekly cost, confirming that exposure is concentrated in a small number of high-stress events rather than spread evenly across operation.

4.2 Limitations

Three limitations temper the financial interpretation. First, imbalance costs during TAO periods are not necessarily a net economic loss for the operator: RTE compensates operators for forced shutdowns through the adjustment mechanism, and the raw cost reported here does not net that revenue. This applies to PARC_1 and PARC_2, which comply with TAO orders. It does not apply to PARC_3, which fails to respect them and is therefore unlikely to qualify for compensation, and may face additional RTE penalties beyond the imbalance cost calculated here. Second, the 0.01 MW and 0.1 MW tolerance thresholds used to distinguish compliance from non-compliance are conservative choices; a stricter threshold would not change PARC_3's verdict but would slightly reclassify PARC_1's 25.6 MWh as borderline rather than acceptable. Third, the analysis covers a single week of operation during a volatile spring regime with repeated negative-SPOT episodes; extrapolating the weekly cost to an annualised figure would require a longer window covering different seasonal price structures.

4.3 Recommendations

Three actions follow from the analysis. First, PARC_3's local curtailment chain requires urgent inspection along two distinct failure modes. The absence of response to negative-SPOT conditions points to a missing or misconfigured price-based curtailment routine at the park level. The premature restart during TAO windows warrants investigation of the three candidate causes identified in Section 3.2—a SCADA-level issue propagating the TAO as a momentary setpoint rather than a time-bounded hold, a fixed-duration timer in the local controller, or an operator override—with the SCADA chain prioritised since it is the easiest layer to instrument. The fact that the same aggregator signals reach PARC_2 correctly localises both issues to the PARC_3 boundary rather than to the dispatch layer. Second, improving the shared forecast model would benefit both wind parks proportionally, but the financial return is concentrated on PARC_3 given its size; a scope decision on forecast investment should weigh this against the cost of the curtailment fix. Third, PARC_1 and PARC_2 can be maintained under current procedures, with the note that solar curtailment inertia on PARC_1 is a physical feature rather than a process failure.

5 Conclusion

This study performs the post-delivery control of a three-park renewable portfolio over the week of 17–25 March 2026, quantifying compliance with negative-SPOT shutdowns, TAO adjustment orders, and resulting market imbalances. PARC_3 produced 139.8 MWh during 27 hours of negative SPOT prices and 237 MWh during 15.8 hours of TAO orders, generating a net imbalance of −874 MWh and a weekly cost of −115,914 €, concentrated on 18/03 and 25/03. PARC_1 and PARC_2 comply with both signals and operate within normal imbalance margins.

A comparison of relative forecast errors on the two wind parks (54.0% vs 53.3%) and of normalised errors (48.8% vs 32.0%) demonstrates that the forecast model is not the root cause of PARC_3's exposure. The park's critical financial impact stems from a failure to curtail during regulatory shutdown signals, not from a worse prediction of its own output.

The immediate operational priority is the inspection of PARC_3's curtailment chain; the longer-term structural question is how exposure to PREP/PREN tails is managed in large-park portfolios where a single asset concentrates the majority of installed capacity.

A Additional Figures

For completeness, this appendix reports three raw-data views produced during the analysis but not strictly required to follow the main argument: actual production per park without overlays (Figure 9), the corresponding day-ahead forecasts (Figure 10), and the 15-minute-resolution imbalance signal before daily aggregation (Figure 11).

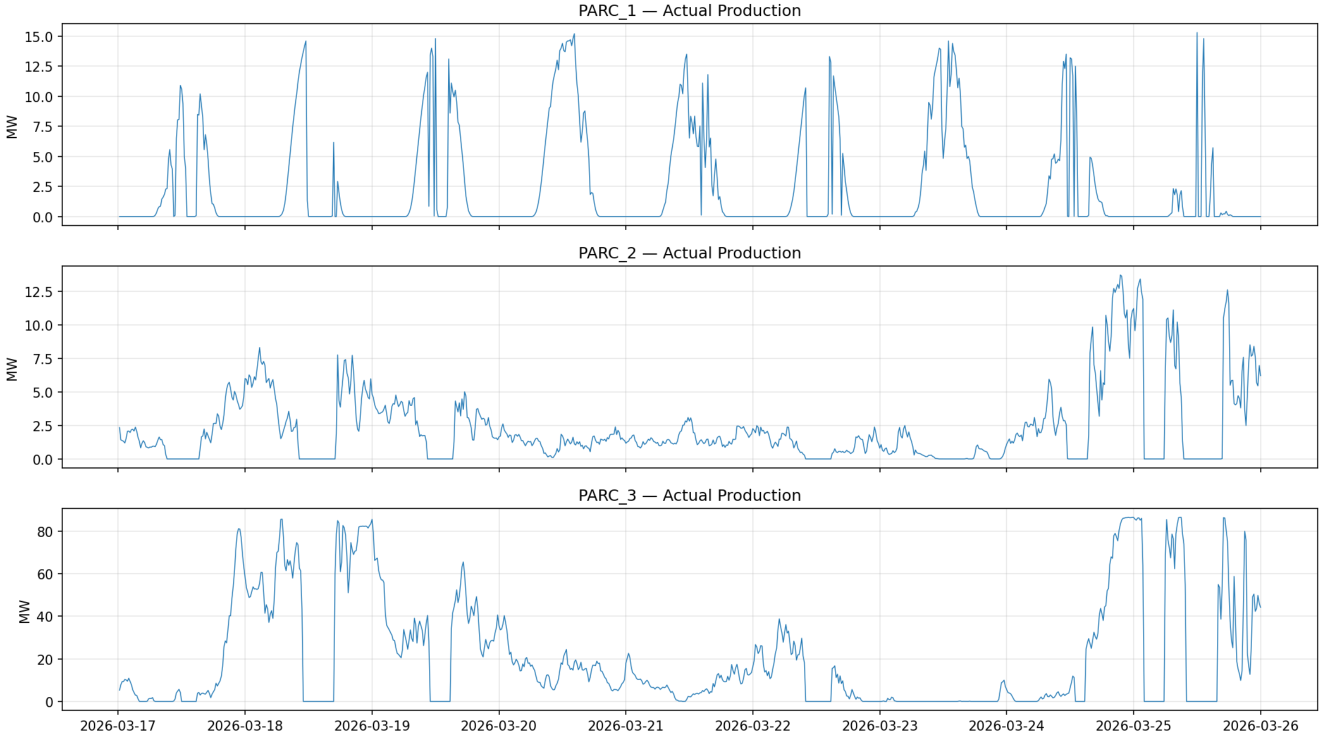

Figure 9: Actual production per park over the delivery week. PARC_1 shows the expected solar diurnal profile; PARC_2 and PARC_3 show wind variability with correlated patterns across the two sites.

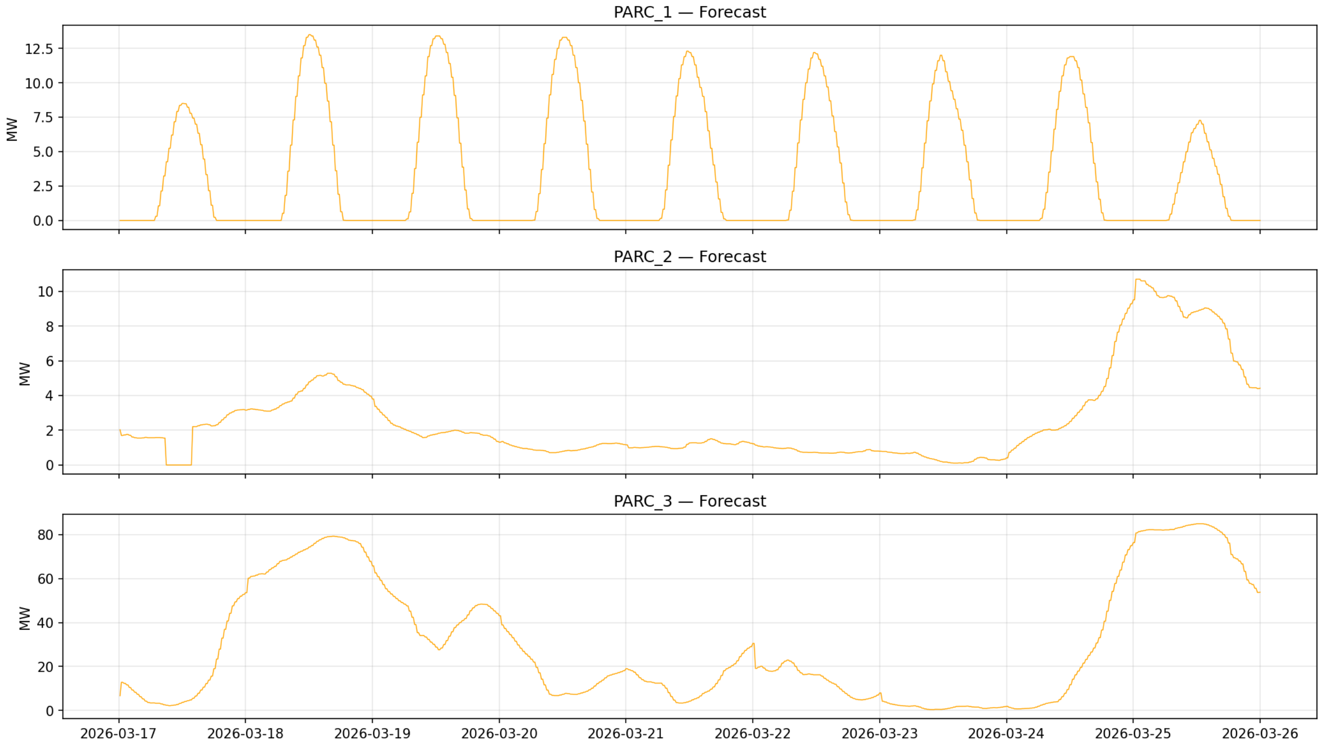

Figure 10: Day-ahead forecast per park, used as the basis for the SPOT bid (except where set to zero by Equation (1)). The solar forecast follows a smooth bell-curve template; the wind forecasts show lower-frequency variation than actual production.

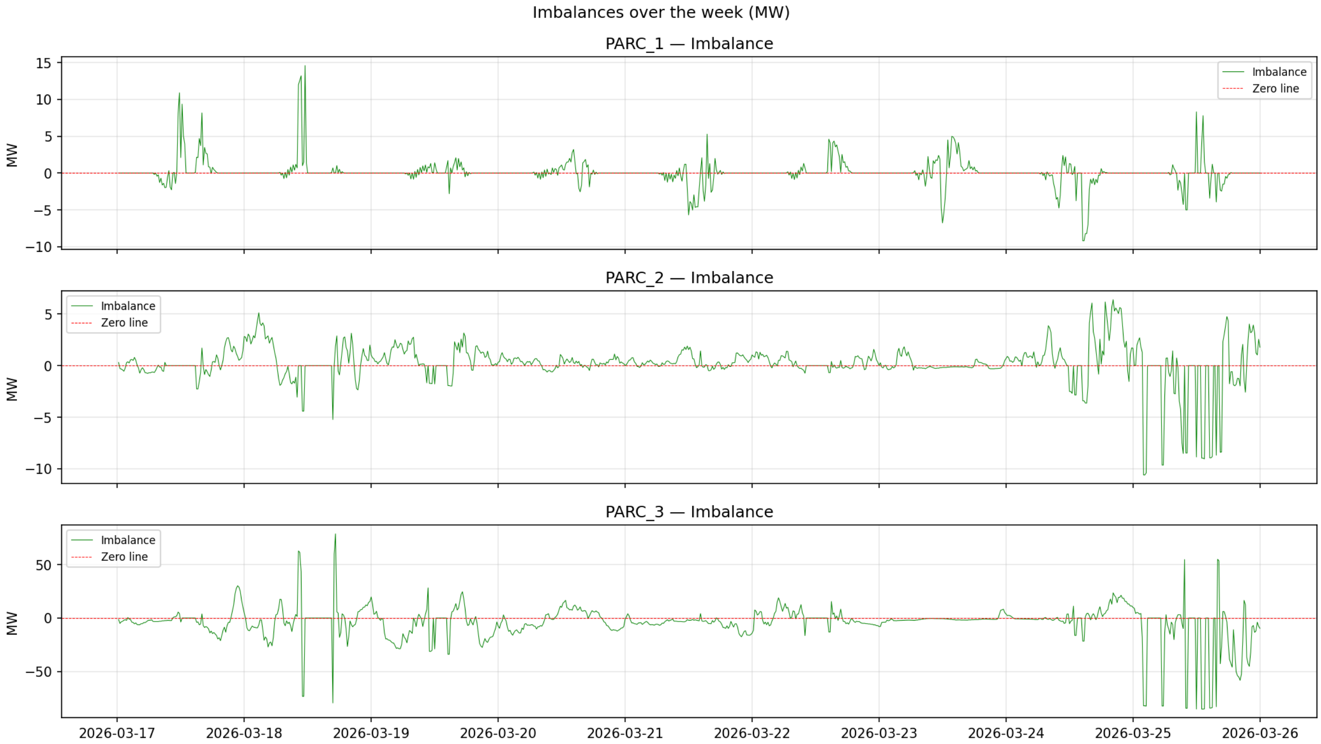

Figure 11: Quarter-hour imbalance signal $E_{p,t}^{\text{imb}}/\Delta t$ in MW. PARC_1 and PARC_2 remain within ±10 MW; PARC_3 reaches ±75 MW with concentrated excursions on 18/03 and 25/03.

B Nomenclature

Abbreviations

Acronym	Meaning
RTE	*Réseau de Transport d'Électricité* — French Transmission System Operator
TSO	Transmission System Operator
SPOT	Day-ahead electricity market (EPEX) clearing price
PREP	*Prix de Règlement des Écarts Positifs* — settlement price paid/charged for positive imbalance (overproduction relative to V^{sold})
PREN	*Prix de Règlement des Écarts Négatifs* — settlement price paid/charged for negative imbalance (underproduction)
TAO	*Traitement Automatique des Ordres* — automated adjustment order issued by RTE requiring a plant to curtail to 0 MW during a specified window [TBD: confirm exact expansion in Agregio internal terminology]
MAE	Mean Absolute Error
MW / MWh	Megawatt (power) / Megawatt-hour (energy)
SCADA	Supervisory Control and Data Acquisition

Symbols

Symbol	Description	Unit
p	Park index, $p \in \{1, 2, 3\}$	—
t	Timestep index (15-min intervals, 864 per week)	—
Δt	Timestep duration	0.25 h
$P^{\text{real}}_{p,t}$	Actual production of park p at timestep t	MW
$P^{\text{prev}}_{p,t}$	Day-ahead forecasted production of park p at timestep t	MW
$V^{\text{sold}}_{p,t}$	Volume sold on the SPOT market ($= P^{\text{prev}}$ if $\pi^{\text{SPOT}} \geq 0$, else 0)	MW
π^{SPOT}_t	Day-ahead SPOT price at timestep t	€/MWh
π^{PREP}_t	Positive imbalance settlement price	€/MWh
π^{PREN}_t	Negative imbalance settlement price	€/MWh
$E^{\text{imb}}_{p,t}$	Quarter-hour imbalance energy, $(P^{\text{real}} - V^{\text{sold}}) \cdot \Delta t$	MWh
$C_{p,t}$	Quarter-hour settlement cost (negative = payment by the operator)	€