The need for intra-day settlements in US electricity markets

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Overview

In the very diverse timescale of wholesale electricity markets —from years-ahead long-term markets, to the very short-term balancing and regulation markets—, the day-ahead market (DAM) has usually played the leading role in determining the economic dispatch of power plants. However, as Variable Energy Resources (VER) achieve relevant shares in power systems, uncertainty in DAM production schedules is shifting the focus to shorter-term markets.

In the European context, intraday markets have proven to be critical in accommodating solar and wind production (Borggrefe and Neuhoff, 2011), the reason being that VER forecast uncertainty significantly decreases in the time horizons considered by these market segments. The multiple intertemporal constraints in power systems make the cost derived from forecast errors quite substantial, especially in systems that rely on thermal generation. This requires forecast errors to be corrected as soon as possible in order to minimize the cost of rescheduling units (Mc Garrigle and Leahy, 2015); the sooner the System Operator or the market is aware of the need to modify the day-ahead market schedule, the lower the costs for redispatching.

Rescheduling cost is mitigated by intraday markets in two ways. Firstly, intraday markets that cover a wide range of timescales allow VER to gradually correct their programs, thus reducing the impact of their forecast errors on the overall cost of the system. Secondly, intraday markets produce intraday prices that reflect the cost of making these corrections at different points in time. Intraday prices serve to efficiently allocate rescheduling costs to the units responsible for such adjustments, thus creating a significant incentive for renewable generators to improve their prediction procedures and to rectify forecast errors as soon as possible (Klessmann et al., 2008).

While European power systems currently rely on different designs of intraday markets (Neuhoff et al., 2015) and are now refining the coordination among them[1], the markets run by the Independent System Operators (ISOs) in the United States follow a different approach, which does not present the same positive characteristics. ISO markets include intraday commitment processes that allow for gradual forecast corrections. However, these intraday commitments do not produce prices. A "two-settlement system" is implemented, which settles all deviations from the day-ahead program at the same real-time price, regardless of when and at which specific cost the deviation was corrected (Helman et al., 2008). This system lacks the more granular signal provided by intraday prices that would capture the different cost in time of forecast corrections, and would allocate it to the units accountable for such cost. Therefore, the North American design does not provide market agents with the increasingly necessary incentive to improve their forecasts[2] as it is the case in the European intraday markets.

In this paper we propose a multi-settlement system conceived for the US ISO context, mimicking the characteristics of European intraday markets. We use a simulation model to evaluate the benefits derived from the economic signals that arose from the proposed settlement system and compare it against the two-settlement system of the US.

Methods

Our proposed multi-settlement system is a natural extension of the day-ahead market, which in the US is cleared via a detailed Unit Commitment & Dispatch (UC&D) model. Each intraday settlement follows the same process used in the day-ahead market for dispatching and pricing, although the time horizon and data available vary. This can be easily adapted from current intraday commitment processes used by ISOs.

In order to simulate the results of applying the proposed scheme, we apply a UC&D model with detailed generation constraints (start-up and shut-down trajectories, ramping limits, minimum up/down time, operating reserves, etc.) to simulate the market sequence from the day-ahead market through the following intraday settlements until the real-time; and a pricing and settlement tool to compute the charges and credits for each unit using both the proposed multi-settlement system and the two-settlement system.

We use a stylized case example to illustrate the incentives produced by these alternative settlement systems. We consider a thermal power system with two solar PV generators, which is subject to a forecast error in the day-ahead

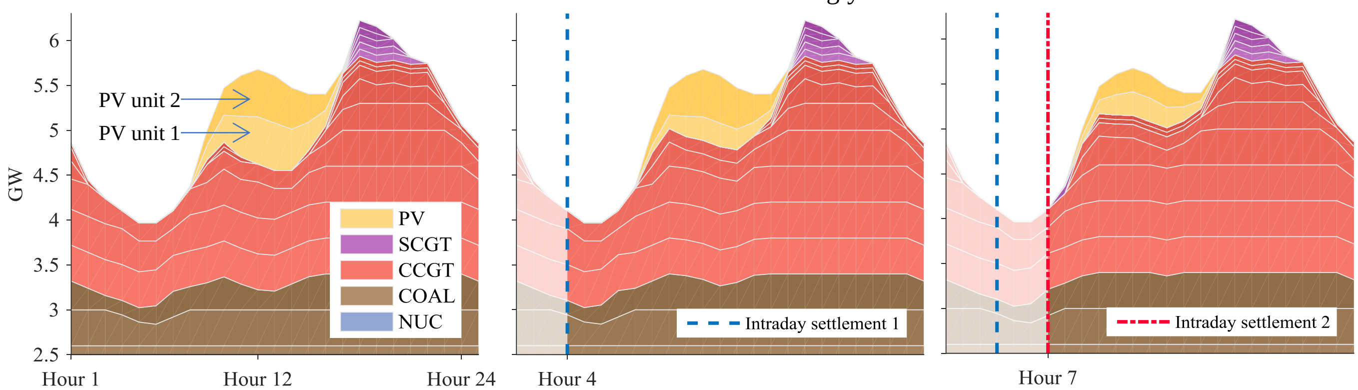
[1] See for example http://networkcodes.entsoe.eu/category/intraday-markets/?p=capacity-alloc-congestion-management

[2] Usually, ISOs are in charge of forecasting renewable generation, but some markets already allow VER to submit their own forecast, which is expected to be more accurate. The option to self-forecast renewable generation is incentivized by the recent Federal Energy Regulatory Commission order 764, see for example http://www.caiso.com/informed/Pages/StakeholderProcesses/FERCOrderNo764MarketChanges.aspx. Our proposal is an additional step in this direction.

market. Then, we compare the impact of correcting this error at different time scales, both on overall system costs and on the particular economic results of each of these two generators.

Results

Figure 1(a) shows the dispatch produced by the day-ahead market, where both of the solar PV generators (on the top of the plot) provide the same forecast, which basically entails that both expect to produce the same amount and with the same profile starting on hour 8. We then consider only two intraday settlements for simplicity, in the first settlement, cleared in hour 4, PV unit 1 corrects the forecast to 50% of the initial program –Figure 1(b) illustrates the resulting economic dispatch–. PV generator 2 should have made the same correction, but due to a lower ability to update its forecast does not make it until the second intraday settlement, held in hour 7 –see Figure 1(c)–. Each of these corrections has an associated cost due to the redispatch of thermal units; although both corrections are for the same quantities, the latter has a higher cost (83% higher in our case example) because of the greater inflexibility found closer to real time. Under the proposed multi-settlement system, intraday prices reflect the different costs of each of these two deviations and allocate it to each of the units accordingly.



(a) Day-ahead market (b) First intraday settlement (c) Second intraday settlement

Figure 1: Dispatch result from each market session

Figure 2 shows the total revenue for each of the PV units, detailing the source of the incomes (day-ahead market) and charges (real-time or intraday markets). In the US markets, power plants receive payments based on the market clearing prices, and separate uplift payments for unrecovered costs. Uplift charges allocated to PV units' imbalances are also considered.

With the two-settlement system, both solar PV units face the same charges, although unit 1 corrected its forecast much sooner. It over-penalizes unit 1 and under-penalizes unit 2. The multi-settlement system provides results that better reflect the costs produced by the deviation of each plant, which critically depends on when (how early) the deviation was corrected.

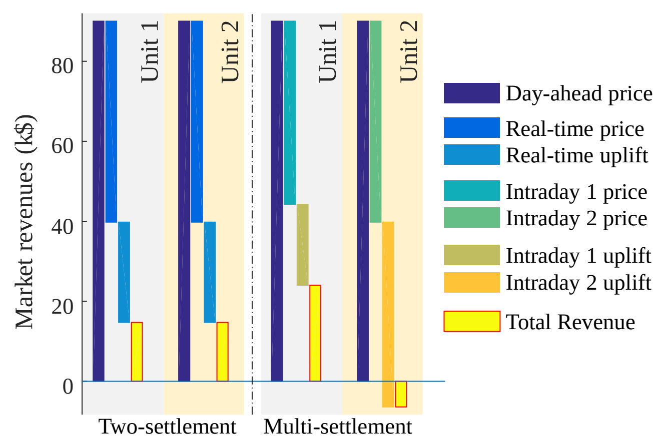


Figure 2: Settlement for PV units

Conclusions

Correcting renewable production forecast errors as soon as possible has a clear economic value, but under the two-settlement system used in ISO markets this value is not disclosed and costs are not properly allocated. A shift towards a multi-settlement system resembling intra-day markets in the European Union would increase market efficiency, as VER installations would be exposed to a clear incentive to improve their forecasts.

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