REDESIGNING DECISION-MAKING ARCHITECTURES TO EXPLOIT MULTI-SCALE ELECTRICITY MARKETS

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Abstract

Electricity markets allow manufacturing facilities to provide energy, ancillary services, and virtual products in day-ahead and real-time settings. A recently developed multi-scale market participation model reveals that a large fraction of these economic opportunities are provided by real-time markets (updated every 5 minutes). We also observe that this trend is likely to persist as more intermittent and nondispatchable power (e.g., wind, solar) is injected into the power grid as system operators will require faster and more flexible demand and supply resources. These observations indicate that there is a need to more closely integrate decision-making layers as well as to coordinate utility systems and process operations to maximize dynamic flexibility.

Keywords

markets, multi-scale, energy, ancillary services, manufacturing, automation

Introduction

Manufacturing facilities use hierarchical decision-making architectures to perform functions at different time scales. These architectures are usually composed of a planning layer that sets production and inventories targets over weeks to months, a scheduling layer that seek to reach those targets over weeks and days, a real-time optimization (RTO) layer that optimizes process conditions over hours to days to reach scheduling signals in a cost-optimal manner, a supervisory control layer (usually MPC) that tracks set-points over minutes to hours, and a regulatory control layer that tracks MPC set-points within seconds to minutes. Several studies recognize the necessity to integrate these layers to obtain more coherent architectures (Biegler and Zavala, 2009; Baldea and Harjunkoski, 2014; Engell, 2007). Automation architectures of energy-intensive manufacturing facilities are already being re-designed to exploit time-varying electricity prices. For example, the Alcoa Point Comfort Power Plant, which is a utility plant that provides electricity and steam to the adjacent aluminum manufacturing facility, re-optimizes its operations every 15 minutes in response to electricity and natural gas price fluctuations (Valadez et al., 2008). These emerging automation architectures coordinate utility and manufacturing systems to provide load flexibility to the power grid in exchange for monetary payments or deferred costs. Traditionally, electricity has been purchased through special agreements with utility companies and/or electricity resellers, but now large industrial consumers are beginning to participate in wholesale electricity markets by directly transacting with independent system operators (ISOs).

Exploiting the flexibility of utility and manufacturing facilities requires careful consideration of the structure of wholesale electricity markets. Modern electricity markets are highly sophisticated, with electricity and ancillary services (*i.e.*, regulation and reserves) being transacted on multiple timescales. Figure 1 shows time-varying prices from the California Independent System Operator (CAISO) for three consecutive days. Energy is transacted at three timescales: in the integrated forward market (IFM) (day-ahead market with 1-hour intervals), in the fifteen minute market (FMM), and through the real-time dispatch (RTD) process (5-minute intervals). Histograms for energy prices at different markets are

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presented in Figure 2. As can be seen, prices are less volatile in the day-ahead market are nearly unbiased. In the real-time market (FMM, RTD) prices are biased and volatile (frequently negative and at times exceeding \$150/MWh). Energy systems with fast dynamics can exploit these fluctuations. As with manufacturing facilities, a hierarchical automation structure is used by ISOs to ensure that generation balances the network loads at all times. Generators/loads providing regulation capacity to the ISO allow their load set-point to be adjusted by the power grid Automatic Generator Control (AGC) layer in exchange for monetary payments. The AGC layer updates load set-points every 2 to 15 seconds. The regulation service provider is compensated both for the amount of regulation capacity provided (a load flexible *band* is offered) plus the amount of *mileage*, which is the sum of the absolute distance between consecutive load set points. Order 755 of the Federal Energy Regulatory Commission (FERC) provides incentives to participants capable of tracking fast changing load set-points. As additional non-dispatchable wind and solar power is absorbed, requirements for ancillary services are expected to grow. In February 2016, CAISO doubled its regulation capacity requirements to account for non-dispatchable sources. As a consequence, the market price for regulation capacity doubled (Mullin, 2016).

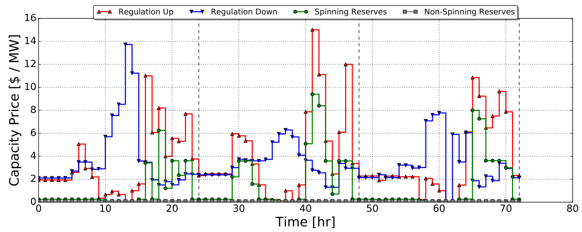
Manufacturing facilities may also participate in markets through Demand Response (DR) programs. DR is typically classified as dispatchable and non-dispatchable (see (Dowling et al., 2016) for details). For dispatchable DR, the ISO directly controls the load (e.g., sends new set points through AGC system to regulation resources), whereas non-dispatchable loads are coordinated through a variety of pricing signals including real-time electricity markets, which are updated every 5 to 15 minutes. In Texas, load resources provide 2,400 MW of energy and ancillary services, including half of the spinning reserve capacity. Around 1,000 MW of this capacity is obtained from a single electrochemical processing facility that provides regulation and other services. Medium (10 to 50 MW each) and small (less than 10 MW) size industrial/commercial facilities provide the remaining 820 MW and 550 MW of capacity, respectively (Kirby et al., 2011). The Alcoa facility in Warrick, IN offers several ancillary services in markets run by the Midcontinent ISO. An aluminum smelter provides 70 MW of regulation capacity, which is 15% of its average load (470 MW). This type of operation represents a paradigm shift in the use of manufacturing loads for ancillary services. The same plant also provides 75 MW of interruptible load, which has been dispatched around 55 times per year for an average length of 42 minutes (Todd et al., 2009). Alcoa generates up to *120,000 \$/day of additional revenue by participating in electricity markets*, and has identified potential for 10% energy cost reductions through more targeted operations (Todd, 2013). Based on data from CAISO, a system providing 10 MW of regulation capacity for every hour in 2015 would have received 500,000 \$/year plus mileage payments. Regulation capacity prices currently reach up to 59 \$/MW and this number might increase as more renewable power is adopted. Moreover, shifting 10 MW of load during the 1% most extreme prices (in the 97 to 1,621\$/MWh range) in the CAISO real-time energy market to the average price (30 \$/MWh) would yield savings of 400,000 \$/yr. The savings for large manufacturing facilities can reach millions of dollars per year. For instance, the pumping system of an oil pipeline comprised of 50 pump units with 6,500 horsepower electric motors has a load of 200 MW. Large refineries in Texas have generation facilities of up to 500 MW and usually have excess power capacity installed.

Electricity Market Organization

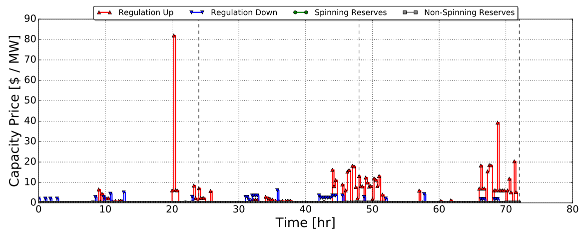
Wholesale electricity markets, including those run by CAISO, PJM, Midcontinent ISO, ISO New England, and New York ISO in the United States allow for energy transactions at multiple timescales and carefully coordinate operational schedules for generators and loads while considering transmission network limits, generator capacity limits, and ramping constraints. Markets normally follow a two-settlement system: the day-ahead market commits transactions based on expected (forecasted) system performance while a real-time market allows for corrections when the system deviates from expected performance due to forecast errors or contingencies (Zavala et al., 2015). Market settlements set prices for multiple products and at different times. The locational marginal price (LMP) reflects the marginal cost of serving an additional unit of energy at a specified node in the transmission system, typically with units \$/MWh. Ancillary service marginal prices (ASMPs) are primarily used in CAISO to compensate ancillary service awards.

Economic Value of Manufacturing Flexibility

The day-ahead market (DAM) seeks to schedule sufficient generation capacity and ancillary services to meet the forecasted demand for the next day. Real-time markets are used to mitigate discrepancies between



(a) Ancillary Services (Day-ahead Market)



(b) Ancillary Services (Real-time Market)

Figure 1. Energy and ancillary service prices for a node in CAISO January 1 - 3, 2015.

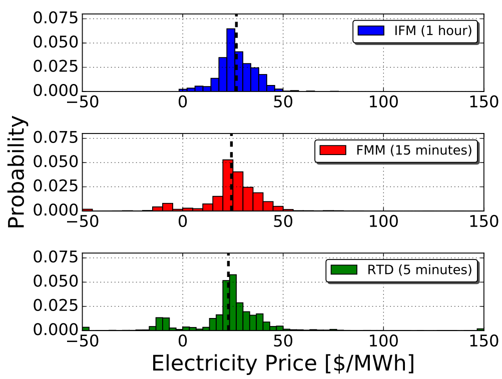


Figure 2. Electricity prices for 2015 for a CAISO node.

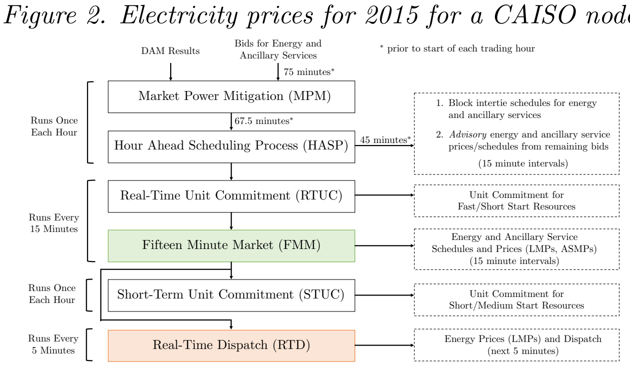


Figure 3. Structure and timeline of the real-time markets (RTM) run by CAISO.

forecasted and actual demand, unplanned outages, and transmission and generator failures by adjusting schedules and procuring additional capacity. The RTM structure is more complex than that of the DAM, as shown in Figure 3. Market participants submit energy and ancillary service 75 minutes before the start of each trading hour. Every 15 minutes, the **Real-Time Unit Commitment** (RTUC) runs and dispatches fast and short start resources. Next, the **Fifteen Minute Market** (FMM) uses these results to establish binding schedules and prices for energy (LMPs) and ancillary services (ASMPs) for 15-minute intervals. Once every hour the **Short-Term Unit Commitment** process dispatches short and medium start resources. Finally, every 5 minutes, the **Real-Time Dispatch** process schedules additional energy and sets 5-minute energy prices (LMPs). The FFM and RTD layers set real-time prices.

Real-time markets are implemented as intricate layers of optimization problems. The RTUC solves a Security Constrained Unit Commitment (SCUC) problem over a 60- to 105-minute horizon. One RTUC run is started every 15 minutes, and the results are used for the HASP and to settle to FMM. As such, FMM settlements are based on the data available 37.5 minutes before each 15-minute interval. This structures introduces errors from lag, and necessitates a faster layer; the RTD runs 7.5 minutes before the start of each 5-minute interval and solves a Security Constrained Economic Dispatch (SCED) problem. It establishes binding energy prices and schedules for the next interval and advisory information for subsequent intervals in the trading hour. Energy payments are settled using the LMPs from the corresponding market. Thus, energy procured in the IFM is settled using LMPs from the IFM.

Diverse studies have analyzed market participation of a variety of technologies such as combined heat and power (CHP) plants (Mitra et al., 2013), steel furnaces (Castro et al., 2013), cement plants (Castro et al., 2011), air separation units (Cao et al., 2015), electrochemical manufacturing facilities (Babu and Ashok, 2008), and HVAC systems (Hao et al., 2012). Economic opportunities for simultaneous energy and ancillary service provisions at multiple timescales, however, remain largely unaddressed in the literature. We recently developed an optimization framework to identify the most lucrative revenue streams provided by day-ahead and real-time markets through energy, ancillary services, and virtual bidding products (Dowling et al., 2016).

Here, we use the proposed multi-scale model to assess revenue opportunities for an industrial CHP system that interacts with the CAISO electricity markets while providing electrical and heat energy (e.g., steam) to a manufacturing facility. We also explore the benefits of coordinating CHP operations with ISOs and manufacturing facilities to allow for electricity and steam demand flexibility. We optimize the operating policy of the CHP system to minimize the net operating costs.

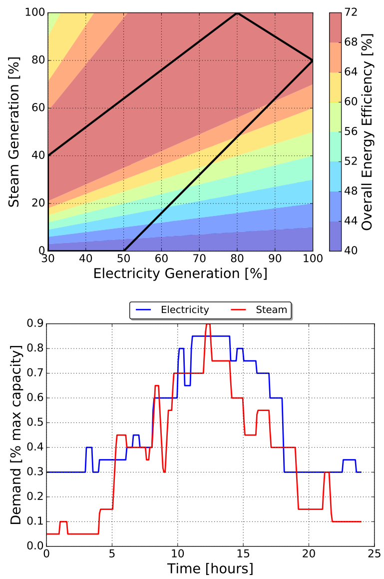


Figure 4. Overall efficiency (Top) and nominal demand profiles for CHP system (Bottom).

The net costs capture fuel usage and market product sales, which are calculated using real CAISO settlement prices for all of the year 2015. We use the nominal time demand profiles shown in Figure 4 for each day. Due to the need to capture multiple time scales over the entire year (with both coarse and fine resolutions), the resulting linear optimization problems include up to 200,000 equality constraints, 1.8 million inequality constraints, and 1 million bounded continuous variables. We examine the distribution of revenues from different market timescales by comparing three participation schemes: day-ahead (DAM) only, real-time (RTM) only, and full participation (DAM and RTM). Figure 5 (top) summarizes both the absolute fuel costs and revenues and Table 1 compares net operating cost savings. As expected, participating in markets at all timescales realized the greatest savings. We observe that *net operating costs decrease from nearly 160,000 \$/year under no market participation to nearly 100,000 \$/year under full market participation (a reduction of over 35%)*. Furthermore, introducing ancillary service sales more than doubled net operating cost savings relative to energy-only market participation. *Restricting participation to only DAM markets limits cost savings to only 34% - 35% of those available from full market participation* (Table 1). In contrast, participating in RTM markets alone limits cost savings to 86% - 91% of the possible savings. We conclude that *the majority of the economic opportunities are obtained at faster timescales (5 to 15 minutes)*.

The previous results assume that onsite electricity

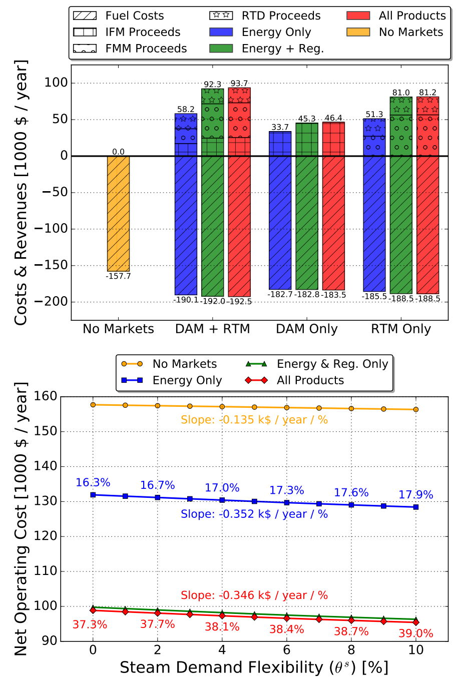
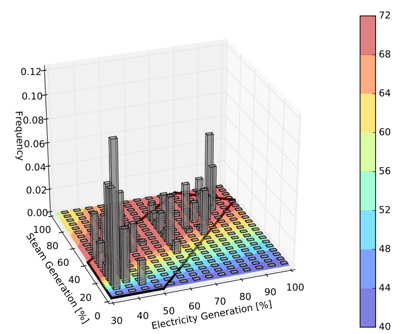
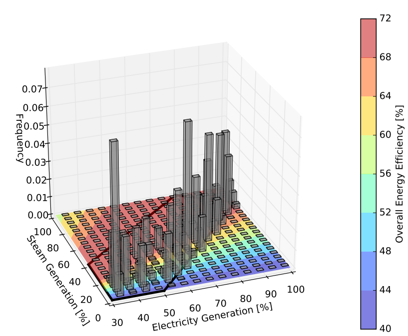


Figure 5. (Top) Fuel costs (negative) and revenues (positive). (Bottom) Net costs as a function of θ_s.



(a) No Markets, $\theta_s = 0\%$



(b) All Markets, $\theta_s = 10\%$

Figure 6. Histogram of operating points for CHP system.

and steam demands are completely inflexible (are followed exactly by the CHP system). Such demands are often dictated by processing plants that need electricity and steam to drive production. With inflexible demands, the CHP system can only use the (unused) residual capacity to participate in the markets. CHP systems are also physically constrained because steam and elec-

Table 1. Absolute savings relative to no participation and percent savings relative to full participation.

	DAM + RTM	DAM	RTM
Energy	25.8 k\$/yr	8.7 k\$/yr	23.5 k\$/yr
	100%	34 %	91%
Energy & Regulation	57.9 k\$/yr	20.2 k\$/yr	50.6 k\$/yr
	100%	35 %	87%
All	58.8 k\$/yr	20.7 k\$/yr	50.4 k\$/yr
	100%	35%	86%

tricity are produced simultaneously (steam being normally the driving product). We now seek to capture effects of additional flexibility in revenue. Sources of flexibility include steam demands (represented by factor θ_s), electrical demands (θ_e), and additional regulation capacity (θ_r). The dominant time constants in many industrial unit operations (e.g., separation systems) are on the order of hours. As such, these systems may be insensitive to small steam supply fluctuations on the order of seconds or minutes. Steam distribution headers also act as small storage volumes and help attenuate high frequency variations. Utility demand flexibility can also be increased by adjusting production schedules. Finally, some loads from mechanical equipment (e.g., pumps, fans) may also be adjusted at high frequency to provide regulation services without compromising performance of other units at slower timescales. From an implementation perspective, however, one area of concern is potential wear and tear of equipment.

We investigate flexibility by individually varying θ_s, θ_e, and θ_r between 0% and 10% and resolving the operational optimization problem for different market interaction schemes. We highlight that total on-site steam and electricity demands are still satisfied: demand profiles are only shifted in time. As shown in Figure 5 (bottom), we find that *additional costs savings of +1.4% to +3.5% are obtained by moving from 0% to 10% flexibility.* The benefits of flexibility are derived from complex trade-offs between CHP system efficiency and market opportunities. In particular *demand flexibility allows synchronization of on-site steam and electricity demands, which are often out of phase.* Without market participation, steam (θ_s) and electrical demand flexibility (θ_e) increase overall energy efficiency from 62.7% to 63.1-63.4%. Increased energy efficiencies translate to fuel conservation. In contrast, overall energy efficiency with market participation is approximately 2%-points lower. These trends are explained through Figure 6, which shows the frequency of operation in the steam-electricity space. For more detailed figures, please see Dowling et al. (2016). Even without market participation, exploiting steam demand flexibility allows the utility system to operate in more efficient regions by synchronizing steam and electricity loads. With market participation, in contrast, operation is shifted to maximize electricity generation and exploiting capacity (at the expense of efficiency).

Redesigning Hierarchical Decision-Making

The previous analysis reveals that: i) Real-time markets provide the most revenue opportunities. ii) Increasing flexibility of steam and electricity demands from processing plants increases revenue (by synchronizing steam, electricity, and potentially chilled water). These observations imply that decision-making layers making economic decisions should be updated at timescales of 5-15 minutes. This would represent a major shift in operations, as real-time optimization layers are currently updated every few hours (to allow processing plants to reach the steady-state set-point). Our analysis indicates that these infrequent updates are only capable of exploiting day-ahead markets with hourly resolutions. Allowing for more frequent updates would require integration of RTO and MPC and in some cases MPC with fast regulatory control layers. The integration of RTO with MPC can be achieved using economic MPC technology (Rawlings and Amrit, 2009) while integration of MPC and regulatory requires capturing fast dynamics of equipment in MPC formulations (e.g., valves, compressors, pumps). These new formulations pose challenges in algorithms, as they will result in computationally expensive optimal control problems with drastically different time scales. Consequently, finer time discretizations and command signals will be needed, likely yielding intractable problems. Such complexity can possibly be overcome using model reduction and timescale decomposition techniques (Zavala, 2016; Baldea and Daoutidis, 2007). Here, the challenge is to design control hierarchies with control layers that can be coordinated to achieve close-to-optimal performance (as opposed to using existing ad-hoc schemes). These observations also point towards the need to coordinate processing plants and central utility plants, leading to site-wide economic MPC formulations. Scattolini (2009); Rawlings and Stewart (2008); Arnold et al. (2010) all proposed coordination schemes for MPC controllers. These techniques have seen limited use in operations, perhaps because the economic benefits have not been fully explored. We highlight that some coordination schemes do not need to be fully deployed to provide insights on benefits. As a first step, such schemes could estimate internal prices for resources, as coordination variables are usually prices (dual variables) that reflect the value of steam or electricity at different times. This helps utility systems understand the value of its different products to different processing plants at different times. Likewise, dual variables can help processing facilities understand how their production schedules ultimately affect central performance. This is critical in situations where a new boiler need to be started to satisfy a small increase in utility demand. Another case is demand flattening: uncoordinated facilities may maximize production at the same time, leading to high peak electricity usage.

Conclusions

We argue that allowing simultaneously participating in day-ahead and real-time energy and ancillary service markets provides manufacturing facilities significant economic opportunities. We use market participation model based on historical prices to illustrate that 70 - 90% of revenue opportunities are provided by real-time markets (updated every 5 minutes). Exploiting fast price fluctuations will require a tighter integration of decision-making layers in hierarchical architectures.

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