Coupling of Day Ahead and Real-Time Power Markets for Energy and Reserves Incorporating Local Distribution Network Costs and Congestion

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***Abstract*—Acknowledging that increasing intermittent clean energy generation is likely to impose a bottleneck in the demand for regulation reserves, we investigate potential increases in the supply of regulation service through enhanced participation of loads in electricity markets. Moreover, we focus on future markets where Loads connected at the distribution network participate extensively and in direct competition with centralized generation whole sale market participants. We focus our analysis to distributed PHEV loads and develop a decision support algorithm for optimal bidding to the existing wholesale as well as to prospective retail/distribution market. We argue that generalization to a broad range of load types is reasonably straight forward.**

I. Introduction

A. Effective Load Management and the Integration of Renewable Generation

In the ongoing debate about energy and environmental sustainability, the power system's ability to absorb renewable generation has featured prominently. In this context, the burden of intermittency that accompanies renewable generation has been a major topic of concern [10], [16], [19]. Wind generation variability over time-scales of minutes and inability to dispatch at will over longer time-scales is likely to increase the reserves required to safeguard system stability including regulation service (5 minute time-scale) and operating reserves (15 minute time-scale). Although wind generation is a competitive source of electric energy, depending on the burden that renewable generation places on load following and regulation service reserves, business as usual where such reserves are provided solely by flexible generation resources may not be economically viable. In this case, we will either have to forgo significant renewable generation expansion or rely on efficient load side support.

Several studies claim that a modest increase in regulation service [13] is required to support significant increases in wind generation. However, more recent studies as well as empirical evidence [4]-[6], [8], [9] indicate that the conclusion of modest regulation service reserve requirements is a significant underestimation. Makarov et al. [8] evaluated a scenario similar to that considered by the CEC, and reported that for a 4,100 MW increment of wind farm nameplate capacity, a maximum increase of 230 MW (5.6%) of regulation-service-down and 500 MW (12.2%) of regulation-service-up would be required! Finally, studies have claimed that with proper geographical diversity in wind farm locations, a sudden loss of wind generation is not a credible event. However, this type of event has occurred in areas with high wind penetration. The Texas balancing authority reported that wind output during certain hours in 2007 was 2,000 MW less then forecasted, and in 2008 wind output unexpectedly dropped 1,300 MW in three hours [3]-[4]. In Europe (e.g., Spain), similar system stability issues due to wind have been experienced [2], [6].

Focusing on alternative sources of fast reserves needed for promoting the clean energy agenda, we argue that efficient load side regulation service support, amongst others by optimal PHEV charging, is achievable by opening up electricity markets to the load side. In this paper we present decision support tools that build upon today's communication capabilities to enable this participation.

B. Energy and Reserve Market Transactions: Existing Wholesale and Contemplated Retail Markets

We agree with Smith et al. that "operating experience from around the world has shown that a deep, liquid, real-time market is the most economical approach to providing the balancing energy required by variable-output wind plants" [16]. We next review existing wholesale power markets and propose the necessary costs that we reason should be transacted in contemplated distribution/retail markets. Since most of the new market participants, distributed loads, generation, storage and other resources (e.g., smart appliances, power electronics capable of dynamic var compensation), are connected at the distribution network, their participation in wholesale markets requires that they also participate in a distribution/retail network market that captures local costs and constraints.

Existing Whole Sale Markets

In the US, *day-ahead, adjustment, and real-time wholesale power markets* have been operating since the mid 1990s, clearing energy (generation offers and demand bids), and requisite reserve capacity specified by transmission system operators. Whole sale market operators include CAISO, ERCOT, MISO, PJM, ISONE, NYISO, and SPP. FERC Order 719, has encouraged all Independent System Operators to initiate demand response programs to complement the reserve capacity transactions in which only centralized generating units were allowed to participate.

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PJM, a pioneer in the evolution of power markets, allowed in 2006 end-use customers to participate through Load Aggregators (LAs) into the wholesale capacity reserves market on a par basis with generating units [12], [14]. At around the same time ISONE implemented Real-Time Price Response and Day-Ahead Load Response Programs. The NYISO has four demand response programs, including a Demand-Side Ancillary Services Program. The CAISO will begin in 2010 to offer a Proxy Demand Response product, which is a load or aggregation of loads that can submit bids into the wholesale day-ahead and real-time markets and respond to CAISO's dispatch orders.

There are several related short-term wholesale markets that clear sequentially in the course of a day.

The *day ahead market* closes to generation, demand and reserve capacity bids and offers at noon of the day before the operating day (t= -12), schedules them simultaneously, and determines clearing prices for each of the 24 hours in the operating day (t=1,2,3,…,24). This market performs short-term planning (e.g., hedging, unit commitment, reserve scheduling) functions.

Adjustment markets allow market response to significant events such as major equipment failures or forecast revisions that occur after the day-ahead market closes. They clear in a manner similar to the day-ahead market, except over a shorter time horizon. For this reason, and for simplicity in our exposition, we will not model them explicitly.

The *real-time market* typically closes to bids and offers one hour before the time t and then schedules generation and reserves every 5 minutes. It performs the final adjustments when essentially all uncertainty has been realized and feasible operational decisions can be made. Clearing prices are used in lieu of ex post marginal costs to charge/debit for deviations from the day ahead schedule. Its basic difference from the day-ahead and adjustment markets is that it schedules a *single* as opposed to *multiple* periods. Since bids and offers are made an hour before the real-time market clears, we will assume that all 12 five minute periods in the hour are similar and approximate the real-time market by an hour ahead market. Figure 1 below shows the day ahead closing at *t*= -12 and scheduling hours 1 through 24, while each real-time market closes at the beginning of hour t and scheduling generation, demand, and reserves over the period from t to the beginning of period *t*+1 as shown in figure 1.

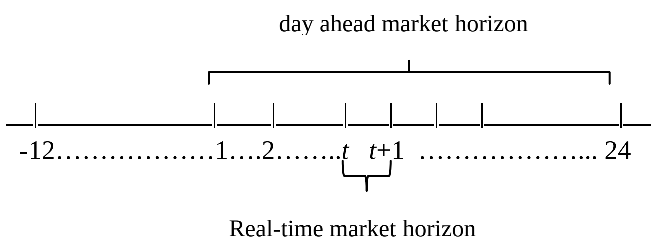

Fig. 1. Day-ahead and real-time market timeline.

Distribution companies purchase energy for their retail clients from a zone (group) of accessible transmission system busses at the day ahead wholesale market clearing prices. Debits/credits for differences between day ahead transacted quantities and actual real-time consumption plus line losses are reconciled at the zonal whole sale market real-time clearing price. Since bids to the real-time market are made approximately an hour before the five minute period that the clearing prices refer to, the real-time market clearing prices can be reasonably considered as the ex-post marginal cost. Wholesale market energy clearing prices at a delivery bus represent the marginal generation cost subject to transmission congestion constraints, and marginal transmission losses for delivery at that bus. However, the following two cost components are not assigned to participants: (*i*) Although requisite reserves are procured from the market, their procurement cost is usually socialized (i.e. averaged) and charged uniformly to consumption since its marginal cost can not be associated to specific participants. This may change in the future. For example, if wind farm generation forecast error is deemed responsible for incremental reserve requirements, wind farms may be charged at the related marginal cost. (*ii*) Although initial proposals [15, 17] prescribed a vector of real and *reactive power* clearing prices, technical and economic considerations at PJM[2] resulted in the decision to not include *reactive power* explicitly in the whole sale market. That decision was based on the well founded argument that not only is the reactive power market in the transmission system disproportionally small, but also, that the reduced effectiveness of distant generators to provide reactive power can not guarantee a competitive market.

Proposed Real-Time Distribution/Retail Markets

Retail markets can be construed as markets run by an independent distribution system operator bearing similarities to the whole sale market's ISO and acting also as a distribution market operator (DMO). In its initial instantiations, the DMO can be thought of as a distribution network that is functionally unbundled from the distribution company that owns it for the purpose of providing equal access to all potential market participants connected to the distribution network. In addition to a connection right, equal access requires that the following information be publicly and freely available:

- The marginal line losses $ML_{i,t}$ resulting from incremental demand of Smart Microgrid Affiliate (SMA) *i* during time period *t*.
- The marginal unit cost of incremental reactive power ($/KVar per hour) consumed during period *t* by SMA *i*.
- The excess distribution capacity available to SMA *i* during period *t*. This excess capacity is dependent on available transformer and grid capacity over and above the capacity used by high value added – infinite reservation price – consumption during period *t*.

[2] Personal communication from PJM's Andrew Ott, the person responsible for the first liberalized whole sale market implementation in the US.

The following comments address the reasonable question of "why these costs have not been represented in the rate structure so far, and why the same arguments put forward for reactive power in the transmission system do not hold for the distribution system as well".

- The lion's share of T&D losses are distribution line losses. Whereas Transmission system marginal losses are of the order of 0.5% to 2%, distribution system losses average to 7-8% with marginal line losses ranging from 4 to 25%.
- Reactive power compensation (dynamic var compensation) is pursued by multimillion cost dynamic var compensators installed at distribution system substations so that they are close to reactive power consumption by inductive loads. At the same time, power electronics that accompany distributed generation and storage-like distributed resources such as PHEVs, are becoming ubiquitous. These distributed power electronics are capable of providing particularly effective dynamic var compensation where it is needed.
- The advent of the smart grid will not only make marginal losses and Var consumption information readily available, but will also be able to monitor overloading of transformer and other transmission assets. This will make treating congestion as hard or soft – penalty – constraints feasible. Transmission asset level loading through optimal maintenance and expansion but most importantly through dynamic network reconfiguration can be enhanced by demand response.

Interaction of Wholesale and Distribution/Retail Markets

Demand-side market participants are already a reality assisted by Load Aggregators – Curtailment Service Providers in PJM and Enrolling Participant in ISONE -- that take advantage of pooling, decision support intelligence, and information gathering. Smart Microgrid Affiliates (SMAs) collaborating with a LA are responsible for handling microgrid connected loads such as PHEVs plugged into the outlet in a house on a suburban feeder line or in a garage of a commercial building. HVAC, lighting and other microgrid monitored and controlled loads. LAs participate in day ahead wholesale markets to buy and sell in advance for their SMAs. LAs also participate in the real-time wholesale markets in coordination with their SMAs which participate in both the real-time whole sale and the proposed distribution/retail markets discussed above.

The remainder of this paper evolves as follows: In section II we present the optimal LA day ahead wholesale market participation problem. To fix ideas, we consider the case of PHEV battery charging loads. We present two versions of the LA participation in the wholesale day ahead market, (*i*) through a run-of-the-mill *uniform bids* as practiced today, where the decision problem is to determine the optimal inter-temporally uncoupled 24 price quantity pair bids, and (*ii*) through more effective *complex bids* [20] involving linear inter-temporal energy and reserve constraints. In section III we present the coordination of the LA's participation in the real-time wholesale market with the participation of the SMAs into the distribution/retail market. In section IV we sketch a preliminary algorithm for coordinated decision support, and describe how the PHEV example can be generalized. We finally conclude in Section V and describe systems challenges emerging from the proposed demand provided regulation service.

II. LA Decisions in the Day Ahead Wholesale Market: Uniform VS Complex Bids For PHEV Loads

A. Uniform Bids

Uniform bids constitute the most common market participation rule today. In the day ahead market, supply- and demand-side market participants make 24 pairs of energy (KWH) and price ($ per KWH) bids, and 24 pairs of capacity reserves (KW) and prices ($ per KW stand by per hour). The day ahead market clears through 24 simultaneous uniform auctions. Although there are three types of capacity reserves with 0.5, 5, and 15 minute response time, for clarity of exposition we will consider only the 5 minute reserves known as *regulation service* reserves that require an up and down stand-by-capacity offer. More specifically, regulation reserve offers are associated with a nominal generation or consumption rate, Q_t^R, and two prices u_t^{RE}, and u_t^{RC}. The prices correspond respectively to the energy reservation price and the cost of modulating generation/consumption capacity in real-time to respond to centralized control commands. For example, if the LA is scheduled by the clearing of the market to provide Q_t^R of regulation service, it will *(i)* start the period consuming at the rate of Q_t^R KW and be charged at the market energy clearing price of $\tilde{P}_t^E$ per KWH, *(ii)* be credited at the market regulation service clearing price, $\tilde{P}_t^R$ per KWH, and *(iii)* promise to respond to market operator commands to move towards an operator specified level in the interval $\left[0, 2Q_t^R\right]$ at the rate of $Q_t^R/5$ KW per min.

The market operator receives bids and offers from all market participants and schedules them to minimize costs over all 24 day-ahead hourly periods. For each period, market-wide clearing prices are determined for energy and regulation service. One usually assumes competitive conditions and equitable availability of information on the joint likelihood of clearing prices conditional upon the state of the system at time -12. This likelihood or j.p.d. allows each market participant to evaluate the probability of four key events, e_k, k=0,1,2,3 described in (1), (2), (3), and (4). These probabilities, are denoted by p_t^k, k=0, 1, 2, 3 and are specific to each participant's price bids and offers. Scheduled quantities are denoted by superscript *s*.

<u>event e_0</u>: $u_t^E \geq \tilde{P}_t^E$ with probability p_t^0 (1)

and the MO schedules $Q_t^{E,s} = Q_t^E$ with probability p_t^0.

Regulation service offers are accepted, scheduled, or rejected according to (2), (3), and (4).

<u>event e_1</u>: $\left|\tilde{P}_t^E - u_t^{RE}\right| + u_t^{RC} \leq \tilde{P}_t^R$ with probability p_t^1 (2)

and the MO schedules $Q_t^{R\,Energy,s} = Q_t^R$ and $Q_t^{R,s} = Q_t^R$.

<u>event e_2</u>: $\left|\tilde{P}_t^E - u_t^{RE}\right| + u_t^{RC} > \tilde{P}_t^R \;\cap\; u_t^{RE} \geq \tilde{P}_t^E$ with probability p_t^2 (3)

and the MO does not schedule the regulation service, but does schedule the associated energy, namely, $Q_t^{R\,Energy,s} = Q_t^R$ and $Q_t^{R,s} = 0$

<u>event e_3</u>: $\left|\tilde{P}_t^E - u_t^{RE}\right| + u_t^{RC} > \tilde{P}_t^R \;\cap\; u_t^{RE} < \tilde{P}_t^E$ with probability p_t^3 (4)

and the MO schedules neither the regulation service nor the associated energy, namely, $Q_t^{R\,Energy,s} = 0$ and $Q_t^{R,s} = 0$.

Note that since probabilities and expectations, as well as control/decision variables depend on the information available at the time decisions are made <u>and</u> the decisions themselves, they are identified by an additional left superscript of *da* or *rt*.

The optimal LA bids to the day ahead wholesale market are made anticipating (*i*) that adjustments will be possible later in the real-time market, and (*ii*) that the cost of energy and the revenue of regulation service scheduled in the day ahead market will be offset by the expected revenue from energy sales to its SMAs and the expected cost of purchases of regulation service from its SMAs in the real-time market. Note that the LA can not consume energy or offer regulation unless it either sells-to/buys-from its SMAs or sells-back-to/buys-back-from the real-time market. This coupling of the day-ahead and real-time markets can be described rigorously as the solution of the following broadly construed stochastic dynamic program (DP), for the day-ahead (5) market.

$$J_{-12}({}^{da}\mathbf{I}_{-12}) =$$

$$\min_{{}^{da}Q_t^E,\,{}^{da}Q_t^R,\,{}^{da}u_t^E,\,{}^{da}u_t^{RE},\,{}^{da}u_t^{RC} \in U(I_{12})\forall t} \Big\{ \sum_{t=1}^{24} \Big[{}^{da}\underset{{}^{da}\tilde{P}_t|e_0}{E}\; {}^{da}\tilde{P}_t^E \;{}^{da}\;{}^{da}p_0^t \;{}^{da}Q_t^E$$

$$+ {}^{da}\underset{{}^{da}\tilde{P}_t|e_1\cup e_2}{E}\; {}^{da}\tilde{P}_t^E ({}^{da}p_1^t + {}^{da}p_2^t)\,{}^{da}Q_t^R \tag{5}$$

$$- {}^{da}\underset{{}^{da}\tilde{P}_t|e_1}{E}\; {}^{da}\tilde{P}_t^E \;{}^{da}p_1^t \;{}^{da}Q_t^R) \Big] + {}^{da}EJ_1({}^{da}\mathbf{I}_1) \Big\}$$

Where:

${}^{da}Q_t^E(\tau)$, ${}^{da}Q_t^R(\tau)$: Day ahead market energy requested and regulation service offered, respectively by the LA.

${}^{da}Q_t^{E,s}(\tau)$, ${}^{da}Q_t^{R,s}(\tau)$: Energy and regulation scheduled to the LA in the clearing of the day ahead market.

${}^{da}u_t^E$, ${}^{da}u_t^{RE}$, ${}^{da}u_t^{RC}$: price bids

${}^{da}\tilde{P}_t^E$, ${}^{da}\tilde{P}_t^R$: Random variables for the day ahead wholesale market clearing prices for energy and regulation service during period *t*, described by their probability distribution as known when the day ahead market closes.

$\mathbf{I}_{-12}$ and $\mathbf{I}_1$ the information/state vectors at time -12 and 1,

$J_{-12}({}^{da}\mathbf{I}_{-12})$ the expected cost to go function at time -12 when the day ahead market clears,

$U({}^{da}I_{-12})$ the allowable decision set given the state or information of the system at time -12, and

${}^{da}EJ_1({}^{da}\mathbf{I}_1)$ the expected cost to go at *t*=1 estimated on the basis of information available at *t*=-12.

Note that ${}^{da}\mathbf{I}_1$ includes (*i*) the energy and regulation service scheduled in the clearing of the day ahead market, as well as (*ii*) forecasts on expected wind output, system outages available at *t*=-12.

We denote the evolution of information by:

$\mathbf{I}_{-12}$ is the relevant information or state vector ust before day-ahead market closes. It contains the jpd of hourly clearing prices, PHEV charging demand, local line capacities, as well as other power system information such as outages, wind farm output forecasts.

$\mathbf{I}_t$ is the relevant information or state vector just before the t^{th} rel-time market closes. It contains the results of the clearing of the day-ahead market and all past real-time markets, the jpds of future real-time market clearing prices, PHEV charging demand, local line capacities, other power system information, the actual local line capacities during period *t* to $t+\Delta_t$, and the actual uncharged battery capacity and desired departure times of PHEVs plugged-in at time *t*. It contains all the relevant information in $\mathbf{I}_{t-1}$ augmented by the clearing of the *t*-1 real-time market, PHEVs plugged-in by time *t* . To generalize we define a function V_t; which updates the information vector as

$${}^{da}\mathbf{I}_1 = {}^{da}V_{-12}({}^{da}\mathbf{I}_{-12}, \text{day ahead market schedule}),$$

$${}^{rt}\mathbf{I}_1 = {}^{rt}V_0({}^{da}\mathbf{I}_1, \text{new forecast info available at t=1}) \text{ and}$$

$${}^{rt}\mathbf{I}_{t+1} = {}^{rt}V_t({}^{rt}\mathbf{I}_t, rt \text{ makr. sched. at t, new forecast}) \tag{6}$$

C. Complex Bids

The uniform bids described above have the advantage of standardization but they also have a major disadvantage: the LA has the onerous task of satisfying inter-temporal dependencies in the energy requirements of its SMAs by relying on imperfect knowledge of system-wide costs embedded in the available estimates of clearing price j.p.d functions.

A complex bid that consists of providing the day ahead whole sale market operator with the actual inter-temporal constraints that describe important state dynamics, capacity constraints and requirements may be much more effective. In particular, if the above can be described by linear relationships, the market operator can include them in the market clearing optimization algorithm and schedule them to optimize costs and benefits with full information on the bids of other participants. Inter-temporal constraints are routinely considered in what are in fact complex bids by generators whose change in output across hours is subject to ramp constraints. Chen et al [18] analyze market behavior in the presence of inter-temporal demand response modeled as an elementary complex bid.

In the case of PHEV loads considered in detail in section III, complex bids would consist of linear relationships that capture SMA-specific local distribution capacity constraints, line losses and the requirement that batteries are fully charged at the declared departure time. Referring to section III, the decision variables in the LA's complex bid will include the appropriate *estimates at time t*=-12 of (*i*) random variables ${}^{da}\tilde{\Delta}n_{i,t}^{\tau}$, ${}^{da}\tilde{\Delta}x_{i,t}^{\tau}$, $\left({}^{da}\hat{C}_{i,t}^{\max}\right)$ realized at future times t=1,2,3,…,24, (*ii*) the battery and number of car dynamics shown below in equations (8) and (9), and (*iii*) the requirement that PHEV batteries full at declared departure times, ${}^{da}x_{i,\tau}^{\tau}=0$ for all τ. Note that left superscripts, *da,* appear in place of *rt* to denote that the estimates represent knowledge at the time the day ahead market closes.

In the complex bid case, the LA is a price taker. However, since the MO schedules LA energy purchases and regulation service sales to minimize overall system costs, the resulting clearing prices will guarantee the lowest cost for the LA.

III. Coordinated Real-Time Market Decisions on PHEV Loads: LA Participates in Wholesale Market, SMAs in the Retail Market.

A. Load Aggregator Master Problem

The LA bids to the day ahead market – uniform or complex – secure hourly energy purchases and regulation reserve sales for *t=1,2,…,24*, ${}^{da}Q_t^{E,s}$ and ${}^{da}Q_t^{R,s}$.

At the real-time market, the LA *(i)* sells energy and buys reserves from its SMAs according to prices $\hat{P}_t^E$ and $\hat{P}_t^R$ that it selects, and *(ii)* sells to/buys from the real-time market the surplus or deficit relative to the secured day-ahead quantities. The real-time market transactions of the LA provide a market based accounting for differences between day-ahead energy and regulation service scheduled quantities and the actual quantities that are consumed/offered in real-time. The real-time market clearing prices are in fact the ex post prices at which differences relative to day-ahead transactions are priced. More specifically, the LA solves the stochastic DP problem (5) in the day-ahead market to obtain uniform or complex bidding policies. Note that in the day-ahead market the LA incurs a cost for energy purchases and realizes revenue for regulation service sales. In the real-time market it obtains revenue by selling energy to SMAs or back to the real-time wholesale market but incurs costs from buying regulation service from the SMAs or buying it back from the real-time wholesale market. Viewed in a broadly construed DP context where sequentially clearing day–ahead and real-time markets are related, the LA day-ahead problem, (5), depends on the expected LA cost to go in the first real-time market, ${}^{da}EJ(\mathbf{I}_1)$, where the expectation is taken over day-ahead clearing quantities as well as future information unknown at the time of the bidding.

The LA solves the real-time problem (7) to determine optimal prices, $\hat{P}_t^E$ and $\hat{P}_t^R$ at which it transacts with its SMAs. To describe (7) we define real-time LA energy sales to and reserve purchases from its SMAs ${}^{rt}\hat{\mathbf{Q}}_t^E=\sum_{i,\tau}{}^{rt}\hat{Q}_{i,t}^E(\tau)$, ${}^{rt}\hat{\mathbf{Q}}_t^R=\sum_{i,\tau}{}^{rt}\hat{Q}_{i,t}^R(\tau)$, where ${}^{rt}\hat{Q}_{i,t}^E(\tau)$, ${}^{rt}\hat{Q}_{i,t}^R(\tau)$ are determined by the SMAs in venues/neighborhoods *i=1,2,…M*, from the solution of the SMA sub-problems described below.

In the real-time market the LA is a price taker as it sells back to the real-time market excess energy relative to the quantities secured in the day-ahead but not demanded by the SMAs and buys back from the real-time market excess reserves scheduled when the day-ahead market cleared but not supplied by the SMAs. Therefore the LA evaluates the cost to go by solving (7).

$$
\begin{aligned}
{}^{rt}J(\mathbf{I}_t) = \min_{{}^{rt}\hat{P}_t^E,\,{}^{rt}\hat{P}_t^R} {}^{rt}E\{ &{}^{rt}\tilde{P}_t^E[{}^{rt}\hat{\mathbf{Q}}_t^E - {}^{rt}Q_t^{E,s}] - {}^{rt}\hat{P}_t^E\,{}^{rt}\hat{\mathbf{Q}}_t^E \\
&- {}^{rt}E^{rt}\,{}^{rt}\tilde{P}_t^R[{}^{rt}\hat{\mathbf{Q}}_t^R - {}^{rt}Q_t^{R,s}] + {}^{rt}\hat{P}_t^R\,{}^{rt}\hat{\mathbf{Q}}_t^R + {}^{rt}J(\mathbf{I}_{t+1})\}
\end{aligned} \tag{7}
$$

B. SmartGrid Affiliate Sub-Problems

We now consider the real-time market problem for each SMA. SMAs are grouped based on characteristics of the physical distribution network and therefore, each SMA must abide by specific local congestion constraints that are associated with a specific transformer or feeder line in the distribution network. In addition, each SMA is subject to location specific marginal line losses. To fix ideas we focus on loads for battery charging of a neighborhood fleet of PHEVs. In the concluding section we argue that generalization to HVAC, lighting and other loads does not increase problem complexity significantly.

1) Indices and parameters.

i : index of SMAs.

rt: : index denoting real time market, appearing as a left superscript

τ : Index of plugged-in PHEV departure classes.
N : Number of time periods in the finite horizon.
c : Penalty ($ per KWh) of uncharged energy at time of PHEV departure.
ρ : Charging rate (KW) of each PHEV.
λ_N^τ : Marginal costs ($ per KWh) of charging PHEVs with departure class outside of the horizon (i.e., $\tau > N$).

2) State and decision variables.

$n_{i,t}^\tau, x_{i,t}^\tau$: Number i^{th} SMA PHEVs and their uncharged energy (KWh) plugged-in at the beginning of period t, in departure class τ.

${}^{rt}\hat{Q}_{i,t}^{E}(\tau),\ {}^{rt}\hat{Q}_{i,t}^{R}(\tau)$: i^{th} SMA energy rate purchased from the LA and regulation service capacity sold to the LA, respectively, during period t.

${}^{rt}Q_{i,t}^{E}(\tau),\ {}^{rt}Q_{i,t}^{R}(\tau)$: i^{th} SMA energy rate requested and regulation service capacity offered, respectively, to the real-time wholesale market during period t.

${}^{rt}u_{i,t}^{E}(\tau)$: i^{th} SMA bid price to real-time market for ${}^{rt}Q_{i,t}^{E}(\tau)$.

$({}^{rt}u_{i,t}^{RE}(\tau),\ {}^{rt}u_{i,t}^{RC}(\tau))$: i^{th} SMA energy and capacity price offered, respectively to the real-time market for ${}^{rt}Q_{i,t}^{R}(\tau)$.

${}^{rt}m_{i,t} = (1 - \text{Marg.Losses}_{i,t})$: the factor of marginal line losses that converts energy and reserves at the exit of the wholesale market transmission system to the available energy and required reserves at the site of SMA i.

$\mathbf{I}_{i,t}$: the information available to the i^{th} SMA at time t, including j.p.d.s of future PHEV demand, and real-time market clearing prices conditional upon physical phenomena such as weather forecasts and the overall power system state including known plant outages and wind output forecasts that may affect reserve requirements, bids by other market participants and ultimately clearing prices. In addition, it contains SMA location-specific distribution capacity available for PHEV battery charging $\left({}^{rt}\hat{C}_{i,t}^{\max}\right)$, and ${}^{rt}m_{i,t}$ Finally, it includes quantities scheduled and clearing prices observed in all hourly markets that closed previously, LA prices ${}^{rt}\hat{P}_t^{E},\ {}^{rt}\hat{P}_t^{R}$, and the number of PHEVs plugged-in SMA i and their uncharged capacity ${}^{rt}n_{i,t}^\tau,\ {}^{rt}x_{i,t}^\tau$.

3) Random Variables.

${}^{rt}\tilde{P}_t^{E},\ {}^{rt}\tilde{P}_t^{R}$: Random variables for the real-time market clearing prices for energy and regulation service during period t, described by their probability distribution as known when the real-time market closes.

${}^{rt}\tilde{\Delta}n_{i,t}^\tau,\ {}^{rt}\tilde{\Delta}x_{i,t}^\tau$: Random variables indicating the number of PHEVs and their uncharged energy (KWh) expected to plug-in at i^{th} SMA during period t in departure class τ.

${}^{rt}p_{i,t}^{k,\tau}$: The probabilities of the four key events k=0,1,2,3 defined in detail in Section I.C in relation to price bid vector ${}^{rt}u_{i,t}^\tau = ({}^{rt}u_{i,t}^{E,\tau},\ {}^{rt}u_{i,t}^{RE,\tau},\ {}^{rt}u_{i,t}^{RC,\tau})$

${}^{rt}\tilde{1}_{i,t}^{RS,\tau}$: A random indicator function dependent upon price bid vector ${}^{rt}u_{i,t}^\tau$ that equals 1 with probability ${}^{rt}p_{i,t}^{\alpha,\tau} = {}^{rt}p_{i,t}^{1,\tau} + {}^{rt}p_{i,t}^{2,\tau}$.

4) System Dynamics. Certain types of non-capacitive loads, for example PHEV charging, will require the SMA to predict, monitor, and maintain system dynamics. Non-capacitive loads can be defined as loads that require a specific quantity of energy, which can be acquired at different time periods t. Up-and-down reserves, including regulation service, are exercised by the market operator so that over a half hour or longer period energy neutrality is maintained. As a result, we can write the remaining energy capacity dynamics (9). Also, included in these dynamics is a connection between the wholesale and the retail market, namely marginal line losses. Equations (8) and (10) provide the remaining system dynamics needed for non-capacitive load. Equation (12) updates the information vector.

$$ {}^{rt}n_{i,t+1}^\tau = {}^{rt}n_{i,t}^\tau + {}^{rt}\tilde{\Delta}n_{i,t}^\tau \tag{8} $$

$$ {}^{rt}x_{i,t+1}^\tau = {}^{rt}x_{i,t}^\tau + {}^{rt}\tilde{\Delta}x_{i,t}^\tau - m_{i,t}[{}^{rt}Q_{i,t}^{E}(\tau) + {}^{rt}\hat{Q}_{i,t}^{E}(\tau) + {}^{rt}\hat{Q}_{i,t}^{R}(\tau) + {}^{rt}\tilde{1}_{i,t}^{RS,\tau}\,{}^{rt}Q_{i,t}^{R}(\tau)] \tag{9} $$

$$ {}^{rt}n_{i,t}^\tau = {}^{rt}x_{i,t}^\tau = 0 \quad \forall \tau < t \tag{10} $$

$$ {}^{rt}\mathbf{I}_{i,t+1} = {}^{rt}V_{i,t}({}^{rt}\mathbf{I}_{i,t}, \text{new info during period } t) \tag{11} $$

5) Allowable Decisions. The SMA must follow market rules to make sure that its energy bid and regulation service offer are realizable. This requires that two constraints (12)-(13) on the maximal consumption rate (i.e., the requested energy rate plus *twice* the offered regulation service). *First*, the excess SMA location specific capacity should be sufficient to support the maximal consumption rate. *Second*, there must be enough load (non-capacitive or otherwise) to absorb the maximal charging rate. The allowable control set also includes non-negativity constraints on all the state and decision variables.

$$ \Sigma_\tau\, {}^{rt}m_{i,t}[{}^{rt}Q_{i,t}^{E}(\tau) + {}^{rt}\hat{Q}_{i,t}^{E}(\tau) + 2({}^{rt}Q_{i,t}^{R}(\tau) + {}^{rt}\hat{Q}_{i,t}^{R}(\tau))] \le {}^{rt}\hat{C}_{i,t}^{\max} \tag{12} $$

$$ {}^{rt}m_{i,t}[{}^{rt}Q_{i,t}^{E}(\tau) + {}^{rt}\hat{Q}_{i,t}^{E}(\tau) + 2({}^{rt}Q_{i,t}^{R}(\tau) + {}^{rt}\hat{Q}_{i,t}^{R}(\tau))] \le \rho\, {}^{rt}n_{i,t}^\tau \tag{13} $$

$$ {}^{rt}m_{i,t}[{}^{rt}Q_{i,t}^{E}(\tau) + {}^{rt}\hat{Q}_{i,t}^{E}(\tau) + {}^{rt}Q_{i,t}^{R}(\tau) + {}^{rt}\hat{Q}_{i,t}^{R}(\tau)] \le {}^{rt}x_{i,t}^\tau \tag{14} $$

5) Bellman Equation. Decisions are made at the beginning of each time period t employing the information or state vector, $\mathbf{I}_{i,t}$. Letting $\mathbf{u}_{i,t}$ be the vector of all the decision variables that have to be decided at time *t*, the Bellman Equation can be written as (15).

$$ {}^{rt}J\left(\mathbf{I}_{i,t}\right) = \min_{\mathbf{u}_{i,t}\in U_{i,t}(\mathbf{I}_{i,t})} {}^{rt}E_t\left[\begin{array}{l} g_{i,t}\left({}^{rt}\mathbf{I}_{i,t},\mathbf{u}_{i,t},{}^{rt}\tilde{P}^E_t,{}^{rt}\tilde{P}^R_t,t\right) \\ +{}^{rt}J_{i,t+1}\left({}^{rt}\mathbf{I}_{i,t+1}\right)\end{array}\right] \quad (15) $$

with boundary condition,

$$ J\left({}^{rt}\mathbf{I}_{i,N}\right) = c\,{}^{rt}x^N_{i,N} + \sum_{\tau>N}{}^{rt}x^{\tau}_{i,N}\lambda^{\tau}_{i,N} . $$

Where

$$ Eg_{i,t}\left({}^{rt}\mathbf{I}_{i,t},{}^{rt}\mathbf{u}_{i,t},{}^{rt}\tilde{P}^E_t,{}^{rt}\tilde{P}^R_t,t\right) = $$

$$ \sum_{\tau}\{ {}^{rt}\underset{\tilde{P}_t|e_0}{E}\,{}^{rt}\tilde{P}^E_{i,t}\,{}^{rt}p^{t,\tau}_{i,0}\,{}^{rt}Q^E_{i,t}(\tau) + {}^{rt}\hat{P}^E_{i,t}\,{}^{rt}\hat{Q}^E_{i,t}(\tau) + $$

$$ {}^{rt}\underset{\tilde{P}_t|e_1\cup e_2}{E}\,{}^{rt}\tilde{P}^E_t\,{}^{rt}p^{t,\tau}_{i,\alpha}\,{}^{rt}Q^R_{i,t}(\tau) - {}^{rt}\underset{\tilde{P}_t|e_1}{E}\,{}^{rt}\tilde{P}^R_t\,{}^{rt}p^{t,\tau}_{i,1}\,{}^{rt}Q^R_{i,t}(\tau) $$

$$ +\left({}^{rt}\hat{P}^E_t - {}^{rt}\hat{P}^R_t\right){}^{rt}\hat{Q}^R_{i,t}(\tau)\} + c^{rt}\,{}^{rt}x^t_{i,t} $$

IV. Coordination Algorithm and Extension to Other Load Types

A Preliminary Coordination Algorithm

Solution of the cascading markets problem defined above requires the simultaneous solution of several linked stochastic DPs. The LA undertakes the hedging function through participation in the day-ahead market and then distributes the scheduled quantities to its SMAs through the real-time markets when the SMAs know the actual real-time distribution network constraints.

In [1], [5], we report an algorithm solving the real-time SMA sub-problem for PHEV loads. The solution approach included an Optimal Open Loop Feedback approximation employing Multistage Stochastic Programming for a finite look-ahead estimate of the expected cost to go. Implementation of the algorithm on CAISO and ERCOT data indicates substantial benefits from demand participation in the various markets, particularly in terms of a substantial increase in the supply of regulation service which indicates positive synergies between PHEV and wind generation.

Using this computational experience as a building block to obtain efficient solutions to the multiple SMA sub-problems we can employ the following algorithm:

1) Solve the day-ahead LA problem to obtain estimates of scheduled energy purchases and regulation service sales $Q^{E,s}_t$ and $Q^{R,s}_t$ for *t=1,2,…,24* using a reasonable – possibly from a similar previous day – estimate of the expected cost to go $J(\mathbf{I}_t)$ for t=1.

2) Using at first reasonable LA real-time energy and reserve prices, $\hat{P}^E_t, \hat{P}^R_t$, for example setting them equal to the expected value of the real-time clearing prices, solve the SMA real-time sub-problems to obtain tentative values for $\hat{Q}^E_{i,t}(\tau), \hat{Q}^R_{i,t}(\tau)$.

3) Solve (7) and estimate the gradient of the objective function w.r.t. ${}^{rt}\hat{Q}^E_{i,t}(\tau), {}^{rt}\hat{Q}^R_{i,t}(\tau)$. Since we know that $\partial\,{}^{rt}\hat{Q}^E_{i,t}(\tau)/\partial\,{}^{rt}\hat{P}^E_t \le 0$ while $\partial\,{}^{rt}\hat{Q}^R_{i,t}(\tau)/\partial\,{}^{rt}\hat{P}^R_t \ge 0$, the sign of elements of the gradient of the objective function w.r.t. ${}^{rt}\hat{P}^E_t$, ${}^{rt}\hat{P}^R_t$ can be estimated, a direction of improvement in the prices, ${}^{rt}\hat{P}^E_t$, ${}^{rt}\hat{P}^R_t$ can be implemented and steps 2 and 3 repeatedly with the most recent ${}^{rt}\hat{P}^E_t$, ${}^{rt}\hat{P}^R_t$ estimates till the real-time market LA and SMA problems converge.

4) Repeat step 1 using ${}^{da}E\,{}^{da}J(\mathbf{I}_t) \approx {}^{rt}\underset{{}^{da}\mathbf{I}_1}{E}\,{}^{rt}J(\mathbf{I}_t)$ for *t*=1 obtained from the converged real-time problem above.

5) Repeat steps 2-5 until $J(\mathbf{I}_t)$ converges for *t*=1.

We acknowledge that at this point in time we have not been able to prove that the algorithm 1-5 converges. However, preliminary computational experience is encouraging. A reasonable problem simplification that appears to be near optimal is to restrict SMA real-time problem decisions to transactions with the LA, limiting real-time transactions to the LA.

Extension to Loads Other than PHEV Loads

the PHEV paradigm of a responsive load with linear dynamics generalizes to other important loads. Consider for example, HVAC systems with the following parameters.

T^{inside}_t	Inside temperature during period *t.*
$T^{outside}_t$	Outside temperature during period *t.*
$T^{\min}_t, T^{\max}_t$	Occupant preferences during period *t.*
K_i	Known building constants for *i* = 1, 2.
$Q^{HC,E}_t$	Energy rate bid for decision period *t.*
$Q^{HC,R}_t$	Regulation service offer for decision period *t.*
$Q^{HC,Capacity}_t$	Capacity of the HVAC system during *t.*

The heating and cooling system dynamics (19)-(21) and allowable control sets are closely analogous to PHEV dynamics and constraints (8)-(14). New plug in vehicle arrival random variables are also analogous to building heat losses and outside temperature, which can be easily predicted from weather forecasts and building properties

$$ T^{inside}_{t+1} = T^{inside}_t - K_1(T^{outside}_t - T^{inside}_t) + K_2(Q^{HC,E}_t + Q^{HC,R}_t) \quad (19) $$

$$ Q^{HC,E}_t + 2Q^{HC,R}_t \le \min(\hat{C}^{\max}_t, Q^{HC,Capacity}_t) \quad (20) $$

$$ T^{\min}_t \le T^{inside}_t \le T^{\max}_t \quad (21) $$

Other load examples include dimmable lighting loads with a preferred lumen range as well as the load of smart appliances.

V. CONCLUSION

We argue that regulation service reserves are likely to present a major bottleneck as significant capacity of intermittent clean energy generation is integrated. We also argue that demand side participation in existing wholesale power markets and emerging retail/distribution markets can provide the needed additional supply of regulation service that is capable to eliminate the bottleneck. We finally propose an enabling coordinated market participation decision support algorithm, explore its applicability to PHEV loads, and show that it can be extended to a wide variety of loads including HVAC, lights and smart appliances.

The issues investigated in this paper point to several systems challenges ranging from robust optimization opportunities in dealing with random variable forecasts needed in the proposed complex bid to the day ahead market, to the coordination of multiple stochastic dynamic programming based decisions, and to market equilibrium considerations, particularly regarding the allocation of local distribution network asset capacity among multiple competing SMAs.

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