Opportunity Costs, Values, and Control and Bidding Strategies for Aggregator-mediated Demand Response

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1 Introduction

Recently the system operator in Taiwan is designing a nationwide ancillary service market. Such development has led to a growing interest in providing flexibility via demand response (DR). Above all, renewable electricity retailers are exploring the possibilities for them to engage with their customers further such that their customers can provide the flexibility needed for DR services. To this end, opportunity costs and values for aggregator-mediated demand response (ADR) should be analyzed thoroughly, and from which a set of control and bidding strategies be proposed for these retailers.

2 Opportunity Costs for ADR

The opportunity costs for providing ADR services depend heavily on the market framework and are thus location specific. Nevertheless we can decompose the opportunity costs into the following two categories:

1. *Spread cost.* If the demand of a customer is shifted from t_A to t_B, then the spread between the electricity procurement costs at t_A and t_B will become one of the opportunity costs for providing such service. This term can of course be negative when the demand is shifted to a time interval which has lower electricity procurement cost. Note that "electricity procurement cost" is a general term and can refer to different prices in the electricity market, depending mostly on the relation between the aggregator and the customers. If the aggregator provides all the bulk energy for the customers, the electricity procurement costs will be a weighted average of the wholesale electricity prices and the fixed contract prices for renewable electricity which the aggregator bought under PPAs (if applicable). However, currently in Taiwan, private retailers are not allowed to sell electricity from non-renewable energy sources. Thus the electricity procurement costs for providing ADR in Taiwan will be the weighted average of the time-of-use (TOU) prices provided by Taipower to the customers and the fixed contract prices for renewable electricity under PPAs (if applicable). In such case the customers directly pay for the spread of the TOU prices, and thus the spread cost can actually be viewed as part of the customers' change of utility cost.

2. *Customers' Changes of Utility Gained Cost.* ADR services require customers of the aggregator to (de)activate certain electric devices that will otherwise be turned on / off. The services these devices provide will be shifted to other periods of time in the day, causing changes of the customers' utility gained. Usually it will result in a net decrease of the customers' utility gain (unless, as mentioned previous, the customers might benefit from the spread of TOU prices due to the shift), and such decrease will be larger if the loads are shifted further away from the original TOU. This will affect the willingness-to-accept prices for customers to provide control access to the aggregator for ADR services.

3 Values of DR and Additional Values of Aggregation

Before we discuss the control and bidding strategies of aggregators that provide ADR, it is worthwhile to know first what DR can do. Below is a list of features DR can provide:

1. *Load shifting or reduction.* From the system operator's perspective, events with extreme residual demand values, too high or too low alike, often lead to higher risks to system reliability. From the customer's perspective, avoiding consuming electricity during time periods with high TOU prices or critical peak prices (CPP) might also be beneficial. By shifting the load of customers to time periods with low residual load / low TOU prices and / or reducing the load of customers at time periods with high residual load / high TOU prices / additional CPP prices, an aggregator can provide additional values to both the system operator and her customers when the right incentives are given. Note that under an incoherent framework, the control strategies that benefit the system operator might not coincide with those that benefit the customers, so the right incentives should be given to the aggregators in order to achieve a win-win situation.

2. *Internal balancing.* The system operator might outsource the balancing responsibility to aggregators. In such case, aggregators could advance / delay loads of her customers should imbalance among her customers be detected. Note that deploying the load of customers to another time interval may cause imbalance on its own, so such measure cannot guarantee to balance out the net imbalance over the considered time horizon. For example, if there exists negative imbalance (the load was underestimated previously) throughout the day, simply bringing the load of customers from one time interval to another will not help reduce the total amount of imbalance energy that day. However, if the imbalance energy prices are expected to differ throughout the day, it will still make sense to perform ADR to reduce such cost. If the aggregator is not responsible for the imbalance of her customers, the imbalance cost will be distributed to a larger pool of customers beyond the control of the aggregator, and she will have fewer incentive to perform internal balancing. Of course, to provide sufficient incentives, if the aggregator becomes a balancing responsible party (BRP), her customers should no longer be liable to the imbalance cost caused by any third party.

3. *Control reserve capacity and energy.* Positive control reserve capacity can be provided by scheduled load at the time interval which the control reserve capacity is required. When the aggregator is called for positive balancing energy, the load is delayed or cancelled (if applicable). On the other hand, negative control reserve capacity can be provided by load that is not scheduled at the time interval and also not yet activated within a considered activity cycle (usually a day). When the aggregator is called for negative balancing energy, the load is activated in advance. Note that the activation of balancing energy may lead to internal imbalance in the near future, and the cost to balance out this imbalance should be considered during the bidding of the energy prices in the control reserve market.

The natural question then, is to ask why we should aggregate the customers to provide ADR. The answer is two-fold. First, by aggregating all the customers, the prediction error of the total load can be reduced, making the aggregated agent a more suitable candidate of providing reliable DR services. Second, a larger pool of flexible load resources can disperse the risk of DR activation resulting in the discomfort of the end-user, since the aggregator will have more choices at her disposal when a DR signal is given by the system operator.

4 Control Strategies of ADR

To demonstrate how an aggregator delivers ADR, a simple market framework is put into the context. Under which we assume:

1. There exist a day-ahead control reserve market (CRM), a day-ahead energy-only market (EOM), and an intraday EOM. The day-ahead markets close the day before delivery, when the dispatch schedule of the next day is determined. The intraday EOM closes an hour before delivery, allowing any BRP to deal with any unscheduled imbalance up until gate closure. The sequence of action is assumed to be the following: first the market clearing of the CRM, then the day-ahead EOM, at last the intraday EOM.

2. The duration of a product in the EOMs is one hour; that in the CRM is 4 hours.
3. The aggregator signed contracts with its customer so that she can advance / delay / cancel the load of electric devices upon which both parties agree when necessary. For load shifting, the maximum advance / delay time would be 3 hours.
4. The willingness-to-accept prices of customers to allow the aggregator to control their devices depend on the notification time before control. If the aggregator notifies the customers day-ahead, she pays less; if she notifies the customers just hours ahead, the cost of the control will be much higher.
5. Although the control command for each individual flexible resource is a continuous signal, whether to commit those resources when scheduling is a binary unit commitment problem.

With these assumptions, an aggregator can follow the below procedures to deliver ADR:

1. The customers submit default schedules of their flexible load to the aggregator in advance.
2. A day before the delivery, the aggregator calculates the available ADR based on the aggregated default schedule.
3. With appropriate control strategies, the aggregator dispatches the flexible load of her customer such that the available ADR she can deliver is optimized.
4. In case of real time internal imbalance (ex. balancing energy is called), the aggregator will try to balance out such imbalance in a cost-efficient manner.

We now explain in detail how the aggregator can optimize her available ADR by dispatching the flexible load of her customers. As shown in table 1, in the default schedule, the aggregator can deliver 1 unit of positive control reserve capacity and 7 units of negative control reserve capacity[1] at the shown CRM time interval . If the aggregator dispatches 1 unit of flexible load at T_1 to T_2, she can then deliver 2 units of positive control reserve capacity and 8 units of negative control reserve capacity at the shown CRM time interval, as shown in table 2.[2]

To dispatch the flexible load, the aggregator can notify the customers a day ahead or near real time. If the aggregator wishes to achieve load shifting or reduction, it is naturally better to notify the customers a day ahead since the opportunity cost of doing so will be much lower for the aggregator. Of course, if the prices in the intraday EOM are high enough, or the price spreads significant enough, it might still make sense to do load shifting / reduction near real time by internal balancing or trading with other agents in the market. On the other hand, balancing internal imbalance will always require near real time dispatch of the flexible load, resulting to higher opportunity costs.

To deliver control reserve capacity additional to the default schedule, the aggregator will have to consider the probability of her being called for balancing energy Pr_{called}. Suppose the aggregator decides to dispatch the flexible load only when the balancing energy is needed; this will result in an expected opportunity cost $(Q_{CRM}\Delta\tau) \cdot (OC_{RT} \cdot (1 - Pr_{called}) + OC_{Im} \cdot Pr_{called})$,[3] where Q_{CRM} the bid quantity in the CRM, $\Delta\tau$ the time duration of 1 product in the CRM, OC_{RT} the opportunity cost of dispatching the flexible load near real time, and OC_{Im} the opportunity cost of balancing out the potential internal imbalance due to the delivery of balancing energy.

Meanwhile, with the same reasoning, if the aggregator decides to dispatch the flexible load a day ahead for the control reserve capacity, the expected opportunity cost for the service will become $(Q_{CRM}\Delta\tau) \cdot (OC_{DA} + (OC_{RT} + OC_{Im}) \cdot Pr_{called})$, where OC_{DA} is the opportunity cost of dispatching the flexible load a day ahead. Therefore, we can determine the criteria where the aggregator should choose to notify the customer a day ahead for the delivery of additional control reserve capacity (equation 1):

[1] We assumed that at the next CRM time interval the demand is a constant of 3 units.

[2] It is possible to achieve more availalbe control reserve capacity at this particular time interval by dispatching flexible load from other time intervals, but this might reduce the available control reserve capacity of the time intervals at which the flexible load is dispatched.

[3] This is an optimistic estimation, assuming that the positive control reserve capacity is delivered by advancing some of the flexible load while the negative control reserve capacity is delivered by postponing some of the flexible load. Therefore, when balancing energy is needed, the corresponding flexible load can be dispatched according to the default schedule.

Table 1: Default Demand Schedule

Time	T1	T2	T3	T4
Demand	3	1	2	4
Positive Capacity	3	1	2	4
Negative Capacity	7	6	4	0
Negative Capacity *(from Next CRM Interval)*	0	3	6	9
Available Pos. Cap.	1			
Available Neg. Cap.	7			

Table 2: Controlled Demand Schedule

Time	T1	T2	T3	T4
Demand	2	2	2	4
Positive Capacity	2	2	2	4
Negative Capacity	8	6	4	0
Negative Capacity *(from Next CRM Interval)*	0	3	6	9
Available Pos. Cap.	2			
Available Neg. Cap.	8			

$$\frac{OC_{DA}}{OC_{RT}} < 1 - 2Pr_{called} \tag{1}$$

If $\frac{OC_{DA}}{OC_{RT}}$ is greater than $1 - 2Pr_{called}$, it will be preferable for the aggregator to notify the customers near real time; the two strategies degenerate when $\frac{OC_{DA}}{OC_{RT}} = 1 - 2Pr_{called}$.

5 Bidding Strategies of ADR

If the aggregator wishes to deliver load shifting from time interval T_1 to T_2 a day ahead, the criteria for expected profitability will be

$$\hat{M}^{DA}_{EOM,T_1} - \hat{M}^{DA}_{EOM,T_2} \geq OC^{cust}_{DA} \tag{2}$$

Where $\hat{M}^{DA}_{EOM,t}$ is the expected price in the day ahead EOM at time interval t. OC^{cust}_{DA} is the day ahead opportunity cost due to the loss of customers' utility for the ADR service.

With this criteria we can determine the desire bidding price for the aggregator in the day ahead EOM: it is the expected minimum price of the neighborhood around a specific time interval, plus OC^{cust}_{DA}.

For load reduction, the criteria for expected profitability is simpler: the aggregator will deliver load reduction whenever $\hat{M}^{DA}_{EOM,t}$ is higher than the opportunity cost of doing so.

Intraday load shifting and internal balancing follow similar strategies to those of load shifting a day ahead. At intraday timescales, the aggregator can profit from shifting the imbalance to time intervals when the prices in the intraday EOM are lower. If such a shift of imbalance results in canceling out of the imbalance at the two time interval (i.e. one of the time interval has positive imbalance while the other has negative imbalance), the avoided cost / profit in the EOM through intraday trading should be considered altogether. At near-real-time timescales, the aggregator will have to predict the expected imbalance cost / reward of the balance settlement to decide upon a dispatch strategy.

For control reserve capacity and energy, if the aggregator decides to notify the customer her dispatch decisions near real time, the capacity price of the control reserve will be $OC_{RT} \cdot \Delta\tau$, and the energy price will be $OC_{Im} - OC_{RT}$. On the other hand, if the aggregator notifies the customer a day ahead, the capacity price of the control reserve will be $OC_{DA} \cdot \Delta\tau$, and the energy price will be $OC_{Im} + OC_{RT}$. Note that these prices are based purely on the opportunity costs of the ADR services; a rent-seeking agent will behave differently in order to gain maximized profit.