This article has been accepted for inclusion in a future issue of this journal. Content is final as presented, with the exception of pagination.

ISO's Optimal Strategies for Scheduling the Hourly Demand Response in Day-Ahead Markets

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***Abstract*—This paper presents a hierarchical demand response (DR) bidding framework in the day-ahead energy markets which integrates customer DR preferences and characteristics in the ISO's market clearing process. In the proposed framework, load aggregators submit aggregated DR offers to the ISO which would centrally optimize final decisions on aggregators' DR contributions in wholesale markets. The hourly load reduction strategies include load shifting and curtailment and the use of onsite generation and energy storage systems. The ISO applies mixed-integer linear programming (MILP) to the solution of the proposed DR model in the day-ahead market clearing problem. The proposed model is implemented using a 6-bus system and the IEEE-RTS, and several studies are conducted to demonstrate the merits of the proposed DR model.**

***Index Terms*—Day-ahead scheduling, equivalent load aggregation, hourly demand response, mixed-integer linear programming.**

NOMENCLATURE

A. Indices and Abbreviations

i	Index of generating units.
l	Index of transmission lines.
t	Index of hour.
b	Index of bus.
d	Index of participants in the DR program.
k	Index of load reduction offers.
LC	Load curtailment offer.
LS	Load shifting offer.
OG	Onsite generation offer.
ES	Energy storage offer.
x	Load reduction option.

Manuscript received April 20, 2013; revised August 10, 2013, November 18, 2013, and January 20, 2014; accepted April 08, 2014. Paper no. TPWRS-00481-2013.

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Digital Object Identifier 10.1109/TPWRS.2014.2316832

B. Sets

NG	Set of generating units.
ND	Set of participants in the DR program.
NT	Set of scheduling hours.
NG_b	Set of generating units connected to bus b.
NL_b	Set of transmission lines connected to bus b.
ND_b	Set of participants of the DR program in bus b.
N_d^x	Set of DR offers of option x by participant d.

C. Constants

$P_{dt}^{D,\mathrm{agg}}$	Adjusted load demand of aggregator d at time t.
$P_{bt}^{D,\mathrm{nonres}}$	Total non-responsive load demand of bus b at time t.
f_{it}^{SR}	Bidding capacity cost of generating unit i for providing spinning reserve at time t.
$PL_l^{\max}$	Maximum capacity of line l.
X_l	Reactance of line l.
IC_{kd}^x	Offered load reduction initiation cost of kth offer of option x submitted by participant d.
c_{kd}^x, q_{kd}^x	Price and quantity of load reduction associated with the kth offer of option x submitted by participant d.
$LRD_{kd}^{\min,x}$	Minimum load reduction duration of load reduction option x submitted by participant d.
$LRD_{kd}^{\max,x}$	Maximum load reduction duration of load reduction option x submitted by participant d.
MN_{kd}^{LC}	Maximum number of daily load curtailments of kth LC offer of participant d.
RU_{kd}^{OG}	Ramp-up limit of kth OG offer of participant d.
RD_{kd}^{OG}	Ramp-down limit of kth OG offer of participant d.
$T_{kd}^{on,OG}$	Minimum on time of kth OG offer of participant d.
$T_{kd}^{off,OG}$	Minimum off time of kth OG offer of participant d.

SC_{kd}^{OG} Startup cost for the kth OG offer of participant d.

SE_{ekd}^{OG} Startup emission of type e for kth OG offer of participant d.

μ_{ekd}^{OG} Coefficient for emission type e of kth OG offer of participant d.

$E_{kd}^{\max,ES}$ Energy capacity of kth ES offer of participant d.

$P_{kd}^{\max,ES}$ Power rating of kth ES offer of participant d.

$\eta_{kd}^{C,ES}$ Charge efficiency of kth ES offer of participant d.

$\eta_{kd}^{D,ES}$ Discharge efficiency of kth ES offer of participant d.

RC_{kd}^{ES} Charging ramp of kth ES offer of participant d.

RD_{kd}^{ES} Discharging ramp of kth ES offer of participant d.

D. Variables

SU_{it} Startup cost of generating unit i at time t.

SD_{it} Shutdown cost of generating unit i at time t.

I_{it} Commitment state of generating unit i at time t.

P_{it} Real power scheduled for generating unit i at time t.

SR_{it} Scheduled spinning reserve of generating unit i at time t.

PL_{lt} Real power flow of line l at time t.

θ_{lt}^{S} Voltage angle of sending-end bus of line l at time t.

θ_{lt}^{R} Voltage angle of receiving-end bus of line l at time t.

$P_{bt}^{D,\mathrm{eq}}$ Equivalent load demand of bus b at time t after DR schedule of the ISO.

u_{kdt}^{x} Status of kth load reduction offer of option x for participant d at time t; 1 if the contract is scheduled, 0 otherwise.

y_{kdt}^{x} Starting indicator of kth load reduction offer of option x for participant d at time t.

z_{kdt}^{x} Stopping indicator of kth load reduction offer of option x for participant d at time t.

LR_{dt}^{x} Scheduled load reduction of option x for participant d at time t.

CLR_{dt}^{x} Cost function of load reduction option x provided by participant d at time t.

$LRIC_{kdt}^{x}$ Load reduction initiation cost of kth load reduction offer of option x for participant d at time t.

SL_{kdt}^{LS} Shifted load of the kth LS offer of participant d to time t.

CL_{kdt}^{ES} Charge load of kth ES offer of participant d at time t.

E_{kdt}^{ES} Energy of kth ES offer of participant d at time t.

SUE_{ekdt}^{OG} Startup emission of type e for kth OG offer of participant d at time t.

EM_{ekdt}^{OG} Total emission of type e for kth OG offer of participant d at time t.

I. Introduction

The applications of smart grid technologies in terms of control and communication infrastructures, as well as widespread utilizations of distributed energy resources, have impacted power systems operations. The generation supply is no longer limited to large conventional units, and the demand-side management continues to play a significant role in day-ahead clearing of electricity markets. The aggregated customers can own energy resources and participate in the demand response (DR) programs.

DR refers to a tariff or program coordinated with power market conditions for motivating changes in electricity consumptions by end-use customers [1]. DR could enhance the economic efficiency of power systems, reduce peak demand and market price volatility, eliminate the need for committing peaking units, and reduce the carbon footprint in the electricity sector [2]–[5]. To achieve these benefits, the FERC order 719 required ISOs to accept DR bids in wholesale markets on a basis that is comparable to other resources [6]. Following this directive, the ISOs have implemented multiple DR programs by adjusting market rules [7].

The rational DR participants would recover the reduced load during hours when the forecasted energy price is low [8], [9]. This shift may result in unanticipated load hikes in certain hours which would complicate the ISO's operation and may cause system security problems [9]. Although ISOs have implemented multiple DR programs, the customer load shifting options have not been fully utilized [10]–[14]. The emergence of smart grid technologies at customer sites, microgrids (with distributed generating units and energy storage systems), and community load aggregation in urban areas have formed effective dialogues for customer participations in wholesale electricity markets which in turn require advanced DR programs for modeling the customer load shifting options. In addition, the emergence of advanced monitoring and sensing devices (a myriad of intelligent electronic devices (IEDs), sophisticated meters, and real-time communication and control infrastructures) have enabled ISOs to collect and apply the DR information in more details, monitor and verify load reductions with more precision, and optimize load recovery activities in DR programs.

The North America Energy Standard Bureau (NAESB) considers DR as a resource in wholesale electricity market operations, and has developed a business process model for DR

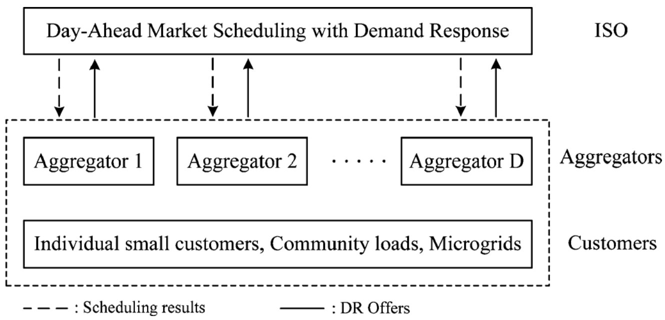

Fig. 1. Proposed hierarchical DR bidding framework.

participations in such markets [15]. The NAESB DR business process model includes steps for enrollment and qualification of DR resources, forward scheduling and award notification, deployment and real-time communications, measurement and performance evaluation, and settlement. DR forward scheduling and award notification process includes DR offer submission, DR commitment and scheduling, and DR award notification, which enable customer participations in electricity markets [16]–[21]. Earlier, DR was modeled by the price elasticity of demand [16], [17]. In [16], the elasticity of demand was incorporated in an iterative market clearing process. However, a convergence problem in the iterative process could result in a time-consuming solution; it could also be difficult to guarantee the existence of a feasible solution in this approach. In [17], the iterative approach proposed in [16] was revisited and the convergence problem was alleviated. Although the analysis of the price elasticity of demand provides a theoretical insight on market impacts of DR, it does not provide a practical tool for DR implementations in electricity markets. This is because the customer price elasticity, which is not known precisely, is considered using historical consumption data. In addition, the model did not treat DR as a market resource nor could it capture customer characteristics and its load reduction preferences.

The FERC order 745 amended the Federal Power Act to ensure that DR can participate in wholesale energy markets and be compensated at market prices for energy [18]. Recent studies have considered DR as a market resource with specific constraints embedded in the day-ahead scheduling [19]–[21]. We considered in [19] a day-ahead market clearing model to incorporate DR for economic and security purposes in the hourly solution of security-constrained unit commitment (SCUC). In that case, aggregators would provide the ISO with DR bids with intertemporal characteristics. In [20], the hourly DR scheduling problem proposed in [19] was considered along with generating unit ramping costs. It was concluded that the optimal hourly DR could be a replacement for frequent ramping of thermal generating units, and the combined hourly DR and generation ramping in the day-ahead scheduling could further mitigate hourly load fluctuations and achieve higher market efficiencies. A DR model is introduced in [21] in which DR aggregators submit offers to day-ahead energy markets. The DR offers are treated as market products which are comparable to GENCO's bids for balancing the supply and demand. The model in [21] considers DR constraints while taking into account the effect of load shifting by participants.

This paper incorporates a hierarchical DR bidding framework in the ISOs day-ahead market clearing which would change the economics of energy supplied by the grid. DR options offered by aggregators to the ISO's day-ahead market scheduling would consider hourly load curtailments, load shifting, onsite generation, and storage systems. The ISO applies the proposed model, considers customer load reduction preferences and characteristics in terms of the four DR options, and calculates equivalent load reductions as strategies for minimizing the cost of balancing the hourly supply and demand in transmission-constrained power systems. The proposed model would optimize hourly DR benefits while providing practical solutions for DR implementations in wholesale energy markets.

This paper contributes to the technical literature as follows: 1) A hierarchical DR bidding framework is proposed which would enable customers to submit load reduction offers to wholesale DR programs. The proposed framework taps the potential DR from small customers via aggregators. The aggregated DR is submitted to the ISO which would centrally optimize final decisions on DR contributions in wholesale markets. In this way, the operated DR is coordinated by the ISO and deployed when and where it is required. We have referred to this setting as the "coordinated DR operation", and demonstrated its superiority to the existing uncoordinated DR approaches, using simple cases in Section VI-A. 2) The DR participants' load reduction offers are explicitly modeled in terms of customer options for reducing loads, i.e., load curtailment (LC), load shifting (LS), utilizing onsite generation (OG), and utilizing onsite energy storage (ES). The proposed model includes two options (LS and ES) with load recovery considerations which would complement existing DR practices. In addition, the proposed model integrates customer load reduction characteristics and preferences into the ISO's decisions for DR deployment. This detailed modeling of options for customer load reductions would enable ISOs to collect and apply the DR information comprehensively, monitor and verify load reductions with more precision, and optimize and customize load recovery activities in DR programs. This approach outperforms the existing price elasticity-based DR models which cannot provide the ISO with the required information on customer load reductions and load recovery preferences.

The rest of this paper is organized as follows. Section II introduces the structure of the hierarchical DR bidding framework and presents the aggregators' offer packages for the four load reduction options. The MILP formulation of the aggregators' DR offer is presented in Section III. The ISO's market clearing method which considers the proposed DR framework is presented in Section IV. Section V presents the numerical studies conducted on a 6-bus system and the IEEE-RTS, and elaborates the features of the proposed model. Finally, conclusions are drawn in Section VI.

II. Hierarchical Demand Response Bidding Framework

The structure of the proposed hierarchical framework for implementing DR scheduling and award notification processes is shown in Fig. 1. The hierarchical DR bidding framework in Fig. 1 maximizes customer exposures to electricity markets in which individual customers participate via aggregators in day-ahead market decisions. The aggregators submit DR offers to the ISO with the additional information on hourly load characteristics. Accordingly, the ISO uses the DR offers and the load reduction information in the proposed DR model for clearing the day-ahead market. The aggregators will utilize the ISO's accepted DR offers to implement the equivalent load reductions (i.e., loads and local resources) in real time.

The DR aggregator could be an independent for-profit organization or an existing market participant (e.g., microgrid operator, community load aggregator). DR aggregators could enroll retail customers to participate in DR and offer the aggregated DR options to the ISO's day-ahead scheduling with DR. The aggregators would provide customers with metering infrastructures for monitoring equivalent load reductions. DR aggregation can be applied to various DR programs (e.g., energy, capacity, ancillary services) and categorized with regards to customer classes, customer locations, and load reduction strategies. DR aggregators usually serve customers located at a geographical area which can be mapped at a certain bus on the transmission network. DR aggregators may focus on serving a certain class of customers, e.g., industrial, commercial, or serving all classes of customers. Load reductions provided through aggregators' DR offers would need to be larger than the ISO's minimum curtailment level in wholesale markets. The structure of aggregators' DR offers is presented next.

A. Structure of DR Offers Supplied by Aggregators

The emergence of smart grid technologies at customer sites, microgrids (with distributed generating units, combined heat and power units, energy storage systems), and community load aggregation in urban areas could facilitate retail customer participations in DR programs. The customers may utilize onsite generation and energy storage rather than curtailing or shifting customer loads in DR programs. Hence, DR aggregation becomes more prevalent when considering large sums of data supplied for various DR options with specific hourly characteristics.

DR aggregators would form hourly DR offers in terms of customer load reduction options which could include load curtailment (LC), load shifting (LS), use of onsite generation (OG), and use of energy storage (ES) systems. The aggregators identify DR characteristics when registering customers' specific technical constraints and response preferences. The DR aggregators would utilize various performance evaluation methodologies in order to assign proper load reduction options and quantities corresponding to customer DR preferences and characteristics [15]. The DR aggregators would accordingly submit portfolios with the four DR options (LC, LS, OG, ES) which could include multiple offers for any DR options. In this model, the DR data passed onto the ISO will be confined into the four load reduction options [15]. The offer packages of DR aggregators, which would contain financial and technical characteristics of hourly load reductions, are presented below.

1) Load Curtailment (LC): In the LC option, DR customers would apply energy efficiency as an alternative to reduce their hourly electricity usage without shifting it to other hours. An LC offer includes a price-quantity pair which specifies how much the DR aggregator is willing to be compensated for reducing its hourly load. LC offers also contain a load reduction initiation cost which would cover customers' fixed costs for load curtailments. Customer constraints may include minimum/maximum duration for daily LCs, maximum number of daily LCs, and daily time for initiating LC.

2) Load Shifting (LS): In the LS option, customers shift reduced loads to other hours within a day. An LS offer includes price-quantity pair, load reduction initiation cost, minimum/maximum duration for daily load reduction, daily time for initiating load reduction, and periods of the day when curtailed loads will be shifted to.

3) Onsite Generation (OG): In the OG option, behind-the-meter onsite generation would be utilized to reduce the local load supplied by the grid. The hourly surplus OG is offered by the aggregator to the market. The offer would include a price-quantity pair, startup cost, ramp up/down rates, minimum on/off times as well as the emission coefficients of the OG fleet. The eligibility of local generators for market participation would be evaluated during aggregators' enrollment and qualification processes [9], [15].

4) Energy Storage (ES): The difference between ES and OG options is that the ES would have to be charged (additional local load) prior to being discharged for customer load reduction. An ES offer to the ISO would include a price-quantity pair, energy capacity, power rating, ramp rates, charge/discharge efficiency, and energy retention time of ES systems [22].

III. Mathematical Modeling of Aggregators

This section presents the MILP mathematical modeling of the aggregators DR offers introduced in Section II.

A. Load Curtailment

An aggregator submits N^{LC} number of the LC offers to the ISO. The kth LC offer of aggregator d at time t is characterized by the quantity of load curtailment q^{LC}_{kdt} and its associated price c^{LC}_{kdt}. The total LC scheduled by the ISO for aggregator d at time t, LR^{LC}_{dt}, and its associated cost function, CLR^{LC}_{dt}, are formulated in (1)–(2). The binary variable u^{LC}_{kdt} represents the load reduction status of the kth LC offer and becomes 1 if the offer is scheduled by the ISO. The binary variable y^{LC}_{kdt} becomes 1 in (3) as the load reduction is initiated for the kth LC offer of participant d, and the binary variable z^{LC}_{kdt} becomes 1 in (3) as the load reduction is terminated. Binary relation (4) assures that the start/stop times would not coincide. Once an LC offer is scheduled, the associated binary indicator y^{LC}_{kdt} becomes 1 and $LRIC^{LC}_{kdt}$ in (5) would take the initiation cost for the load reduction. The minimum/maximum durations for LC, and maximum number of daily LC are formulated in (6)–(8), receptively. Constraint (6) enforces the load reduction status indicator u^{LC}_{kdt} to be 1 for the minimum duration of LC. The load reduction stopping indicator z_{kdt}^{LC} will become 1 in (7) at the maximum duration of LC, once LC is started at hour t. Constraint (8) would limit the maximum number of daily LCs:

$$LR_{dt}^{LC} = \sum_{k \in N_d^{LC}} q_{kdt}^{LC} u_{kdt}^{LC} \quad (1)$$

$$CLR_{dt}^{LC} = \sum_{k \in N_d^{LC}} \left(LRIC_{kdt}^{LC} + c_{kdt}^{LC} q_{kdt}^{LC} u_{kdt}^{LC} \right) \quad (2)$$

$$y_{kdt}^{LC} - z_{kdt}^{LC} = u_{kdt}^{LC} - u_{kd(t-1)}^{LC} \quad \forall k, \forall d, \forall t \quad (3)$$

$$y_{kdt}^{LC} + z_{kdt}^{LC} \le 1 \quad \forall k, \forall d, \forall t \quad (4)$$

$$LRIC_{kdt}^{LC} \ge \mathrm{IC}_{kd}^{LC} y_{kdt}^{LC} \quad \forall k, \forall d, \forall t \quad (5)$$

$$\sum_{t'=t}^{t+\mathrm{LRD}_{kd}^{\min,LC}-1} u_{kdt'}^{LC} \ge \mathrm{LRD}_{kd}^{\min,LC} y_{kdt}^{LC} \quad \forall k, \forall d, \forall t \quad (6)$$

$$\sum_{t'=t}^{t+\mathrm{LRD}_{kd}^{\max,LC}-1} z_{kdt'}^{LC} \ge y_{kdt}^{LC} \quad \forall k, \forall d, \forall t \quad (7)$$

$$\sum_{t \in T} y_{kdt}^{LC} \le \mathrm{MN}_{kd}^{LC} \quad \forall k, \forall d. \quad (8)$$

B. Load Shifting

The LS option is modeled similar to that of the LC (1)–(8), although the LS option does not constrain the maximum number of daily LS. The main difference between LC and LS options is that the LS quantity will be served at a different time rather than being curtailed. The LS offer includes $(T_{kd}^{LS}, T_{kd}^{SH})$ which specifies that the customers on the kth LS offer would reduce their load in T_{kd}^{LS} period of day-ahead and would shift the reduced load to the T_{kd}^{SH} period. Accordingly, the energy balance between the reduced load and the shifted load is given in (9), while (10) states that the reduced load would be recovered at the T_{kd}^{SH} period, and would not exceed the earlier load reductions:

$$\sum_{t \in T_{kd}^{SH}} SL_{kdt}^{LS} = \sum_{t \in T_{kd}^{LR}} q_{kd}^{LS} u_{kdt}^{LS} \quad \forall k, \forall d \quad (9)$$

$$\begin{cases} 0 < SL_{kdt}^{LS} < q_{kd}^{LS} & \forall k, \forall d, \forall t \in T_{kd}^{SH} \\ SL_{kdt}^{LS} = 0 & \forall k, \forall d, \forall t \notin T_{kd}^{SH}. \end{cases} \quad (10)$$

C. Onsite Generation

Aggregators would prioritize local loads to be supplied by the OG fleet. The aggregators calculate surplus OG capacity for bidding to the market. The total load reduction scheduled by the ISO for the OG offers of aggregator d at time t along with the associated cost function constraints are presented by (11)–(13), respectively. The binary variable u_{kdt}^{OG} indicates whether the ISO schedules any load reductions by considering the kth OG offer of aggregator d at hour t. The continuous variable P_{kdt}^{OG} represents the ISO's schedule for the kth OG offer of aggregator d at time t. Once an OG offer is scheduled, the term $(u_{kdt}^{OG} - u_{kd(t-1)}^{OG})$ in (13) becomes 1 and SU_{kdt}^{OG} would be the startup cost. Constraint (14) presents the minimum/maximum dispatch of OG, while (15) shows ramp up/down constraints of OG. The constraint (16) would enforce the OG to reduce load for a minimum number of hours. The constraint (17) ensures that the OG would be off for a minimum number of hours before providing further load reduction. The total emission produced by OG is formulated by (18), while (19) defines the associated startup emission.

$$LR_{dt}^{OG} = \sum_{k \in N_d^{OG}} P_{kdt}^{OG} \quad (11)$$

$$CLR_{dt}^{OG} = \sum_{k \in N_d^{OG}} \left(SU_{kdt}^{OG} + c_{kdt}^{OG} P_{kdt}^{OG} \right) \quad (12)$$

$$SU_{kdt}^{OG} \ge SC_{kd}^{OG} \left(u_{kdt}^{OG} - u_{kd(t-1)}^{OG} \right) \quad \forall k, \forall d, \forall t \quad (13)$$

$$u_{kdt}^{OG} P_{kdt}^{\min,OG} \le P_{kdt}^{OG} \le u_{kdt}^{OG} P_{kdt}^{\max,OG} \quad \forall k, \forall d, \forall t \quad (14)$$

$$-RD_{kd}^{OG} \le P_{kdt}^{OG} - P_{kd(t-1)}^{OG} \le RU_{kd}^{OG} \quad \forall k, \forall d, \forall t \quad (15)$$

$$\sum_{t'=t}^{t+T_{kd}^{on,OG}-1} u_{kdt'}^{OG} \ge T_{kd}^{on,OG} \left(u_{kdt}^{OG} - u_{kd(t-1)}^{OG} \right) \forall k, \forall d, \forall t \quad (16)$$

$$\sum_{t'=t}^{t+T_{kd}^{off,OG}-1} \left(1 - u_{kdt'}^{OG} \right) \ge T_{kd}^{off,OG} \left(u_{kd(t-1)}^{OG} - u_{kdt}^{OG} \right) \forall k, \forall d, \forall t \quad (17)$$

$$EM_{ekdt}^{OG} = \sum_{k \in N_d^{OG}} \mu_{ekd}^{OG} P_{kdt}^{OG} + SUE_{ekdt}^{OG} \quad (18)$$

$$SUE_{ekdt}^{OG} \ge SE_{ekd}^{OG} \left(u_{kdt}^{OG} - u_{kd(t-1)}^{OG} \right) \quad \forall e, \forall k, \forall d, \forall t \quad (19)$$

D. ES System

The ES option would supply the hourly local load and be charged locally as part of the aggregator's load profile adjustment. At hours, the ES could reduce the local load when discharging energy and increase the local load when charged by the available OG. An aggregator utilizes the available ES systems to adjust local loads, evaluates the hourly surplus ES capacity and submits a total of N^{ES} offers to the ISO's day-ahead market to provide load reductions by ES. The hourly ES model is presented in (20)–(23). The continuous variable P_{kdt}^{ES} represents the ISO's schedule for the kth ES offer of aggregator d at time t. The total ES load reduction and the associated cost function, defined by (20)–(21), are the sum of ISO's load reduction schedules and its cost over the submitted offers. Constraint (22) would limit the total load reduction to the ES rating, while constraint (23) would limit the discharge rate of ES:

$$LR_{dt}^{ES} = \sum_{k \in N_d^{ES}} P_{kdt}^{ES} \quad (20)$$

$$CLR_{dt}^{ES} = \sum_{k \in N_d^{ES}} c_{kdt}^{ES} P_{kdt}^{ES} \quad (21)$$

$$0 \le P_{kdt}^{ES} \le P_{kd}^{\max,ES} \quad \forall k, \forall d, \forall t \quad (22)$$

$$-RD_{kd}^{ES} \le P_{kdt}^{ES} - P_{kd(t-1)}^{ES} \le RD_{kd}^{ES} \quad \forall k, \forall d, \forall t. \quad (23)$$

The ES hourly energy balance in (24) would provide sufficient energy during load reduction hours. The ISO is responsible for optimizing the hourly schedule of the offered ES. Constraints (25) represent the initial charging state of ES and (26) limit the ES charging state to the maximum available energy of the ES fleet. Constraints (27) indicate that the ES charging is limited by its power rating, while constraints (28) would limit the ES charging rate. The ES energy retention constraint (29) would ensure that the ES energy will not be kept longer than its energy retention time. The binary variable u_{kdt}^{ES} in (26) indicates whether the kth ES offer of participant d contains any ES energy at time t. The start and the stop binary indicators y_{kdt}^{ES} and z_{kdt}^{ES} are introduced to model the energy retention constraint of ES in (29). The binary variables are constrained by (30)–(31). The energy retention time is an important characteristic of ES systems which states that the ES energy should not be kept longer than a specified time (energy retention time) [22]. The start and the stop binary indicators can be eliminated from the model when the energy retention time is not a concern:

$$E_{kd(t+1)}^{ES} = E_{kdt}^{ES} + \left[\eta_{kd}^{C,ES} CL_{kdt}^{ES} - \frac{1}{\eta_{kd}^{D,ES}} P_{kdt}^{ES}\right] \quad \forall k, \forall d, \forall t \tag{24}$$

$$E_{kd,0}^{ES} = E_{kd}^{ES,initial} \quad \forall k, \forall d, \forall t \tag{25}$$

$$E_{kd}^{\min,ES} u_{kdt}^{ES} \le E_{kdt}^{ES} \le E_{kd}^{\max,ES} u_{kdt}^{ES} \quad \forall k, \forall d, \forall t \tag{26}$$

$$0 \le CL_{kdt}^{ES} \le P_{kd}^{\max,ES} \quad \forall k, \forall d, \forall t \tag{27}$$

$$-RC_{kd}^{ES} \le CL_{kdt}^{ES} - CL_{kd(t-1)}^{ES} \le RC_{kd}^{ES} \quad \forall d, \forall t \tag{28}$$

$$\sum_{t'=t}^{t+ERT_d^{ES}} z_{kdt}^{ES} \ge y_{kdt}^{ES} \quad \forall k, \forall d, \forall t \tag{29}$$

$$y_{kdt}^{ES} - z_{kdt}^{ES} = u_{kdt}^{ES} - u_{kd(t-1)}^{ES} \quad \forall k, \forall d, \forall t \tag{30}$$

$$y_{kdt}^{ES} + z_{kdt}^{ES} \le 1 \quad \forall k, \forall d, \forall t. \tag{31}$$

IV. Proposed DR for Day-Ahead Market Clearing

The available resources are scheduled by the ISO in the day-ahead energy market to meet the hourly load requirements. In the day-ahead market, the ISO receives generation offers and load bids and clears the market subject to applicable transmission network, generation unit, and system constraints. The load bids include the information on MW quantities and purchasing locations at applicable hours. In our proposed model, DR aggregators, on behalf of responsive loads, also submit bids for providing load reduction options in the market. In some markets, non-responsive loads do not submit bids and the ISO would have to predict the non-responsive day-ahead loads. The ISO clears the day-ahead market and uses the following model for optimizing the DR offers for hourly load reductions.

The objective function of the day-ahead market clearing is to minimize the total system cost formulated as follows:

$$\begin{aligned}\sum_{t\in NT} \Bigg\{ & \sum_{i\in NG} \left(C(I_{it}, P_{it}) + SU_{it} + SD_{it}\right) \\ & + \sum_{i\in NG} \left(f_{it}^{SR} SR_{it}\right) \\ & + \sum_{d\in ND} \left(CLR_{dt}^{LC} + CLR_{dt}^{LS} + CLR_{dt}^{OG} + CLR_{dt}^{ES}\right) \Bigg\}\end{aligned} \tag{32}$$

in which the first line is the cost of energy production by thermal generating units including startup and shutdown costs; the second line is the cost of scheduling spinning reserves provided by generating units; and the third line is the cost of DR scheduling. Here, the DR does not include the reserve market [23]. In the day-ahead market, there are two approaches (i.e., sequential and simultaneous) to the energy and the operating reserve scheduling. The experience with the application of these two approaches indicates that the simultaneous approach would simplify market processes and reduce market prices due to the integration of energy and operating reserve markets [24].

In the proposed model, spinning reserve is procured to assure the security of day-ahead operations. Spinning reserve represents the unused capacity of online generating units which can be accessed in 10 min upon operators' call. The spinning reserve will be provided by the same units which provide energy in real time. So, the coordinated commitment of energy and spinning reserve would prevent any conflict between the schedules. In addition, the availability of spinning reserves merely depends on the hourly schedule of generating units in energy markets, which is the focus of this paper. The other types of reserves, e.g., non-spinning reserve, negligibly impact energy market schedules and are excluded in the model. However, the proposed model can be revised easily to consider other types of generation reserves. The objective function (32) is constrained by load reduction offers (1)–(31), dc power flow and line flow constraints (33)–(35), DR constraints (36)–(37), as well as thermal generating unit operating constraints, system spinning reserve requirements, and emission constraints [21], [25].

The dc power flow equation (33) assures a power balance between generation offers and responsive/non-responsive loads. The line flow is defined in (34) which are constrained by (35). In (36), $P_{dt}^{D,\text{agg}}$ represents the aggregator's adjusted load considering the local utilization of ES and OG, which would be submitted to the ISO. DR_{dt} represents the ISO's schedule for hourly LC and LS as well as the surplus hourly OG and ES offered by aggregators. The equivalent local load after ISO's DR schedule is designated by $P_{dt}^{D,\text{eq}}$. The constraint (36) represents the prevailing DR aggregation constraint which states that the aggregators would first supply local loads. The local supply larger than the aggregators' adjusted load would be submitted to the grid. The total DR schedule in (37) includes offers from the four DR options as well as the recovered loads and charging loads associated with LS and ES. In (37), SL_{kdt}^{LS} which is the shifted load of the kth LS offer of aggregator d, is set to zero during hours when $t \notin T_{kd}^{SH}$ and shifted at $t \in T_{kd}^{SH}$ according to (9)–(10). The ES charging periods are optimized by the ISO considering the offered ES characteristics in (20)–(31). In this way, the ISO co-optimizes the shifting and charging periods of LS and ES during the day-ahead market clearing process, while considering the aggregators' preferences and characteristics:

$$\sum_{i\in NG_b} P_{it} - P_{bt}^{D,nonres} - \sum_{d\in ND_b} P_{dt}^{D,eq} = \sum_{l\in NL_b} PL_{lt} \; \forall b, \forall t \tag{33}$$

$$PL_{lt} = \frac{1}{X_l}\left(\theta_{lt}^S - \theta_{lt}^R\right) \quad \forall l, \forall t \tag{34}$$

$$-PL_{lt}^{\max} \le PL_{lt} \le PL_{lt}^{\max} \quad \forall l, \forall t \tag{35}$$

$$P_{dt}^{D,eq} = P_{dt}^{D,agg} - DR_{dt} \quad \forall d, \forall t \tag{36}$$

$$\begin{aligned}DR_{dt} = {} & LR_{dt}^{LC} + LR_{dt}^{LS} + LR_{dt}^{OG} + LR_{dt}^{ES} \\ & - \sum_{k\in N_d^{LS}} SL_{kdt}^{LS} - \sum_{k\in N_d^{ES}} CL_{kdt}^{ES} \quad \forall d, \forall t.\end{aligned} \tag{37}$$

This article has been accepted for inclusion in a future issue of this journal. Content is final as presented, with the exception of pagination.

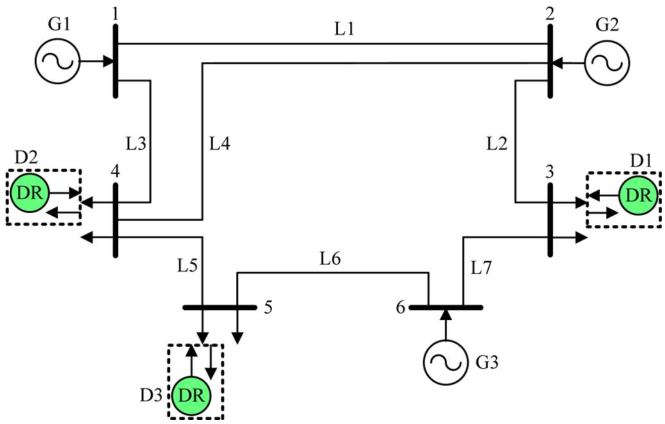

Fig. 2. One-line diagram of the 6-bus system.

TABLE I
LOAD REDUCTION OFFER PRICES

Offer #	1	2	3	4	5
LC Price ($/MW)	10	11	12	13	14
LS Price ($/MW)	10	11	12	13	14
OG Price ($/MW)	10	11	12	13	14
ES Price ($/MW)	10	11	12	13	14

V. NUMERICAL STUDIES

The proposed DR model is implemented here on a 6-bus system and the IEEE-RTS.

A. The 6-Bus System

In the six-bus system shown in Fig. 2, a DR aggregator is available at each load bus which offers the DR portfolio. Three cases are studied on the 6-bus system. In Case 0, the DR program is not implemented. In Cases 1 and 2, 20% of customers at each bus are considered to be responsive to load reduction offers. In Case 1, an uncoordinated DR is considered in which aggregators locally schedule DR and submit adjusted fixed loads for the day-ahead scheduling. In this case, the aggregator decided to reduce the load at peak hours and shift it to off-peak hours. This would simply reshape the load at the aggregator's location, by which the ISO's operation would be impacted. In Case 2, the proposed hierarchical DR bidding framework is considered in which the aggregators calculate the available load reduction capacity in the four DR options and submit five DR offers of each option to the ISO based on the format proposed in Section III. The load reduction offer prices are given in Table I. The other load reduction offer data along with the 6-bus system data are given at http://motor.ece.iit.edu/data/6bus_Data_DR.pdf. The study cases were solved using MILP solver of CPLEX 12.2 [26] on a desktop computer with a 2.2-GHz i7 processor and 6 GB of RAM. The computation time is trivial for such a small system while the upper bound on the duality gap is set to be zero. The emission constraints were not considered in this study.

Fig. 3 shows that the DR utilization in Cases 1 and 2 would reduce hourly peak loads. The off-peak load increase occurs when utilizing LS and ES options. In Fig. 3, the equivalent load profile in Case 1 is volatile with load hikes at hours 10 and 18. However, the equivalent load profile in Case 2 is smooth based on

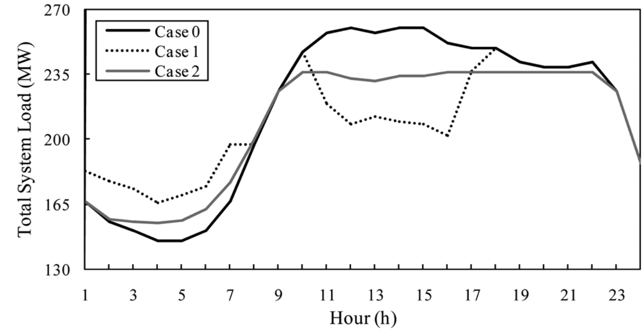

Fig. 3. Daily load profile of the 6-bus system.

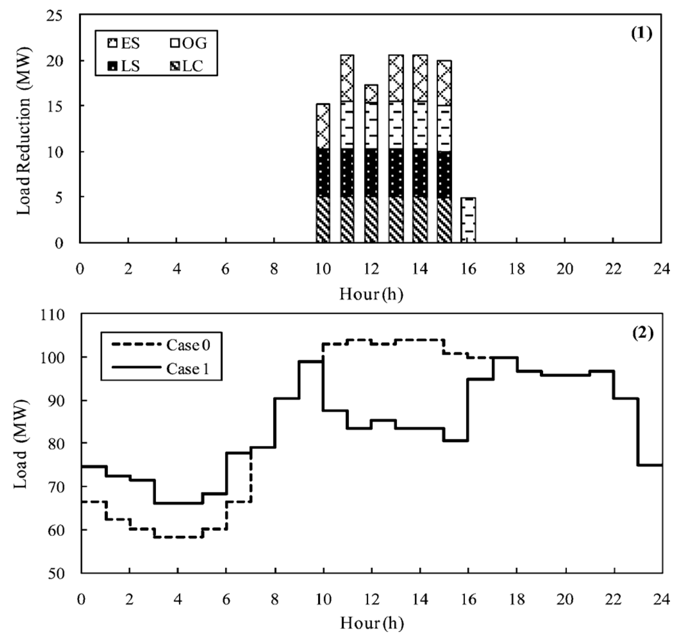

Fig. 4. (1) Load reduction and (2) equivalent load of the aggregator at Bus B5 in Case 1.

the proposed DR approach. The hourly load adjustments would modify the daily load factor from 0.829 in Case 0 to 0.841 and 0.883 in Cases 1 and 2, respectively. The non-smooth daily load profile in Case 1 has aggravated the load factor. Figs. 4 and 5 show the hourly load reductions and the equivalent load of the aggregator at Bus B5 in Cases 1 and 2. The load reductions in both cases meet the aggregator's limits.

In Fig. 4(1), load reductions are scheduled by customers at high LMP hours and the equivalent load of the aggregator in Fig. 4(2) is non-smooth which would complicate the ISO's operation and reduce the DR benefits.

However, the ISO's load reduction schedule in Case 2 is within a wider range of scheduling hours in Fig. 5(1). Most of the load reduction in Fig. 5(1) corresponds to LC and OG options so that system loads would not be increased at other hours. The LS offers are scheduled less which is due to restrictions posed on load reduction and recovery periods. The ISO's schedule in Case 2 provides a smooth equivalent load for the aggregator in Fig. 5(2).

In Table II, the total operating cost in Case 1 is $107 176.8 which shows a minor reduction as compared to Case 0. In Case

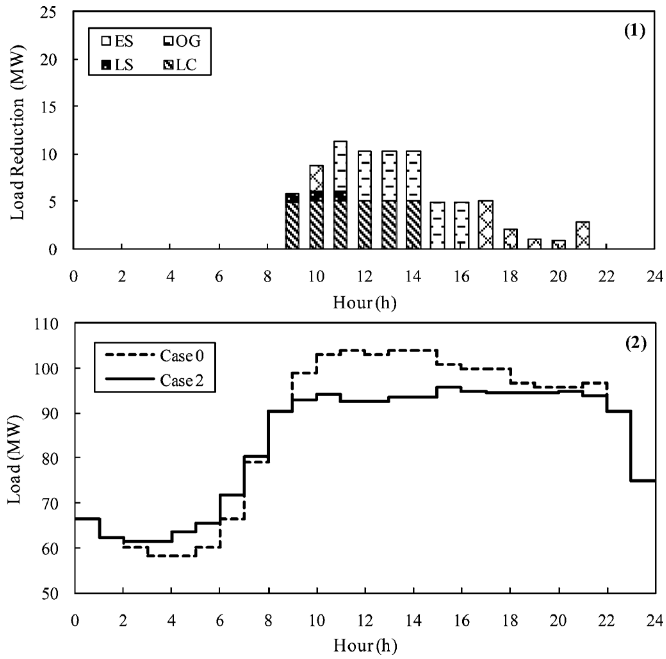

Fig. 5. (1) Load reduction and (2) equivalent load of the aggregator at Bus B5 in Case 2.

TABLE II
SYSTEM COSTS—6-BUS SYSTEM

Case	Total Cost ($)	Energy Cost ($)	Spinning Reserve Scheduling Cost ($)	Load Reduction Scheduling Cost ($)
0	110,710.2	106,778.7	3,931.5	–
1	107,176.8	99,346.7	3,640.2	4,189.9
2	101,520.9	94,885.8	3,719.1	2,915.9

TABLE III
HOURLY UNIT COMMITMENT—CASE 0

Unit	Hours (1-24)																							
G1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G2	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0
G3	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

TABLE IV
HOURLY UNIT COMMITMENT—CASE 1

Unit	Hours (1-24)																							
G1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G2	0	0	0	0	0	0	0	0	0	1	1	1	**0**	**0**	**0**	**0**	1	1	1	1	1	1	0	0
G3	0	0	0	0	0	0	0	**0**	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	**0**

TABLE V
HOURLY UNIT COMMITMENT—CASE 2

Unit	Hours (1-24)																							
G1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G2	0	0	0	0	0	0	0	0	0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	0	0
G3	0	0	0	0	0	0	0	**0**	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	**0**

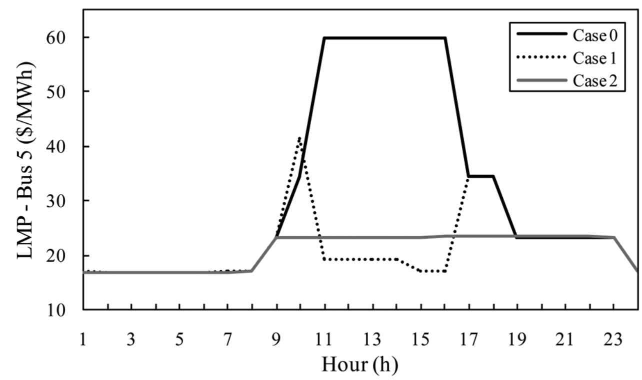

Fig. 6. Daily LMP in Bus 5 of the 6-Bus system.

TABLE VI
AGGREGATORS' COST REDUCTION AND REVENUE

Bus	Aggregators' Cost of Serving Load ($)			Aggregators' DR Revenue ($)
	Without DR	With the Proposed DR	Reduction in Aggregator Cost	
3	32140.9	20706.4	11434.5	785.1
4	71903.3	43422.3	28481.0	1916.6
5	70457.2	43041.7	27415.5	1850.8
Total	174501.4	107170.4	67331.0	4552.5

2, the total operating cost is $101 520.9 which shows an 8.3% reduction in daily operating costs as compared to that in Case 0. In Table II, the cost of load reduction in Case 2 is less than that in Case 1. However, the proposed DR aggregation would lower the cost in Case 2 with a smaller DR. This result emphasizes that the DR would be more attractive in power system operations when optimized by the ISO.

DR could modify the hourly commitment and dispatch of generating units and provide more economic options. In Table IV, all the generating units are committed in Case 1 with a minor alteration as compared to that in Case 0 given in Table III. The reason is that the system peak load shown in Fig. 3 is not reduced a lot. However, the DR optimal schedule in Case 2 would reshape the load profile in Fig. 3 and the expensive generating unit G2 would not be committed. In Table V, the commitment of G3 in Case 2 is reduced by 2 hours when local resources would improve the system efficiency and satisfy the aggregator's constraints.

The daily LMP profile in Fig. 6 follows that of loads in Figs. 4 and 5. The LMP profile in Case 1 shows spikes when resources are not optimized for reducing transmission congestions. In contrast, LMPs of Case 2 in Fig. 6 are more flat when the expensive unit G2 is turned off. A more flat LMP demonstrates a milestone for DR applications. In Case 0, customers that would not respond to peak hour prices are subject to higher electricity charges. In Case 2, a limited number of customers participate in DR though the rest would also benefit from the proposed load reductions.

The aggregators' financial merits include payments they receive for DR and the reduced cost of supplying loads due to LMP reductions. The aggregators' costs in Table VI for supplying loads are calculated using LMPs and the associated load profiles. In Table VI, the aggregators' cost at the three buses is reduced to $107 170.4 with DR, which demonstrates a 38.6% reduction. The reductions in cost are due to the aggregators' equivalent load profiles after DR when peak loads are optimally shifted to other hours. Also, bus LMPs are reduced because of the optimal DR utilization (see Fig. 6). It is important to point out that the aggregators' revenue of selling DR in energy market is calculated in Table VI which is adopted from current FERC order 745 with the assumption that the aggregators' awarded

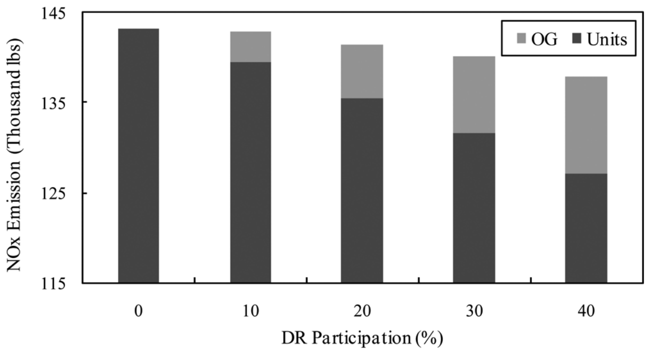

Fig. 7. NO_x emission at DR participation levels.

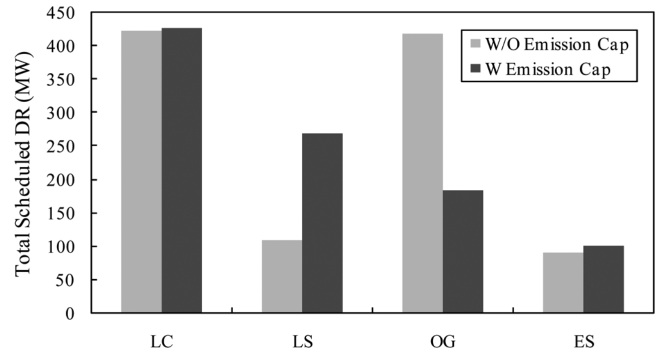

Fig. 8. Total scheduled DR with and without emission cap.

TABLE VII
IMPACT OF DR LEVEL ON IEEE-RTS

DR Participation Level (%)	Total System Cost ($)	Number of Committed Units	Average LMP ($/MWh)
0	549,949.6	22	17.10
10	540,638.6	20	16.55
20	532,662.4	20	16.12
30	525,908.7	19	15.88
40	520,428.3	19	15.11

load reduction is compensated according to the associated bus LMPs. [18]. However, payments the aggregators receive for DR is an ex-post analysis, in which our DR scheduling model is not dependent and any other payment methods can be utilized. In Table VI, the highest cost reduction and revenue are offered to the aggregator at bus 4 which is an attractive location for DR. Table VI savings are based on a single-day operation which would be added up on an annual basis.

B. The IEEE-RTS

The proposed model is applied over a 24-h horizon to the IEEE-RTS [27]. The system data are given in [27]. The shutdown costs of generating units are 50% of startup costs. The hourly load corresponds to a day in week 23 with a peak of 2850 MW. There is an aggregator at each load bus and the DR offer data are the same as those given in the 6-bus system. The emission constraints are considered in the studies below. As discussed in Section IV, the detailed mathematical model for the applicable emission constraints is provided in [25].

1) Study 1: We examine the level of customer participation in DR. The model is considered for 0%, 10%, 20%, 30%, and 40% of DR at each bus. The capacities of the four DR options are the same. In Table VII, the DR load reduction would reduce the generation dispatch and the number of committed generating units. The day-ahead average LMPs are reduced as more DR is utilized. DR would also reduce the emission level as shown in Fig. 7. However, the onsite generation could remain to be a source of emission. This result indicates that the environmental benefits of DR may not be accurately estimated when load reduction options are not coordinated properly.

The proposed DR model introduces additional binary variables, for new resources in the day-ahead market clearing problem. However, the inclusion of a large number of binary variables does not increase the computation time dramatically. The computation times for introducing 0%, 10%, and 40% DR in the IEEE-RTS are 1.482 s, 3.994 s, and 4.586 s, with the upper bound of the duality gap set at 0.1%. There are two reasons for the enhanced efficiency of the proposed model. First, the proposed MILP model for DR is linear, which does not require any additional inequality constraints or auxiliary variables for linearization. Second, DR variables are unbundled from the other problem variables except in the network power balance equation. Therefore, adding binary variables associated with DR would not largely increase the computational time.

2) Study 2: The impact of the proposed DR algorithm is analyzed on an emission-constrained power system. The total NO_x emission in the daily operation without any DR or emission cap is 143 276.5 *lbs* while the total system cost is $549 949.6. We study two cases here. In Case 1, the daily NO_x emission cap of the system is 140 000 *lbs*, while DR is not utilized. The total system cost in Case 1 is increased to $556 549.5 which shows a $6599.9 increase in the daily operation cost. In Case 2, 10% of customers participate in DR within the emission-constrained system. The DR data are the same as those in Study 1. The total system cost is $543 616.7 which is $12 932.8 lower than that of Case 1. In Fig. 8, LS and ES have replaced the pollutant OG as we consider the emission cap. So a higher emission cap could change the hourly DR schedule and have an impact on system economics.

VI. CONCLUSION

This paper presented a hierarchical DR bidding framework for electricity markets in which DR aggregators proposed load shifting and curtailment, utilized onsite generation, and energy storage systems in the ISO's market clearing problem. The proposed model is formulated as a MILP problem which would provide a practical DR solution [28]. The proposed MILP model is implemented on a 6-bus system and on the IEEE-RTS. The results indicate that the explicit modeling of customer DR would provide ISOs with more flexible options for scheduling the available energy resources in day-ahead energy markets. In the proposed model, the customer load reduction would be verified by measuring the dispatch of OG and ES. The aggregators would monitor and verify LC and LS by assessing the actual load shifting and curtailment quantities at individual customer sites.

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