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Impact of demand response resources on unit commitment and dispatch in a day-ahead electricity market ☆

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ABSTRACT

Demand response (DR) has recently become an important resource in both system operation and market operation. The focus of this paper is to investigate and quantify the cost impact of various demand response modelings on unit commitment and dispatch in a day-ahead market regime. We have used mixed integer programming unit commitment model, in the market operation framework. Day-ahead market is modeled with a typical test system. Our research results show that DR can exert downward pressure on electricity prices, causing significant implications on social welfare. Results from this work will help policy makers, resource planners, and market designers to make more informed decisions with the goal of better accommodating more demand response resources in the future.

Introduction

Nowadays, several emerging issues pose challenge to the traditional power system operation. Some of these issues include growing environmental threats, and limited system resources which force the system operators to operate their system closer to its limits, causing occasional price spikes in electricity markets. Increasing amount of variable renewable energy resources also increases the generation variability due to their uncertain output. These concerns motivated us to explore and investigate new ways of improving the efficient utilization of all available resources in power and market operations.

One of the resources that is drawing increasing attention is the demand response (DR). Demand response can be defined as any resource that has the capability to change or reduce the electricity consumption at a given time. The mode to change the electricity consumption can be instantaneous or pre-scheduled. Since DR is a demand side resource, in contrast to supply side resource, the key players of DR resources are those who consume, not supply, electricity. Typically, they are represented by residential, commercial, and industrial customers of electricity.

DR is becoming an integral part of the power system and market operational practice. Application of a DR program can provide better manageability to system operators, optimizing their position, and maximizing the revenue opportunities for DR providers. The inclusion of DR in conjunction with renewable energy, distributed generation, and plug-in hybrid electric vehicles will provide benefits to optimize the use of these resources and as a conclusion improve the efficiency of the system operation.

At the same time, the advances in communications, information systems, and computer technologies have opened up new opportunities to operate power system in a new way. A good example of that would be the automatic control of demand at the distribution level. The controllable demand becomes a very important source of flexibility which can be used to improve the system controllability, and which cannot easily be provided by conventional generators, due to several constraints, such as generator ramp rates. In a sense, the controllable demand can and should respond quite fast.

Under current market-clearing regime, the traditional generator scheduling or Unit Commitment (UC) and the Security-Constrained Unit Commitment (SCUC) programs deal only with fixed demand estimated by load forecasting process. Incorporating DR into these programs induces to a complicated objective function and creates additional constraints which must be dealt more carefully. At

☆ The views presented in this paper do not necessarily represent those of the PJM Interconnection.

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Nomenclature

t	index for simulation hours
b	index for cost curve segments
n	index for start-up cost curve
g	index for generation units
j	index for demands
k	index for demand blocks
T	total number of simulation hours
G	total number of thermal units
B	total number of segments for production cost curve
$Cp_{g,t}$	production cost for unit g at hour t \$/h
$Cup_{g,t}$	start-up cost for unit g at hour t \$
$p_{g,t}$	active generation for unit g at hour t MW
$r_{g,t}$	active reserve contribution of unit g at hour t MW
$\delta_{b,g,t}$	active generation for segment b, unit g, hour t MW
$u_{g,t}$	binary state variable for unit g, hour t
$s_{g,t}$	start-up variable for unit g, hour t
$h_{g,t}$	shut-down variable for unit g, hour t
θ	bus voltage angle
f	branch flows
$x,\ z$	penalty variables
Δ	corrective dispatch
π	shadow prices for the Network sub problem
$DB_{j,t}$	demand bid function value at demand j, hour t
$Bid_{k,j,t}$	demand bid value at block k, demand j, hour t \$/MW h
$d_{j,t}$	demand value for j, hour t MW
D_t	system demand at time t MW
R_t	system spinning reserve requirement at hour t MW
MU_g	minimum up time for unit g h
MD_g	minimum down time for unit g h
T_g^{off}	number of hours unit g has been off at $t = 0$ h
T_g^{on}	number of hours unit g has been on at $t = 0$ h
c_g	fixed cost for unit g \$/h
$F_{b,g}$	slope for segment b, unit g \$/MW h
$\overline{P}_g$	maximum capacity for unit m MW
$\underline{P}_g$	minimum capacity for unit m MW
$K_{n,g}$	cost for start-up cost step n, unit g \$/h
$\mathrm{Tr}_{b,g}$	active power limits, block b, unit g
RUL_g	ramp up limit, unit g MW
RDL_g	ramp down limit, unit g MW
$\underline{Y}_s$	susceptance matrix
$\overline{f}$	branch flow limits
$\mathbf{c}_x$	sub problem costs (set to one)
$CB_{k,j,t}$	demand cost value, block k, demand j, hour t \$
$MWB_{k,j,t}$	MW value for block k, demand j, hour t MW
$\overline{D}_{j,t}$	maximum demand value for demand j, hour t MW
$\underline{D}_{j,t}$	minimum demand value for demand j, hour t MW

minimum, the objective function and constraints have to be modified to correctly account for the unique characteristics of DR. Different formulations of objective functions and constraints can lead to different solutions, which can trigger different market system outcomes (MW, price schedules, and other subsequent system outcomes).

Federal Energy Regulatory Commission (FERC) [1] highlights areas of research related to DR and its inclusion into scheduling formulation. Proposed areas of research include the study of benefits, potential costs, cost recovery, rate design, and program marketing, payback horizons associated with DR programs. Other topics include analysis of the impact on the emission mitigation effects of DR, integration of DR with renewable energy, distributed generation, and plug-in hybrid electric vehicles (PHEVs), coordination of different DR programs, utility DR programs with RTO/ISO demand response programs for organized power markets.

In addition, the "USA National Action Plan" recognizes that for the United States to realize its full demand response potential, electricity customers must have access to, and a better understanding of, information about real-time or near-real-time energy prices. Better price information delivered more clearly will help potential demand response providers design market offerings, assist utilities in designing DR-encouraging rates, and help potential DR customers evaluate whether to participate in a demand response program.

We provide, as below, a brief review of literature on this important topic.

Market simulation approach [2] was used to quantify the variable impact of demand response on market performance, generation dispatch, transmission usage, environmental and other system effects. The work was done in light of planning and policy analysis studies. Implementation issues, related to large-scale systems over longer-term periods were also discussed.

In Ref. [3], although generation scheduling problem was considered as part of framework for incorporating demand response in a competitive market, the issue of unit commitment was ignored. Instead, it tried to solve economic dispatch problem only with the assumption that a generator is turned off when its output is zero.

It can be observed from Ref. [4] that the papers from the state of the art work treat generation in a simplified manner, disregarding short term operational constraints and demand response is not considered for short term simulations.

In the literature, several DLC (direct load control) algorithms have been developed to determine the optimal load control schedules of groups of domestic devices [5,6]. Most of them are based on linear programming [5,6,7,8], or dynamic programming [9,10], and tried to minimize peak load [5,6] or electricity production cost [5,9] over a certain time period.

Demand response, in combination with wind, can provide more cost-effective emission reductions, than just wind alone, using a case study based on Texas power system [11]. The authors found that while wind variability can increase the price, DR can be an alternative providing the opposite effect to help reduce that price volatility. Some recent work [12] was done to investigate the impact of price-based demand response on market clearing and LMP. The test system used in this work was too small to have any meaning. Similarly, the work in [13] investigated the effects of responsive load models on unit commitment in collaboration with demand-side resources. The author concluded that it is not possible to obtain the minimum cost for system using an unsuitable scheme of demand response programs or unrealistic model of responsive loads. Authors in [14,15] also solved the stochastic unit commitment problem with modeling of uncertain demand response. Integrating commercial demand response resources with unit commitment was also done in [16].

The aim of this paper is to analyze the utilization patterns of the DR resources from a system operation point of view, their impact on the operation of competitive markets, unit commitment solutions, and on market prices. Different types of DR models and methods are reviewed and the simulations are carried out on IEEE 118 bus system [17]. Based on the results, some recommendations are made regarding the efficient operation of power system and power market, with inclusion of DR resources.

The paper is organized as follows. We describe the general classifications of DR and various DR programs at RTO/ISOs in Section 'Demand response'. In Section 'Unit commitment problem formulation', we review the unit commitment problem formulation in the context of day-ahead electricity market, define different DR models, and formulate new UC problems with DR models. Numerical results of these formulations are shown in Section 'Numerical results' while conclusions are given in the final section.

Demand response

(DR) classifications

Different types of demand response have been proposed in the industry. FERC classifies the demand response based on how these programs affect the electricity price and the time frame. Two main categories of DR programs are defined: the incentive-based program and the time-based program. The incentive-based program is further divided into a classical program and the market-based program. Within the classical program, two different approaches have been defined. The first approach is the interruptible/curtailable program where participants receive incentive upfront payments or rate discounts. In this program, participants are asked to reduce their load to predefined values. Otherwise, they will face penalties. The second approach is the direct load control program where some of the participants equipments, such as air conditioners or water heaters, are remotely controlled or possibly shut down by utility or system operator.

The other type of incentive-based program is defined as market-based program. There are four sub-categories in this program: demand bidding, emergency DR, capacity market, and ancillary services market. In the demand bidding program, consumers bid for a specific load that can be reduced. The bid is accepted in market clearing solution if it is less than the market price. Otherwise the customer should curtail the load. In the emergency demand response program, the demand is paid incentives for load reduction during a system emergency. For DR program in capacity market, the load reduction is used to alleviate congestion. Finally, the load curtailment is used to provide reserve in the ancillary services market.

The principal objective of the time-based program is to motivate participants to change the demand values at different time frames in order to flatten the demand curve (aka peak shaving). The electricity price is set to high values for periods when demand reduction is desirable and is set to low values for periods when demand increase is preferable. These price differences are set at different time frames depending on the types of demand response programs: critical peak, extreme day, time of use or real time program.

NERC's demand-side management task force [18] classifies the incentive-based demand response programs into two main categories: the dispatchable controllable demand response (DCDR) and dispatchable economic demand response (DEDR). The first category includes the capacity, ancillary and emergency demand response programs while the demand bid program is included in the second category.

For the purpose of this paper, we can reclassify all available demand response (DRs) into two broad categories: emergency DR and economic DR. Emergency DRs are called and dispatched when system emergency condition requires it to do so. Typically, when the supply situation in the system becomes tighter, then the task of balancing supply and demand can be made easier by calling DRs.

On the other hand, the economic DRs are more voluntary in nature in the sense that the owners of such DRs are willing to reduce or cut their potential demand if they are reasonably compensated by means of favorable price in a market setting or by other means. For example, during a specific market period, if an economic DR owner bid is 30 $/MW h, and the market clears at 50 $/MW h, then, that DR will be cleared in that market. In this case, the owner of the DRs be paid 50 $/MW h (by uniform-pricing rule) for forgoing that demand consumption.

DR programs at RTO/ISOs and utilities

Different RTO/ISOs have different DR programs. The goal here is not to provide detailed analysis of DR programs at RTO/ISOs, but to provide its overview.

For example, PJM operates two main types of demand-related programs: emergency and economic. Emergency Demand Program includes Emergency (capacity and energy) DR Programs and Interruptible Load for Reliability (ILR). Emergency capacity DR is used only in reliability planning study. In Emergency Energy DR program, there are three kinds: annual DR, extended summer DR, and limited DR. Annual DR can be called upon for an unlimited number of times in a delivery year and is required to maintain reduction level for at least a 10 h period. Extended summer DR can be called upon for an unlimited number of times from June through October (extended summer period) and is required to maintain reduction level for at least a 10 h period. Limited DR can be called for a maximum of 10 interruptions per year and has a maximum length of a single interruption of 6 h. Economic demand programs include Price Responsive Demand (PRD), Energy Efficiency Resource, day-ahead DR, and real-time DR Program.

New York ISO (NYISO) operates five demand response programs: Emergency DR program, Special Case Resource program, Targeted Demand Response Program, Day-Ahead DR Program, and Demand Side Ancillary Service Program. California ISO (CAISO) supports three types of DR resources: Non Participating Loads, Participating Loads, and Proxy Demand resources. ERCOT has an emergency interruptible load service program.

In terms of DR programs at utilities, Baltimore Gas and Electric (BGE) offers "Peak Rewards". This DR program is the next generation of Rider 5. BGE offers credits to customers for installing a smart switch or smart thermostat. BGE also employs "smart energy pricing". BGE piloted various dynamic pricing schemes in 2008 and 2009, including a peak-time rebate and critical peak pricing. These pilot programs focused primarily on residential customers and gave them price signals one day in advance of high-priced periods. As an option for the conservation of energy, BGE offers a number of rebates and cost buy-down programs for residential and commercial customers.

Similarly, Sacramento Municipal Utility District (SMUD) in California believed that the smart grid will have a significant impact on SMUD's ability to control loads during peak periods. At Duke Energy in North Carolina, a web-based customer interface directly links the utility-controlled DR to a system in which DR is one of a host of interactive technology solutions for a smarter electric grid.

Unit commitment problem formulation

Unit commitment in a day-ahead market framework

The day-ahead electricity market framework, used in this work, is a simplified market clearing model. This day-ahead market clearing framework only considers transmission system network, generator offers, and fixed load, without or with price-sensitive demand bids (similar to bid-based DRs). The authors understood that the practical day-ahead electricity market also allows participation of additional types of financial instruments, such as virtual bids (incremental offers, decremental bids, and up-to congestion transactions). Modeling these additional components in the day-ahead market clearing framework is beyond the scope of this work. Since our current work is to investigate the impact of DRs on Unit Commitment (UC) and dispatch in the day-ahead market framework, we will focus on the detailed formulation of UC, without or with DRs.

The traditional Unit Commitment (UC) problem [19,20] is formulated as a cost minimization function considering a fixed demand profile without violating any system or unit's operational constraints. The minimization function considers the reduction of generation cost including production cost, start up cost, and no load cost. The UC problem can be expressed mathematically as follows:

$$\min_{p} \sum_{t=1}^{T} \sum_{g=1}^{G} (Cp_{g,t} + Cup_{g,t}) \tag{1}$$

subject to system, unit, and network constraints.

The detailed mathematical formulation for the objective function as well as the constraints included in the simulated model are presented next.

Production cost

Considering the incremental cost function represented by the piecewise function, the production cost function for each unit g at a simulation period t, can be formulated as:

$$Cp_{g,t} = c_g \; u_{g,t} + \sum_{b=1}^{B} F_{b,g} \; \delta_{b,g,t} \tag{2}$$

Additional constraints that need to be added are:

$$p_{g,t} = u_{g,t} \, \underline{P}_g + \sum_{b=1}^{B} \delta_{b,g,t} \quad \forall g, \; \forall t \tag{3}$$

$$(\mathrm{Tr}_{1,g} - \underline{P}_g) \leqslant \delta_{1,g,t} \quad \forall g, \; \forall t \tag{4}$$

$$\delta_{1,g,t} \leqslant (\mathrm{Tr}_{1,g} - \underline{P}_g) u_{g,t} \quad \forall g, \; \forall t \tag{5}$$

$$(\mathrm{Tr}_{b,g} - \mathrm{Tr}_{b-1,g}) \leqslant \delta_{b,g,t} \quad \forall g, \forall t, \; b = 2, \ldots, B-1 \tag{6}$$

$$\delta_{b,g,t} \leqslant (\mathrm{Tr}_{b,g} - \mathrm{Tr}_{b-1,g}) \quad \forall g, \forall t, \; b = 2, \ldots, B-1 \tag{7}$$

$$\delta_{B,g,t} \geqslant 0 \quad \forall g, \; \forall t \tag{8}$$

$$\delta_{B,g,t} \leqslant (\overline{P}_g - \mathrm{Tr}_{B-1,g}) \quad \forall g, \; \forall t \tag{9}$$

Eq. (2) represents the production costs. Eqs. (3)–(9) are the piecewise linearization of production costs. Fig. 1 illustrates the different variables used for this formulation.

Start up cost

For the start up cost model, a discretized exponential model can be used. Based on the discretized approximation, a simple mathematical formulation for the start up cost is included per unit g and per simulation period t:

$$\mathrm{Cup}_{g,t} \geqslant K_{\tau,g} \left(u_{g,t} - \sum_{n=1}^{\tau} u_{g,t-n} \right) \quad \forall g, \; \forall t \tag{10}$$

System constraints

The system restrictions include the power balance equation and the reserve constraints

$$D_t - \sum_{g=1}^{G} p_{g,t} = 0 \tag{11}$$

$$R_t + D_t - \sum_{g=1}^{G} r_{g,t} \leqslant 0 \tag{12}$$

Minimum on/off conditions

These restrictions can be formulated as follows [21]:

$$\begin{aligned} &\sum_{i=t-MU_g+1}^{t} s_{g,i} \leqslant u_{g,t} \quad \forall g, \; \forall t \in [MU_g + 1, \mathrm{T}] \\ &\sum_{i=t-MD_g+1}^{t} h_{g,i} \leqslant 1 - u_{g,t} \quad \forall g, \; \forall t \in [MD_g + 1, \mathrm{T}] \end{aligned} \tag{13}$$

For the initial period, the number of periods that the unit is on or off need to be considered:

$$\begin{aligned} &\sum_{i=0}^{i \leqslant T_g^{on}} 1 - u_{g,i} = 0 \quad \forall g, \; t = 0 \\ &\sum_{i=0}^{i \leqslant T_g^{off}} u_{g,i} = 0 \quad \forall g, \; t = 0 \end{aligned} \tag{14}$$

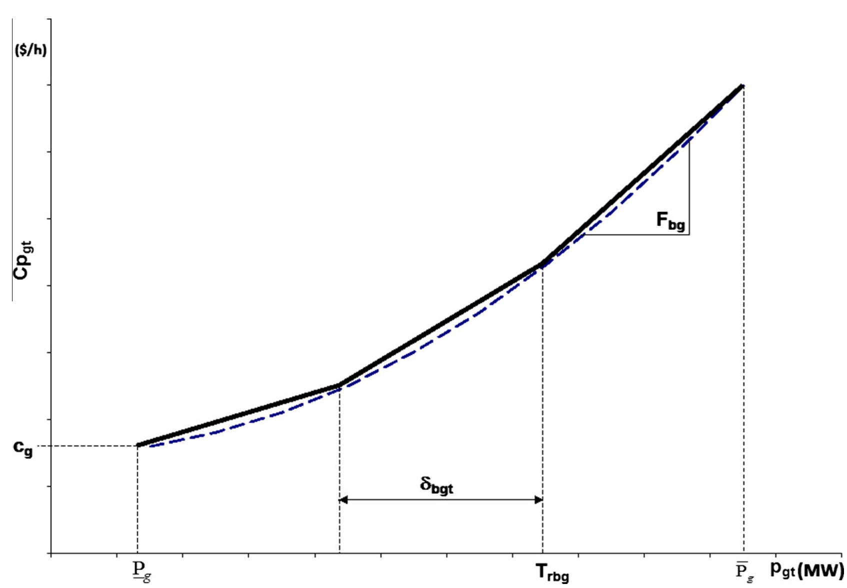

Fig. 1. Linear production cost curve.

Ramp up and down constraints

$$
\begin{aligned}
& p_{g,t} - p_{g,t-1} \leqslant \mathrm{RUL}_g \quad \forall g,\ \forall t \geq 0 \\
& p_{g,t-1} - p_{g,t} \leqslant \mathrm{RDL}_g \quad \forall g,\ \forall t \geq 0
\end{aligned} \tag{15}
$$

Network constraints are included using Bender's Cuts, this formulation is explained in the next section.

Benders cut constraint

The coupling between the UC problem and the network sub-problems is done through the economic dispatch variable $\mathbf{P}^*$, which is the solution of problem shown in Eqs. (1)–(15). The sub-problem can be formulated as:

$$w^* = \min(\mathbf{c}_x \cdot \mathbf{x}^i) \tag{16}$$

subject to:

$$
\left.
\begin{array}{ll}
\mathbf{Y}_s^i \theta^i = \mathbf{P}^i - \mathbf{D} & \pi_D \\
-\bar{\mathbf{f}}^i \leqslant \mathbf{f}^i + \mathbf{z}^i \leqslant \bar{\mathbf{f}}^i & \pi_f \\
\underline{P}_i \leqslant \mathbf{P}^i \leqslant \bar{P}_i & \pi_p \\
|\mathbf{P}^i - \mathbf{P}^0| + \mathbf{x}^i \leqslant \Delta^i & \pi_\Delta
\end{array}
\right\} \text{constraints for network scenario} \quad i \epsilon [0, \Omega_{NC}] \tag{17}
$$

In this case, the Benders Cut is created for each network scenario:

$$w^* + \pi_\Delta.(\mathbf{P} - \mathbf{P}^*) \leqslant 0 \tag{18}$$

A more detailed explanation of how the network constrains are included into the problem using Benders decomposition can be found in [22–24].

Demand response models

In the UC formulation described in the previous section, the demand is considered as a fixed value. However, in order to consider the effect of the demand response, a variable demand as a function of the bid needs to be modeled. One logical alternative is to model that bid-dependent demand as shown in Fig. 2. Each price-sensitive demand can submit multiple non-incremental demand bid blocks as shown in the same figure. Note that the demand bids are represented by downward-sloping curves.

Mathematically, the demand bid value function can be defined by:

$$DB_{j,t}(d_{j,t}) = \sum_{k=1}^{\Omega_{b,j,t}} CB_{k,j,t} \cdot Bid_{k,j,t} \quad \forall j,\ \forall t \tag{19}$$

where

$$\sum_{k=1}^{\Omega_{b,j,t}} Bid_{k,j,t} = d_{j,t} \quad \forall j,\ \forall t \tag{20}$$

and

$$Bid_{k,j,t} \leqslant MWB_{k,j,t} \quad \forall j,\ \forall k,\ \forall t \tag{21}$$

New unit commitment problem with DR models

In this new UC problem formulation, the price sensitive demand can be introduced into the minimization objective function as follows:

$$\min \sum_t \left[\sum_{g=1}^{G} (Cp_{g,t} + Cup_{g,t}) - \sum_j DB_{j,t}(d_{j,t}) \cdot dU_{j,t} \right] \tag{22}$$

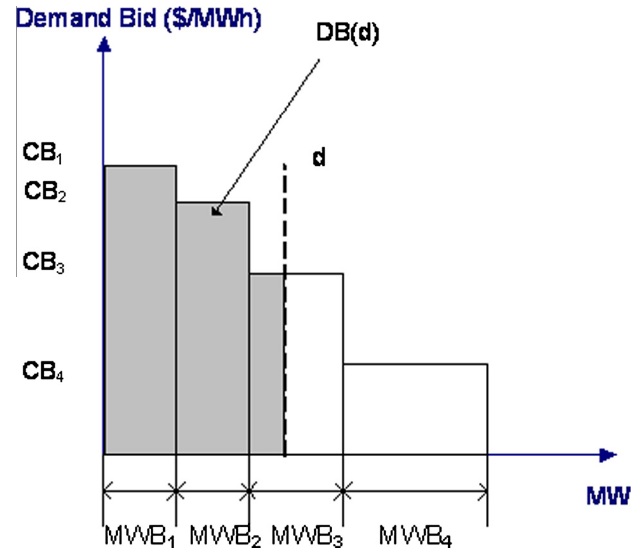

Fig. 2. Price sensitive demand bid blocks.

The additional constraints due to the demand model are:

$$D_{j,t}^{\min} \cdot dU_{j,t} \leqslant d_{j,t} \leqslant D_{j,t}^{max} \cdot dU_{j,t} \quad \forall j, t \tag{23}$$

$$dU_{j,t} = 0 \quad (\text{or}) \quad 1 \quad \forall j, t \tag{24}$$

$$dU_{j,t} = \begin{cases} 0 & \text{if demand resource } j \text{ is off at period } t \\ 1 & \text{if demand resource } j \text{ is on at period } t \end{cases} \tag{25}$$

The system constraint must also be modified as:

$$\left[D_t + \sum_j d_{j,t} - \sum_{g=1}^{G} p_{g,t} \right] = 0 \quad \forall t \tag{26}$$

Numerical results

The main objective of this work is to simulate and evaluate the impact of DR on unit commitment, generation dispatch, and resultant LMPs based on the formulation previously described. The IEEE 118 bus test system [17] is used to study the problem. Additional input data into the UC problem such as the generator bids and the hourly load profiles are described in Appendix A. The model is implemented in GAMS using CPLEX as the solver, with all the parameter options set to the default values.

We classify the study cases into two main categories: without network constraints and with network constraints.

Without network constraints

First, the system with fixed load, but without any DR resources, is simulated without any network constraints for a 24 h simulation time frame. The hourly marginal prices, also known as market prices (MP) or LMP, are calculated. These results are compared with those of the same system with a DR resource bid of 9 $/MW h (arbitrarily chosen) up to 500 MW from hour 12 to hour 24. The comparisons of MPs for the two cases are illustrated in Fig. 3.

The load forecast described in the Appendix illustrates that this load was larger than the demand max bid of 500 MW, for periods 19 and 20. Therefore, this specific load for those periods was reduced to 500 MW with DR bids, thus, reducing the market prices ($/MW) accordingly. However, there was also a scheduling impact

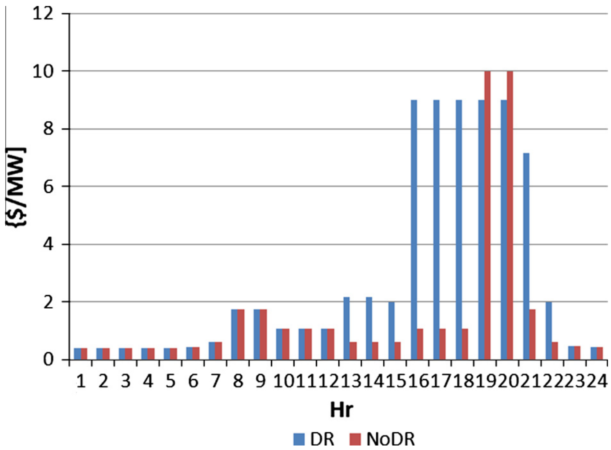

Fig. 3. Resultant MPs for cases with and without DR bids.

for the other hours. Due to such differences in generator scheduling, the MPs can increase in other periods as can be seen from periods 13 through 18, as well as in periods 21 and 22. Regardless of price variations, the total costs of production are reduced from the simulation case without DR resource (4312.3) to the simulation case with DR resource (1152.9). Note the significant reduction of production cost in the case with DR resource.

For the case with DR resource bid, the DR bid MWs were also increased to observe the evolution of market prices. Fig. 4 shows the comparison of results for four different DR bid MW values: 500 MW, 1000 MW, 1500 MW, and 2000 MW, denoted by DR500, DR1000, DR1500, and DR2000 respectively in the same figure.

Results show that the market prices were reduced by modeling and incorporation of the demand response in the market clearing problem formulation. However, some price spikes can be observed when the values of DR MWs were increased due to the non-convexity of the unit commitment problem. Therefore, it is recommended that this type of impact should be considered and evaluated before such a DR program is incorporated into any relevant unit commitment and dispatch problem in an electricity market environment. The authors also believe that different power systems would behave differently with the inclusion of different amount of DR resources.

With network constraints

In addition to previous cases (without and with DRs) without network constraints, simulations were also carried out for a system including network constraints. Since the branches in the test system have no thermal limits, some reasonable limits were added for these branches in order to make the system suitable for the SCUC simulation, considering some network binding constraints. For that reason, the limit for a branch from bus 30 (Sorenson) to

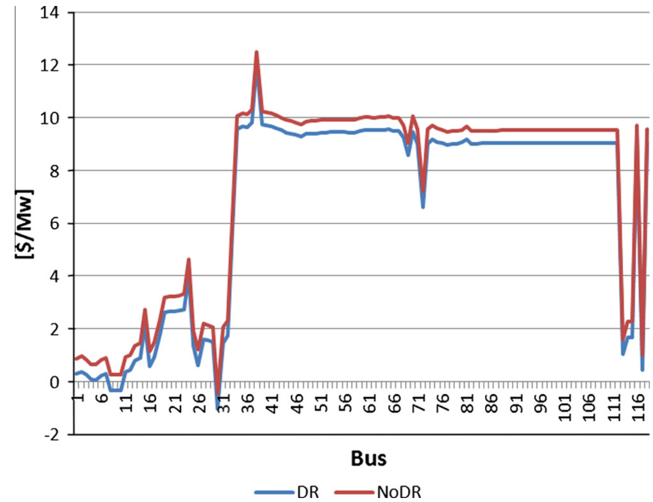

Fig. 5. Bus LMP differences for cases with network congestion at hour 16.

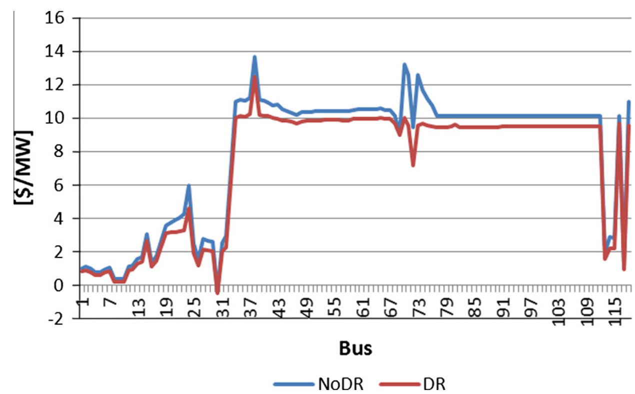

Fig. 6. Bus LMP differences for cases with network congestion at hour 18.

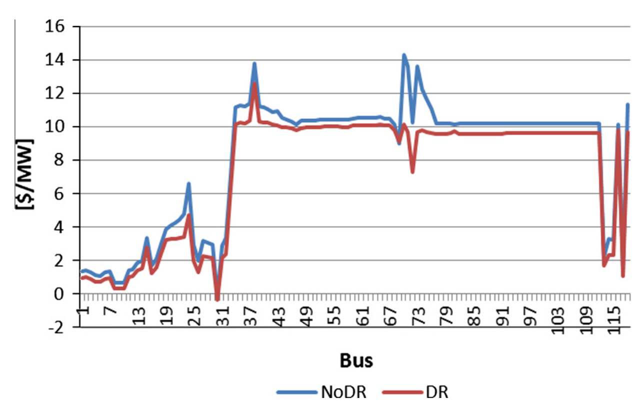

Fig. 7. Bus LMP differences for cases with network congestion at hour 19.

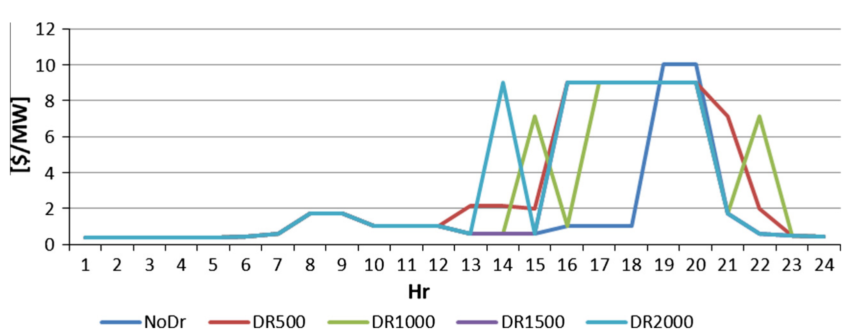

Fig. 4. Hourly LMP differences for cases with different DR bid MWs.

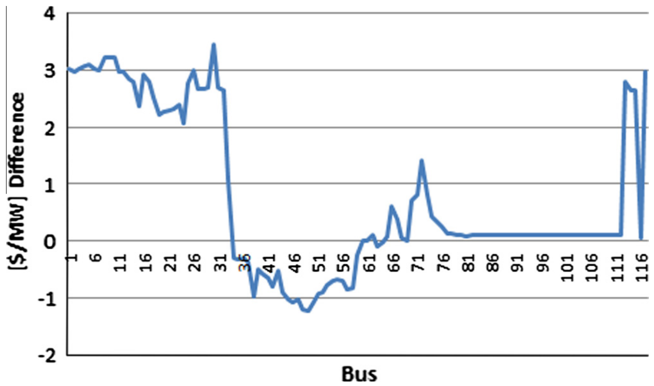

Fig. 8. Bus LMP differences between cases of NoDR and Load Response at hour 19.

Table A.1
Hourly LMP differences [$/MW].

Period [h]	No Bid	500 MW	1000 MW	1500 MW	2000 MW
13	0.61	2.17	0.61	0.61	0.61
14	0.61	2.17	0.61	0.61	9
15	0.61	2	7.14	0.61	0.61
16	1.05	9	1.05	9	9
17	1.05	9	9	9	9
18	1.05	9	9	9	9
19	10	9	9	9	9
20	10	9	9	9	9
21	1.72	7.14	1.72	1.72	1.72
22	0.61	2	7.14	0.61	0.61
23	0.47	0.47	0.47	0.47	0.47
24	0.43	0.43	0.43	0.43	0.43

bus 38 (EastLima) was set to 83 MVA, the limit for a branch from bus 9 (Bequine) to bus 10 (Breed) was set to 460 MVA, and the limit for a branch from bus 49 (Philo) to bus 66 (Muskngum) was set to 132 MVA respectively. Figs. 5–7 show the comparisons of bus MPs for the cases with and without DR bids, for three different hours (hour 16, 18, and 19). The DR bids for this case were set to have the same values as in the previous case without network constraints.

Fig. 8 illustrates the price difference at each bus, for hour 19, between the case without DR (NoDR) and the case with load response. The load response was modeled as component of the load that can be scheduled to shut down. The cost of that shut down was modeled as $1 for shutting down 100 MW of load at any instant. Note that in this case, although the total cost is reduced, due to the network constraints, LMPs at some buses may increase. We included the same network limits in this case, as in previous cases.

From these results, it can be concluded that the DR resources which are distributed at different load buses, can also have a positive impact in alleviating the network congestion, as well as the reduction of the LMPs at different buses. Table A.1 provides hourly LMP differences between basecase and those cases with DRs. Table A.2 also shows the cost reduction as a percent of the basecase results due to the increase in MW of the demand bid.

Conclusion

Demand response (DR) resources are going to play a more important role in the operation of power systems and electricity market in the near future. Their participations in the electricity market are going to have a significant impact on market outcome by impacting the security-constrained unit commitment and dispatch results. In this new work, we have attempted to quantify the economic impact, primarily the production cost and market price impacts, of modeling and incorporating different types of DR in a day-ahead electricity market. As a general matter, DR can have significant drag on electricity prices, as evidenced from the results. While this phenomenon helps reduce the load payment, it also has the effect of reduced generator revenue, hence, affecting the social welfare. In this case, generators (suppliers) portion of social welfare was reduced, while consumers, representing DR, portion of social welfare was increased. This outcome would certainly force us to revisit the question of efficient and fair allocation mechanism for a system with varying social welfare due to DR resources.

Table A.2
Cost reduction (in percentage) due to demand bid.

Demand bid (% w.r.t base demand)	UC total cost reduction (%)	SUCU total cost reduction (%)
1.25	3	3
2.50	2.3	2
3.75	3.2	3
5.00	4.5	3.5
7.50	7.3	6
10.00	10	7
12.50	14	7.5

Table A.3
Generator offers.

Bus	Bid ($/MW h)	Bus	Bid ($/MW h)	Bus	Bid ($/MW h)
1	10	49	0.47	90	10
4	10	54	1.72	91	10
6	10	55	10	92	10
8	10	56	10	99	10
10	0.22	59	0.61	100	0.38
12	1.05	61	0.59	103	2
15	10	62	10	104	10
18	10	65	0.25	105	10
19	10	66	0.25	107	10
24	10	69	0.19	110	10
25	0.43	70	10	111	2.17
26	0.31	72	10	112	10
27	10	73	10	113	10
31	5.88	74	10	116	10
32	10	76	10		
34	10	77	10		
36	10	80	0.21		
40	10	85	10		
42	10	87	7.14		
46	3.45	89	0.16		

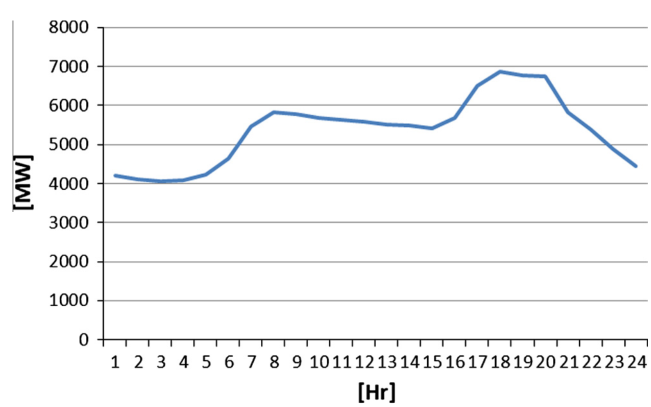

Fig. A.9. Daily load profile.

Appendix A. System data

The following Table A.3 shows the generator offers, used in the simulation of the paper. The following load profile representing 24 h load shape, shown in Fig. A.9, was also used in the simulation.

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