Reserve Procurement through Demand Response Markets in Wind Integrated Power Systems

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Reserve Procurement through Demand Response Markets in Wind Integrated Power Systems

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Abstract— **The volatility of power production by wind power stations has always been considered as a drawback for high penetration of this type of energy. To deal with the uncertainty of wind power, system operators must ensure a desirable level of reserves in their power systems. In this context, demand response (DR) markets can be used as options for system operators to procure their reserve requirements. The recently introduced DR market is a separate market where DR is considered as resource to be traded between DR buyers and sellers. There are still challenges to integrate the DR markets into the existing markets. This paper tries to combine the DR market with the energy/reserve markets with the aim of mitigating the wind-uncertainty costs. For this purpose, the joint clearance of DR markets with the energy/reserve markets is formulated as a bilevel programming problem. In this framework, system requirements for reserve in power systems with high wind power integration determined in the upper-level problem. The lower-level problem belongs to the DR market clearing problem. The solution approach for the resulting bilevel model is introduced. Finally, the proposed model is verified by a realistic case study.**

Keywords-Demand response market; wind power; bilevel programming; reserves

NOTATION

The main notation used in this paper is provided below. Some of the following constants and variables incorporate superscript *U, D* or *NS* when referring to the upward, downward or non-spinning reserve/DR, respectively.

A. Indices and Numbers

n	Index of system buses, running from 1 to N_B.
i	Index of generating units, running from 1 to N_U.
j	Index of loads, running from 1 to N_L.
m	Index of energy blocks offered by generating units, running from 1 to N_{Oi}.
g	Index of costumer groups, running from 1 to N_{Gj}.
b	Index of DR buyers, running from 1 to N_{Bj}.
l	Index of aggregators, running from 1 to N_{Aj}.
w	Index of wind power scenarios, running from 1 to N_w.

B. Variables

$p_{Gi}(m)$	Power output scheduled from the *m*-th block of energy offered by unit *i* [MW]. Limited to $p_{Gi}^{\max}(m)$.
$R_{i,t}$	Spinning reserve scheduled for unit *i* in period *t* [MW]. Limited to R_i^{max} .
$Rd_{j,t}$	Reserve scheduled for load *j* in period *t* [MW].
$P_{G_{i,t}}^{s}$	Scheduled power of unit *i* in period *t* [MW].
$P_t^{WP,S}$	Scheduled wind power in period *t* [MW].
$C_{i,t}^{S}$	Start-up cost of unit *i* in period *t* [$].
$d_{j,t,w}$	Deployed DR reserve of *j*th consumer in period *t* and scenario *w* [MW].
$L_{j,t,w}^{sh}$	Load shedding of *j*th consumer in period *t* and scenario *w* [MW].
$L_{j,t,w}^{C}$	Power consumption of *j*th consumer in period *t* and scenario *w* [MW].
$S_{t,w}$	Wind power spillage in period *t* and scenario *w* [MW].
$P_{G_{i,t,w}}$	Power generation of unit *i* in period *t* and scenario *w* [MW].
$r_{i,t,w}$	Deployed reserve of unit *i* in period *t* and scenario *w* [MW].
$C_{i,t,w}^{A}$	Cost due to the change in start-up plan of unit *i* in period *t* and scenario *w* [MW].
$f_{t,w}(n,r)$	Power flow through line *(n,r)* in period *t* and scenario *w*. Limited to $f^{\max}(n,r)$.
$s_{j,b,g,t}$	DR supplied to buyer *b* from costumer group *g* of load *j* in period *t* [MW].
$q_{j,l,t}$	DR provided by aggregator *l* of load *j* in period *t* [MW]. Limited to $q_{j,l,t}^{\max}$.

$u_{i,t}$	0/1 variable that is equal to 1 if unit *i* is scheduled to be committed in period *t*.
$v_{i,t,w}$	0/1 variable that is equal to 1 if unit *i* is scheduled to be committed in period *t* and scenario *w*.

C. Dual variables

The dual variables below are associated with the following constraints:

$\gamma_{j,t}$	DR supply-demand for TSO and load *j*.
$\lambda_{j,b,g,t}$	DR supply-demand for Retailer/distributor *b* and costumer group *g* of load *j*.
$\overline{\mu}_{j,l,t}$	Upper bound on DR provided by aggregator *l* of load *j*.
$\underline{\mu}_{j,l,t}$	Lower bound on DR provided by aggregator *l* of load *j*.

D. Constants

λ_i^S	Start-up offer cost of unit *i* [\$].
$\lambda_{Gi}(m)$	Marginal cost of the *m*-th block of energy offered by unit *i* [\$/MWh].
$C_{i,t}^R$	Offer cost of spinning reserve of unit *i* [\$/MWh].
$\lambda_{Lj,t}$	Utility of consumer *j* in period *t* [\$/MWh].
$P_{G_i}^{\min} / P_{G_i}^{\max}$	Minimum/maximum power output of unit *i* [MW].
$\mathrm{L}_{j,t}$	Power consumption of *j*th consumer in period *t* [MW].
$VOLL_{j,t}$	Value of load shed for consumer *j* in period *t* [\$/MWh].
$P_{t,w}^{PW}$	Wind power generation in period *t* and scenario *w* [MW].
V_t^S	Cost of wind power spillage in period *t* [\$/MWh]
π_w	Probability of wind power scenario *w*.
λ_t^{WP}	Marginal cost of the energy offer submitted by wind power producer in period *t* [\$/MWh].
$\alpha_{j,b,g,t} / \beta_{j,b,g,t}$	Coefficients of DR demand function of buyer *b* from costumer group *g* of load *j* [\$/MWh^2]/[\$/MWh].
$a_{j,l,t} / b_{j,l,t}$	Coefficients of DR supply function offered by aggregator *l* of load *j* [\$/MWh^2]/[\$/MWh].
$\theta_{j,l}$	Willingness of aggregator *l* of load *j* to provide DR.

F. Sets

Λ	Set of transmission lines.
M_U	Mapping of the sets of generating units into the set of buses.
M_L	Mapping of the set of loads into the set of buses.
M_C	Mapping of the sets of costumer groups into the set of loads.

I. INTRODUCTION

Environmental concerns and increasing price of fossil fuel necessitate utilization of renewable energy resources in the power generation sector. Variability and uncertainty of renewable energies (namely wind power) increase the power system requirement for reserve. Therefore, the transmission system operator (TSO) must procure a desirable lever of reserves with the aim of ensuring secure and efficient operation of the power system.

The flexibility of power system can be increased by demand response (DR) due to providing very fast upward/downward change in the demand. This potential can be translated as providing a fast upward/downward reserve which in turn facilitates utilizing wind power in the system. In some of the existing markets, besides the supply-side, DR resources are also permitted to participate in energy/reserve market. The providing reserve from the DR has been studied in [1-6]. The energy/reserve market clearing model with stochastic and probabilistic reserve considering demand-side reserve offers proposed in [1] and [3]. The effects of load recovery of demand response providers (DRPs) in the energy/reserve market are investigated in [8]. Authors in [7-10] studied incorporating the DR into the security-constrained unit commitment (SCUC). Investigating the impacts of the flexibility provided by DR in mitigating the integration issues of renewable energies into the power systems are provided in [11-15].

DR is a public good in the sense that one MW of DR may be profitable for various players in the electricity markets. The players who are the DR beneficiaries are TSO, retailers and distributors. However, this property of the DR has not been considered in the literature for DR scheduling. In other word, the existing approaches schedule the DR from the view point of only one DR beneficiary that may be unfair towards other participants [16]. To cope with this issue, designing a separate trading environment for DR with specific clearing rules may be useful. In this regard, Nguyen *et al.* [17] proposed a comprehensive approach for scheduling the DR known as DR exchange market. In the DR market, DR is exchanged between the DR buyers (TSO, retailers and distributors) and sellers (DRPs). The fair allocation of the incentive payments across all market participants is the main advantage of using DR market for the DR scheduling [18].

Scheduling DR in a separate market with specific clearing rules can leads to an efficient approach. However, it introduces some new challenges regarding the integration of the DR market into the existing energy and reserve markets. These challenges are: 1) modeling the interaction between DR market and the energy/reserve market 2) considering technical and physical constraints of the power system in clearing the DR market. This paper tries to bring the retail DR markets into the wholesale energy markets via bilevel programming approach. A first introduction of this approach is published in [19] to procure reserve requirements, determined by n-1 contingency

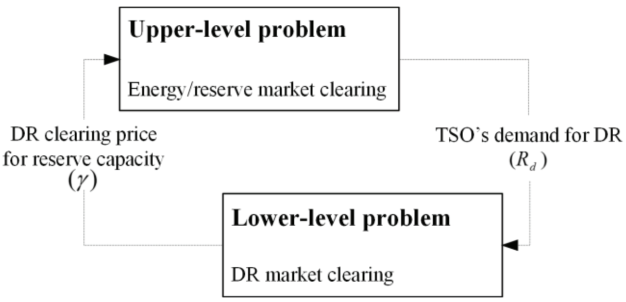

Fig.1. Proposed bilevel model

criteria, from DR market. In this paper, the application of the proposed approach in mitigating wind-uncertainty effects is illustrated.

II. MODEL

A. Assumptions

Bringing the DR market into the energy/reserve market is the main aim of this paper. Stochastic programming is used for clearing the energy/reserve market with high wind power penetration [20]. The system reserve requirements for covering wind-uncertainty are determined in this market. In the energy/reserve market, the generating units offer their marginal cost of energy through *m*-block price-quota curve, while a single flat rate is considered for their reserve offering [1-4]. The hourly day-ahead time horizon is considered for scheduling.

In the DR market, the DR market operator gathers the demand-side offers for providing up- and downward reserves as well as DR purchasing bids of retailers and distributors. In this paper, quadratically increasing and decreasing functions are assumed for DR sellers' cost and buyers' benefit, respectively. It should be noted that the TSO's demand for the DR is determined at the upper-level problem as well.

B. Bilevel Programming

Figure 1 depicts the structure of the proposed bilevel model for integrating the DR market into the energy/reserve market. stochastic energy/reserve market with high wind power penetration is cleared at the upper level problem. The TSO's demand for DR reserve in order to cover wind power uncertainty is determined at the upper-level. Then, considering the TSO's demand for the DR, the lower-level problem clears the DR market. The clearing price for the DR capacity is determined in the lower-level problem which used as input of the upper-level problem.

The proposed bilevel model for utilizing DR markets in the energy/reserve market with high wind power penetration is as follows:

Minimize

$$
\begin{aligned}
&\sum_{t=1}^{N_T}\Bigg[\sum_{i=1}^{N_U} C_{i,t}^{S} + \sum_{i=1}^{N_U}\sum_{m=1}^{N_{Oi}} \lambda_{Gi,t}(m)\, p_{Gi,t}(m) - \sum_{j=1}^{N_L} \lambda_{Lj,t}\, \mathrm{L}_{j,t} \\
&+\sum_{i=1}^{N_U}\left(C_{i,t}^{RU} R_{i,t}^{U} + C_{i,t}^{RD} R_{i,t}^{D} + C_{i,t}^{RNS} R_{i,t}^{NS}\right) \\
&+\sum_{j=1}^{N_L}\left(\gamma_{j,t}^{U} Rd_{j,t}^{U} + \gamma_{j,t}^{D} Rd_{j,t}^{D}\right) + \lambda_t^{WP} P_t^{WP,S}\Bigg] \\
&+\sum_{w=1}^{N_W} \pi_w \Bigg\{\sum_{t=1}^{N_T}\Bigg[\sum_{i=1}^{N_U} C_{i,t,w}^{A} + \sum_{i=1}^{N_U}\sum_{m=1}^{N_{Oi}} \lambda_{Gi,t}(m)\, r_{Gi,t,w}(m) \\
&+\sum_{j=1}^{N_L} \lambda_{Lj,t}\left(d_{j,t,w}^{U} - d_{j,t,w}^{D}\right) + \sum_{j=1}^{N_L} VOLL_{j,t} L_{j,t,w}^{sh} + V_t^{S} S_{t,w}\Bigg]\Bigg\}
\end{aligned}
\tag{1}
$$

Subject to:

$$\sum_{i=1}^{N_G} P_{G_{i,t}}^{s} + P_t^{WP,s} = \sum_{j=1}^{N_L} L_{j,t} \quad , \forall t \tag{2}$$

$$P_{G_i}^{\min} u_{i,t} \le P_{G_{i,t}}^{s} \le P_{G_i}^{\max} u_{i,t} \quad , \forall i,t \tag{3}$$

$$0 \le p_{Gi,t}(m) \le p_{Gi,t}^{\max}(m) \quad , \forall m,i,t \tag{4}$$

$$P_{G_{i,t}}^{s} = \sum_{m=1}^{N_{Oit}} p_{Gi,t}(m) \quad , \forall i,t \tag{5}$$

$$P_t^{WP,\min} \le P_t^{WP,s} \le P_t^{WP,\max} \quad , \forall t \tag{6}$$

$$0 \le R_{i,t}^{U} \le R_i^{U,\max} u_{it} \quad , \forall i,t \tag{7}$$

$$0 \le R_{i,t}^{D} \le R_i^{D,\max} u_{it} \quad , \forall i,t \tag{8}$$

$$0 \le R_{i,t}^{NS} \le R_i^{NS,\max}(1-u_{i,t}) \quad , \forall i,t \tag{9}$$

$$C_{i,t}^{S} \ge \lambda_{i,t}^{S}(u_{i,t} - u_{i,t-1}) \quad , \forall i,t \tag{10}$$

$$C_{i,t}^{S} \ge 0 \quad , \forall i,t \tag{11}$$

$$
\begin{aligned}
&\sum_{i:(i,n)\in M_G} P_{G_{i,t,w}} + P_{t,w}^{WP} - \sum_{j:(j,n)\in M_L}\left(L_{j,t,w}^{C} - L_{j,t,w}^{sh}\right) \\
&-f_{t,w}(n,r) = 0 \quad , \forall n,t,w
\end{aligned}
\tag{12}
$$

$$P_i^{\min} v_{i,t,w} \le P_{G_{i,t,w}} \le P_i^{\max} v_{i,t,w} \quad , \forall i,t,w \tag{13}$$

$$-f^{\max}(n,r) \le f_{t,w}(n,r) \le f^{\max}(n,r) \quad , \forall (n,r)\in \Lambda \tag{14}$$

$$0 \le L_{j,t,w}^{sh} \le L_{j,t,w}^{C} \quad , \forall j,t,w \tag{15}$$

$$0 \le S_{t,w} \le P_{t,w}^{PW} \quad , \forall t,w \tag{16}$$

$$P_{G_{i,t,w}} = P_{G_{i,t}}^{s} + r_{i,t,w}^{U} + r_{i,t,w}^{NS} - r_{i,t,w}^{D} \quad , \forall i,t,w \tag{17}$$

$$L_{j,t,w}^{C} = L_{j,t} - rd_{j,t,w}^{U} + rd_{j,t,w}^{D} \quad , \forall j,t,w \tag{18}$$

$$0 \le r_{i,t,w}^{U} \le R_{i,t}^{U} \quad , \forall i,t,w \tag{19}$$

$$0 \le r_{i,t,w}^{D} \le R_{i,t}^{D} \quad , \forall i,t,w \tag{20}$$

$$0 \le r_{i,t,w}^{NS} \le R_{i,t}^{NS} \quad , \forall i,t,w \tag{21}$$

$$0 \le d_{j,t,w}^{U} \le Rd_{j,t}^{U} \quad , \forall j,t,w \tag{22}$$

$$0 \le d_{j,t,w}^{D} \le Rd_{j,t}^{D} \quad , \forall j,t,w \tag{23}$$

$$r_{i,t,w}^{U} + r_{i,t,w}^{NS} - r_{i,t,w}^{D} = \sum_{m=1}^{N_{Oit}} r_{Gi,t,w}(m) \quad , \forall i,t,w \tag{24}$$

$$r_{Gi,t,w}(m) \le p_{Gi,t}^{\max}(m) - p_{Gi,t}(m) \quad , \forall i,t,w \tag{25}$$

$$r_{Gi,t,w}(m) \ge -p_{Gi,t}(m) \quad , \forall i,t,w \tag{26}$$

$$C_{i,t,w}^{A} = C_{i,t,w}^{S} - C_{i,t}^{S} \quad , \forall i,t,w \tag{27}$$

$$C_{i,t,w}^{A} \ge \lambda_{i,t}^{S} (v_{i,t,w} - v_{i,t-1,w}) \quad , \forall i,t,w \tag{28}$$

$$C_{i,t,w}^{A} \ge 0 \quad , \forall i,t,w \tag{29}$$

where

$$\gamma_{j,t}^{U}, \forall j,t ; \gamma_{j,t}^{D}, \forall j,t \in \arg : \text{Maximize}$$

$$\begin{aligned}
&\sum_{j=1}^{N_L} \sum_{b=1}^{N_{Bj}} \sum_{g=1}^{N_{Gb}} \sum_{t \in T^U(b)} \left(-\alpha_{j,b,g,t}^{U} (s_{j,b,g,t}^{U})^2 + \beta_{j,b,g,t}^{U} s_{j,b,g,t}^{U} \right) \\
&+ \sum_{j=1}^{N_L} \sum_{b=1}^{N_{Bj}} \sum_{g=1}^{N_{Gb}} \sum_{t \in T^D(b)} \left(-\alpha_{j,b,g,t}^{D} (s_{j,b,g,t}^{D})^2 + \beta_{j,b,g,t}^{D} s_{j,b,g,t}^{D} \right) \\
&- \sum_{j=1}^{N_L} \sum_{l=1}^{N_{Aj}} \sum_{t \in T^U(j)} \left(a_{j,l,t}^{U} (q_{j,l,t}^{U})^2 + b_{j,l,t}^{U} (1 - \theta_{j,l,t}) q_{j,l,t}^{U} \right) \\
&- \sum_{j=1}^{N_L} \sum_{l=1}^{N_{Aj}} \sum_{t \in T^D(j)} \left(a_{j,l,t}^{D} (q_{j,l,t}^{D})^2 + b_{j,l,t}^{D} (1 - \theta_{j,l,t}) q_{j,l,t}^{D} \right)
\end{aligned} \tag{30}$$

Subject to:

$$Rd_{j,t}^{U} = \sum_{l=1}^{N_{Aj}} q_{j,l,t}^{U} \qquad : \gamma_{j,t}^{U}, \ \forall j,t \tag{31}$$

$$Rd_{j,t}^{D} = \sum_{l=1}^{N_{Aj}} q_{j,l,t}^{D} \qquad : \gamma_{j,t}^{D}, \ \forall j,t \tag{32}$$

$$s_{j,b,g,t}^{U} = \sum_{l=1}^{N_{Aj}} q_{j,l,t}^{U} c_{j,l}^{bg} \qquad : \lambda_{j,b,g,t}^{U}, \ \forall j,b,g,t \tag{33}$$

$$s_{j,b,g,t}^{D} = \sum_{l=1}^{N_{Aj}} q_{j,l,t}^{D} c_{j,l}^{bg} \qquad : \lambda_{j,b,g,t}^{D}, \ \forall j,b,g,t \tag{34}$$

$$0 \le q_{j,l,t}^{U} \le q_{j,l,t}^{U,\max} \qquad : \overline{\mu}_{j,l,t}^{U}, \underline{\mu}_{j,l,t}^{U}, \ \forall j,l,t \tag{35}$$

$$0 \le q_{j,l,t}^{D} \le q_{j,l,t}^{D,\max} \qquad : \overline{\mu}_{j,l,t}^{D}, \underline{\mu}_{j,l,t}^{D}, \ \forall j,l,t \tag{36}$$

In the bilevel model, the upper-level problem (1)-(29) belongs to the multi-period stochastic energy/reserve market clearing problem with high wind power penetration. The variables $Rd_{j,t}^{U}$ and $Rd_{j,t}^{D}$ determine the TSO's demand for DR capacity to cover wind power uncertainty. The DR market is cleared at the lower level problem (30)-(36). The dual variables of constraints (31) and (32) calculate the up and downward DR capacity prices $\gamma_{j,t}^{U}$ and $\gamma_{j,t}^{D}$ which are used in the objective function of the upper-level problem (1).

The upper-level objective function (1) is to minimize total expected operation cost. The first line of (1) is related to the energy offer and start-up costs of generating units minus consumers' utility [19]. The offer cost of reserves from generating units is included in the second line of (1). The demand-side reserve offers and energy offer cost of wind generation are presented in the third line of the objective function. The fourth line of (1) includes expected rescheduling cost of generating units in wind power generation scenarios. Finally, the last line of the objective function (1) refers to the expected costs of change in the consumers' utility, load shedding and wind power spillage. This objective function is subject to the following constraints [20]: market equilibria for the scheduling quantities (2), production limits (3), approximation of the energy offer cost function of generating units by blocks (4) and (5), wind power generation limits (6), generation-side scheduled reserve determination constraints (7)-(9), calculation of the start-up costs (10) and (11), power balance constraints in each considered scenario (12), generation limits in each scenario (13), line power flow constraints (14), upper bounds on load shedding and wind power spillage (15) and (16), decomposition of generation output in each scenario (17), decomposition of power consumed in each scenario (18), determination of the deployed reserves of generation units (19)-(21), determination of the deployed reserves of demand-side (22)-(23), decomposition of the generation-side deployed reserves into blocks (24)-(26) and start-up cost adjustments of generating units in each scenario (27)-(29).

The objective function of the lower-level problem (30) is to maximize the sum of the benefit function of the retailers and distributors minus total aggregators' cost. It is supposed that buyer *b* who maybe a retailer or distributor bids for purchasing DR via a quadratic gross benefit function for each of his/her associated customer group *g* in each time period *t* [17]. On the other hands, for the aggregators participating in the DR market, non-decreasing quadratic cost functions are assumed. The aggregator's willingness for providing the DR are modeled by coefficient $\theta_{j,l,t}$ in the DR cost function.

TABLE I. AGGREGATORS' WILLINGNESS

Bus	θ_{jlt}	Bus	θ_{jlt}	Bus	θ_{jlt}	Bus	θ_{jlt}
1	0.86	5	0.82	10 & 14	0.94	16	0.85
2	0.84	6	0.89	13	0.96	18	0.98
3	0.92	7	0.87	15	0.97	19	0.93
4	0.83	8	0.90	9	0.91	20	0.98

TABLE II. DR BUYERS' COST COEFFICIENTS

Bus	($/MWh)		Bus	($/MWh)	
	$\beta^{D}_{b,g}$	$\beta^{U}_{b,g}$		$\beta^{D}_{b,g}$	$\beta^{U}_{b,g}$
1	21	28	9	13.5	18
2	24	32	10 & 14	9	12
3	12	16	13	6	8
4	25.5	34	15	4.5	6
5	27	36	16	22.5	30
6	16.5	22	18	3	4
7	19.5	26	19	14	10.5
8	15	20	20	18	24

The up- and downward DR demand-supply balance for the TSO in each time period are represented in constraints (31) and (32), respectively. Similarly, constraints (33) and (34) state the demand-supply balance constraints for retailers and distributors, respectively. Binary coefficient $c^{bg}_{j,l}$ represents a relational status of aggregator *l* to the group *g* of the DR buyer *b* at time period *t*, respectively [17]. The upper and lower bounds on the up- and downward DR which can be provided by aggregator *l* are enforced by equations (35) and (36), respectively.

C. Solution Approach

With the assumed benefit and cost functions for DR buyers and sellers in (30), the lower-level problem (30)-(36) is a convex optimization. Therefore, it can be replaced by its KKT optimality conditions. Then, the bilevel problem can be translated into a single level programing problem by replacing the KKT conditions of the lower-level problem as constraints into the upper-level problem. However, since in the resulted single-level problem there are some non-linear terms and binary variables, it can be stated as a mixed-integer non-linear programming (MINLP) problem. Using some linearization techniques [19], the resulted MINLP can be represented as mixed-integer linear programming (MIP) problem which can be solved using commercially available software [21].

III. RESULTS

In this section, the application of the proposed bilevel model in facilitating of wind power integration into the power systems is illustrated. The IEEE reliability test system (RTS) over a 24-h horizon is used for simulations [22]. This system contains 32 generating units and 17 load buses. The hydro units are considered must-run generators and operate at half of their capacities. The required data for simulations have been extracted from [22] and [23]. It is assumed that all the generating units offer to provide spinning reserves at the rate of 25% of their highest marginal cost of energy production [22]. The wind power producer with the installed capacity of 150 MW is located on Bus 20.

TABLE III. SCHEDULED RESERVES

	Upward Reserve [MWh]	Downward Reserve [MWh]	DR Reserve [MWh]		Total [MWh]
			Up	Down	
Case I	2731.80	75.52	–	–	2807.32
Case II	2388.10	175.35	184.22	11.41	2759.08
Case III	1855.23	47.91	617.65	28.75	2549.54

TABLE IV. SYSTEM OPERATION COSTS

	Energy/Reserve Market Objective [$]	Energy Cost [$]	Reserve Cost [$]	DR Payment [$]
Case I	540052.63	530482.65	9569.98	–
Case II	538937.86	526236.83	8686.74	2430.82
Case III	535980.70	517351.25	7097.68	6743.52

The load profile which is corresponding to a Monday of a winter weekday with a peak load of 2850 MW has been extracted from [22]. It is assumed that there is one retailer, one distributor and one aggregator in each load bus. For the sake of simplicity, it is assumed that the offering benefit functions of retailers and distributors and the bidding cost function of aggregators are the same for all 24 hours, respectively. The coefficients of the aggregators' cost function for upward DR are 0.25 $/MWh^2 and 350 $/MWh. For downward DR, these coefficients are assumed 0.25 $/MWh^2 and 250 $/MWh. The willingness of the aggregators to provide DR, i.e. θ, is reported in Table I. The coefficients of the DR buyers' supply functions are included in Table II ($\alpha_{j,b,g,l}$=0.25 $/MWh^2). The VOLL is considered 3000 $/MWh. Simulations are conducted for the following cases:

- Case I: Energy/reserve market without DR
- Case II: TSO-based partial approach where DR is directly scheduled in the energy/reserve market and only TSO pays for the DR
- Case III: The Proposed bilevel model in which DR is scheduled through the DR market with all DR buyers and sellers considered.

Table III reports the scheduled up- and downward reserves in each case study. As can be seen, DR leads to decrement of the system required reserve in cases II and III. In Case III, the DR participation in the energy/reserve market is increased up to 5%, resulting in decrement of the scheduled reserve by 9.2%.

The costs of energy, reserve and DR in three cases are reported in Table IV. It can be seen in Table IV that DR can decrease the costs of energy and reserve. The decrement of energy cost in Case II and III is 0.8 and 2.4 percent while the reserve cost decreases by 9.2 and 25.8 percent, respectively. Since using DR market leads to allocation of DR cost to all the DR buyers, in Case III more DR is scheduled and the total cost of energy and reserve scheduling is less.

To evaluate the impact of DR on decrement of the uncertainty-cost of the wind power, energy and reserve costs per MWh are calculated as follow. The cost of energy per

TABLE V. ENERGY/RESERVE COSTS PER MWH

	Reserve Cost per MWh [$/MWh]	*Energy Cost per MWh [$/MWh]*
Case I	1.94	6.49
Case II	1.76	6.44
Case III	1.36	6.33

MWh is obtained by dividing the total cost of the energy by the length of the scheduling period (24 hours) and total system power capacity (excluding wind power) [20]. Since wind power is responsible for reserve requirements, the cost of reserve per MWh is obtained by dividing the total cost of reserve by the installed wind power (150 MW) and the time horizon (24 hours) [20]. Table V reports the energy and reserve costs per MWh for three considered cases. The proposed framework for clearing the energy/reserve and DR markets decreases the per MWh cost of the energy and reserve by 2.5 and 30 percent, respectively.

IV. CONCLUSIONS

The main purpose of this paper was to combine DR markets with the energy/reserve markets to facilitate wind power integration. To jointly clear DR market with the energy/reserve market, a bilevel model was proposed. In the proposed bilevel model, the upper-level problem states the stochastic multi-period energy/reserve market clearing with high wind power integration. The DR market is cleared in the lower-level problem. The resulted non-linear bilevel problem is then translated into a single-level MIP by replacing the lower-level problem by its KKT optimality conditions and some well-known linearization techniques.

The IEEE RTS was used to illustrate the applicability and effectiveness of the proposed bilevel model in facilitating wind power integration into power systems. It was shown that operation of the DR markets for scheduling DR in wholesale energy/reserve markets brings about lower reserve cost and higher social welfare.

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