Toward mitigating wind-uncertainty costs in power system operation: A demand response exchange market framework

Javad Saebi*, Mohammad Hossein Javidi, Majid Oloomi Buygi

Department of Electrical Engineering, Ferdowsi University of Mashhad, Mashhad, Iran

**ARTICLE INFO**

Article history:
Received 20 May 2014
Received in revised form 9 September 2014
Accepted 12 September 2014

Keywords:
Demand response exchange
Stochastic programming
Reserves
Wind power system operation
Wind power
DR

**ABSTRACT**

The intermittent nature of the wind generation poses an obstacle to high penetration of wind energy in electric power systems. Demand response (DR) increases the flexibility of the power system by allowing very fast upward/downward changes in the demand. This potential can be interpreted as the ability to provide fast upward/downward reserves, facilitating the utilization of the wind power in the power system. Demand response exchange (DRX) market is a separate market in which DR is treated as a virtual resource to be exchanged between DR buyers and sellers. The major advantage of the DRX market in comparison to other DR proposals is that it allocates benefits and payments across all participants, fairly. However, there are still obstacles to its integration into the existing power markets. This paper proposes a short-term framework for DRX market that considers the interactions between the DRX market and energy/reserve markets. The proposed framework is aimed at reducing the operational costs incurred by the uncertainty of the wind power and providing a fair mechanism for valuation of the DR as a virtual resource. A stochastic programming model is used to clear the DRX market considering the wind power production scenarios. To illustrate the efficiency of the proposed DRX market framework, it is implemented on a simple and a realistic case study.

© 2014 Elsevier B.V. All rights reserved.

1. Introduction

Today, increasing price of the fossil fuels together with the environmental concerns has motivated governments to utilize renewable energy resources in the electrical energy sector. However, large-scale integration of the renewable energy resources (particularly wind power) in the electric energy systems has introduced two serious concerns which must be addressed in the operation of the power system [1–3]. First, the power system must be able to deal with the volatilities of the wind power generation. The effects of such volatilities are less profound in systems benefiting from sufficient flexible power resources, such as reversible hydro dams, energy storage technologies, and fast conventional generators. Second, high penetration of the intermittent resources into the power system may affect the operation of the conventional generators, leading to the deviation from economically-scheduled operating points.

Demand response (DR) may be considered as an efficient approach to cope with such effects in power systems with high level of wind power integration [4–7]. Basically, DR is considered as the consumers’ ability to alter their normal consumption patterns in response to changes in electricity prices or because of incentive payments designed to resolve reliability issues [8]. Note that DR can be classified as either demand curtailment or demand increment.

The role of the DR in the operation and planning of the power systems with high level of wind power integration has been investigated by many researchers. These researches can be categorized into two groups based on the type of the investigated DR programs, including price-based DR and incentive-based DR. The effect of the price-based DR on the integration of the wind power has been investigated in [9–14]. Sioshansi and Short [9] used a unit commitment model to demonstrate the effect of real time pricing (RTP) on the wind power integration. They showed that RTP can increase the amount of load served by the wind generation and the wind power generation actually utilized in real-time. The effects of DR in a future German power system have been investigated in [10]. It has been shown that using DR, the wind-uncertainty costs are reduced to less than € 2/MWh. The authors in [11] examined the use of RTP on a future UK power system with 15 GW wind penetration level. They showed that the RTP has the potential of removing the requirement of 8–11 GW of standby generation with a capital cost of €2.6–€3.6 billion. The impacts of demand shifting and peak shaving on wind integration are investigated in [12]. Finn et al. [13] investigated the effect of dynamic pricing and time-of-use tariffs in...
### Notation

#### Indices

- $t$: index of time periods, running from 1 to $T$
- $i$: index of generating units, running from 1 to $I$
- $j$: index of aggregators, running from 1 to $J$
- $q$: index of wind power producers, running from 1 to $Q$
- $m$: index of DR supply function blocks offered by aggregators, running from 1 to $M$
- $w$: index of wind power scenarios, running from 1 to $S$

#### Variables

- $d_{i,t,w}^{UL}$: upward/downward DR deployed by aggregator $j$ in period $t$ and scenario $w$ (MW)
- $sd_{i,j,t}^{UL}$: upward/downward DR scheduled for aggregator $j$ in period $t$ (MW)
- $d_{i,t,w}^{NS}$: substituted upward/downward reserve of unit $i$ deployed in period $t$ and scenario $w$ by DR (MW)
- $ds_{q,t,w}$: substituted wind power spillage of producer $q$ in period $t$ and scenario $w$ by DR (MW)
- $s_{t,j,t}^{UL}$: uniform price of energy in real time operation conditions at period $t$ and scenario $w$ ($/MWh$)
- $p_{DB,j,t}^{D,m}(m)$: upward/downward DR scheduled from the $m$-th block of supply function offered by aggregator $j$ in period $t$ (MW).
- $f_{j,t}^{D,max}$: load recovery coefficient offered by aggregator $j$

#### Functions

- $b_{j,t,w}^{UL}$: benefits obtained by reduction in load shedding imposed on consumer $j$ in period $t$ and scenario $w$ due to DR ($$/h$)
- $sp_{q,t,w}$: benefits gained from DR for reducing wind power generation spillage of producer $q$ in period $t$ and scenario $w$ ($$/h$)
- $su_{j,t,w}^{UL}$: benefits obtained through replacement of start-up cost of unit $i$ in period $t$ and scenario $w$ by DR ($$/h$)

#### Constants

- $C_{SI,j,t}^{UL}$, $C_{DI,j,t}^{UL}$: start-up and availability cost of upward/downward DR offered by aggregator $j$ in period $t$ ($$/MWh$)
- $C_{RI,j,t}^{UL}$, $C_{RD,j,t}^{UL}$: cost of upward/downward spinning reserve of unit $i$ in period $t$ ($$/MWh$)
- $L_{sh,j,t,w}$: load shedding of consumer $j$ in period $t$ and scenario $w$ (MW)
- $R_{UL,i,t,w}^{D,d}$: deployed upward/downward spinning reserve by unit $i$ in period $t$ and scenario $w$ (MW)
- $R_{UL,i,t,w}^{NS}$: scheduled upward/downward reserve for unit $i$ in period $t$ (MW).

---

Ireland power grid, showing that by use of these programs Ireland's current generation portfolio could move from 11 to $40\%$ renewable energy supply. However, the authors in [14] demonstrated that delays in the consumers' response to the price signals dramatically decrease the benefits of the DR in mitigating wind-uncertainty costs.

Some researchers have focused on incentive-based DR in the operation of the power systems [15–18]. The authors in [15] proposed an incentive-based DR program that facilitates the grid integration of wind power by reshaping the system load. Economic evaluation of the DR according to its potential for mitigating the wind power forecast error in the power system operation is proposed in [16]. Wu et al. [17] proposed a stochastic security-constrained unit commitment incorporating DR and storage program with the aim of managing renewable energy resources. Incorporating deferrable demand response resources and intermittent renewable resources in the stochastic unit commitment and economic dispatch models has been investigated in [18]. Falsafi et al. [19] proposed a stochastic model for scheduling energy and reserves provided by both the generating units and demand response providers (DRPs) with the aim of covering uncertainty of wind power.

Negnevitsky et al. [20] believe that as most existing approaches for DR scheduling consider only one or some participants' point of view, they may be unfair toward other participants. For example, all the above mentioned approaches deal with the DR scheduling from TSO's point of view without considering other DR beneficiaries (i.e., retailers and distributors). Maximizing an individual player's DR benefits may conflict with another individual's benefits [21]. Nguyen et al. [22] proposed a comprehensive approach for DR scheduling. They designed a separate market for trading DR, known as demand response exchange (DRX) market, in which DR is treated as a virtual resource to be exchanged between the DR buyers (TSOs, retailers, and consumers) and sellers (DRPs). Electricity consumers are the providers of the DR. They, via aggregators, can participate in the DRX market as DR sellers. The aggregators are independent agents that combine multiple consumers into a single unit to negotiate purchase from the retailers. The main advantage of using DRX market for DR scheduling is fair allocation of the incentive payments across all market participants [23]. A Walrasian [24] market clearing for the DRX market has been proposed in [25].
inter-temporal impact of load recovery on DR scheduling via DRX market has been modeled in [26].

The main purpose of our paper is DR scheduling through the DRX market with the aim of mitigating wind-uncertainty costs in power system operation. While the DRX market is a comprehensive approach for DR scheduling, there are still obstacles to its integration into the existing power markets. The DRX market proposed in [22] is in the form of financial market without considering any technical/physical constraints of the power system. Therefore, in its previously proposed form, it cannot work effectively along with the existing energy/reserve markets, which are essentially physical markets. On the other hand, in [22], it has been assumed that the buyers in the DRX market offer for purchasing DR through a simple demand function, while the demand for DR is not a predefined value and depends on load and technical/physical conditions of the power systems. Therefore, DR cannot be traded and scheduled in a separate market without considering other participants of the power system and the interactions among them. To cope with the above mentioned limitations, in this paper, a refinement of the DRX market structure is proposed. For this purpose, an insight is provided into the system operation under high wind power penetration with the aim of determining TSO’s demand for the DR. Accordingly, a new framework for the DRX market is proposed in which load recovery effects are also modeled. To consider wind power uncertainty, stochastic programming is used to clear the proposed DRX market framework.

Today, smart power systems (or as they are commonly known, smart grids) are being introduced. In the environment of the smart grids, beside deployment of the advanced metering infrastructures (AMI) and technologies, the linkage between the demand-side management and bulk power system is facilitated. In other words, the smart grid technologies allow to consider DR as a dispatchable resource. In such an environment, the proposed DRX market framework, as a comprehensive approach for scheduling of the DR, can be integrated into the existing energy markets. In the power systems benefiting from high wind power generation, the TSOs may participate in the proposed framework to cope with wind-uncertainty costs.

2. Proposed framework for DRX market

In this paper, DR as a virtual resource is implemented as a source of operational reserve to cope with the effects of wind-uncertainty on the power system operation. The use of DR for providing reserves has been studied in [27–29]. As mentioned earlier, to determine the level of reserves that can be supplied by the demand-side, the DRX market is utilized in this paper, since it is the most economic approach for DR scheduling. For this purpose, to determine the operating reserve requirements from conventional generating units, the TSO runs a stochastic programming market-clearing model in a power system under high wind power generation. Then, the TSO tries purchasing DR reserves through the DRX market, before declaring the results of the energy/reserve market to generating companies. The DRX market is cleared based on the proposed framework in this paper (Section 2.2). In the proposed DRX market, the pre-scheduled reserves of the generating units may be replaced by the DR. Finally, according to the operating reserves substituted by the DR, the scheduled reserves of the generating units are declared to generation companies.

In the rest of this section, first the energy/reserve market-clearing model in a power system with high wind power integration is described. Then, using the results obtained from the energy/reserve market clearing, the proposed framework for DRX market is introduced.

2.1. Short-term electricity market clearing with high wind power integration

A two-stage stochastic programming for hourly auction of the energy and reserve market with high wind power penetration has been proposed in [30]. In the first stage of this method, the market is cleared based on determination of the wind generation. Then in the second stage, the operation of the system is modeled under a set of possible wind power production scenarios. Wind curtailment and load shedding are considered in this energy/reserve market as decision variables. To find the TSO’s demand for the DR, first the effects of the wind-uncertainty on the power system operation costs are evaluated. These undesirable effects can be classified as follows:

- Deviation of the output of the conventional generators from their scheduled quantities and additional reserve requirements due to the probable difference between the wind power in the scenarios and the scheduled wind generation.
- Startups of generating units that may occur in some scenarios due to the low wind power generation.
- Involuntary load shedding that may occur in some scenarios due to the low wind power generation.
- Wind power spillage in some scenarios with high wind power generation.

The DR has the ability to reduce the above mentioned operational costs by allowing very fast upward/downward changes in the demand. According to the potential of the DR for reducing the undesirable effects of the wind power, some benefit functions are developed for the DR. These benefits are defined as functions of the DR quantities. Inclusion of these benefit function in the objective function of the DRX market along with their corresponding constraints reflects the TSO’s demand for the DR to mitigate wind-uncertainty costs. Therefore, the proposed DRX model can guarantee mitigation of the impacts of the wind power uncertainty. In this paper, the obtained results from the energy/reserve market are used to determine the benefit functions of the DR. The output variables of the energy/reserve market which will be employed in the proposed DRX market (Section 2.2) with the aim of determining the TSO’s demand for the DR are as follows:

- Scheduled up-, down-, and non-spinning reserves \( R_{i,t}^{up}, R_{i,t}^{dn} \) and \( p_{i,t}^{NS} \), \( \forall i, t \).
- Deployed up-, down-, and non-spinning reserves \( n_{i,t,w}^{up}, n_{i,t,w}^{dn} \) and \( p_{i,t,w}^{NS} \), \( \forall i, t, w \).
- Load shedding \( l_{j,t,w}^{sh} \), \( \forall j, t, w \).
- Wind power spillage \( S_{q,t,w} \), \( \forall q, t, w \).
- Market clearing prices \( h_{j,t,w} \), \( \forall j, t, w \).

2.2. Proposed DRX market framework

As mentioned earlier, the DRX market is run after clearing the energy/reserve market. Some of the power system technical/physical constraints, such as power balance equation that are satisfied in the energy/reserve market [30], are not included in the proposed model. The reason is that the scheduled variables used in these constraints may be substituted by the DR in the DRX market. Therefore, these constraints are not violated in the DRX market. For example, the power balance for any plausible wind power scenario are satisfied in the energy/reserve market stage by means of deploying the reserves of the conventional generators, load shedding and/or wind power spillage. In the DRX market stage, the deployed generation of the conventional units, load
shedding and/or wind power spillage may be substituted by the DR (upward/downward). According to the constraints of the proposed framework, these substitutions do not violate the energy balance constraint, satisfied in the previous stage (energy/reserve market).

Furthermore, in our proposed model the “obligatory contribution” constraint as proposed in the basic model of DRX market [22] is not considered. This constraint is included in the DRX model to force DR buyers to reveal their benefits from utilizing the DR, honestly. As mentioned earlier, the main purpose of this paper is to propose a framework for the DRX market considering its interactions with the existing energy/reserve markets. The proposed framework is aimed at mitigating the wind-uncertainty costs in the power system operation. To do this, the interactions between the DRX and energy/reserve market from the TSO’s point of view is investigated in this paper. To avoid the complexity of the formulation, and without loss of generality, other DR beneficiaries, i.e. retailers and distributors, are not considered in the proposed framework. Therefore, since only the TSO is considered as a buyer in this framework, there is no need to include the obligatory contribution in the proposed framework. However, it should be mentioned that this constraint and other DR buyers may be easily included in the framework (see [22]).

To model the uncertainty of the wind power generation, stochastic programming is used in the proposed DRX market framework. The time horizon is considered one day on an hourly basis. In this paper, both types of DR, i.e. demand curtailment and demand increment, are utilized. Moreover, the DR is considered as a virtual resource which can be utilized in power system operation. In other words, a DRP is modeled as a virtual unit. By decreasing the load of such units, DR is provided in the form of “upward” energy ramp. Therefore, in this paper the “demand curtailment” is defined as “upward DR”. Similarly, by increasing the load of such virtual units, the DR is provided in the form of “downward” energy ramp. Hence, “demand increase” is defined as “downward DR”.

2.2.1. Objective function

The objective function of the proposed framework for the DRX market represents the DR benefits minus the total payments to the DRPs. The DR benefits are proportional to the potential of the DR in reducing the effects of wind power uncertainty on the system operation (Section 2.1). The objective function to be maximized can be stated as follows:

\[ F = \sum_{t \in T} \sum_{j \in J} \left[ \sum_{s \in S} \left( \sum_{j \in J} \left( s_{RU,t}^{j} (K_{RU,t}^{j} - s_{RU,t}^{j}) + s_{RD,t}^{j} (K_{RD,t}^{j} - s_{RD,t}^{j}) + s_{RNS}^{j} (K_{RNS,t}^{j} - s_{RNS,t}^{j}) \right) \right) \right] 
+ \sum_{w \in W} \left( \sum_{t \in T} \sum_{j \in J} \left( d_{RU,t,w}^{j} - d_{RU,t,w}^{j} \right) \right) 
+ \sum_{w \in W} \left( \sum_{t \in T} \sum_{j \in J} \left( s_{RU,t}^{j} + s_{RD,t}^{j} + s_{RNS}^{j} \right) \right) 
- \sum_{t \in T} \left( \sum_{j \in J} \left( \sum_{s \in S} \left( p_{RU,t}^{j} (m_{j,t}^{U} - m_{j,t}^{U}) + p_{RD,t}^{j} (m_{j,t}^{D} - m_{j,t}^{D}) + p_{RNS,t}^{j} (m_{j,t}^{NS} - m_{j,t}^{NS}) \right) \right) \right) \]

The first line in (1) states the potential of the DR in reducing the spinning and non-spinning reserve costs. If demand-side provides upward/downward reserves, the costs of the TSO in covering reserve requirements of the power system from the conventional generators will be reduced. Decrease/increase in the demand will decrease/increase the operational costs to meet the change in the demand based on the uniform price of the energy. This fact is considered in the objective function (the second line in (1)). The third line of the objective function in (1) belongs to the DR benefits resulted from the reduction in the spillage, load shedding and start-up costs. These benefits will be elaborated in Section 2.2.3. On the other hand, payments to the DRPs are minimized by the last three lines in (1). These payments consist of two terms, including the availability payment and the expected payment to the DRPs for providing demand reduction (upward DR) and/or demand increment (downward DR) in the actual operation conditions.

2.2.2. Constraints

2.2.2.1. DR’s bid block limits. It is supposed that each aggregator, participating in the DRX market, submits its bids for providing upward and downward DR through non-decreasing step functions. The following equations are used to compute the supply functions for the DR offers of the aggregators.

\[ 0 \leq p_{DRU,t}^{j} (m) \leq p_{DRU,t}^{max} (m), \forall j, t \in T^{U} (j) \]
\[ d_{RU,t,w}^{j} = \sum_{m \in M} p_{DRU,t}^{j} (m), \forall j, t \in T^{U} (j), w \]
\[ 0 \leq p_{DRD,t}^{j} (m) \leq p_{DRD,t}^{max} (m), \forall j, t \in T^{D} (j) \]
\[ d_{RD,t,w}^{j} = \sum_{m \in M} p_{DRD,t}^{j} (m), \forall j, t \in T^{D} (j), w \]

2.2.2.2. Deployed DR limits. The deployed amounts of the upward and downward DR during time period t and scenario w must be smaller than or equal to the scheduled values during this period.

\[ 0 \leq d_{RU,t,w}^{j} - s_{RU,t}^{j}, \forall j, t \in T^{U} (j), w \]
\[ 0 \leq d_{RD,t,w}^{j} - s_{RD,t}^{j}, \forall j, t \in T^{D} (j), w \]

2.2.2.3. Provided DR limits. The scheduled DR in period t must be smaller than or equal to the maximum value of the DR offered by aggregator j.

\[ s_{RU,t}^{j} \leq D_{RU,t}^{max} (j), \forall j, t \in T^{U} (j) \]
\[ s_{RD,t}^{j} \leq D_{RD,t}^{max} (j), \forall j, t \in T^{D} (j) \]

2.2.2.4. Constraints associated with DR potential in reduction of reserve costs. Upward DR has the potential of reducing the upward reserve scheduled for the conventional generating units. Similarly, downward DR will reduce the costs associated with the downward reserve. The following equations together with the first line of the objective function (1) model the potential of DR in reducing the costs of energy reserve. Note that \( s_{RU,t}^{j} \), \( s_{RD,t}^{j} \) and \( s_{RNS,t}^{j} \) indicate auxiliary positive variables employed for computing the amount of up-, down-, and non-spinning reserves replaced by the DR, respectively.

\[ s_{RU,t}^{j} \leq K_{RU,t}^{j} \leq d_{RU,t,w}^{j}, \forall i, t, w \]
\[ s_{RD,t}^{j} \leq K_{RD,t}^{j} \leq d_{RD,t,w}^{j}, \forall i, t, w \]
\[ s_{RNS,t}^{j} \leq K_{RNS,t}^{j} \leq d_{RNS,t,w}^{j}, \forall i, t, w \]
2.2.2.5. Load recovery constraint. In this paper, it is assumed that the demand-side can provide both the upward and downward reserves. The use of DR for providing both types of the reserves, i.e. upward and downward, has also been studied in the literature, e.g. in [19,30]. In these researches, the DR is scheduled in the energy/reserve market for providing upward and downward reserves. However, there are two obstacles to the applicability of these models. First, in [19,30], it has been assumed that the demand-side can provide upward or downward reserve in all time periods. Due to the technical and social constraints of the consumers, the aggregators may not be able to alter their consumption at all time periods. Second, the inter-temporal characteristics of the demand have not been taken into account in [19,30]. For a consumer providing DR, the demand curtailment may be subject to load recovery and the demand increase may be followed by the demand curtailment. To overcome these shortcomings practically, in this paper it is assumed that an aggregator participating in the DRX market, has to offer the time periods that he/she is willing to provide the upward and downward DR (TU(j) and TD(j), respectively). Moreover, to model the inter-temporal characteristics of the upward and downward DRs, a load recovery coefficient (σj) is defined for each aggregator. Using these offering terms, the aggregator allows the TSO to decide on aggregator’s load reduction in TU(j) and compensate this reduction in some other periods (TD(j)). In return to this allowance for load displacement, payment will be made to the aggregator.

As mentioned earlier, one of the objectives of this paper is to investigate the demand-side potential for providing both types of the reserves, i.e. upward and downward reserves. Therefore, to better investigate this potential application of the DR, the deferrable loads are studied in this paper. There are many types of flexible consumption characterized as deferrable, referring to those consumers who need a certain amount of energy within a certain time window [18]. Under the smart grid paradigm, the aggregated deferrable loads can be scheduled to be curtailed and recovered during their offered time periods, i.e. TU(j) and TD(j), respectively. Electric vehicle charging, thermal storage, agricultural pumping, pre-cooling, and residential consumption, such as laundry, are examples of the deferrable demand. From the view point of the TSO, deferrable demand behaves much like a hydro or storage resource. The benefits of the deferrable loads in mitigating the uncertainty costs of the renewable energies in the power system operation have been addressed in the literature (e.g. [18,31]).

The effects of the load recovery are modeled by the following constraints,

\[
\sum_{t \in \text{TD}(j)} \sum_{w \in W} \pi_{w} d_{j,t,w}^{U} \geq \sigma_{j} \sum_{t \in \text{TU}(j)} \sum_{w \in W} \pi_{w} d_{j,t,w}^{U}, \quad \forall j
\]  

Eq. (13) indicates that the expected load recovery (downward DR) of aggregator j during the scheduling horizon must be at least \(\sigma_{j}\) percent of the aggregator’s expected load reduction (upward DR). The downward DR is required during periods when downward reserve is scheduled and/or wind power spillage occurs. The amount of the deployed downward DR in each time period should not be greater than the sum of the total deployed downward reserve and wind power spillage. Otherwise, additional upward reserve will be required for the demand increase in such conditions. This fact is modeled in (14) as follows:

\[
\sum_{j \in J} d_{j,t,w}^{U} \leq \sum_{j \in J} d_{j,t,w}^{NS} + \sum_{q \in Q} S_{q,t,w}, \quad \forall w, t \in \text{TU}(j)
\]

2.2.2.6. Computation of the benefits obtained through replacement of start-up cost by DR. If the total demand reduction due to the DR in period t and scenario w, where unit i is scheduled to be started, is lower than the scheduled generation of unit i (i.e. \(d_{i,t,w}^{NS} < R_{i,t,w}^{NS}\)), then the start-up of this unit cannot be prevented by the demand reduction (\(su_{i,t,w}^{B} = 0\)). Otherwise, if \(d_{i,t,w}^{NS} \geq R_{i,t,w}^{NS}\), then the expected benefit from the replacement of the start-up cost of unit i by DR in period t and scenario w is calculated from the product of the probability of scenario w and start-up cost of unit i.

\[
SU_{i,t,w}^{B} = \begin{cases} 
0; & d_{i,t,w}^{NS} < R_{i,t,w}^{NS} \\
\pi_{w} C_{SU}^{i} d_{i,t,w}^{NS} & d_{i,t,w}^{NS} \geq R_{i,t,w}^{NS} 
\end{cases}
\]

2.2.2.7. Computation of the benefits obtained by reduction in load shedding due to DR. Wind power volatility together with the technical limits of the conventional generators may cause involuntary load shedding in the actual operation conditions. In such circumstances, the TSO employs the available contracts with the aggregators in the DRX market to avoid load shedding. The benefit gained from reducing the involuntary load shedding by the DR can be defined as follows:

\[
l_{j,t,w}^{SU} = \pi_{w} V_{j,t,w}^{SU} d_{j,t,w}^{U}, \quad \text{for } \{(j, t, w)|l_{j,t,w}^{SU} \neq 0\}
\]

2.2.2.8. Computation of the benefits obtained by reduction of wind power generation spillage due to DR. DR can help the TSO avoid the unwanted wind power spillage in actual operation conditions. Technical constraints of the generators such as; ramp rate limits, minimum production limits, etc., may result in wind power spillage. As mentioned earlier, consumers who participate in the DRX market would like to compensate the called reduction in their demands during other time periods. If this demand reduction is compensated during the periods when the TSO has to spill the generation of the wind power, occurred due to the inadequate downward reserve, then the TSO can benefit from the downward DR for lowering the wind power spillage and increase utilization of the wind power in operation of the power system. Therefore, the benefit of DR for reducing the wind power spillage can be stated as:

\[
s_{q,t,w}^{SU} = \pi_{w} V_{q,t,w}^{SU} d_{q,t,w}^{U}, \quad \text{for } \{(q, t, w)|s_{q,t,w}^{SU} \neq 0\}
\]

where; \(V_{q}^{SU}\) refers to the average benefit obtained by decreasing the total operation cost of the system when one MWh of wind power is injected by producer q. While one MWh injection of wind power into the power system results in reducing the expected operation cost, but the associated uncertainty costs will be increased. Therefore, \(V_{q}^{SU}\) is equal to the average benefit minus the average uncertainty cost caused by the injection of an additional MWh of the wind power produced by producer q [30].

2.2.2.9. DRX market equilibria. The following equations ensure the balancing of the supply and demand for the upward and downward DRs. The demand for the upward DR, determined according to the willingness of the TSO for reducing the cost of upward reserves in (10) and (12), and load shedding in (16), must be supplied by the aggregators:

\[
\sum_{i} (d_{i,t,w}^{U} + d_{i,t,w}^{NS}) + \sum_{j} d_{j,t,w}^{U} = \sum_{j} (d_{j,t,w}^{U} - d_{j,t,w}), \quad \forall t \in J, j
\]  

It should be noted that in the periods when upward DR is required, some aggregators may recover their previous load reductions
Table 1

Data of GenCos.

<table>
<thead>
<tr>
<th>GenCo</th>
<th>Unit (i)</th>
<th>(P_{\text{max}}^{\text{G}}) (MW)</th>
<th>(P_{\text{max}}^{\text{d}}) (MW)</th>
<th>Marginal cost ($/MWh)</th>
<th>(R_{i,t,w}^{G_{\text{max}}} = R_{i,t,w}^{G_{\text{max}}}) (MW/h)</th>
<th>(R_{i,t,w}^{\text{DRX}<em>{\text{max}}} = R</em>{i,t,w}^{\text{DRX}_{\text{max}}}) (MW/h)</th>
<th>(\epsilon_{i,t,w}^{G_{\text{max}}} = \epsilon_{i,t,w}^{G_{\text{max}}}) ($/MWh)</th>
<th>(\epsilon_{i,t,w}^{\text{DRX}<em>{\text{max}}} = \epsilon</em>{i,t,w}^{\text{DRX}_{\text{max}}}) ($/MWh)</th>
<th>Start-up cost ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>50</td>
<td>50</td>
<td>30</td>
<td>45</td>
<td>50</td>
<td>8</td>
<td>7</td>
<td>200</td>
</tr>
<tr>
<td>2</td>
<td>2</td>
<td>25</td>
<td>25</td>
<td>60</td>
<td>20</td>
<td>25</td>
<td>7</td>
<td>6</td>
<td>200</td>
</tr>
<tr>
<td>3</td>
<td>3</td>
<td>25</td>
<td>25</td>
<td>70</td>
<td>20</td>
<td>25</td>
<td>7</td>
<td>6</td>
<td>200</td>
</tr>
<tr>
<td>4</td>
<td>4</td>
<td>25</td>
<td>25</td>
<td>80</td>
<td>20</td>
<td>25</td>
<td>7</td>
<td>6</td>
<td>200</td>
</tr>
<tr>
<td>5</td>
<td>5</td>
<td>50</td>
<td>10</td>
<td>45</td>
<td>10</td>
<td>50</td>
<td>10</td>
<td>8</td>
<td>300</td>
</tr>
</tbody>
</table>

\(d_{j,t,w}^{p}\). To take this effect into account, the downward DR is subtracted from the upward DR in \((20)\).

Similarly, the downward DR for the downward DR, determined based on the willingness of the TSO for reducing the cost of downward reserve in \((11)\) and wind spillage in \((18)\), must be supplied by the aggregators:

\[
\sum_{i} d_{i,t,w}^{p} + \sum_{q} d_{q,t,w}^{s} = \sum_{j} (d_{j,t,w}^{u} - d_{j,t,w}^{u}) , \quad \forall t, w (21)
\]

2.2.2 Transmission capacity constraints. Transmission capacity limits are modeled by:

\[
-f_{l,t,w}^{j_{\text{max}}} \leq f_{l,t,w}^{j} + \sum_{n} a_{l,n} \sum_{i,j,n \in A} (d_{j,t,w}^{u} - d_{j,t,w}^{u}) \leq f_{l,t,w}^{j_{\text{max}}} , \quad \forall l, t, w (22)
\]

where \(a_{l,n}\), referred to as the generation shift factor, represents the sensitivity of the flow of line \(l\) with respect to changes in the power injection at bus \(n\) \([32]\). \(f_{l,t,w}^{j}\) is the flow of line \(l\) in time period \(t\) and scenario \(w\) after clearing the energy/reserve market and \(f_{l,t,w}^{j_{\text{max}}}\) is the maximum capacity of line \(l\). The term \(\sum_{i,j,n \in A} (d_{j,t,w}^{u} - d_{j,t,w}^{u})\) in \((22)\) represents the change in power injection at bus \(n\) due to the DR. The set \(A\) is the mapping of the set of aggregators \((j)\) into the set of buses \((n)\).

3. Small-scale study

To illustrate the effectiveness of the proposed framework for DRX market, it has been applied to a simple six-bus test system, shown in Fig. 1. The test system includes three generation companies (GenCos) and two aggregators. The data of GenCos are presented in Table 1.

It is assumed that each aggregator can submit two non-decreasing step functions for its upward and downward DR marginal cost to the DRX market. With its offer, the aggregator states how much DR it is willing to provide at each price. The capacity of the offered blocks is 1 MW. The offered step function of the upward DR marginal cost for aggregators 1 and 2 starts from 10 and 20 $/MWh, respectively, with 1 $/MWh increment. Similarly, the offered step function of the downward DR marginal cost for aggregators 1 and 2 starts from 2 and 4 $/MWh, respectively, with 1 $/MWh increment. It should be noted that the offering price for the upward DR \((\gamma_{l,t,w}^{G_{\text{up}}}\)) is equal to the sum of the energy price and aggregators’ marginal cost for providing the upward DR. The availability price offer for upward and downward DRs are assumed to be 25 $/MWh and 1 $/MWh for aggregator 1 and 4 $/MWh and 2 $/MWh for aggregator 2. Maximum participation of each aggregator in the DRX market is assumed 10% of its hourly demand. The load recovery coefficient \((\sigma_{l})\) is assumed 0.6.

The wind plant (WP) is located on bus 5, as illustrated in Fig. 1. For the sake of simplicity, only three scenarios are considered for wind power realization in each time period, including predicted (pre), high and low with the probabilities of 0.6, 0.2 and 0.2, respectively \([30]\). Furthermore, the time horizon (24 h in this study) is divided into four periods, which can involve any of the three aforementioned wind power realization scenarios. Table 2 shows the wind power scenarios for these periods.

Three different cases are considered to assess effectiveness of the proposed DRX market framework, including:

- Case 1: base case with normal operation condition
- Case 2: loss of a large generator
- Case 3: large wind power variation

All of these cases are simulated using CPLEX 10.1.1 in GAMS \([33]\).

3.1 Case 1: base case with normal operation condition

Simulation results for some plausible scenarios of this case indicate the volatility of the wind power leads to the unwanted startups, additional spinning/non-spinning reserve and deviation in the generation of the units from their scheduled quantities. No load shedding and wind power spillage are required in the normal operation condition. Table 3 shows the results of the energy/reserve market for hour 13. As observed in this table, for unit 1 an amount of 1.5 MW spinning reserve and for unit 2 an amount of 9.5 MW non-spinning reserve is scheduled in the energy/reserve market during 13th hour. As a result, to reduce the reserve and start-up costs in this hour, it is useful for the TSO to call upward DR.

Table 2

Wind power scenarios.

<table>
<thead>
<tr>
<th>Period</th>
<th>Hours</th>
<th>Wind power output (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Pre.</td>
</tr>
<tr>
<td>1</td>
<td>1–6</td>
<td>8</td>
</tr>
<tr>
<td>2</td>
<td>7–12</td>
<td>6</td>
</tr>
<tr>
<td>3</td>
<td>13–18</td>
<td>36</td>
</tr>
<tr>
<td>4</td>
<td>19–24</td>
<td>20</td>
</tr>
</tbody>
</table>
Table 3
Results of energy/reserve market in hour 13 in case 1.

<table>
<thead>
<tr>
<th>i</th>
<th>Scheduled output (MW)</th>
<th>Output in real-time operation conditions (MW)</th>
<th>$R_{i,t}^{U/p}$</th>
<th>$R_{i,t}^{D/p}$</th>
<th>$R_{i,t}^{E/p}$</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Pre.</td>
<td>Low</td>
<td>High</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>48.5</td>
<td>48.5</td>
<td>50</td>
<td>49.5</td>
<td>1.5</td>
</tr>
<tr>
<td>2</td>
<td>0</td>
<td>5</td>
<td>9.5</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>3</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>4</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>5</td>
<td>50</td>
<td>50</td>
<td>50</td>
<td>50</td>
<td>0</td>
</tr>
<tr>
<td>WP</td>
<td>41</td>
<td>36</td>
<td>30</td>
<td>40</td>
<td>–</td>
</tr>
</tbody>
</table>

Fig. 2. DRX market results in real-time operation conditions in case 1.

Fig. 2 shows the DRX market results, including the level of deployed DR and market clearing price for the upward and downward DRs in three considered scenarios of the wind power. As seen in this figure, the upward and downward DRs are deployed during peak and off-peak hours, respectively. This is consistent with the demand-side management objectives. Furthermore, because of low wind power, the highest amount of upward DR is deployed in scenario low while no downward DR is deployed in this scenario. On the other hand, the majority of the load is recovered during the off-peak hours in scenario high. Table 4 reports the detailed results of the DRX market at hours 13 and 23. While the energy price at hour 13 is $30/MWh, the clearing price of the upward DR in scenario low is $50/MWh. This means that the TSO repurchases 10 MW of the demand from the aggregators in the DRX market at a higher price. This happens since in this situation the DR is replaced by the high cost required for the upward reserve and start-up of units 1 and 2 (Table 3). The benefits of demand reduction in scenario low during hour 13 are gained from the reduction of spinning reserve cost for unit 1, which is equal to 0.5 × 8 = 4$, reduction of non-spinning reserve cost of unit 2, which is equal to 9.5 × 6 = 57$ and finally elimination of the expected start-up cost of unit 2, which is equal to 200 × 0.2 = 40$. The clearing price of the downward DR during the 23rd hour of the scenario high is equal to 8$/MWh. The SO will pay to the aggregators if they compensate their demand reductions in this period. This is due to the high wind power and the need for the downward reserve in this situation. The benefit from the demand increase in this hour is gained due to the reduction in the cost of the downward reserve for unit 1, which is equal to 8 × 9.45 = 75.6$.

Table 4 shows total benefits obtained from the proposed framework for DRX market in case 1. Simulations indicate that use of the DRX and energy/reserve markets lowers the upward (spinning and non-spinning) and downward reserve requirements up to 67.62 and 39.54 percent, respectively. Fig. 3 illustrates the scheduled

<table>
<thead>
<tr>
<th>Hour (h)</th>
<th>Scenario</th>
<th>Reserve requirements (MWh)</th>
<th>Deployed DR (MWh)</th>
<th>DR benefit in reserve reduction ($)</th>
<th>$\text{su}_{i,t,\text{DR}}$</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Up</td>
<td>Down</td>
<td>N.S.</td>
<td>Up</td>
</tr>
<tr>
<td>13</td>
<td>Pre.</td>
<td>0</td>
<td>0</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td>Low</td>
<td>1.5</td>
<td>0</td>
<td>9.5</td>
<td>10</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>23</td>
<td>Pre.</td>
<td>0</td>
<td>8</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Low</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>0</td>
<td>18</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>
Table 5
Total benefits of DR in case 1.

<table>
<thead>
<tr>
<th>Reserves before DRX (MWh)</th>
<th>Reserves after DRX (MWh)</th>
<th>$\eta_{DRX}$</th>
<th>Change in the costs of meeting load ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Upward spinning reserve</td>
<td>Downward spinning reserve</td>
<td>Non-spinning reserve</td>
</tr>
<tr>
<td>Scenario pre.</td>
<td>0</td>
<td>40</td>
<td>38</td>
</tr>
<tr>
<td>Scenario low</td>
<td>34</td>
<td>2</td>
<td>84</td>
</tr>
<tr>
<td>Scenario high</td>
<td>1</td>
<td>134.5</td>
<td>5</td>
</tr>
<tr>
<td>Scheduled reserve</td>
<td>34</td>
<td>136.5</td>
<td>84</td>
</tr>
<tr>
<td>Total reduction (%)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total benefits ($)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 6
Payments to aggregators for providing DR in case 1.

<table>
<thead>
<tr>
<th>Availability payment ($)</th>
<th>Payments for deploying DR ($)</th>
<th>Pre</th>
<th>Low</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Agg. 1</td>
<td>Up</td>
<td>131.80</td>
<td>1836.00</td>
<td>3678.90</td>
</tr>
<tr>
<td></td>
<td>Down</td>
<td>69.00</td>
<td>43.12</td>
<td>0</td>
</tr>
<tr>
<td>Agg. 2</td>
<td>Up</td>
<td>55.60</td>
<td>100.00</td>
<td>803.00</td>
</tr>
<tr>
<td></td>
<td>Down</td>
<td>23.94</td>
<td>0.62</td>
<td>0</td>
</tr>
<tr>
<td>Total ($)</td>
<td></td>
<td>280.34</td>
<td>2249.64</td>
<td></td>
</tr>
</tbody>
</table>

reserve of the system before and after running the DRX market. On the other hand, by participation in the DRX market the aggregators will have access to an additional resource (i.e. DR) by which they may maximize their benefits. Table 6 shows the income of the aggregators through participating in the DRX market in case 1.

### 3.2. Case 2: loss of a large generator

In this case, the outage of a large generator is investigated (unit 5 at bus 6 in our test system). For this case, the decrease in system reserve leads to the load shedding in some scenarios of wind generation. Table 7 shows the results of the energy/reserve market during hour 19 where 13 MW of load shedding occurs in scenario low. In this situation the value of lost load (VOLL) is 1000 $/\text{MWh}$. To avoid load shedding in this situation, the TSO may contract to the aggregators for supplying upward DR. In hour 19, due to the high cost of load loss, 10 and 3 MW upward DR is procured from the aggregators 1 and 2 in the DRX market, respectively. High bid price of the aggregator 2 for upward DR and energy price at this hour (80 $/\text{MWh}) increase the price of upward DR up to 102 $/\text{MWh}$. However, even at this high price of the DR the TSO is willing to pay for the DR during hour 19 in scenario low to avoid the higher cost of the expected VOLL (1000 × 0.2 = 200 $/\text{MWh})

3.3. Case 3: large wind power variation

In a power system with high wind power integration, large variation of the intermittent resource will need adequate ramp rate of the conventional generators. Otherwise, wind power generation spillage or load shedding might be required. To investigate this issue, it is assumed that during the first period the wind power experiences a wide range of variations. The maximum wind power generation for scenario high during period 1 is assumed as 26 MW. Moreover, the ramp rate of unit 1 is limited to 6 MW/h. In this situation, 8 MW of the wind power is curtailed during some hours of this period.

The benefit obtained by one MW injection of the wind power at bus 5 (V_W) is equal to 38.1 $/\text{MWh}$. Therefore, if the load reduction is compensated during period 1, when the wind power has to be spilled, the system will benefit from the utilization of the wind power. In such a circumstance, the proposed framework for DRX market will help the TSO to contract with the aggregators who wish to compensate their load reductions in periods called by the TSO. In this case the expected benefit gained from reducing the wind power spillage by employing the DR is 137.16 $.

4. IEEE RTS study

In this section, the proposed DRX market framework is tested over a 24-h horizon on the IEEE Reliability Test System [34]. This system contains 32 generating units and 17 load buses. The data for the generators and loads have been extracted from [35]. It is assumed that the nuclear and hydro units are must-run generators. The generating units submit their generation offers, which include four incremental cost/power blocks as reported in [34]. It is assumed that all the generating units offer to provide spinning and non-spinning reserves at the rate of 25 and 20% of their highest marginal cost of energy production, respectively [30]. Furthermore, it is assumed that a wind farm with the installed capacity of 20% of the peak load is installed on Bus 20. The data for wind power generation are extracted from [36].

The load profile has been extracted from [34], corresponding to a Monday of a winter weekday with a peak load of 2850 MW. The bus loads which are greater than 60% of the total system load

Table 7
Results of energy/reserve market in hour 19 in case 2.

<table>
<thead>
<tr>
<th>i</th>
<th>Scheduled output (MW)</th>
<th>Output in real-time operation conditions (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Pre</td>
<td>Low</td>
</tr>
<tr>
<td>1</td>
<td>50</td>
<td>50</td>
</tr>
<tr>
<td>2</td>
<td>25</td>
<td>25</td>
</tr>
<tr>
<td>3</td>
<td>25</td>
<td>25</td>
</tr>
<tr>
<td>4</td>
<td>24</td>
<td>25</td>
</tr>
<tr>
<td>5</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>WP</td>
<td>30</td>
<td>20</td>
</tr>
<tr>
<td></td>
<td>Load shedding</td>
<td>5</td>
</tr>
</tbody>
</table>
Table 8
Results of implementing the proposed DRX market on IEEE RTS.

<table>
<thead>
<tr>
<th>DR participation (%)</th>
<th>Objective function ($)</th>
<th>Reserve reduction ($)</th>
<th>Startup reduction ($)</th>
<th>Load shedding reduction ($)</th>
<th>Load meeting reduction ($)</th>
<th>DR cost ($)</th>
<th>OCR (%)</th>
<th>OCR (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>3231.51</td>
<td>705.21</td>
<td>364.78</td>
<td>3000</td>
<td>583.15</td>
<td>1421.62</td>
<td>12.65</td>
<td>8.8</td>
</tr>
<tr>
<td>5</td>
<td>3478.40</td>
<td>1346.72</td>
<td>740.37</td>
<td>3000</td>
<td>1113.02</td>
<td>2721.71</td>
<td>16.85</td>
<td>9.5</td>
</tr>
<tr>
<td>10</td>
<td>3780.88</td>
<td>3100.83</td>
<td>1651.40</td>
<td>3000</td>
<td>2012.54</td>
<td>5983.89</td>
<td>26.54</td>
<td>10.3</td>
</tr>
</tbody>
</table>

are considered as the DRPs. The availability price for the upward and downward DRs are assumed 4 and 2 $/MWh for all the DRPs, respectively. The aggregators submit their offers, composed of four incremental cost/power blocks, to provide DR. The marginal costs of these aggregators’ for the upward and downward DRs start from 5 and 3 $/MWh, respectively, with 1 $/MWh increment. The load recovery coefficient is assumed 0.6. The value of lost load is considered 3000 $/MWh.

Similar to the small-scale study, the energy/reserve and DRX market problems in this case were solved using the mixed-integer linear programming solver CPLEX 10.1.1 under GAMS [33]. Table 8 reports the results of implementing the proposed DRX market framework on the IEEE RTS for three different DR participation levels. These results include the objective function (1) and its subitems, including the DR cost and the DR benefits corresponding to reducing the cost of reserve, startup, load shedding and load meeting. Furthermore, the contribution of the DR to the uncertainty cost reduction (UCR) and the reduction in operational cost using the proposed method (OCR) is reported in Table 8. The wind-uncertainty cost, composed of the cost of scheduling reserves and the expected cost of deploying reserve, startups, load shedding and wind power spillage in the energy/reserve market, is obtained 36,786 $. As shown in Table 8, 12.65% of the wind-uncertainty cost can be substituted by utilizing 2% of DR participation in this case study. The UCR reaches up to 26% for the DR participation level of 10%. The DR benefit in reducing reserve, startup and load meeting costs is increased by increasing the DR participation level. However, since the amount of load shedding scheduled in the energy/reserve market is much lower than 2% of the load, the DR benefit in reducing the load shedding is obtained 3000 $. for the three participation levels. The variation in the DR cost with the DR participation level is due to the increase in the deployed DR in higher participation levels. The OCR is also increased by increase in the DR participation. However, as seen in Table 8, no significant increase occurs in the OCR due to the increase in the DR participation level from 5% to 10%. The reason is that the price of the DR increases when the provided DR increases.

4.1. Impact of DR prices

As mentioned earlier, in this paper two terms are considered for the DR cost including availability and deploying costs [28]. To investigate the impact of the DR prices on the results of the proposed DRX market framework, the first step of the aggregators’ marginal costs is changed from 0 to 20 $/MWh in the following cases:

- Case 1: It is assumed that upward and downward DR availability costs are 2 and 1 $/MWh, respectively.
- Case 2: It is assumed that upward and downward DR availability costs are 4 and 2 $/MWh, respectively.
- Case 3: It is assumed that upward and downward DR availability costs are 8 and 4 $/MWh, respectively.

Fig. 4 illustrates the impact of changing the DR prices (availability and deploying) on the objective function of the proposed framework (1) and OCR. The OCR is calculated by dividing the objective function (1) by the wind-uncertainty cost. As shown in this figure, the OCR decreases from 15 to 8% by increasing the DR marginal cost from 0 to 20 $/MWh (from case 1 to 3). Please note that the deploying price of the upward DR is equal to the sum of the energy price and the aggregators’ marginal cost for providing the upward DR. Furthermore, it is found that the price is more sensitive to the DR availability than the deploying cost. It should be noted that because of the potential of DR for mitigating the high cost of the load shedding, the DR is traded in the DRX market even if the deploying price of the DR is increased up to VOLL.

4.2. Impact of wind power penetration level

Increase in the wind power penetration level worsens its undesirable effects on the power system operation. The proposed DRX market framework is aimed at mitigating wind the power uncertainty effects. Therefore, the wind power penetration level may influence the DRX market clearing results. To investigate this fact, the proposed DRX market is run for three levels of the installed wind power capacity, including 10, 20 and 30% of the peak load. Table 9 shows the DRX market results for these states. As seen, the deployment of DR in the DRX market increases when the wind power participation level increases. Consequently, the contributions of the proposed framework to mitigation of the wind-uncertainty costs increase in the power systems with higher wind power penetration levels. This analysis is conducted for the DR penetration level of 5%.

4.3. Comparison with the basic DRX model

To show the advantage of our proposed model, it is compared with the basic DRX market model [22]. For the sake of simplicity, the comparison is carried out for a single time period (hour 19). As mentioned earlier, it is assumed in [22] that the TSO, as a buyer, offers for purchasing DR through a simple demand function. Therefore, to incorporate in the DRX model in [22], the TSO must estimate its benefit function based on its experience. To carry out the comparison, two different benefit functions are considered for the TSO, including overestimated TSO benefit and underestimated TSO benefit. Fig. 5 shows the aggregated DR supply function (marginal cost function + energy price) and the assumed marginal benefit functions for the TSO (B1 and B2) at hour 19. Using the proposed DRX market framework, the TSO’s demand for the DR at this hour is calculated. Fig. 5 shows the impact of the DR prices (availability and deploying) on the objective function of the proposed framework (1) and OCR. The OCR is calculated by dividing the objective function (1) by the wind-uncertainty cost. As shown in Table 8, the OCR reaches up to 26% for the DR participation level of 10%. The DR benefit in reducing reserve, startup and load meeting costs is increased by increasing the DR participation level. However, since the amount of load shedding scheduled in the energy/reserve market is much lower than 2% of the load, the DR benefit in reducing the load shedding is obtained 3000 $ for the three participation levels. The variation in the DR cost with the DR participation level is due to the increase in the deployed DR in higher participation levels. The OCR is also increased by increase in the DR participation. However, as seen in Table 8, no significant increase occurs in the OCR due to the increase in the DR participation level from 5% to 10%. The reason is that the price of the DR increases when the provided DR increases.

4.1. Impact of DR prices

As mentioned earlier, in this paper two terms are considered for the DR cost including availability and deploying costs [28]. To investigate the impact of the DR prices on the results of the proposed DRX market framework, the first step of the aggregators’ marginal costs is changed from 0 to 20 $/MWh in the following cases:

- Case 1: It is assumed that upward and downward DR availability costs are 2 and 1 $/MWh, respectively.
- Case 2: It is assumed that upward and downward DR availability costs are 4 and 2 $/MWh, respectively.
- Case 3: It is assumed that upward and downward DR availability costs are 8 and 4 $/MWh, respectively.

Fig. 4 illustrates the impact of changing the DR prices (availability and deploying) on the objective function of the proposed framework (1) and OCR. The OCR is calculated by dividing the objective function (1) by the wind-uncertainty cost. As shown in
Table 9
DRX market results for different wind power penetrations levels.

<table>
<thead>
<tr>
<th>Wind power penetration (%)</th>
<th>Total upward DR (MWh)</th>
<th>Total downward DR (MWh)</th>
<th>Objective function ($)</th>
<th>OCR (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>79.85</td>
<td>55.53</td>
<td>987.8</td>
<td>7.2</td>
</tr>
<tr>
<td>20</td>
<td>153.33</td>
<td>118.0</td>
<td>3478.40</td>
<td>9.5</td>
</tr>
<tr>
<td>30</td>
<td>501.25</td>
<td>299.61</td>
<td>13,570.5</td>
<td>20.5</td>
</tr>
</tbody>
</table>

Table 10
Comparison of the proposed model with the basic DRX model.

<table>
<thead>
<tr>
<th></th>
<th>Cleared DR (MW)</th>
<th>TSO benefit ($)</th>
<th>DR cost ($)</th>
<th>Market outcome ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proposed model</td>
<td>68.95</td>
<td>1119.97</td>
<td>844.71</td>
<td>275.26</td>
</tr>
<tr>
<td>Basic DRX model</td>
<td>B1 = 90</td>
<td>1188.29</td>
<td>980.94</td>
<td>207.35</td>
</tr>
<tr>
<td></td>
<td>B2 = 50</td>
<td>590.50</td>
<td>606.97</td>
<td>−16.47</td>
</tr>
</tbody>
</table>

Fig. 5. DRX market clearing at hour 19.

hour is 68.95 MW and the cleared DR price is 27.66 $/MWh (point $p_0$ in Fig. 5). On the other hand, in the basic DRX model, if the TSO overestimate its benefit and offers $B_1$ into the DRX market, 90 MW of the DR is cleared at the price of 27.66 $/MWh (point $p_1$ in Fig. 5). Similarly, if the TSO benefit is underestimated and $B_2$ is offered into the DRX market, the 50 MW of the DR is cleared at the price of 26.66 $/MWh (point $p_2$ in Fig. 5).

To compare the abovementioned market clearing points, the real benefit of the TSO for each of the equilibrium points is calculated. In order to calculate the real benefit of the TSO obtained from utilizing the DR, the DRX market clearing results (DR quantity and price) are used in the energy/reserve market model in [30]. The real benefit of the TSO is equal to the difference between the operation costs with and without utilizing the DR. Table 10 reports the TSO’s benefit and the DR cost for each of the DRX market equilibrium points. In the case that the TSO benefit is overestimated, the cleared DR price is same as the one obtained by the proposed model. However, the DR quantity in this case is about 20 MW greater than the DR quantity obtained in the proposed model. As seen in Table 10, in the proposed model the market outcome, i.e. TSO benefit minus the DR cost, is greater than the market outcome obtained from the basic DRX market in the case that $B_1$ is offered by the TSO. This means that the proposed model leads to a better market outcome. The importance of the estimation of the TSO benefit is more visible in case that it is underestimated. While the DR price in this case is lower than the cleared price in our proposed model, but the TSO benefit from the DR quantity of 50 MW is lower than the corresponding DR cost. Hence, the market outcome is negative in this case. In other words, in such situations while the TSO pay for the DR, but it may not be deployed in the system operation.

5. Conclusions

Demand response exchange (DRX) market is a separate market in which DR is treated as a virtual resource to be exchanged between DR buyers and sellers. The major advantage of the DRX market in comparison to other DR proposals is that it allocates benefits and payments across all participants, fairly. However, there are still obstacles to its integration into the existing power markets. In this paper, a new framework was proposed for the DRX market considering its interactions with the energy/reserve market. Using the proposed DRX market framework, transmission system operator (TSO) will enjoy DR’s benefits of mitigating the uncertainty costs of wind power generation.

The proposed framework for DRX market was implemented on a six-bus test system and IEEE RTS. The simulation results demonstrated the capabilities and benefits of the proposed DRX market framework from the TSO’s and demand-side’s points of view. With a proper contracting and market settlement framework as proposed in this paper, the DRX market would be an effective option to mitigate the wind-uncertainty costs in power systems operations.

References

[33] ILOG CPLEX, ILOG CPLEX Homepage 2009 (Online). Available at: http://www.ilog.com/