A Dynamic Penalty Cost Allocation Based Uncertain Wind Energy Scheduling in Smart Grid

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Abstract- The intermittent nature of wind energy conversion presents a risk to the Independent System Operator (ISO) in a real time electricity market. Consequently, there is a need to appropriately incorporate this risk in the wind energy scheduling paradigm. In the present work, the intermittency associated risk has been modelled as part of a cost optimization problem for the ISO in real time. A model to minimize the risk has also been proposed using various cost models that use dynamic risk aversion costs and reflect the market and system operating conditions. The two dynamic penalty cost/risk models included are, rescheduling cost and contractual compensation cost for wind energy deviation. The results obtained are compared with those from the deterministic model. The proposed approach is simulated on the IEEE 30 bus system and the findings from the proposed approach for wind energy scheduling lead to a low operational cost to the ISO in the real time market considered in the study. Among other observations, the consideration of uncertainty in Day-Ahead market leads to increase in cost savings of ISO with increase in wind uncertainty, but a corresponding reduction in the scheduled wind energy in the same market.

Keywords Day ahead market; real time market; wind energy; independent system operator; market clearing price; spot market price.

1. Introduction

In the present scenario, environmental pollution is a major problem associated with non-judicious utilization of fossilized energy sources. Such conventional sources are getting degraded day by day and the associated fuel prices are also increasing gradually. Renewable sources of energy play a dominant role in the electricity market to minimize these effects. Out of all renewable sources, wind energy is emerging as a force to reckon due to its abundant availability and ability to provide rated output in regions of potential. However the main disadvantage associated with wind energy is its variable nature. In some countries, wind energy is traded in both Day-Ahead (DA) and Real Time (RT) markets. Due to the variability of wind energy, the wind electric system may not produce the same power in real time as it might have traded in the DA market. In such a case, the Independent System Operator (ISO) who operates all these transactions has to procure the balance of power in real time. The spinning reserves can supply the unbalanced power in real time.

Sometimes the RT market price is more than DA market price. At this time, the ISO has to pay the extra cost, in real time, and this variability-induced risk is borne by the ISO. On this issue, some studies have been considering the uncertain-wind availability factor. An economic dispatch model considering both the wind and thermal generators developed in [1] considered wind uncertainty as a constraint. A two-stage stochastic programming approach for the development of optimal offering strategies for wind power producers was developed in [2]. Reference [3] presents a mixed integer programming model for power generation scheduling in DA market which considers various scenarios and reserve shortage pricing in RT. Spinning reserve has an important role to play in ancillary services that help in maintaining reliability in case of sudden faults. The spinning reserve cost should be kept minimum and adjusted for various generating units to keep total operating cost as minimum [4]. In market calculations both DA and spinning reserve energy units are required. A model proposed in [5] identified the reserve cost with wind uncertainty factor. An optimal spinning reserve scheduling with unit commitment function was developed in [6].

Given the uncertainties involved in load forecasting and wind power generation, we have to consider some strategies to minimize this uncertainty effect in RT. In this work, authors have proposed a model to minimize the risk of ISO in RT market. The wind uncertainty considered in this paper ranges in between 20% to 30%. Accordingly consideration of the wind uncertainty range can reduce the scheduled wind energy in energy market. As a consequence, the deviation between the RT power and DA power is reduced so as to minimize the wind power producer and ISO risk in RT. Considering the limitations of existing works in terms of static energy penalty for deviation in the wind energy, lack of consideration of deviation sensitivity on energy balancing market, lack of consideration in price difference in DA and RT market etc., a dynamically varying energy penalty cost model is devised in this paper. The contributions of the paper are listed as follows:

- This paper considers multiple cost model rather than a single cost model for accounting the energy balancing cost pertaining to wind energy deviation from DA to RT market. The multiple cost model can be extended to different market models in restructured as well as traditional electricity market structures.
- The cost models are devised to vary dynamically depending upon the range of wind energy deviations and price variations from DA to RT conditions rather than a static energy penalty which may be ineffective in capturing the temporal aspects of resource and price volatility.
- The dynamic reserve procurement cost under volatile wind energy consideration is included to account temporal variation of wind energy uncertainty in scheduling operations.

The rest of the paper is structured as follows. The problem formulation along with stochastic wind model and wind uncertainty cost models is explained in Section 2. The test system description, test solver information along with results is presented and discussed in Section 3. The concluding remarks of the paper are presented in Section 4 and possible future scope of the work is also elaborated.

2. Figures and Tables

The problem is formulated with scheduling cost minimization objective for independent system operator (ISO) where the wind energy schedule is optimized based on the expected penalty costs (EPC). Leading into the problem formulation, penalty/cost attributes of uncertain wind energy generation in deregulated market are discussed first.

2.1. Nomenclature

T	Scheduling time horizon (hour)
t	Hour of the scheduling day (hour)
N	Number of thermal generator units
i	Index for thermal generator unit
j	Index for wind generator unit
W	Number of wind generator units
$\mathbf{P}_{\mathbf{c,i}}^{\mathbf{t}}$	Scheduled Conventional Power (MW)
$\mathbf{P}_{W,j}^{t}$	Scheduled Wind Power (MW)
$P_{W,RT}^{j}$	Real Time Wind Power (MW)
φ_w	Wind uncertainty factor
Ω	Disincentive ($/MWh)
SP_{req}	Required spinning reserve (MW)
$P_{W,j}^{max}$	Maximum wind energy schedule in DA (MW)
P_{W}^{f}	Forecasted wind energy (MW)

2.2. Overview of market operation

This section briefs the general insights of deregulated market operations with respect to balance energy scheduling aspects. The deregulation of electricity markets is considered to be a pivotal element in introducing competitiveness among electricity market players [7]. The operational procedure of many electricity markets around the globe can be characterized by two phases i.e., day ahead settling and real time market settling. Both the market mechanisms are constrained by supply-demand energy balance at any given instant of time and are taken care by the system operator [8].

In DAM, for each hour of the next operating day, ISO invites energy/load supply bids from the participating players /GenCo's. The system operator estimates the purchase value of electricity by estimating the market clearing price (MCP). Which is often the least price bid submitted by GenCo after alleviating the market power (if any). The generation units of various GenCo's are resolved by ISO through MCP settlements carried out for every hour of the next operating day. There may exist bilateral contracts those take place between a pair of GenCo and demand entities. The approach considers a hybrid approach of negotiating the bilateral contracts at MCP of centralized clearing. In this approach, buyer pays directly to the seller at the cleared MCP and therefore, are dependent on market settlements of ISO [9].

The DAM has other counterparts in the name of Spot market, where electricity is traded in real time on hourly basis [9]. Apart from generation bids, the market settlements in spot market are also affected by the system congestion. The ISO uses the real time spot market energy offers mainly to reduce the adverse effects of congestion on the network operation.

Additionally, the real time generation offers from GenCo's provides cushion to ISO operation to alleviate the risk of supply-load imbalance in real time scenario. The transactions in the real time spot market are handled using price stamps called as spot market prices (SMP) [7]. The same is often recorded lower at off peak hours and higher at peak hours when compared to MCP of respective hour of scheduling. In this mode of operation or bidding, the GenCo receives immediate returns for the energy supplied in real time clearing. The estimation of SMP as a function of generic pattern of historical MCP can be obtained as follow [10].

$$SMP_t = MCP_t(1+\varepsilon) \tag{1}$$

The range of ε can be decided by upper and lower bounds as given by,

$$\begin{cases} \varepsilon_{min} = \left\{\frac{SMP_{min}}{MCP_{ave}}\right\} - 1 \\ \varepsilon_{max} = \left\{\frac{SMP_{max}}{MCP_{ave}}\right\} - 1 \end{cases} \tag{2}$$

where, SMP_{min} and SMP_{max}can be obtained from MCPs of historical data, MCP_{ave} is the average historical MCP. The volatility in case of SMP is observed to higher than that of MCP [11]. The failure of GenCo to schedule generators to the DAM settled powers will incur various costs. The deviations in DAM to RTM for a generator can be represented in terms of monetary values can be derived from the historical price stamps of MCP and SMP values. Similar to the deviations in conventional generation, the deviation in estimated wind energy from DA to RT market can also be represented using monetary penalty.

A. ISO with no performance based incentives/penalties

The ISO's in this market structure act as non-profit bodies and mostly asset-free entities regulated by governmental or regulation bodies [12]. Therefore, these ISO's do not acquire any incentives out of market operations in day ahead and real time as well. The services provided by ISO such as congestion management and the energy imbalance alleviation in real time scheduling can be attributed to the incentives [13]. The early changes in this market structure neglected to extend transmission arrange however balanced out later (US ISOs).

B. ISO with performance based incentives/penalties

In this market structure, more often than not system operator may claim transmission network yet not generation resources and controls the overall system generation. These are for the most part named as Independent Transmission System Operator (ITSO) and generalized as system operator (SO) gets impressive revenue driven motivators in view of execution for instance the National Grid Electricity Transmission (NGET) in the UK. Thus, the incentives allocated SO for exercising duties such as congestion management, energy market imbalance have prompted to compelling usage of transmission system and lessening of interests in relieving transmission imperatives [14]. Thus, both of the market structures have their benefits and demerits and this paper concentrates on ideal wind energy dispatch in both sorts of markets.

2.3. Stochastic wind energy generation

The power generation from wind turbine can be dictated by considering the wind speed dispersion for selected site and power curve of the turbine selected. It is frequently accepted that for a decent wind site wind speed dissemination follows a Weibull distribution affected by Weibull parameters "c,k" named as scale and shape parameters [15]. The wind speed likelihood distribution function as per the wind speed and Weibull parameters is given by [15],

$$\rho(v) = \frac{k}{c}\left(\frac{v}{c}\right)^{k-1} \exp\left(-\frac{v}{c}\right)^{k} \tag{3}$$

where c, k represent the webull curve parameters and v denotes the wind speed expressed in m/sec. The Weibull parameter estimation in literature is carried out using many approaches [16]. One of the frequently used approach is extraction of these parameters from mean historical wind speed ($\bar{v}$) and associated deviation (σ_s) expressed as follows.

$$k = \left(\frac{\sigma_s}{\bar{v}}\right)^{-1.086};\ c = \frac{\bar{v}}{\Gamma\left(1+\frac{1}{k}\right)} \tag{4}$$

The relation between the power curve (Fig. 1) and the associated power generation as a function of wind speed can be deduced as follows.

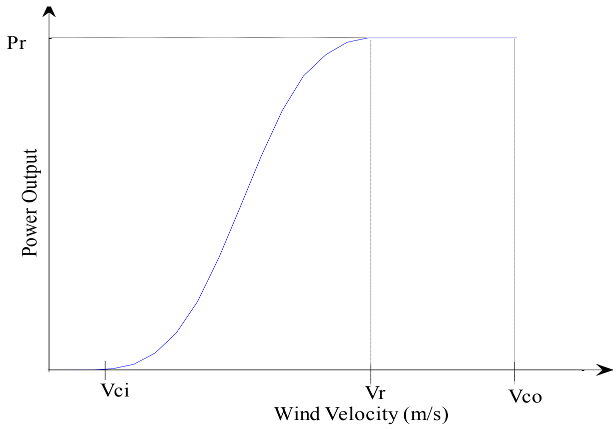


Fig. 1 Power curve characteristic of typical modern wind turbine

$$p_w = \begin{cases} 0 & v < v_{ci} \,||\, v \geq v_{co} \\ p_r * \left(\frac{v - v_{ci}}{v_r - v_{ci}}\right) & v_r \geq v \geq v_{ci} \\ v & v_{co} \geq v \geq v_r \end{cases} \tag{5}$$

where, p_r denotes the power generation of wind turbine at nominal/rated speed. The rated cut in and cut out speeds of wind power turbine-generator set are respectively represented byv_r, v_{ci} andv_{co}. The actual power generation of wind energy generator in terms of wind speed probability, wind turbine characteristics can be expresses as follows [17].

$$\rho_p(p_w) = \begin{cases} \left[\left(\frac{k}{v_{ci}}\right) * \left(\frac{1}{c}\right)\right]\left[\frac{(1+\tau\ell)*v_{ci}}{c}\right] \ exp\left(\left[\frac{(1+\tau\iota)*v_{ci}}{c}\right]^k\right) & 0 \leq p_w \leq p_r \\ 1 - exp\left(-\left\{\frac{v_{ci}}{c}\right\}^k\right) + exp\left(-\left\{\frac{v_{co}}{c}\right\}^k\right) & p_w = 0 \\ exp\left(-\left\{\frac{v_{ci}}{c}\right\}^k\right) + exp\left(-\left\{\frac{v_{co}}{c}\right\}^k\right) & p_w = p_r \end{cases} \tag{6}$$

Where, $\tau = \frac{p_w}{p_r}$ and$\ell = \frac{v_r - v_{ci}}{v_{ci}}$.

2.4. Objective function

The objective is to minimize the ISO cost and is expressed as:

$$\text{Min} \sum_{t=1}^{T} \left[\sum_{i=1}^{N} C_g(P_{c,i}^t) + \sum_{j=1}^{W}(C_c(P_{w,j}^t) + C_r(P_{w,j}^t)) + C_{k,ADSR}^{w}(P_{w,j}^t)\right] \quad (7)$$

Where $C_g(P_{c,i}^t)$ is the cost function of conventional thermal generators which is given by,

$$C_g(P_{c,i}^t) = a_i P_c(i,t)^2 + b_i P_c(i,t) + c_i \quad (8)$$

The estimated wind energy generation for the next 24 operating hours is scheduled by wind SO in the DAM market alongside the conventional generation units. However, the same schedule may or may not be possible in actual scheduling hour due to uncertainties in wind energy that will ultimately result in deficit or surplus generation resources. The supply-demand imbalance is created by such uncertain wind generation, which required either increment or decrement in the generation of the conventional units. Thus, the additional cost of mitigating the energy imbalance in RT market can be expressed as follows.

$$C_c(P_{w,j}^t) = (P_{w,DA}^j(t)) - P_{w,RT}^j(t)) \mid smp_t - mcp_t \mid \quad (9)$$

From (), it is clear that the compensation cost in real time market is in proportion with the energy imbalance and the price volatility between DA and RT markets. In case the deviation in SMP and MCP is –ve with SMP being cleared at lower price than MCP, the wind energy deviation may not be penalized. Because, the energy offers from other generation sources are lower than MCP corresponding to the scheduling hour. Due to the uncertainty in wind energy in real time, the deviated power will be supplied by conventional sources. For this, the schedule of the generators will change. This extra scheduling of generators leads to ISO paying the extra cost. This cost is known as rescheduling cost and it is given by,

$$C_r(P_{w,j}^t) = P_{w,DA}^j(t) \times \varphi_w(i,t) \times \omega \quad (10)$$

Where ω is the disincentive due to the uncertainty of wind. There is some penalty in case of deviated power in RT. This implies that when RT power is less than DA power, then some disincentives are applicable. The additional reserve cost applicable due to uncertain wind energy can be expressed as follows.

$$C_{k,ADSR}^{w}(P_{w,j}^t) = \begin{cases} P_{w,DA}^j(t)\,\varphi_w(i,t)\,RP_t, & \varphi_w\widetilde{(\iota,t)} > 0 \\ 0, & \varphi_w(i,t) \le 0 \end{cases} \quad (11)$$

2.5. Constraints

The problem of wind energy scheduling is formulated and solved for optimal power flow problem of power system network whose system level and generation level constraints are explained as follows.

2.5.1. Power balance constraints

For all the scheduling hours, the power balance can be assured by implementing following active and reactive power balance constraints at each node.

$$P_g^i = P_d^i + V_i \sum_{j=1}^{n} V_j\{G_i^j \cos(\delta_i - \delta_j) + B_i^j \sin(\delta_i - \delta_j)\} \quad (12)$$
$$Q_g^i = Q_d^i + V_i \sum_{j=1}^{n} V_j\{G_i^j \sin(\delta_i - \delta_j) + B_i^j \cos(\delta_i - \delta_j)\} \quad (13)$$
$$\forall\, i \in [1,2,3,\dots.n]$$

Where, P_d^i, Q_d^i respectively denote the active and reactive power demand for i^{th} node.

2.5.2. Reserve constraints

Apart from the regular spinning reserve margin of the system, an additional amount of conventional generation online capacity is required to deploy in case of uncertain wind energy accommodation. Thus, the hourly spinning reserve constraint can be expressed as follows.

$$SPT_{rq}^t = SP_{rq}^t + ADSR_w^t;\ \forall\, t \in T \quad (14)$$

Where, SPT_{rq}^t represents the online spinning reserve requirement of conventional system without any wind energy penetration and $ADSR_w^t$ comprises of the additional online spinning generation which can be expressed as a function wind energy uncertainty as follows.

$$ADSR_w^t = \int_0^{P_{w,j}^t} (P_{w,j}^t - p_w)\,\rho_p(p_w)\,dp;\ \forall\, t \in T \quad (15)$$

Therefore, the overall spinning reserve requirement can be specified as,

$$\sum_{i=1}^{N} GSR_i^t \ge SPT_{rq}^t;\ \forall\, t \in T \quad (16)$$

Where, GSR_i^t represents the spinning reserve available from i^{th}conventional generator for t^{th}hour and is given by,

$$GSR_i^t = P_{c,i}^{max} - P_c(i,t);\ \forall\, i \in N, t \in T \quad (17)$$

2.5.3. Generator constraints

The constraint for generation bounds of conventional generation units can be represented as follows.

$$P_{c,i}^{min} < P_c(i,t) < P_{c,i}^{max};\ \forall\, i \in N, t \in T \quad (18)$$

In case of wind energy, the schedulable wind energy is limited by its forecasted value as given by,

$$0 < P_{w,j}^t < P_w^f(k,h);\ \forall\, t \in T \quad (19)$$

The wind forecast with an error of prediction ρ_w, the range of wind nergy generation is schedulable for any hour can be expressed as follows.

$$P_{w,j}^{Lmax}(t) \le P_{w,j}^{max}(t) \le P_{w,j}^{Umax}(t);\ s.t. P_{w,j}^t \le P_{w,j}^{max}(t) \quad (20)$$

Where,

$$\begin{cases} P_{w,j}^{Lmax}(t) = P_w^f(j,t) * \{1 - \rho_w\} & \\ P_{w,j}^{Umax}(t) = P_w^f(j,t) * \{1 + \rho_w\}, & P_{w,j}^{Umax}(t) < P_{w,j}^{max} \\ P_{w,j}^{Umax}(t) = P_{w,j}^{max}, & P_{w,j}^{Umax}(t) > P_{w,j}^{max} \end{cases} \quad (21)$$

Apart from generation limits, the operation of thermal generation units is also limited by the operational constraints specified as follows.

$$Q_i^{min} < Q_i^t < Q_i^{max}, \forall\, i \in \{N + W\}, t \in T \quad (22)$$

$$V_i^{min} < V_i^h < V_i^{max}, \forall\, i \in \{N + W\}, t \in T \quad (23)$$

Where, Q_i^{min}, $Q_i^{max}$and V_i^{min}, V_i^{max} respectively denote the bounds on reactive power and voltage respectively for i^{th} conventional generation unit.

2.5.4. System security constraints

Similar to the voltage limits on generation, network operation is also constrained by nodal voltage limits as follows.

$$V_{L,k}^{min} \leq V_{L,k}^{h} \leq V_{L,k}^{min}, \forall\, k \in [1,2,3 \dots K];\, t \in T \quad (24)$$

Apart from individual nodal limits, the line flow between two different nodes is also constrained by branch loadability limits expressed as follows.

$$\left|S_k^l\right| \leq S_{k,l}^{max}, \forall\, k, l \in \{1,2,3 \dots K\} \quad (25)$$

2.5.5. Allowable wind penetration

The physical ramp rates on thermal generation acts as a limiting factor to the total wind energy penetration of the system as follows.

$$\sum_{j=1}^{W} 0 < P_{w,j}^{t} = \min(W_{a1}, W_{a2}),\ \forall\, h \in H \quad (26)$$

where, W_{a1}, W_{a2} can be expressed as follows.

$$\begin{cases} W_{a1} = \sum_{i=1}^{N} \frac{U_r(i,t) - SP_c^t}{(1-\rho_w)} \\ W_{a2} = \sum_{i=1}^{N} \frac{D_r(i,t)}{(1-\rho_w)} \end{cases} ;\ \forall\, t \in T \quad (27)$$

where, $U_r(i,t), D_r(i,t)$ respectively represent the upper and lower ramp rate capabilities of the generation units expresses as follows.

$$\begin{cases} U_r(i,t) = \min\left(R_i^{US}, \{P_{c,i}^{max} - P_c(i,t)\}\right) \\ D_r(i,t) = \min\left(R_i^{DS}, \{P_c(i,t) - P_{c,t}^{min}\}\right) \end{cases} \forall\, i \in N, t \in T \quad (28)$$

3. Results and Discussion

The proposed methodology for the wind and thermal generators scheduling has been carried on the IEEE 30 bus system and implemented in MATPOWER 5.1. MATPOWER is a package of MATLAB M-files for solving power flow and optimal power flow problems. The system consists of six conventional generators and two wind generators. The six conventional generators are placed at 1, 2, 13, 22, 23 and 27 buses [18] and two wind generators have been placed at buses 15 and 21 respectively. The capacity of each wind generator is 12 MW [19]. The output power of wind generator can be estimated using forecasted wind speed and power curve of the wind turbine [20]. The complete solution methodology of the proposed framework for accommodating the uncertain wind energy generation is presented in Fig. 2. In this paper, the market clearing (DA) price and spot market (RT) prices (Fig. 3) are taken from PJM (Pennsylvania, New Jersey, Maryland) market for the year 2013. In this work, the average values for the whole year of 2013 have been considered. The price ranges given and the hourly average prices are shown in Fig.3. The generation from various thermal generation units along with losses and load of the system is presented in Table I.

The conventional case with no wind generation is also tested to observe the conventional thermal generator techno-economic aspects like loading, system loss, generation cost etc., when presented with the same load. The total operational cost over the scheduling time horizon is seen to be $ 15352.31 which is the sum of fuel cost ($ 11355.13) and spinning reserve cost ($ 3997.17) in DAM. The total system losses are 49.14 MW in supplying 3884.13 MW for a scheduling horizon of 24 hours. The total energy supplied by all the conventional generators over 24 hours is given in Table I.

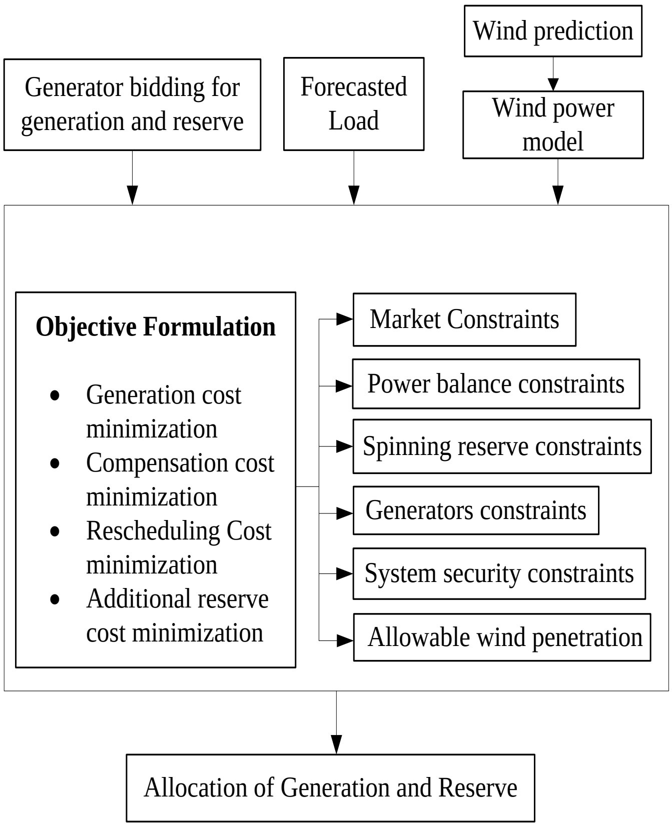


Fig. 2 Flowchart of simulation procedure for scheduling under wind uncertainty

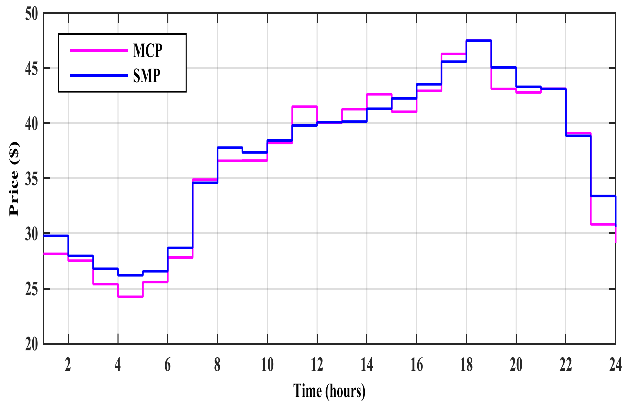


Fig. 3 Average price for each hour

In this paper, two scenarios have been considered: 20% and 30% wind uncertainty in DA market each with three cases namely 10%, 20% and 30% wind penetration out of the total load. The case with 10% wind penetration is considered to be the base case. The hourly scheduling aspects of thermal and wind generation for Scenario 1 (20% uncertainty) and Scenario 2 (30% uncertainty) for base case (Case 1 with 10% penetration) are presented in Table II and Table III respectively. Compensation costs obtained for different Cases and Scenarios is shown in Fig. 4. Here the proposed model is the one that considers wind uncertainty in DA market unlike the Deterministic model that does not consider the same.

Table I Generation schedule without wind energy

PG1 (MW)	PG2 (MW)	PG3 (MW)	PG4 (MW)	PG5 (MW)	PG6 (MW)	Load (MW)	Losses (MW)	Total Generation (MW)
926.17	1245.26	512.79	612.69	318.73	317.60	3884.13	49.14	3933.54

Table II Hourly schedules and cost attributes of conventional and wind energy generation for Scenario 1 under 10% wind energy penetration

	Fuel cost ($)	CC_w	PW1 (MW)	PW2 (MW)	ADSR (MW)	C_{ADSR} ($)	PG1 (MW)	PG2 (MW)	PG3 (MW)	PG4 (MW)	PG5 (MW)	PG6 (MW)	Loss (MW)	Total cost ($)
Hour1	374.4	0.7	8.2	8.2	16.4	5.4	35.2	47.9	19.8	14.3	9.5	9.8	1.5	447.3
Hour2	335.4	0.9	7.9	7.9	16.0	13.3	33.5	45.9	19.2	10.4	8.1	8.3	1.3	443.0
Hour3	314.1	0.9	7.2	7.2	14.7	3.6	32.4	44.7	18.9	8.1	7.3	7.4	1.3	351.7
Hour4	305.1	1.3	6.6	6.6	14.2	3.4	32.0	44.2	18.7	7.2	7.0	7.1	1.2	342.3
Hour5	282.4	1.4	7.9	7.9	14.0	4.6	31.0	43.0	18.3	5.0	6.1	6.2	1.2	324.2
Hour6	295.3	1.3	8.9	8.9	14.6	11.8	31.6	43.7	18.6	6.4	6.6	6.7	1.2	407.7
Hour7	293.8	1.5	8.5	7.7	14.0	25.0	31.6	43.7	18.5	6.2	6.6	6.6	1.2	580.6
Hour8	360.8	1.3	6.8	7.7	15.6	21.1	34.6	47.2	19.6	12.9	9.1	9.3	1.4	688.6
Hour9	378.5	3.2	9.6	9.6	17.3	11.2	35.4	48.1	19.9	14.8	9.6	9.9	1.5	488.9
Hour10	410.0	4.8	9.7	9.7	18.6	16.0	36.2	49.1	20.3	19.7	10.6	10.8	1.6	554.2
Hour11	440.6	6.3	9.7	9.7	18.8	14.8	36.9	49.9	20.7	24.6	11.5	11.6	1.8	630.8
Hour12	473.1	3.7	7.8	6.8	18.6	19.9	38.1	51.3	21.2	28.2	12.6	12.7	2.0	858.3
Hour13	447.9	10.1	9.7	9.7	19.9	18.6	37.1	50.1	20.7	25.8	11.7	11.8	1.9	613.5
Hour14	440.6	10.1	9.7	9.7	19.3	16.2	36.9	49.9	20.7	24.6	11.5	11.6	1.8	603.8
Hour15	426.3	9.2	9.7	9.7	18.5	12.4	36.6	49.6	20.5	22.2	11.1	11.3	1.7	574.6
Hour16	477.5	10.4	9.7	9.7	20.2	14.8	37.6	50.8	21.1	30.8	12.5	12.5	2.2	642.0
Hour17	455.2	7.3	9.7	9.7	20.1	22.9	37.2	50.3	20.8	27.0	11.9	12.0	2.0	651.5
Hour18	547.2	1.3	6.7	6.7	20.4	23.7	38.6	52.0	22.0	42.3	14.7	14.2	2.8	1073.9
Hour19	529.3	7.3	7.9	7.9	21.1	22.5	38.4	51.7	21.7	39.8	13.9	13.7	2.7	790.9
Hour20	511.4	3.7	8.2	8.2	20.2	13.9	38.5	51.9	21.5	35.5	13.6	13.5	2.5	727.6
Hour21	489.1	4.8	8.2	8.2	20.3	18.6	38.2	51.5	21.3	31.6	13.0	13.0	2.2	677.3
Hour22	456.5	3.8	8.5	8.5	19.3	28.6	37.5	50.6	20.9	26.4	12.1	12.2	1.9	764.9
Hour23	437.2	4.0	8.2	8.2	18.8	14.3	37.2	50.3	20.7	23.0	11.5	11.8	1.8	584.3
Hour24	394.9	3.6	8.2	8.2	17.8	14.6	36.0	48.9	20.2	16.6	10.2	10.5	1.5	525.9

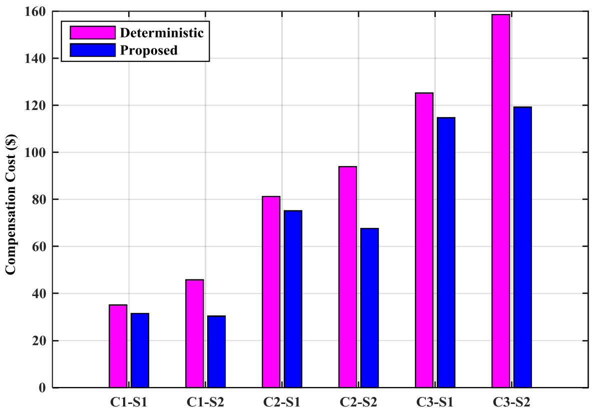


Fig.4. Compensation cost for different cases and scenarios

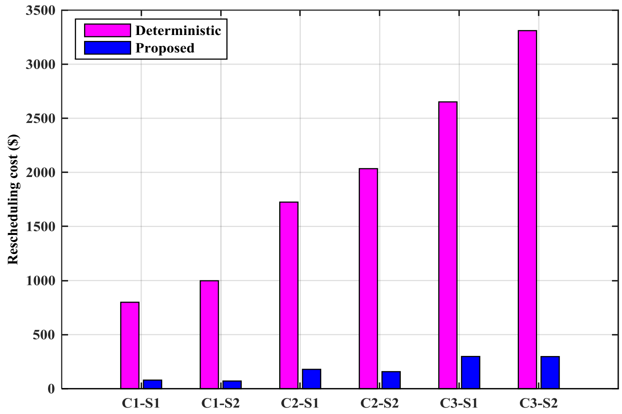


Fig. 5. Rescheduling cost for different cases and scenarios

Table III Hourly Schedules of conventional and generators for Scenario 2 under 10% penetration (Case 1)

	Fuel cost ($)	CC_w	PW1 (MW)	PW2 (MW)	ADSR (MW)	C_{ADSR} ($)	PG1 (MW)	PG2 (MW)	PG3 (MW)	PG4 (MW)	PG5 (MW)	PG6 (MW)	Loss (MW)	Total cost ($)
Hour1	374.4	1.6	8.2	8.2	17.8	11.8	35.2	47.9	19.8	14.3	9.5	9.8	1.5	387.8
Hour2	335.4	0.9	7.9	7.9	16.1	14.3	33.5	45.9	19.2	10.4	8.1	8.3	1.3	350.5
Hour3	314.1	1.4	7.2	7.2	15.4	5.4	32.4	44.7	18.9	8.1	7.3	7.4	1.3	320.9
Hour4	305.1	1.9	6.6	6.6	14.7	4.9	32.0	44.2	18.7	7.2	7.0	7.1	1.2	311.8
Hour5	282.3	1.5	7.9	7.9	15.1	7.6	31.0	43.0	18.3	5.0	6.1	6.2	1.2	291.4
Hour6	294.6	2.0	8.9	8.9	15.5	18.7	31.6	43.7	18.6	6.4	6.6	6.7	1.2	315.3
Hour7	319.0	1.7	4.4	4.3	13.5	14.6	32.7	45.0	19.0	8.7	7.6	7.7	1.3	335.3
Hour8	380.9	0.8	3.4	5.4	15.2	12.9	35.5	48.2	20.0	14.7	9.9	10.1	1.5	394.6
Hour9	378.5	5.1	9.6	9.6	18.4	17.7	35.4	48.1	19.9	14.8	9.6	9.9	1.5	401.2
Hour10	410.0	6.2	9.7	9.7	19.2	20.7	36.2	49.1	20.3	19.7	10.6	10.8	1.6	436.9
Hour11	448.7	10.1	9.4	7.8	19.7	23.9	37.3	50.4	20.8	25.2	11.8	12.0	1.9	482.8
Hour12	487.3	2.3	3.9	6.8	18.3	12.1	38.8	52.1	21.4	29.2	13.3	13.4	2.1	501.7
Hour13	447.9	12.7	9.7	9.7	20.5	23.4	37.1	50.1	20.7	25.8	11.7	11.8	1.9	484.0
Hour14	444.8	11.9	9.7	8.6	19.7	19.0	37.1	50.2	20.7	24.9	11.6	11.8	1.9	475.7
Hour15	436.8	13.7	8.7	7.8	19.4	18.5	37.2	50.2	20.7	22.9	11.5	11.7	1.8	469.1
Hour16	477.5	11.7	9.7	9.7	20.4	16.7	37.6	50.8	21.1	30.8	12.5	12.5	2.2	505.9
Hour17	458.6	7.1	8.8	9.7	20.1	22.6	37.4	50.5	20.9	27.2	12.1	12.2	2.0	488.4
Hour18	561.7	0.9	3.8	5.7	20.1	16.3	39.4	52.9	22.3	42.5	15.6	15.0	2.9	578.9
Hour19	541.1	5.5	6.3	6.3	20.6	17.2	39.1	52.5	21.9	40.0	14.5	14.3	2.7	563.9
Hour20	515.5	6.2	7.4	7.9	21.1	23.5	38.7	52.1	21.6	35.8	13.8	13.7	2.5	545.2
Hour21	489.1	5.7	8.2	8.2	20.7	22.1	38.2	51.5	21.3	31.6	13.0	13.0	2.2	516.9
Hour22	484.7	1.7	5.1	4.3	18.3	13.1	38.9	52.3	21.4	28.3	13.2	13.4	2.0	499.5
Hour23	437.2	5.9	8.2	8.2	19.6	20.9	37.2	50.3	20.7	23.0	11.5	11.8	1.8	463.9
Hour24	394.9	4.3	8.2	8.2	18.2	17.3	36.0	48.9	20.2	16.6	10.2	10.5	1.5	416.6

Since, in the proposed model wind uncertainty in the DA market has been considered, there is less deviation of wind power from RT to DA market. Due to this less deviation, the compensation cost is low for proposed model as compared to the deterministic model. If more uncertainty in DA is considered, then there are more savings in the compensation cost. Similarly, as we increase the wind penetration level out of the total load, then the compensation cost (Fig. 4) is increased in both proposed and deterministic models. For an increasing wind penetration, the deviation between RT and DA market prices also increases so that the compensation cost increases. The total re scheduling cost and total scheduling cost across various cases and scenarios is presented in Fig. 5 and Fig. 6 respectively. Since rescheduling cost depends on the uncertainty factor, the consideration of wind uncertainty in DA market in proposed method reduces the uncertainty factor and DA wind power in proposed method and hence this cost also decreases in comparison to the deterministic method.

With increase in penetration levels, the rescheduling cost also increases due to consideration of more wind power in DA market. From Fig. 4, we conclude that in each case proposed method gives low rescheduling cost when compared to the deterministic model. Also interestingly, if we consider more uncertainty in DA market then there are more savings in rescheduling cost in each case.

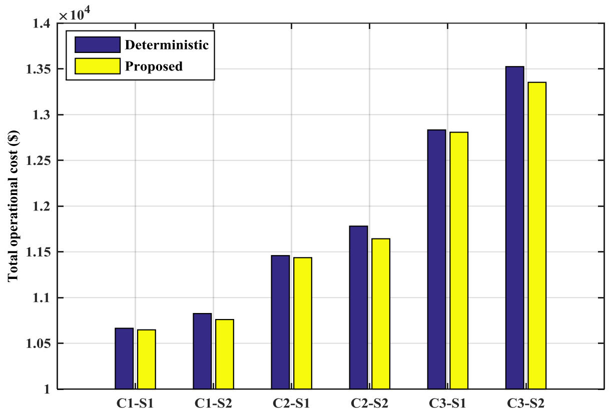
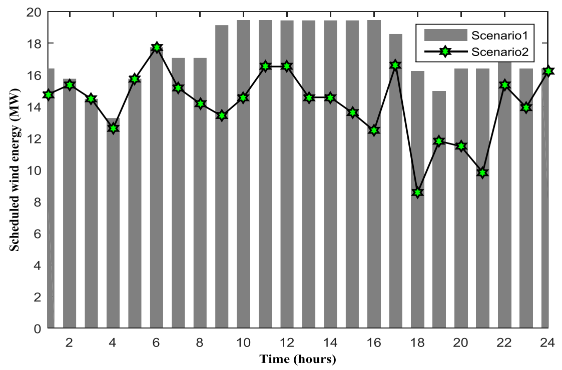
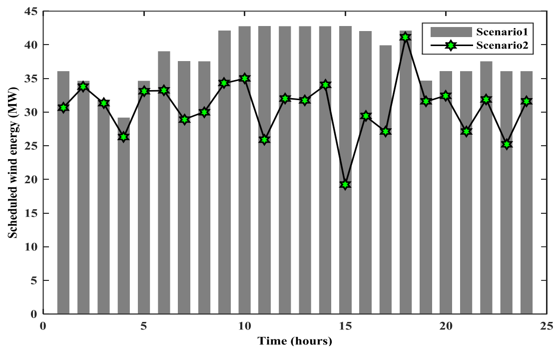


Fig. 6. Total operational cost for different cases and scenarios

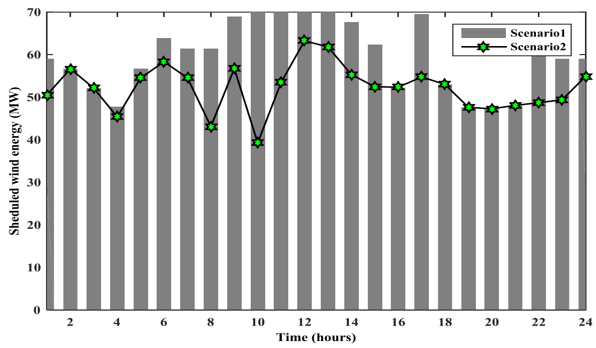
The total operational cost of ISO is the sum of conventional thermal generators cost, compensation cost and the rescheduling cost. The total operational cost of ISO for different cases and scenarios is given in Fig. 5. As can be seen in every case, the proposed approach has low operational cost when compared to the deterministic approach. As wind penetration increases the operational cost also increases. Accordingly from the results, we conclude that due to consideration of wind uncertainty in DA market, there is a minimum risk for ISO. The scheduled wind energy at each hour for different cases is shown in Fig. 7. It is observed that the scheduled wind energy is more in scenario 1 when compared to scenario 2. In scenario 1 only 20% wind uncertainty is considered whereas in scenario 2, 30% wind uncertainty has been considered for the DA market. Conclusively, as more uncertainty is considered in DA market, then less wind energy is scheduled. In Figures 6(a), 6(b) and 6(c) as wind penetration level increases, the scheduled wind power also increases due to more penetration.



(a)



(b)



(c)

Fig.7 Scheduled wind energy for (a) Case 1 (b) Case 2 (c) Case 3

4. Conclusion

In this paper, a model has been proposed to minimize the wind energy scheduling related risk to the ISO due to wind energy uncertainty in RT. The cost various cost models are appended into the objective function to include temporal variations in market as well as resource conditions. The dynamic compensation cost and rescheduling cost models considered in this model can be appended to restructured and traditional electricity markets. The results suggest the reduction in energy balancing costs in dynamic energy penalty costs compared to the deterministic models. The effectiveness of the proposed dynamic cost models increased with increment in renewable energy penetration. Thus, at higher penetration levels, the proposed dynamic cost models can result in substantial reduction in real time operational costs. The same may limit the allowed energy penetration of wind energy in RT market compared to the DA market. As a consequence, except compensation cost, other costs are proportional to the uncertainty in wind energy model. The difference between deterministic and proposed stochastic method has increased as a function of penetration as well as uncertainty level. Therefore, by considering the dynamic cost models, the economic aspects of system resource scheduling can be considerably improved in real time energy balancing market. From the observations made, the same work will be continued by considering other factors like load variation, price variation etc. in the model proposed.

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