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Flexible Scheduling of Active Distribution Networks for Market Participation with Considering DGs Availability

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Abstract

The availability of sufficient and economic online capacity to support the network while encountering disturbances and failures leading to supply and demand imbalance has a crucial role in today distribution networks with high share of Distributed Energy Resources (DERs), especially Renewable Energy Resources (RESs). This paper proposes a two-stage decision making framework for the Distribution Management System (DMS) to flexibly optimize the day-ahead schedule of DERs and market participation of distribution networks under uncertainties, imposed by DGs outage and wind generators. The uncertainties are modeled via scenarios and convolved with each other, and then the joint scenario set is applied in the proposed two-stage programming model. Also the role of network constraints on DMS decisions are seen via a linearized AC power flow model and finally the resulted proposed framework is based on mixed-integer-linear programming (MILP) layout solved by CPLEX 12.6. To examine the effectiveness of the proposed framework, it is used for decision making of DERs scheduling and market participation strategy of a test distribution network.

Keywords: Day-ahead scheduling, Two-stage programming, Unit availability, DERs, Distribution networks, Operation, Flexibility
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Nomenclature

Indices and sets:

t, T	Index and set of time periods.
ω, Ω	Index and set of possible scenarios.
n, m, N	Indices and set of buses.
$\phi_{(.)}$	Set of buses connected to bus (.)
$s, ES_{(.)}, g, G_{(.)}, w, W_{(.)}$	Index and set of energy storages, DGs, wind generators connected to bus (.).

Parameters and constants:

g, b	Line conductance and susceptance [p.u]
$p(.)$	Probability of scenario (.)
ρ^{DA}, ρ^{RT}	Day-ahead and Real-time market price
$VOLL$	Value of lost load
P^{D}, Q^{D}	Active and reactive power loads
$LGPI$	Limitation of grid power import
a	Availability of DGs
UR_g, DR_g	Ramp up and ramp down rate

Functions and Variables:

P, Q	Active and reactive powers of feeders
$P^{DG}, P^{ES}, P^{wind} / Q$	Active powers of DGs, energy storages and wind generators / reactive powers of DGs
I	Binary variable representing on (1)/off (0) states of DGs
P^{LC}, Q^{LC}	Active and reactive powers decreased by Load Curtailment
δ, V	Bus voltage angle and amplitude

P^{DA}, P^{RT}	Day-ahead and Real-time market power purchase
$L_l(.)$	Fitted line for cos(x) linearization
$C^P(.), C^{SU}(.), C^{SD}(.)$	Generation, start-up and shot-down costs of DGs

1. Introduction

Powering the next generation can't be tolerated and continued in the current path, because of emerging issues such as environmental problems, drastic load growth, depletion of fossil fuels and energy crisis. Therefore, the role of centralized power plants based on fossil fuels, in future power systems, become inconspicuous, and it should be replaced with DERs, especially Renewable Energy Sources (RES). In recent years, the penetration level of DERs has increased significantly in distribution networks and following that the essence of distribution networks has been changed from passive networks to active ones, and also microgrid concept has been more common.

Obviously, the entering of DERs into distribution networks and also the restructuring and deregulation of power systems have broadly altered the operational strategies of distribution networks and bring them with complexity like the operational strategies of transmission networks. In the new created environment, the DMS as the heart of economical and technical operational decision making process is responsible for supplying customers demand. For this purpose, the DMS must coordinate the available sources such as Upstream Grid, Dispatchable DGs, non-Dispatchable DGs, Demand side resources and Energy storages (ESs) and schedules them in an economic and secure manner. The most important challenges which the DMS should conquer them are: (1) the uncertainty of market signals, (2) the difficulty to accurately predict customer's demand, (3) the volatility and uncertainty of RESs outputs, (4) the probable outage of networks equipment. As it is clear, all these challenges derived from uncertainties put the system under stress and jeopardize system's security. Then, the flexibility of the operational plan resulted by the DMS to adapt the system with unplanned situations is vital.

The scheduling of DERs in distribution networks is widely investigated in the literature and we just peruse them in terms of diversity. For example in [1] a deterministic day-ahead scheduling of DGs with considering network reconfiguration is proposed. Reference [2] propose a deterministic model for microgrid scheduling considering multi-period islanding constraints. Reference [3, 4] proposed a stochastic two-layer optimization problem which the first layer determines DERs commitments and the day-ahead power purchase, and the second layer stands for real-time operational decisions. In [5] , authors aim to investigate the major roles of demand response in a residential active distribution network operation. Reference [6] presents an analysis on the impact of demand side bidding and adequacy constraints of online capacity ,in case of intentional islanding , to cover the critical loads. In [7] ,a probabilistic decision making framework based on particle swarm optimization is proposed to balance between security and economy. According to the recent researches, the DERs scheduling studies in distribution networks which consider the probable outage of equipment are very limited, and then it is necessary to address and investigate this issue more than ever.

This paper aims to develop a stochastic decision making framework, which considers probable outage of DGs and uncertainty of RESs outputs, to optimize decisions made by the DMS for participation in Day-Ahead Market. The proposed approach for the optimization problem is based on two-stage programming. The first stage decisions, recognized as here and now decisions, deal with the operational decisions on purchasing power from Day-Ahead market, on/off states of DGs, and charging/discharging states of storages. The second stage decisions, recognized as wait and see decisions, deal with the DMS activities in real-time to compensate unbalancing caused by uncertainty in wind power output and DGs failures. Indeed, these decisions made on real-time market transactions, dispatch of online DGs, dispatch of storages, and invocation of controllable load curtailments guarantee the flexibility of the system. In this work, we also use a linearized AC power flow model for the network to consider the role of network constraints on DMS decisions.

The rest of this paper is organized as follows. Section 2 presents the problem definition. Uncertainty representation is discussed in section 3 . In section 4 the network is modeled. The day-ahead scheduling problem is formulated in section 5. Finally the numerical results and conclusion are provided in section 6 and 7, respectively.

2. Problem Definition

As noted earlier, the DMS seeks to supply the customers demand with minimum operation cost and in a rational security level. To achieve this goal, the DMS should tackle with different challenges which the probable outage of DGs and the uncertainty of RESs outputs, represented by a finite number of scenarios, are specifically discussed in this paper.

If the DMS in its Day-Ahead scheduling for participation in the Day-Ahead Market ignores the existing uncertainties in the optimization problem and doesn't prepare adequate online capacity, the scheduling problem is prone to unforeseen disturbances, which are occurring in real time operation, causing load-generation imbalance. In this case, sometimes the DMS, for reviving the load-generation balance, is urged to purchase power from the real time market and in inevitable conditions curtail part of the customers' demand, but it has to pay for damages inflicted to customers due to a power interruption. However, the DMS can mitigate imposed costs by unforeseen disturbances through modeling the uncertainties and implementation appropriate security metric in Day-Ahead scheduling. It is clear that improving the flexibility of the Day-Ahead scheduling problem against the disturbances such as probable outage of the DGs and overestimation of the RESs outputs lead to additional operation cost. Thus the DMS should make a tradeoff between economic and flexible operation scheduling. The security metric that is used in this paper is Expected Load Not Served (ELNS) enforced in objective function through Value Of Lost Load (VOLL) ,provided by each customer[8, 9].

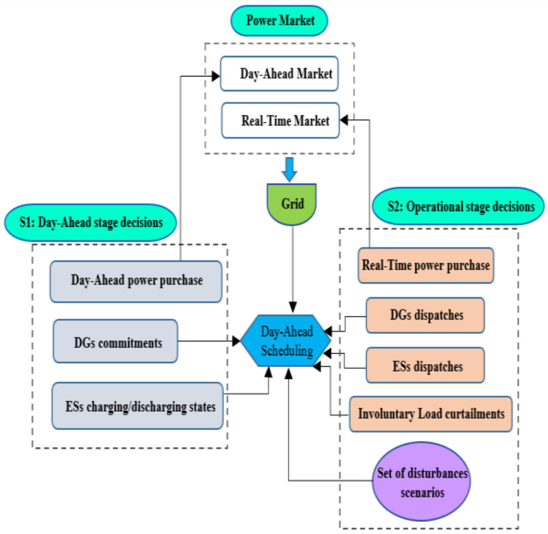

Fig. 1. Proposed decision making framework of the DMS

Fig. 1 shows the proposed decision making framework and illustrates the relationship between two stage decisions and their interactions with power market and electricity grid.

3. Uncertainty Representation

For representing the corresponding uncertainties in the problem, we use scenario-based stochastic programming to optimize the decisions made by the DMS. Scenario-based stochastic programming has been widely used in the literature to model uncertainty in power systems [10, 11]. However, when the number of scenarios grows, the computational burden increases rapidly. Therefore , the initial set of generated scenarios is truncated to a tractable set using a well-accepted scenario reduction method [12]. In the following, we are going to model the uncertainty of DGs outages and wind power outputs through a finite set of scenarios.

A)*Unit Availability Uncertainty*

In a distribution network comprising DERs, loads, branches and buses, the outage of equipment are not out of mind, and the availability of a component can be considered as an uncertain variable. Then as discussed in previous sections, the DMS should consider the availability of equipment in its scheduling for reaching a flexible operation. In this paper, only the probable outage of DGs is considered, however other outages such as buses, branches, storages and wind generators can be considered in the same way.

The Availability of DGs can be defined by the time to failure (t_F) and the time to repair (t_R), which constitute random variables following exponential distributions:

$$t_F = -MTTF \times \ln(u_1)$$
$$t_R = -MTTR \times \ln(u_2) \tag{1}$$

In recent equation, (1) MTTF and MTTR are mean time to failure and mean time to repair, respectively. These parameters can be achieved with according to historical data of DGs outage and repair reports. Also u_1 and u_2 are random numbers generated via uniform distribution function.

An availability scenario of a given DG is a chronological set of 1s and 0s which length is equal to the number of scheduling time periods. The unit is available, if the t-element of the availability scenario is equal to 1 and unavailable if that element is equal to 0. Fig. 2 illustrates the availability scenario-generation procedure for a set of N_Ω scenarios with a time domain encompassed N_T parts [13].

B)*Wind Power Uncertainty*

In recent years, the penetration level of renewable resources, especially wind resources, has been increased in the distribution networks.

For this reason, the wind power uncertainty modeling becomes more challenging in a way that significant effort has been paid by research community on this issue. In this paper, to model the wind power uncertainty, the time series autoregressive moving-average (ARMA) method is used [14] The ARMA model expresses the future values of a parameter as a linear function of its past values and the past values of an error term [15].

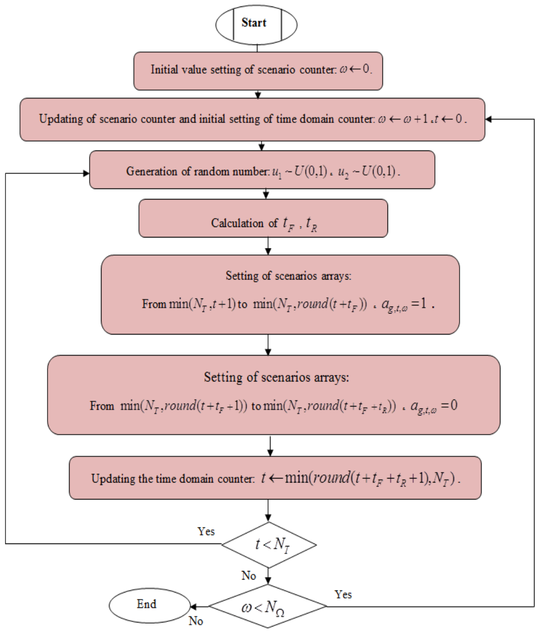

Fig. 2. Availability scenario-generation algorithm

4. Network Representation

The stochastic scheduling of DERs in the Day-Ahead Market is a large-scale problem with binary variables and hard to be solved. In this situation, the implementation of AC power flow equations by non-linear term makes the problem very complex and infeasible. For this reason, several approaches, like Semi definite programming (SDP), second order cone programming (SOCP) and linearization methods have been proposed in recent years [16].In this paper , we adapt a linearized AC power flow was proposed in [17] to formulate the favorable problem.

This linearization procedure is based on three main steps: 1) Approximate $\sin(x)$ by x .

2) Use piecewise linearization method to Approximate $\cos(x)$ by a set of linear constraints, and

3) Break down the bus voltages into a fixed value (normally 1 p.u) and a small variation.

The linearized model applied into this paper is described below:

$$\begin{aligned} P_{t,\omega}^{n,m} &= g_{n,m} - g_{n,m}\,\widehat{\cos}(\delta_{t,\omega}^{n} - \delta_{t,\omega}^{m}) \\ &\quad - b_{n,m}(\delta_{t,\omega}^{n} - \delta_{t,\omega}^{m}) \end{aligned} \tag{2}$$

$$\begin{aligned} Q_{t,\omega}^{n,m} &= -b_{n,m} + b_{n,m}\,\widehat{\cos}(\delta_{t,\omega}^{n} - \delta_{t,\omega}^{m}) \\ &\quad - g_{n,m}(\delta_{t,\omega}^{n} - \delta_{t,\omega}^{m}) - b_{n,m}\left(\left|\Delta V_{t,\omega}^{n}\right| - \left|\Delta V_{t,\omega}^{m}\right|\right) \end{aligned} \tag{3}$$

$$\widehat{\cos}(\delta_{t,\omega}^{n} - \delta_{t,\omega}^{m}) \le \mathrm{L}_l(\delta_{t,\omega}^{n} - \delta_{t,\omega}^{m}) \tag{4}$$

$$\left|V_{t,\omega}^{n}\right| = 1 + \left|\Delta V_{t,\omega}^{n}\right| \tag{5}$$

5. Day-Ahead Scheduling Formulation

The resulted optimization problem is a large-scale Mixed- Integer Linear Program (MILP), and in the next sections we characterize the objective function of the proposed model as well as the feasible set of results.

A)*Objective Function*

As mentioned before, the goal of the DMS is to minimizing the operational cost of day-ahead scheduling as follow:

$$\begin{aligned} \min & \sum_{\omega\in\Omega}\sum_{t\in T}\sum_{g\in G} p(\omega) C_g^{\,P}(\mathrm{P}_{g,t,\omega}^{DG}, I_{g,t}^{DG}) + \sum_{t\in T}\sum_{g\in G} C_g^{\,SU}(I_{g,t}^{DG}) \\ & + \sum_{t\in T}\sum_{g\in G} C_g^{\,SD}(I_{g,t}^{DG}) + \sum_{t\in T}\rho_t^{DA} P_t^{DA} + \sum_{\omega\in\Omega}\sum_{t\in T} p(\omega)\rho_t^{RT} P_{t,\omega}^{RT} \\ & + \sum_{\omega\in\Omega}\sum_{n\in N}\sum_{t\in T} p(\omega) P_{n,t,\omega}^{LC} VOLL_n \end{aligned} \tag{6}$$

The first term in (6) represents the expected cost of DGs operation cost, based on their cost function multiplied by the probability of each scenarios. Start-up and shut-down costs of DGs are calculated respectively in second and third terms. Cost of market participation for the DMS include two terms, fourth and fifth, which respectively reflect the cost of day-ahead market power purchase and expected cost of real-time market power purchase. In the last term, the imposed penalty cost to the DMS resulted from the involuntary load curtailment of customers is calculated.

B)*Network Constraints*

For satisfying the load-generation balance in the network, in each node of the network, the load-generation balance equation is enforced, separately for active and reactive power.

$$\begin{aligned} & \mathrm{n}=1, \forall t\in T, \forall \omega\in\Omega : P_t^{DA} + P_{t,\omega}^{RT} + \sum_{g\in Gn} P_{g,t,\omega}^{DG} + \sum_{s\in ESn} P_{s,t,\omega}^{ES} \\ & + \sum_{w\in Wn} P_{w,t,\omega}^{wind} + \sum_{n\in N} P_{n,t,\omega}^{LC} - \sum_{m\in\Phi n} P_{t,\omega}^{n,m} - P_{n,t}^{D} = 0 \end{aligned} \tag{7}$$

$$\begin{aligned} & \mathrm{n}=1, \forall t\in T, \forall \omega\in\Omega : \\ & \mathrm{Q}_{t,\omega}^{G} + \sum_{g\in Gn} Q_{g,t,\omega}^{DG} + \sum_{n\in N} Q_{n,t,\omega}^{LC} - \sum_{m\in\Phi n} Q_{t,\omega}^{n,m} - Q_{n,t}^{D} = 0 \end{aligned} \tag{8}$$

$$\forall n \in N-\{1\}, \forall t \in T, \forall \omega \in \Omega: \sum_{g \in Gn} P_{g,t,\omega}^{DG} + \sum_{s \in ESn} P_{s,t,\omega}^{ES} + \sum_{w \in Wn} P_{w,t,\omega}^{wind} + \sum_{n \in N} P_{n,t,\omega}^{LC} - \sum_{m \in \Phi n} P_{t,\omega}^{n,m} - P_{n,t}^{D} = 0 \quad (9)$$

$$\forall n \in N-\{1\}, \forall t \in T, \forall \omega \in \Omega: \sum_{g \in Gn} Q_{g,t,\omega}^{DG} + \sum_{n \in N} Q_{n,t,\omega}^{LC} - \sum_{m \in \Phi n} Q_{t,\omega}^{n,m} - Q_{n,t}^{D} = 0 \quad (10)$$

$$\forall t \in T, \forall \mathrm{n,m} \in \mathrm{N}, \forall \omega \in \Omega: -P_f^{\max} \le \left[P_{t,\omega}^{2\,n,m} + Q_{t,\omega}^{2\,n,m} \right]^{1/2} \le P_f^{\max} \quad (11)$$

$$\forall n \in \mathrm{N}, \forall t \in T, \forall \omega \in \Omega: V^{\min} \le \left| V_{t,\omega}^{n} \right| \le V^{\max} \quad (12)$$

Constraints (11) and (12) guarantee, respectively, the maximum power flow in each section of the network and the allowed range of voltage for the network nodes. The equations described in section 4 : (2)-(5) should be added in this subsection to complete the network constraints.

C)*Limitation of Grid Power Import*

This constraint prevents the DMS from purchasing power from up-stream grid which violates the limitation of grid power import. This limitation is enforced because of the sub-transmission substation transformers capacity.

$$\forall t \in T, \forall \omega \in \Omega: \left[\left(P_t^{DA} + P_{t,\omega}^{RT} \right)^2 + \mathrm{Q}_{t,\omega}^{G\;2} \right]^{1/2} \le LGPI \quad (13)$$

D)*DGs Generation Limit*

As can be seen in equations (14) and (15), the impact of DGs availability is modeled through the binary variable $a_{g,t,\omega}$ multiplied to the DGs active and reactive power limits.

$$\forall t \in T, \forall \omega \in \Omega: I_{g,t}^{DG} a_{g,t,\omega} P_g^{DG,\min} \le P_{g,t,\omega}^{DG} \le I_{g,t}^{DG} a_{g,t,\omega} P_g^{DG,\max} \quad (14)$$

$$\forall t \in T, \forall \omega \in \Omega: I_{g,t}^{DG} a_{g,t,\omega} Q_g^{DG,\min} \le Q_{g,t,\omega}^{DG} \le I_{g,t}^{DG} a_{g,t,\omega} Q_g^{DG,\max} \quad (15)$$

E)*DGs Ramping Constraints*

$$\forall g \in G, \forall \omega \in \Omega, \forall t \in T: P_{g,t,\omega}^{DG} - P_{g,(t-1),\omega}^{DG} \le UR_g \quad (16)$$

$$\forall g \in G, \forall \omega \in \Omega, \forall t \in T: P_{g,(t-1),\omega}^{DG} - P_{g,t,\omega}^{DG} \le DR_g \quad (17)$$

F)*DGs Intertemporal Constraints*

The minimum up-time(UT) and minimum down-time(DT) of DGs are modeled according to [18] as below:

$$\forall g \in G, \forall t' = 1,2,...,T - UT_g + 1: \quad \sum_{t=t'}^{t'+UT_g-1} I_{g,t}^{DG} \ge UT_g [I_{g,t'}^{DG} - I_{g,(t'-1)}^{DG}] \quad (18)$$

$$\forall g \in G, \forall t' = T - UT_g + 2,...,\mathrm{T}: \quad \sum_{t=t'}^{T} \left\{ I_{g,t}^{DG} - [I_{g,t'}^{DG} - I_{g,(t'-1)}^{DG}] \right\} \ge 0 \quad (19)$$

$$\forall g \in G, \forall t' = 1,2,...,\mathrm{T} - \mathrm{DT}_g + 1: \sum_{t=t'}^{t'+DT_g-1} [1 - I_{g,t}^{DG}] \ge DT_g [\mathrm{I}_{g,(t'-1)}^{DG} - I_{g,t'}^{DG}] \quad (20)$$

$$\forall g \in G, \forall t' = T - DT_g + 2,...,T: \quad \sum_{t=t'}^{T} \left\{ 1 - I_{g,t}^{DG} - [I_{g,(t'-1)}^{DG} - I_{g,t'}^{DG}] \right\} \ge 0 \quad (21)$$

G)*Load Curtailments Constraints*

$$\forall n \in N, \forall \omega \in \Omega, \forall t \in T: 0 \le P_{n,t,\omega}^{LC} \le P_{n,t}^{D} \quad (22)$$

$$\forall n \in N, \forall \omega \in \Omega, \forall t \in T: 0 \le Q_{n,t,\omega}^{LC} \le Q_{n,t}^{D} \quad (23)$$

H)*Storage Constraints*

These constraints are modeled comprehensive and in detail in [2], and are used in this formulation.

6. Numerical Results

The proposed decision making framework is applied to a typical distribution network test case [19] with two 5-MW and two 3-MW dispatchable DGs, one 10-MWh ES, and one 1-MW wind generator. This distribution network is connected to the main grid via a 10-MVA substation. The problem is implemented on a 2.2-GHz personal computer using CPLEX 12.6.

The historical data of Austrian Power Grid (APG) which are available online at [20] are used to model the wind power uncertainty via a set of 1000 scenarios reduced to 10 scenarios. Also each of the DGs availability uncertainties are modeled via a set of 500 scenarios reduced to 3 scenarios, with considering corresponding DGs MTTF and MTTR. Combining 10 wind scenarios and 3 scenarios for each DG, a joint scenario set of 810 scenarios is achieved. It should be noted that all of data used in this paper are available online on [19].

The day-ahead scheduling problem is solved for the given input data. According to the results, cost of Day-Ahead Market purchased power, expected cost of Real-Time Market purchased power, expected cost of DGs produced power, expected penalty cost of loss of load and total cost of operation are 1615.984$, 1076.3$,7295.8$, 618.28$ and 10606.364$, respectively. In the case of deterministic day-ahead scheduling, the total operation cost is equal to 8021.566 which is significantly lower than the total operation cost in the case of considering probable disturbances. Indeed, the additional operation cost, which is imposed to DMS, is caused by additional online capacity prepared to support the unavailability of DGs and overestimation of the wind turbine output in some scenarios during the scheduling period.

The hourly strategy of the DMS for market participation is depicted in Fig. 3. The DMS has more participation in Day-Ahead Market in almost every hour because the day-ahead prices are lower than real-time prices most of the time. Table I shows the DGs commitments and ES charging/discharging state. The commitment state is one when the DG is on and zero otherwise.

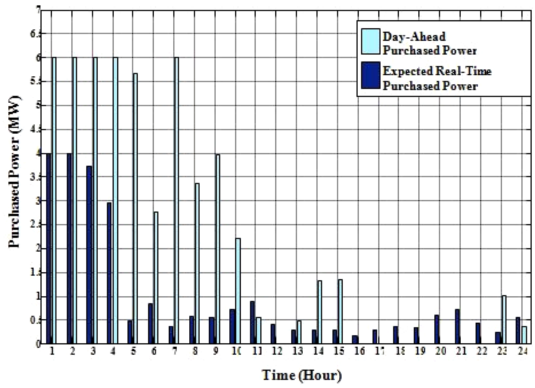

Fig. 3. Market participation strategy of the DMS

Table.1.
DERs Commitments

	Hours (1-24)																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DG1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
DG2	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
DG3	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
DG4	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0
ESs	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	-1	-1	-1	-1	-1	-1	-1	0	0

The energy storage charging, discharging and stand by states are represented by -1, 1 and 0, respectively. According to Table I, we see that the all DGs are on during the second half of scheduling horizon and also the ES is on discharging state in mentioned period. This observation is justifiable because during the second half of the scheduling horizon the share of purchased power from the market is decreased significantly. Also Table II shows the DGs dispatches which are coordinated with the DGs commitments. The charging/discharging pattern of the ES is depicted in Fig. 4 . In the early hours of scheduling horizon when the market prices are almost low than in final hours, the ES is charging, and the DMS is willing to discharge the stored energy in final hours. Also, Table 2. shows the DGs dispatches during the scheduling period.

7. Conclusion

According to revolutionary changes of the nature and operational strategy of distribution networks, this paper presents a decision making model for the DMS Day-Ahead Market participation, under the wind power and probable outage of DGs uncertainties. The proposed model is based on two-stage programming, and for avoiding the complexity of the problem a linearized AC power flow module is used, then the resulted problem is a MILP. The proposed model reflects the interactions between DERs and power market and assists the DMS to prepare adequate online capacity to counteract with uncertainties. Also, it is seen that the improving the flexibility of the day-ahead scheduling comes with additional cost, and then the DMS should make a tradeoff between economic and flexible operation.

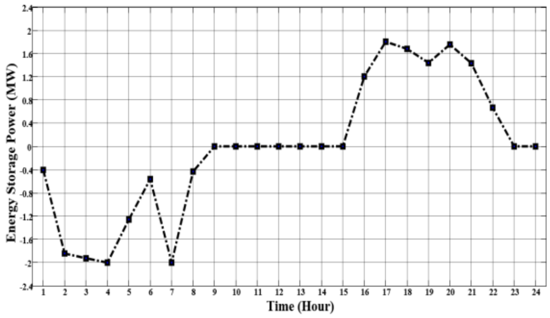

Fig. 4. Charhing/discharging schedule of the ES

Table.2.
DGs Dispatches(MW)

Generation Unit	Hours											
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
DG1	0	1.25	0.89	0.97	3.19	4.43	2.95	4.43	4.38	4.43	4.43	4.43
DG2	0	0	0	0	0	0	0	0	0	2.33	4.66	4.68
DG3	0	0	0	0	0	0	0	0	0	0	0	1.50
DG4	0	0	0	0	0	0	0	0	0	0	0	1.11
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
DG1	4.43	4.43	4.43	4.43	4.43	4.50	4.57	4.57	4.57	4.57	4.57	4.57
DG2	4.68	4.68	4.68	4.68	4.68	4.68	4.68	4.68	4.68	4.68	4.67	4.65
DG3	1.12	1.15	1.15	1.41	1.28	1.97	2.12	2.26	2.42	1.81	1.08	0.98
DG4	1.12	1.12	1.12	1.11	1.21	1.22	1.18	1.20	1.20	1.19	1.07	0

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