A DSO Framework for Comprehensive Market Participation of DER Aggregators

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Abstract—In this paper, a distribution system operator (DSO) framework is proposed to optimally coordinate distributed energy resources (DER) aggregators’ comprehensive participation in retail energy market as well as wholesale energy and regulation markets. Various types of DER aggregators, including energy storage aggregators (ESAGs), dispatchable distributed generation aggregators (DDGAGs), electric vehicles charging stations (EVCSs), and demand response aggregators (DRAGs), are modeled in the proposed DSO framework. Distribution network constraints are considered by using a linearized power flow. Case studies are performed to analyze the interactions between DER aggregators and wholesale/retail electricity markets.

I. INTRODUCTION

Due to environmental issues and increasing demand, the installed capacity of distributed energy resources (DER) is growing rapidly. DER aggregators, with low operating costs and fast ramping capability, can effectively participate in the wholesale energy and regulation markets. However, to participate in the wholesale markets, DER aggregators need to control DER power outputs across the distribution network, which will cause security and reliability issues to the distribution system operation. Hence, there is a need for an entity that coordinate DER aggregators to participate in the wholesale and retail markets while ensuring distribution network security.

Recently, many issues have been investigated for DER market participation [1]–[7]. In [1], the DER aggregator is defined to enable DER market participation. In [2], DER wholesale market participation is enabled through the virtual power plant. In [3], a decentralized approach, based on Dantzig-Wolfe decomposition, is proposed for DER coordination. This approach allows a numerous number of households to interact with an aggregator to minimize the total cost of purchasing electricity. In [4], [5], the optimal operation of a microgrid for its wholesale market participation is presented. Above previous works neglect the distribution network power flow constraints, therefore ignore the distribution network security while coordinating DER market participation. In [6], the bidding strategy of the virtual power plant considering the demand response market is presented. The demand response market is defined as a stage between the day-ahead market and the real-time market. In [7], the optimal bidding strategy of EV aggregators for participating in the day-ahead and the real-time markets is presented. In [6], [7], DC power flow is presented as distribution power balance constraints, which is inappropriate due to high impedances in distribution grids.

Motivated by the increasing DER penetration level and emerging smart distribution grid technologies, the power industry calls for a distribution operation framework which can handle DER market participation at the distribution level while respecting the distribution system operating constraints. Recently, the distribution system operator (DSO) is introduced to operate the distribution system and retail market with DER integration [8]–[10]. In [8], a day-ahead market framework operated by a DSO is presented. The DSO pays the distribution market participants at distribution locational marginal prices (D-LMPs). However, the distribution network and related constraints are not considered in the proposed model. In [9], a two-stage stochastic programming is applied to model day-ahead energy and reserve markets operated by a DSO. In [10], a distribution market operator (DMO) is defined which gathers offers from microgrids and aggregates them to participate in the wholesale market. A penalty factor is defined to represent the relationship between D-LMP and transmission-level LMP. Both [9] and [10] adopt DC power flow as the distribution system model, which is insufficient as discussed previously.

To the best of our knowledge, the DSO framework for optimal coordination of DER aggregators’ participation in wholesale energy and regulation markets as well as retail energy market has not been studied. In this paper, a DSO framework is proposed based on the mixed-integer linear programming (MILP) formulation. The proposed DSO operates the retail energy market and also gathers offers from DER aggregators for wholesale energy and regulation markets participation. Various types of DER aggregators, including energy storage aggregators (ESAGs), dispatchable distributed generation (DG) aggregators (DDGAGs), electric vehicles (EV) charging stations (EVCSs), and demand response aggregators (DRAGs), are considered in the proposed DSO framework. Moreover, the distribution network constraints are considered using a linearized power flow. Case studies are performed to analyze the interactions between DER aggregators and wholesale/retail electricity markets.

II. DSO MARKET FORMULATION

In this paper, the DSO is defined as a mediator that participates in the wholesale markets on one side and interacts with DER aggregators and end-user customers on the other
side. Various types of DER aggregators submit their offers to the DSO. The DSO collects these offers to operate the retail market as well as coordinate the offers to construct an aggregated bid for participating in day-ahead wholesale energy and regulation markets operated by the independent system operator (ISO). At the wholesale level, this paper assumes the market framework of California ISO (CAISO), whose pay-per-performance regulation market considers offers for both regulation capacity (with capacity-up and capacity-down offers) and regulation mileage [11]. The DSO is modeled as a price-taker in the day-ahead wholesale market. The MILP formulation of this DSO framework is presented below.

A. Objective Function

The proposed DSO minimizes the total operating cost while maximizing total social welfare in the distribution network. The regulation market model in [12], [13] is adopted. The objective function is presented in (1).

\[
\min \sum_{t \in T} \left[-P_{t, \pi, k}^{\text{cap}, \text{up}} - P_{t, \pi, k}^{\text{cap}, \text{dn}} - r_{t, \pi, k}^{\text{cap}, \text{up}} - r_{t, \pi, k}^{\text{cap}, \text{dn}} + \sum_{k \in K} P_{t, k, \pi, k} - \sum_{k \in K} r_{t, k, \pi, k}^{\text{cap}, \text{up}} + r_{t, k, \pi, k}^{\text{cap}, \text{dn}} - \sum_{k \in K} \sum_{\pi, k \in A} P_{t, \pi, k, \pi, k}^{\text{cap}, \text{up}}\right]
\]

where \( t \) and \( T \) are the index and set for the entire operating timespan; \( k \) and \( K = \{K_1, K_2, K_3, K_4\} \) are the index and set for all DER aggregators; \( k_1 \) and \( K_1 \) are the index and set for all DRAGs; \( k_2 \) and \( K_2 \) are the index and set for all ESAGs; \( k_3 \) and \( K_3 \) are the index and set for all EVCSs; \( k_4 \) and \( K_4 \) are the index and set for all DDGAGs; \( a \) and \( A \) are the index and set for all demand blocks; \( P_{t, \pi, k}^{\text{cap}, \text{up}} \) and \( P_{t, \pi, k}^{\text{cap}, \text{dn}} \) are the DSO’s aggregated offers to wholesale energy, regulation capacity-up and capacity-down markets, respectively; \( P_{t, k, \pi, k}^{\text{cap}, \text{up}} \) and \( P_{t, k, \pi, k}^{\text{cap}, \text{dn}} \) are the regulation market model in [12], [13]; \( r_{t, \pi, k}^{\text{cap}, \text{up}} \) and \( r_{t, \pi, k}^{\text{cap}, \text{dn}} \) are the wholesale energy, regulation capacity-up and capacity-down prices, respectively; \( P_{t, k, \pi, k}^{\text{cap}, \text{up}} \) and \( P_{t, k, \pi, k}^{\text{cap}, \text{dn}} \) are the wholesale regulation mileage-up and mileage-down prices; \( P_{t, k, \pi, k}^{\text{cap}, \text{up}} \) and \( P_{t, k, \pi, k}^{\text{cap}, \text{dn}} \) are the energy regulation capacity-up and capacity-down offers made by DER aggregator \( k \) with corresponding prices \( \pi_{t, \pi, k}^{\text{cap}, \text{up}} \); \( \pi_{t, \pi, k}^{\text{cap}, \text{dn}} \); \( \pi_{t, k, \pi, k}^{\text{cap}, \text{up}} \); \( \pi_{t, k, \pi, k}^{\text{cap}, \text{dn}} \), respectively; \( \mu_{t, \pi, k}^{\text{cap}, \text{up}} \) and \( \mu_{t, k, \pi, k}^{\text{cap}, \text{dn}} \) are historical scores for providing regulation mileage-up and mileage-down services; \( S_{t, \pi, k}^{\text{up}} \) and \( S_{t, k, \pi, k}^{\text{up}} \) are the regulation mileage-up and mileage-down ratios (the expected mileage for 1MW provided regulation capacity); \( P_{t, \pi, k}^{\text{cap}, \text{up}} \) and \( \pi_{t, \pi, k}^{\text{cap}, \text{up}} \) are the power consumption and the corresponding energy price at each demand block.

B. Constraints for Demand Response Aggregators (DRAGs)

The operating constraints for DRAGs are as follows:

\[
\sum_{a \in A} P_{a, t, k_1} - r_{t, k_1}^{\text{cap}, \text{dn}} \geq 0; \quad \forall t \in T, \forall k_1 \in K_1
\]
are in their permitted ranges. Equations (18)-(19) limit ESAG’s offers to the energy, regulation capacity-up and capacity-down markets with respect to the charging and discharging rates.

D. Constraints for EV Charging Stations (EVCSs)

EVCSs are modeled as EV charging aggregators and are assumed to have unidirectional flow power as assumed in [13]. Constraints related to the operation of EVCSs are as follows:

\[ 0 \leq P_{k_3} \leq E_{k_3}^{max} b_{k_3}; \quad \forall t \in T', \forall k_3 \in K_3 \]  
\[ 0 \leq r_{t,k_3}^{cap,up} \leq E_{k_3}^{max} b_{k_3}; \quad \forall t \in T', \forall k_3 \in K_3 \]  
\[ 0 \leq r_{t,k_3}^{cap,dn} \leq E_{k_3}^{max} b_{k_3}; \quad \forall t \in T', \forall k_3 \in K_3 \]  
\[ P_{t,k_3} + r_{t,k_3}^{cap,up} \leq E_{k_3}^{max}; \quad \forall t \in T', \forall k_3 \in K_3 \]  
\[ P_{t,k_3} - r_{t,k_3}^{cap,dn} \geq 0; \quad \forall t \in T', \forall k_3 \in K_3 \]  
\[ 0.9C L_{k_3}^{max} b_{k_3} \leq E_{k_3}^{int} b_{k_3} + \sum_{t \in T'} [P_{t,k_3} + r_{t,k_3}^{cap,up}] \mu_{t,3}^{ramp} \leq [C L_{k_3}^{max} b_{k_3}]; \quad \forall k_3 \in K_3 \]

where \( T' \subseteq T \) is the set of hours when \( E_{k_3}^{max} \) is available; \( E_{k_3}^{max} \) is the maximum charging rate; \( E_{k_3}^{max} \) is the maximum permitted value for regulation capacity offers, \( C L_{k_3}^{max} \) is the maximum charge level; \( E_{k_3}^{int} b_{k_3} \) is the initial charge level; \( \gamma_{k_3}^{ramp} \) is the ramping efficiency; \( b_{k_3} \) is a binary variable which enables the DSO not to allocate the minimum power to EVCSs when their offering price is low.

Equations (20)-(24) limit EVCS’s offers to the energy, regulation capacity-up and capacity-down markets. Equation (25) ensures that the charge level of EVs is full.

E. Constraints for Dispatchable DG Aggregators (DDDGAs)

The operating constraints for DDDGAs are as follows:

\[ P_{t,k_4} + r_{t,k_4}^{cap,up} \leq P_{k_4}^{max}; \quad \forall t \in T, \forall k_4 \in K_4 \]  
\[ P_{t,k_4} - r_{t,k_4}^{cap,dn} \geq P_{k_4}^{min}; \quad \forall t \in T, \forall k_4 \in K_4 \]  
\[ 0 \leq r_{t,k_4}^{cap,up} \leq R U_{k_4}; \quad \forall t \in T, \forall k_4 \in K_4 \]  
\[ 0 \leq r_{t,k_4}^{cap,dn} \leq R D_{k_4}; \quad \forall t \in T, \forall k_4 \in K_4 \]

where \( P_{k_4}^{max} \) and \( P_{k_4}^{min} \) are the maximum and minimum power generations; \( R U_{k_4} \) and \( R D_{k_4} \) are the ramp-up and ramp-down rates.

Equations (26) and (27) limit DDDGAG’s offers to the energy, regulation capacity-up and capacity-down markets. Equations (28) and (29) ensure the regulation capacity-up/capacity-down offers are lower than maximum ramp-up/ramp-down rates.

F. Distribution Power Flow Equations

The linearized power flow equations are adopted from [14]:

\[ \sum_{k_1 \in K_1 \cap A} H_{n,k_1} P_{a,t,k_1} + \sum_{k_3 \in K_3} H_{n,k_3} P_{t,k_3} + P_{t,n}^D \]  
\[ - \sum_{k_2 \in K_2} H_{n,k_2} P_{t,k_2} - \sum_{k_4 \in K_4} H_{n,k_4} P_{t,k_4} \]  
\[ + H_{n}^{sub} P_{t}^{sub} + \sum_{j \in J} P_{j,t} A_{j,n} = 0; \quad \forall t \in T, \forall n \in N \]

where \( H_{n,k} \) is the mapping matrix of DER aggregator \( k \) to bus \( n \); \( P_{t,n}^D \) and \( Q_{t,n}^D \) are the inelastic active and reactive power loads at each node; \( P_{j,t} \) and \( Q_{j,t} \) are the active and reactive power flow at branch \( j \); \( A_{j,n} \) is the incidence matrix of branches and buses; \( \phi \) is the phase angle; \( C_m \) is the connecting nodes matrix.

Equations (30) and (31) represent the active and reactive power flow. Voltage drop at each line is represented by equation (32) and is limited by equation (33). Active and reactive power limits at each line are represented by (34) and (35). Equations (36) and (37) represent DSO’s aggregated offers for participating in the wholesale energy, regulation capacity-up and capacity-down markets.

III. CASE STUDIES

Case studies are performed on the small distribution network shown in Fig.1. The system contains 5 nodes, where \( N = \{1, 2, 3, 4, 5\}; \) 4 lines, where \( J = \{1, 2, 3, 4\}; \) a DRAG, where \( k_1 = \{1\}; \) an ESAG, where \( k_2 = \{2\}; \) an EVCS, where \( k_3 = \{3\}; \) a DDDGA, where \( k_4 = \{4\}. \) The studies are performed over 24 hours, \( T = \{1, 2, ..., 24\}. \) \( ES \) are available between hour 16 and hour 24, \( T' = \{16, 17, ..., 24\}. \) Initial charge level of ESAG is 8MW. The following parameters are assumed: \( \eta_{k_2}^{a} = 0.9, \epsilon_{k_2}^{b} = 1, E_{k_2}^{int} = 10MW, D R_{k_2}^{max} = 2MW, \) \( E_{k_2}^{max} = 10MW, \) \( DR_{k_3}^{max} = 0.5MW, \) \( E_{k_3}^{max} = 5MW, \) \( ERR_{k_3}^{max} = 0.5MW, \) \( P_{k_4}^{min} = 0, \)
During peak hours, the DDGAG’s remaining capacity (i.e., the wholesale energy price is higher than the wholesale regulation capacity price) offers regulation capacity-up service at its maximum ramping rate. Hence, the DDGAG offers regulation capacity-up service since this can increase its charging level. This causes the ESAG to purchase energy from the wholesale market at these hours are high. The DSO buys energy from the wholesale market at other hours. The EVCS purchases energy at hours 16 and 24, when the wholesale energy price is the lowest among all the hours when EVs are available. The EVCS offers regulation capacity-up service at hours 19-22, since 1) the wholesale regulation capacity-up price is high; and 2) the EVCS can increase EV charge levels by offering regulation capacity-up service. The DRAG does not purchase energy from the wholesale market at peak hours. Also, it is not supplied by ESAG and DDGAG at peak hours, as they both sell energy to the wholesale market. However, the DRAG prefers offering regulation capacity to the wholesale market. Hence, it purchases energy that is enough for offering regulation capacity-down service.

| t  | Wholesale | ESAG | DDGAG | EVCS | DRAG | Regulation |
|----|-----------|------|-------|------|------|------------|
|    | E (MW)    | C (MW) | E (MW) | C (MW) | E (MW) | C (MW) | up (MW) | dn (MW) |
| 1  | 24.3      | 14.7  | 25     | 28    | 27    | 29     | 30      | 0.45   | 0.42  |
| 2  | 23.7      | 17.3  | 25     | 28    | 27    | 29     | 30      | 0.45   | 0.42  |
| 3  | 23        | 16.6  | 25     | 28    | 27    | 29     | 30      | 0.45   | 0.42  |
| 4  | 23        | 16.6  | 25     | 28    | 27    | 29     | 30      | 0.45   | 0.42  |
| 5  | 23        | 17.3  | 25     | 28    | 27    | 29     | 30      | 0.45   | 0.42  |
| 6  | 25.9      | 22.7  | 28     | 29    | 28    | 29     | 31      | 0.48   | 0.48  |
| 7  | 29.4      | 30.4  | 28     | 29    | 28    | 29     | 31      | 0.48   | 0.48  |
| 8  | 30.7      | 33.6  | 28     | 29    | 28    | 29     | 31      | 0.48   | 0.48  |
| 9  | 30.1      | 33.6  | 28     | 29    | 28    | 29     | 31      | 0.48   | 0.48  |
| 10 | 29.1      | 31.4  | 28     | 29    | 28    | 29     | 31      | 0.48   | 0.48  |

**TABLE I**

| Hour | Wholesale share (MW) | ESAG share (MW) | DDGAG share (MW) | EVCS share (MW) | DRAG Share (MW) | Regulation |
|------|----------------------|-----------------|------------------|-----------------|----------------|------------|
| 1    | 24.3                 | 14.7            | 25               | 28              | 27             | 29         |
| 2    | 23.7                 | 17.3            | 25               | 28              | 27             | 29         |
| 3    | 23                   | 16.6            | 25               | 28              | 27             | 29         |
| 4    | 23                   | 16.6            | 25               | 28              | 27             | 29         |
| 5    | 23                   | 17.3            | 25               | 28              | 27             | 29         |
| 6    | 25.9                 | 22.7            | 28               | 29              | 28             | 29         |
| 7    | 29.4                 | 30.4            | 28               | 29              | 28             | 29         |
| 8    | 30.7                 | 33.6            | 28               | 29              | 28             | 29         |
| 9    | 30.1                 | 33.6            | 28               | 29              | 28             | 29         |
| 10   | 29.1                 | 31.4            | 28               | 29              | 28             | 29         |

\[ P_{k_1}^{cap,max} = 5\text{ MW}, \quad R_{U,k_1} = RD_{k_4} = 1\text{ MW}, \quad P_{a,t,k_1}^{cap,max} = 10\text{ MW}, \quad r_{k_1}^{cap,up,max} = r_{k_1}^{cap,dn,max} = 1\text{ MW}. \]

The energy and regulation capacity prices in [12] are considered. The hourly factors in [15] are used to generate hourly prices. The regulation capacity-up and capacity-down prices are assumed to be equal. Regulation mileage-up and mileage-down prices are assumed to be equal. Regulation mileage prices are assumed to be 1/20 of corresponding regulation capacity prices. Hourly energy prices, capacity up/down prices, and hourly regulation signals are given in Table I, where \( E \) denotes energy price, \( C \) denotes regulation capacity price.

1) Market Outcomes: The outcomes of DSO market coordination are presented in Fig. 2. The trades between the DSO and the wholesale market are shown in Fig. 2(a). The awarded energy and regulation market shares of ESAG, DDGAG, EVCS, and DRAG are shown in Fig. 2(b)-Fig. 2(e), respectively. At hours 8, 9, 18, 19, 20, 21, the DSO sells energy to the wholesale market since the prices of energy of the wholesale market at these hours are high. The DSO buys energy from the wholesale market at other hours.

The ESAG prefers offering regulation capacity-down service since this can increase its charging level. This causes the ESAG to offer regulation capacity-down service. The EVCS purchases energy at hours 16 and 24, when the wholesale energy price is the lowest among all the hours when EVs are available. The EVCS offers regulation capacity-up service at hours 19-22, since 1) the wholesale regulation capacity-up price is high; and 2) the EVCS can increase EV charge levels by offering regulation capacity-up service.
DDGAG’s energy price offer is higher than the whole market price. This prevents the DDGAG from selling energy to the wholesale market, and also causes the DDGAG to provide regulation capacity-up service only. Therefore, the DDGAG’s regulation capacity revenue becomes constant after Case 15.

IV. CONCLUSION

This paper proposes a DSO framework for coordinating DER aggregators to participate in the wholesale energy/regulation markets and retail energy market. Various types of aggregators are considered in the DSO operation. Case studies on a small distribution grid show the key interactions among wholesale energy/regulation markets, retail energy market operation, and DER aggregators’ market participation. Sensitivity analysis shows the DER aggregators’ total revenue tends to decrease as they increase their energy price offers.

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