Distribution System Operator (DSO) Design for Distributed Energy Resources Market Participation

by

Mohammad Mousavi

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Graduate Supervisory Committee:

Meng Wu, Chair
Mojdeh Khorsand
Geunyeong Byeon
Duong Nguyen

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ABSTRACT

In this dissertation, a distribution system operator (DSO) framework is proposed to optimally coordinate distributed energy resources (DER) aggregators' comprehensive participation in the 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. An important characteristic of a DSO is being capable of handling uncertainties in the system operation. An appropriate method for a market operator to cover uncertainties is using two-stage stochastic programming. To handle comprehensive retail and wholesale markets participation of distributed energy resource (DER) aggregators under uncertainty, a two-stage stochastic programming model for the DSO is proposed. To handle unbalanced distribution grids with single-phase aggregators, A DSO framework is proposed for unbalanced distribution networks based on a linearized unbalanced power flow which coordinates with wholesale market clearing process and ensures the DSO's non-profit characteristic.

When proposing a DSO, coordination with the ISO is important. A framework is proposed to coordinate the operation of the independent system operator (ISO) and distribution system operator (DSO). The framework is compatible with current practice of the U.S. wholesale market to enable massive distributed energy resources (DERs) to participate in the wholesale market. The DSO builds a bid-in cost function to be submitted to the ISO market through parametric programming. A pricing problem for the DSO is proposed. In pricing problem, after ISO clears the wholesale market, the locational marginal price (LMP) of the ISO-DSO coupling substation is determined, the DSO utilizes this price to solve the DSO pricing problem. The DSO pricing problem determines the distribution LMP (D-LMP) in the distribution system and calculates the payment to each aggregator. An efficient algorithm is proposed to solve the ISO-DSO coordination parametric programming problem. Notably, our proposed algorithm significantly improves the computational efficiency of solving the parametric programming DSO problem which is computationally intensive. Various case studies are performed to analyze the market outcome of the proposed DSO framework and coordination with the ISO.

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NOMENCLATURE

Indices and sets:

t/T	Index/set for the entire operating timespan.
k/K	Index/set for all DER aggregators (K=$\{K_1 \cup K_2 \cup K_3 \cup K_4 \cup K_5\}$).
k_1/K_1	Index/set for all DRAGs.
k_2/K_2	Index/set for all ESAGs.
k_3/K_3	Index/set for all EVCSs.
k_4/K_4	Index/set for all DDGAGs.
k_5/K_5	Index/set for all REAGs.
ϕ/Φ	Index/set for all phases.
j/J	Index/set for all branches.
m, n/N	Index/set for all nodes.
a/A	Index/set for all demand blocks.
$T^{'} \subseteq T$	Set of hours when EVs are available.

Constants and parameters:

π_t^e	Wholesale energy price at time t (\$/MWh).
$\pi_t^{cap,up}/\pi_t^{cap,dn}$	Wholesale regulation capacity-up/down price at time t (\$/MWh).
$\pi_t^{mil,up}/\pi_t^{mil,dn}$	Wholesale regulation mileage-up/down price at time t (\$/MWh).
$\pi_{t,k}^e$	Energy offering price of DER aggregator k at time t (\$/MWh).
$\pi_{t,k}^{cap,up}/\pi_{t,k}^{cap,dn}$	Regulation capacity-up/down offering price of DER aggregator k at time t (\$/MWh).
$\pi_{t,k}^{mil,up}/\pi_{t,k}^{mil,dn}$	Regulation mileage-up/down offering price of DER aggregator k at time t (\$/MWh).
μ_t^{up}/μ_t^{dn}	Regulation mileage-up/down ratio at time t (the expected mileage for 1 MW provided regulation capacity).
S^{up}/S^{dn}	Historical scores for providing regulation mileage-up/down services.

π^{e}_{a,t,k_1}	Energy offering price of demand block a of DRAG k_1 at time t (\$/MWh).
$\overline{P}_{a,k_1,\phi}$	Maximum power consumption of demand block a of DRAG k_1 on phase ϕ (MW).
$\overline{r}^{up}_{k,\phi}/\overline{r}^{dn}_{k,\phi}$	Maximum regulation capacity-up/down for aggregator k on phase ϕ (MW).
$\eta^{ch}_{k_2}/\eta^{di}_{k_2}$	Charge/discharge efficiency of ESAG k_2.
$\overline{C}_{k_2,\phi}/\overline{D}_{k_2,\phi}$	Maximum charge/discharge rate of ESAG k_2 on phase ϕ (MW).
$\underline{E}_{k_2,\phi}$, $\overline{E}_{k_2,\phi}$	Minimum/Maximum charge level of ESAG k_2 on phase ϕ (MWh).
$\overline{R}^{c}_{k_3,\phi}$	Maximum charge rate of EVCS k_3 on phase ϕ (MW).
$\overline{CL}_{k_3,\phi}$	Maximum charge level of EVCS k_3 on phase ϕ (MWh).
$E^{int}_{k_3,\phi}$	Initial charge level of EVCS k_3 on phase ϕ (MWh).
$\gamma^{ch}_{k_3}$	Charge efficiency of EVCS k_3.
$\overline{P}_{k_4,\phi}/\underline{P}_{k_4,\phi}$	Maximum/minimum power generation of DDGAG k_4 on phase ϕ (MW).
$H_{n,k}$	Mapping matrix of aggregator k to node n.
H^{sub}_{n}	Mapping matrix of substation to node n.
$P^{D}_{t,n,\phi}/Q^{D}_{t,n,\phi}$	Inelastic active/reactive power load at time t at node n on phase ϕ (MW).
$A_{j,n}$	Incidence matrix of branches and nodes.
δ	Phase angle.
$C_{m,n}$	Incidence matrix of nodes.
$Z_{j,\phi,\psi}$	Impedance between phases ϕ and ψ of branch j (Ω).
$\underline{V}/\overline{V}$	Lower/Upper voltage limit (kV).
$\overline{Pl_j}/\overline{Ql_j}$	Maximum active/reactive permissible flow of branch j (MW/MVar).

Variables:

$P^{sub}_{t,\phi}/Q^{sub}_{t,\phi}$ DSO's aggregated offer to the wholesale energy market at time t on phase ϕ (MW).

$r^{sub,up}_{t,\phi}/r^{sub,dn}_{t,\phi}$ DSO's aggregated offer to wholesale regulation capacity-up/down market at time t on phase ϕ (MW).

$P_{t,k,\phi}$ Energy offer made by aggregator k at time t on phase ϕ (MW).

$r^{up}_{t,k,\phi}/r^{dn}_{t,k,\phi}$ Regulation capacity-up/down offer of aggregator k at time t on phase ϕ (MW).

$P_{a,t,k_1,\phi}$ Energy offer of demand block a of DRAG k_1 at time t on phase ϕ (MW).

$E_{t,k_2,\phi}$ Charge level of ESAG k_2 at time t on phase ϕ (MWh).

$P^{di}_{t,k_2,\phi}/P^{ch}_{t,k_2,\phi}$ Discharge/charge power of ESAG k_2 at time t on phase ϕ (MW).

$r^{up,di}_{t,k_2,\phi}/r^{dn,di}_{t,k_2,\phi}$ Regulation capacity-up/down provided by ESAG k_2 at time t on phase ϕ in the discharge mode (MW).

$r^{dn,ch}_{t,k_2,\phi}/r^{up,ch}_{t,k_2,\phi}$ Regulation capacity-up/down provided by ESAG k_2 at time t on phase ϕ in the charge mode (MW).

$b_{t,k_2,\phi}$ Binary variable indicating charge or discharge ($b_{t,k_2,\phi} = 0$ or 1) mode of ESAG k_2 at time t on phase ϕ.

$b_{k_3,\phi}$ Binary variable for not allocating the minimum power to EVCS k_3 on phase ϕ when its offering price is low (when $b_{k_3} = 0$).

$Pl_{j,t,\phi}/Ql_{j,t,\phi}$ Active/reactive power flow of branch j at time t on phase ϕ in (MW/MVar).

$S_{j,\phi}$ Apparent power of branch j on phase ϕ (MVA).

$I_{j,\phi}$ Current of branch j on phase ϕ (A).

$V_{n,\phi}$ Voltage of node n on phase ϕ (kV).

Chapter 1

INTRODUCTION

1.1 Motivation

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.

Federal Energy Regulatory Commission (FERC) Order No. 2222 has required all the US independent system operators (ISOs) to completely open their wholesale markets for distributed energy resources (DERs) [1]. A huge number of DER aggregators are anticipated to enter the wholesale energy and ancillary services markets in the near future. This may cause significant challenges to transmission and distribution operations [2]: 1) These aggregators are modeled as small generators in the ISO's market system. Adopting a huge number of these small generators could cause a significant computational burden to the ISO's unit commitment and economic dispatch process. 2) To participate in the ISO's market, the aggregators need to control numerous DER outputs across the distribution system without any information on the operating constraints of the distribution grid, which could cause voltage and thermal violations in the distribution system. Therefore, there is a need for an entity to coordinate DER aggregators' market activities while assuring the secure and reliable operation of the distribution network and reducing the computational burden for the wholesale market clearing process.

1.2 FERC Order No. 2222

On September 17, 2020, FERC issued Order No. 2222 to remove the barriers preventing DERs from participation in the wholesale market. Based on this order, all the ISOs should revise their tariffs such that the DERs with a capacity of greater than 100 kW can participate in the energy and ancillary service markets under one or more participation models. Integrating the DERs in the ISOs wholesale markets has a variety of benefits. All the ISOs need to revise their tariffs such that:

- Allow DERs to participate directly in the wholesale market.
- Allow DERs aggregators to participate under one or more participation models which capture their operational and technical constraints.
- Their minimum size requirement should not exceed 100 kW.
- Provide locational requirements.
- Determine distribution factors for DER aggregations.
- Provide data requirements and telemetry requirements.
- Coordination between ISOs, utility companies, and DER aggregators.
- Provide agreements for DER aggregators' market participation.

1.2.1 Definition of DERs and DER aggregators

FERC has defined a DER as "any source located on the distribution system, any substation thereof or behind a customer meter. These resources may include, but are not limited to, the resources that are in front of and behind the customer meter, electric storage resources, intermittent generation, distributed generation, demand response energy efficiency, thermal storage, and electric vehicles and their supply equipment- as long as such a resource is located on the distribution system, any substation thereof or behind a customer meter."

FERC has defined a DER aggregator as "the entity that aggregates one or more distributed energy resources for purpose of participation in capacity, energy and/or ancillary service markets of the regional transmission organizations and/or independent system operators."

1.2.2 Eligibility to participate through a DER aggregator

Participation model

In the final rule, the proposal is revised to enable ISOs to have more flexibility to see whether they should revise their existing models. The ISOs have the flexibility to use their existing market models or create one or more new participation models or use a combination.

Types of technology

FERC requires that ISOs do not prevent any type of technology from wholesale market participation. They must revise their tariffs such that different types of technology of DERs can participate in a single DER aggregation.

Double counting of services

FERC allows ISOs to limit the participation of DERs that are receiving compensation for participation in the same service in another market. FERC requires that ISOs revise their tariffs such that 1) allow DERs to participate in the retail program for wholesale market participation 2) allow DERs to participate in multiple wholesale market programs 3) limit the participation of DERs that are receiving compensation for the same service in the retail market.

Minimum and maximum size of aggregation

FERC requires that ISOs revise their tariffs such that their minimum participation requirement does not exceed 100 kW. FERC does not adopt any maximum requirement for DER aggregators that have multiple pricing nodes.

Minimum and maximum capacity requirements for DERs participating in an aggregation

The FERC does not adopt any minimum and maximum size requirement for individual DERs participating in the wholesale market through DER aggregations.

Single resource aggregation

The FERC requires that ISO revise their tariffs such that a single qualified DER can participate in the wholesale market as a DER aggregation.

1.3 Participation through distribution system operator (DSO)

As mentioned, 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.

The DSO can run the retail market and gather the offers from different aggregators in the distribution network to aggregate a bid for wholesale market participation of the DER aggregators while making sure that the physical and operational constraints of the distribution system are met. The proposed DSO reduces the computational burden for wholesale market clearing by moving the DER-related market clearing computations to the DSO level, while satisfying distribution system operating constraints and being compatible with the current wholesale market structures.

1.4 Overview of the report

This report is organized as follows: Chapter 2 provides a literature review on the existing works on DER market participation. First, a literature review on the direct market participation of DERs is presented. Then, existing works on market participation of DERs through DSO are reviewed.

Chapter 3 provides a DSO framework for comprehensive market participation of DER aggregators. The DSO is defined as a mediator that runs the retail market on the distribution network and gathers offers from the DER aggregators to build an aggregated bid for wholesale market participation. Without loss of generality, wholesale market rules of the California ISO (CAISO) are adopted here. A market settlement procedure is presented which ensures the non-profit role of the DSO in the market. Simulation results on a small distribution system are implemented to verify the effectiveness of the proposed DSO model. The role of the DSO is investigated through simulation results.

Chapter 4 provides a two-stage stochastic programming approach for designing the DSO to handle uncertainty in the market. The formulation of the previous chapter is updated based on considering the two-stage stochastic programming approach. Simulation results are provided in this chapter to investigate the proposed model for handling uncertainty.

Chapter 5 provides a distribution system operator (DSO) framework for wholesale and retail market participation of distributed energy resources (DERs) aggregators as well as single-phase aggregators through the unbalanced retail market.

Chapter 6 proposes a framework to coordinate the operation of the independent system operator (ISO) and distribution system operator (DSO) to leverage the wholesale market participation of distributed energy resources (DERs) aggregators while ensuring secure operation of distribution grids based on parametric programming.

Finally, Chapter **??** provides potentials for the future work of this report.

Chapter 2

LITERATURE SURVEY

Existing works on DER market participation fall into two categories. The first category considers DERs participating in the wholesale markets directly through aggregators. Second category of works defines the distribution system operator (DSO) to coordinate the DER market participation.

2.1 DER market participation through aggregators

In [3], the concept of the aggregator is defined to enable distributed energy resources (DERs) in order to participate in the electricity market. The proposed aggregator consists of local energy sources as well as demand flexibility. The aggregator gathers the electricity from the local energy systems in order to trade with the electricity market. In the proposed method, local energy systems are responsible for meeting the demand. Also, they can trade with each other. The proposed method is modeled by a stochastic optimization problem due to the intermittent nature of some DERs. The model of the problem is mixed-integer linear programming. In this paper, the proposed market structure is novel. However, the paper does not consider the market behavior and the independent system operator (ISO). Also, the network is not considered in the paper. The aggregator is located in the distribution system. Hence, considering the distribution network is important.

In [4], an optimal bidding strategy problem of a load-serving entity (LSE) is proposed in order to participate in the wholesale energy and reserve markets. The energy and reserve markets are cleared simultaneously. A trilayer market framework is proposed. In the upper layer of the market, the ISO clears the wholesale electricity market. In the middle layer, LSE determines the energy and reserve bids such that its total profit is maximized. In the lower layer, end-user customers purchase energy from the retail electricity market and also sell reserve to the retail electricity market. The trilayer market is modeled as a bi-level optimization problem in which in the upper level, the total profit of the LSE is maximized, and in the lower-level problem, wholesale electricity market, as well as retail electricity market, are cleared. The proposed optimization problem is nonlinear and hard to solve. Hence, the problem is converted to mixed-integer linear programming by using the KKT condition of the lower level problem and big number mathematical technique. The distribution network is ignored in this study. It is assumed that end-user consumers are located in the transmission network. Hence, the technical constraints of the distribution network are neglected. DERs are ignored in this study.

In [5], a mathematical model for the PJM clearing process considering energy and regulation markets is presented. In the proposed regulation market, regulation capacity and regulation performance are considered. Also, the optimal offering strategy of an energy resource in order to participate in the proposed market is presented. The transmission network is not considered in the market framework. Local markets are not considered in this letter.

In [6], the optimal operation of the EVs and an energy storage aggregator in the day-ahead energy and regulation market is proposed. The aggregator controls numerous EVs and an energy storage system. The model of the EVs is considered to be unidirectional which is coordinated with the energy storage system. The uncertainty is also considered in the model using stochastic programming. Also, conditional value at risk as a tool for risk management is considered. The day-ahead energy and regulation markets are proposed based on the California ISO in which participants are paid based on capacity and mileage performances. In the proposed model, energy storage degradation is also considered. Due to the fact that EVs and energy storage systems are located in the distribution network, constraints related to the network are also considered using linear power flow. The model of the optimization problem is mixed-integer linear programming which is solvable by commercial solvers. Renewable energy resources and their coordination with EVs and energy storage systems are not considered. The retail electricity market is not considered in this study. Flexible loads are not considered in this study.

In [7], a decentralized approach is proposed for coordinating DERs in which a numerous number of households interact with an aggregator in order to minimize the total cost of purchasing electricity. The focus of this paper is based on the demand response aspect of DERs. The presented decentralized model is based on Dantzig-Wolfe decomposition in which any type of resource that can be modeled using mixed integer programming is allowed to be included in the problem. From the global optimality point of view, it is stated that the decentralized approach is the same as the centralized model. The market framework is not considered. It is important since DERs can effectively participate in the electricity market and make a profit. The distribution network is not considered in this study. Hence, network constraints can not be considered in the proposed model.

In [8], the optimal operation of a virtual power plant in order to participate in energy and reserve markets is presented. The proposed virtual power plant consists of a conventional generating unit, a wind power plant, an energy storage system, and a flexible load. An adaptive robust optimization model is presented to cover the uncertainty in the wind power plant generation and market prices. The uncertainty in the market prices is modeled using generating scenarios while uncertainty in the wind power generation is modeled using confidence bands. The adaptive robust optimization problem is proposed as a trilevel optimization problem and is solved using a decomposition algorithm. The distribution system network is not considered in the proposed model. The model of the optimization problem is nonlinear and the globally optimum solution can not be guaranteed.

In [9], the optimal bidding strategy of a microgrid in order to participate in the day-ahead and real-time markets is presented. The microgrid consists of DG, storage, and price responsive loads. In order to cover the uncertainties in the generating power of DG, load variation, and market prices, a hybrid stochastic robust optimization model is proposed. The problem is modeled using mixed-integer linear programming. The problem is formulated in three-stage stochastic programming. In the first stage, microgrid as a utility submits its bid before the day-ahead, and real-time markets get cleared and the output power of intermittent DGs becomes known. In the second stage, day-ahead market prices are known and the power output of the DGs is estimated using generating scenarios before the real-time market gets cleared. In the second stage, real-time market prices are known. EVs are not considered in this study. The retail electricity market is not considered. The distribution network is not considered.

In [10], the bidding strategy problem of the virtual power plant considering the demand response market is presented. In this paper, a commercial virtual power plant consists of renewable energy resources, conventional units, and energy storage systems. Due to the uncertainty in renewable power outputs, retail demand, and market prices, stochastic programming is considered. The demand response market is defined as a stage between the day-ahead market and real-time market in which the virtual power plant is able to compensate the unbalance power between the day-ahead market by purchasing flexibility from demand response providers. This can increase the total profit of the virtual power plant since prices in the real-time market are higher than that of the demand response market. The proposed optimization problem is modeled by using mixed-integer linear programming. EVs are not considered in the proposed model. This is important due to the fact that they can significantly participate in the defined demand response market. In order to include power flow equations, DC power flow is considered. Since the VPP is located in the distribution system DC power flow is not accurate due to the high power losses.

In [11], the optimal bidding strategy of EV aggregators for participating in day-ahead and the real-time market is presented. Uncertainties in the day-ahead and real-time markets are considered. Conditional value at risk is presented as a tool for risk management. The objective is to minimize the conditional expected total cost of purchasing energy from the day-ahead and real-time markets. In the proposed model, a penalty cost is defined in order to avoid a large difference between bidding of day-ahead and real-time markets. The pool structure of PJM which includes day-ahead market and real-time balancing market is considered as the market framework. Renewable energy resources are neglected in this study. Participation in the regulation market is neglected in this study. In order to include power balance equations, DC power flow is presented. This assumption is not accurate due to the fact the EVs are located in the distribution network in which power losses are high. Hence, DC power flow is not appropriate.

In [12], optimal resource management of a microgrid in order to participate in the wholesale and local markets as well as transactive energy including the integration of these two markets is presented. The microgrid includes DGs, EVs, energy storage systems, and demand response. In order to model the resource management problem of the microgrid in the presence of uncertainty, stochastic optimization is used. The objective is to minimize the total cost of the operation of the proposed microgrid. The problem is modeled using mixed-integer linear programming. The distribution network is not considered in the proposed model. Degradation of storage and EVs are not considered. Bilateral transactive energy is not considered in the model.

In [13], the optimal operation of a retailer in the day-ahead and real-time wholesale markets considering DR is presented. The retail customers submit their bids to the retailer to increase or decrease their consumption once needed. The retailer coordinates its generation along with considering customers' offers to participate in the day-ahead and real-time markets. It is assumed that the retailer participates in the day-ahead market in order to supply its customers and its renewable energy production is assumed only to supply its demand. However, it can trade its power deviation in the real-time market. Due to the presence of uncertainty in the proposed model, two-sage stochastic programming is proposed to model the problem. The regulation market is not considered in this work. However, the retailer can trade the flexibility provided by retail customers in order to participate in the regulation market. Renewable energy resources are not included in the wholesale market. The distribution system is not considered in this work. Energy storage systems and EVs are not considered.

2.2 DER market participation through DSO

In [14], it is stated that due to the high penetration of DERs, the distribution system operator (DSO) needs a high value of flexibility. The local flexibility market is defined to propose a framework for selling flexibility. A smart energy service provider is defined as an aggregator which is responsible for gathering the flexibility and running the local flexibility market. This aggregator will run the local flexibility market and send control signals for flexible loads which have signed contracts for selling flexibility to the market. It is assumed that the aggregator will control these loads through signals that will send at the time the flexibility is requested. The proposed market is modeled by a mixed-integer linear programming optimization problem. The distribution network is neglected. This can not be ignored due to the fact that DERs, as well as flexible loads, are located in the distribution system. Due to the fact that the distribution network is ignored, technical constraints of the distribution network can not be considered. The wholesale market is not considered. The aggregator can buy flexibility from the wholesale market when it cannot meet the flexibility required from DERs. Also, it can sell flexibility to the wholesale market once there is flexibility more than required by DSO.

In [15], DERs market integration through the concept of virtual power plant is presented considering the secure operation of the distribution network. The virtual power plant coordinates its resources in order to participate in the day-ahead and intraday markets. Then, DSO performs a power flow to determine lines that are overloaded. By using sensitivity factors, which relate the overloaded line power to the injected power of the bus at which the VPP is located, the DSO determines the power exchange in order to relieve congestion. The DSO repeats this action until no line is congested. Optimization problems are solved sequentially. Hence, there is no guarantee that the solution is globally optimum. Since the congestion is not considered in the coordination optimization problem of VPP, the congestion can not be related to the locational marginal prices. The regulation market is not considered. EVs are not considered.

In [16], a bilateral electricity market in the distribution system is proposed. Market participants consist of DERs, responsive loads, and DSO. It is assumed that responsible loads (RLs), as well as DERs, are able to estimate their electricity demand and supply, respectively. DERs and RLs are allowed to sign bilateral contracts without considering network constraints. Then, they submit their bilateral transactions to the DSO which is responsible for the secure operation of the distribution network. By informing about bilateral transactions, DSO will run a real-time electricity market in which social welfare is maximized subject to supply to meet demand. In this stage, network constraints are not considered. DSO is responsible for ensuring the security of the distribution network. If one of the security constraints is violated, DSO will implement optimal power flow in order to determine the minimum change in the bilateral transactions in order to meet the security limits of the distribution network. The proposed optimization problem is linear. This optimization problem is distributed using Dantzig-Wolfe decomposition. The merit of this method is decentralizing the optimization problem and distributing the computation burden to all of the market participants. The wholesale electricity market is not considered in this study. DERs may consider participating in the wholesale market instead of bilateral transactions or considering both for maximizing their profit. Flexible loads which provide flexibility to the market are not considered. In the real-time market stage, DSO does not consider network constraints. In the stage that DSO runs optimal power flow for ensuring the security of the system, the model of the proposed optimization problem is quadratically constrained quadratic programming which is nonconvex and is hard to solve for large distribution networks.

In [17], optimal transactive market operation of the DSO which is responsible for the secure operation of the distribution network is proposed. DERs are considered in the local distribution areas. An iterative method is proposed in which DSO performs a transactive electricity market at the distribution level. The objective function is nonlinear. There is no guarantee that the proposed iterative method converges to a globally optimum solution. Energy storage systems and EVs are not considered. DC power flow is used in the distribution network which is not appropriate.

In [18], optimal market participation of the shiftable loads considering distribution network constraints and renewable resources is proposed. DSO as a utility is responsible for meeting its demand while ensuring the secure operation of the distribution network. The problem is to determine optimal demand bids in order to participate in the day-ahead and real-time electricity markets based on the California ISO electricity market framework considering distribution network constraints. In order to include network constraints, linear power flow is used. Due to the intermittent nature of renewable energy resources and market prices, uncertainty is modeled using two-stage robust stochastic programming. The proposed problem is solved using a decomposition algorithm. Energy storage systems, as well as EVs, are not considered in this study. The proposed optimization problem is nonlinear and is solved using the decomposition algorithm which the globally optimum solution can not be guaranteed. The retail electricity market is not considered in this model.

In [19], the optimal operation of an aggregator considering DR and DG is presented. To model the problem of the aggregator, a bi-level optimization is presented in which in the upper-level, the total profit of the aggregator is maximized and in the lower-level problem, economic dispatch performed by the DSO is modeled. The bi-level problem, which is nonlinear and hard to solve, is transformed into a single optimization problem by writing the optimality conditions of the lower-level problem. The resulting optimization problem is transformed into a MILP problem by using the strong duality theorem and the big number mathematical technique. The aggregator does not participate in the wholesale market. DC power flow is used to include power balance equations. Energy storage systems and EVs are not considered.

In [20], the day-ahead energy and reserve market framework is presented for a DSO. Renewable energy resources, flexible loads, and dispatchable distributed generations, as well as uncertainties associated with these units, are considered. Flexible loads and dispatchable distributed generations submit their offers for energy and reserve to the DSO. The problem is modeled by using two-stage stochastic programming in which in the first stage, the day-ahead market is proposed and the second stage ensures the balance between supply and demand for every renewable energy production scenario. The problem is solved using Monte Carlo simulation based on sample average approximation. Energy storage systems and EVs are not considered. DC power flow is used in this work. However, DC power flow is not appropriate in the distribution network. The convergence of the solution method is not guaranteed.

In [21], the day-ahead market framework operated by a DSO is presented. Renewable energy resources supported by energy storage systems, dispatchable generating units, and flexible loads are included in the proposed market model. The DSO supplies the demand from the wholesale market at the locational marginal price (LMP) and pays to distribution market participants at the distribution LMP. The model of the proposed optimization problem is MILP which is solvable with commercial solvers. Network and related constraints are not considered in the proposed model. Hence, congestion and voltage issues can not be modeled. Uncertainty related to renewable energy resources is not covered. Participation of DERs in the wholesale market is not considered.

In [22], the market framework operated by the distribution market operator (DMO) is presented. The proposed DMO gathers offers from microgrids and aggregates them to participate in the wholesale market. Once the wholesale market gets cleared, the DMO determines the power generation and consumption in the distribution network. The distribution LMP and transmission LMP are related by defining a penalty factor that forces DMO to follow the assigned power determined by the ISO. DC power flow is used for ensuring power balance in the distribution network. Energy storage systems, EVs, renewable energy resources are not considered. Uncertainties are not covered.

In [23], a day-ahead market model operated by a DSO is presented. In the proposed market framework, energy storage systems, distributed generations, and load aggregators are considered to participate in the market operated by the DSO. The DSO considers DERs offers as well as interaction with the wholesale market in order to clear the day-ahead market in the distribution system. In the proposed model, network reconfiguration, and voltage control are considered. To determine the involvement of each participant, the distribution LMP is decomposed to its components including active power, reactive power, congestion, voltage support, and power loss marginal costs. The DSO incentivizes the DERs for congestion management and voltage control. In order to ensure power balance, AC power flow is presented by using the second-order cone programming model. Renewable energy resources and uncertainties related to them are not covered. Participation of DERs in the wholesale market is not considered. EVs and degradation related to the energy storage systems are not considered in the proposed model.

In [24], a distribution electricity pricing operated by a DSO is presented. Uncertainties in DERs are covered by using chance-constrained optimal power flow (OPF). Linearized AC power flow is used to ensure power balance in the distribution system. The deterministic equivalent OPF is proposed by using second-order cone reformulations of chance-constrained equations. Wholesale participation of DERs is not considered in this work. The proposed model is computationally expensive. Hence, it can not be implemented in large distribution networks. Energy storage systems and EVs are not covered in this work.

In [25], a re-dispatch OPF is modeled as a congestion management method implemented by a DSO. The operator of the wholesale market clears the day-ahead market and determines the dispatch of generating units and zonal prices. The wholesale market operator does not care about distribution system constraints. Then, the DSO runs the day-ahead flexibility market in order to meet the distribution network constraints. Linear and conic relaxation models of the OPF are represented. The wholesale market participation of DERs is neglected. Energy storage systems and EVs are not modeled.

In [26], a comprehensive congestion management method for a DSO is presented using dynamic tariff, network reconfiguration, and flexibility provided by aggregators. First, the DSO predicts the load and input data in order to determine network topology and tariffs. Then, the DSO sends the tariffs to the aggregators. They optimize their offers and submit them to the day-ahead market and also gather flexibility for offering in the day-ahead flexibility market. If there is congestion, the DSO runs the day-ahead flexibility market. Wholesale participation of DERs is not considered in this study. There is no guarantee that the proposed congestion management method works.

2.3 Discussion on reviewed papers

Even though DER aggregators have a good ramping capability provided by EVs and energy storage systems, just one of the reviewed papers considered the regulation market [7]. By coordinating DERs, they can effectively participate in the regulation market and make a profit. From the reviewed papers, just two of them directly considered the distribution network constraints in their coordination problem [7, 9]. Considering the distribution network is crucial due to the fact that DERs are located in the distribution system.

Hence, Although a lot of issues have been investigated in the DERs market integration, there is a need for the comprehensive investigation of DER market integration which considers the following aspects:

- An entity is needed to aggregate DERs and coordinate their operation.
- Wholesale and retail electricity markets should be considered.

- Considering the regulation electricity market is crucial due to the fact that DER aggregators can effectively participate in the regulation market since they have a good ramping capability provided by energy storage systems and EVs.

- Distribution network should be considered due to the fact that DERs are located in the distribution system. Their high penetration has caused some problems such as thermal congestion and voltage issues. Hence, considering distribution system constraints is crucial for DER aggregators in order to participate in the wholesale electricity market.

Several questions remain unexplored in the existing literature. How to design a DSO to coordinate DER aggregators' wholesale market participation as well as operate the retail/local market? How does a DSO coordinate the DER aggregators' regulation market participation? What is the appropriate market settlement approach for the DSO in coordination with the wholesale market clearing process? How to coordinate the DSO and ISO operations?

In this comprehensive exam report, the above questions have been answered.

Chapter 3

A DSO FRAMEWORK FOR COMPREHENSIVE MARKET PARTICIPATION OF DER AGGREGATORS

In this section, 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. The problem is modeled using mixed-integer linear programming (MILP) which can be solved by commercial solvers. Case studies are performed to analyze the interactions between DER aggregators and wholesale/retail electricity markets.

3.1 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[3, 8, 7, 9, 12, 10, 11]. In [3], the DER aggregator is defined to enable DER market participation. In [8], DER wholesale market participation is enabled through the virtual power plant. In [7], 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 [9, 12], 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 [10], 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 [11], the optimal bidding strategy of EV aggregators for participating in the day-ahead and the real-time markets is presented. In [10, 11], 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 distirbution operation framework which can handle DER market participation at the distribution level while respecting the distirbution system operating constraints. Recently, the distribution system operator (DSO) is introduced to operate the distribution system and retail market with DER integration [21, 20, 22]. In [21], 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 [20], a two-stage stochastic programming is applied to model day-ahead energy and reserve markets operated by a DSO. In [22], 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 reprensent the relationship betwen D-LMP and transmission-level LMP. Both [20] and [22] 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 yet. In this chapter, a DSO framework is proposed based on the mixed-integer linear programming (MILP) formulation. The proposed DSO operates the reatil 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.

3.2 DSO Market Formulation

Due to the high penetration of DERs and emerging smart distribution grid, traditional distribution operation, which aimed to supply end-user customers with reliability, is not appropriate. Hence, there is a need for an entity to integrate DERs with considering the reliable and secure operation of the distribution network. Recently, the DSO is deployed to operate the distribution system as well as operate the market at the retail level in order to integrate DERs and retail transactions.

In the retail market side, DER aggregators can sell energy to the end-user customers and purchase flexibility from them to participate in the regulation market or use the flexibility to cover the uncertainty of their renewable energy resources to avoid purchasing from real-time markets in which prices are higher than that of the day-ahead market.

Based on the aforementioned reasons along with considering the impact of distribution network, a DSO, which is responsible for secure and reliable operation of the distribution network as well as neutral market operator, can be defined to run the market in the distribution system and integrate the DER aggregators in order to comprehensively participate in the wholesale market. The DSO collects the offers from DER aggregators to participate in the wholesale market and run the market in the distribution network to maximize social welfare. The DER aggregators, which are geographically dispersed in the distribution network, are not able to participate in the wholesale electricity market since their power production or consumption is lower than the minimum involvement determined by the wholesale market operator. However, they can effectively participate in the retail electricity market which will be run by the DSO. The DSO, as an entity, will gather energy and regulation reserve from DER aggregators and coordinate them in order to effectively participate in the day-ahead and real-time energy and regulation markets. Regarding the situation, the DSO may purchase energy from the wholesale market once its total demand exceeds its total generation and sell energy once its total generation exceeds its total demand.

The DSO, as an entity in the distribution network, faces an optimization problem which is as follows:

Objective: Maximizing social welfare in the distribution market

Subject to:

- Power balance equations

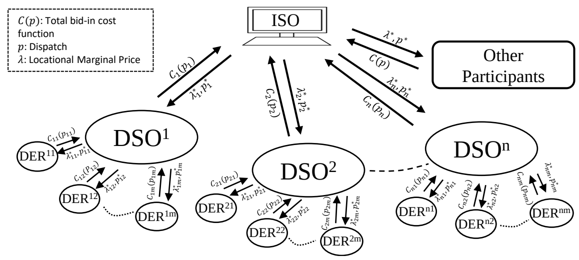


Figure 3.1: DSO framework.

- Distribution network constraints
- Energy storage system aggregators constraints
- EV aggregators constraints
- DR aggregators constraints.
- DDG aggregators constraints.

The role of the DSO is the same as the ISO that is in the distribution network. The DSO is a mediator that trades with the wholesale market at the substation in onside and interacts with DER aggregators and end-user customers on the other side. The proposed DSO model is shown in Fig. 1. DER aggregators submit their offers to the DSO. The DSO collects the offers to run the retail market as well as coordinate the offers to construct an aggregated bid for participating in the day-ahead wholesale energy and regulation markets operated by the ISO. Once the day-ahead wholesale energy and regulation markets get cleared, the DSO share will be determined. The DSO will distribute the awarded share to all market participants in the distribution network.

At the wholesale level, this report assumes the market framework of California ISO (CAISO), whose pay-for-performance regulation market considers offers for both regulation capacity (with capacity-up and capacity-down offers) and regulation mileage

[27]. The DSO is modeled as a price-taker in the day-ahead wholesale market. The MILP formulation of this DSO framework is presented below.

3.2.1 Objective function

The DSO minimizes the total operating cost while maximizing total social welfare in the distribution network. The model of regulation market which is introduced in [5] and [6] is considered. The objective function is given in (9.1). It includes benefits related to the energy storage system, dispatchable DG, responsible load, and EV as well as benefits related to the DERs participation in the day-ahead wholesale energy and regulation markets. The day-ahead regulation market includes regulation capacity and regulation mileage.

$$
\begin{aligned}
min \sum_{t \in T} [& -P_t^{sub} \pi_t^e - r_t^{sub,up} \pi_t^{cap,up} - r_t^{sub,dn} \pi_t^{cap,dn} \\
& - r_t^{sub,up} S_t^{up} \mu_t^{up} \pi_t^{mil,up} - r_t^{sub,dn} S_t^{dn} \mu_t^{dn} \pi_t^{mil,dn} \\
& + \sum_{k \in \{K_2, K_4\}} P_{t,k} \pi_{t,k}^e - \sum_{k_3 \in K_3} P_{t,k_3} \pi_{t,k_3}^e \\
& + \sum_{k \in K} [r_{t,k}^{up} \pi_{t,k}^{cap,up} + r_{t,k}^{dn} \pi_{t,k}^{cap,dn} \\
& + r_{t,k}^{up} S_t^{up} \mu_t^{up} \pi_{t,k}^{mil,up} + r_{t,k}^{dn} S_t^{dn} \mu_t^{dn} \pi_{t,k}^{mil,dn}] \\
& - \sum_{k_1 \in K_1} \sum_{a \in A} P_{a,t,k_1} \pi_{a,t,k_1}^e]
\end{aligned}
\tag{3.1}
$$

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^{sub}, $r_t^{sub,up}$, and $r_t^{sub,dn}$ are the DSO's aggregated offers to wholesale energy, regulation capacity-up and capacity-down markets, respectively; $\pi_t^e, \pi_t^{cap,up}$, and $\pi_t^{cap,dn}$ are the wholesale energy, regulation capacity-up, and capacity-down prices, respectively; $\pi_t^{mil,up}$ and $\pi_t^{mil,dn}$ are the wholesale regulation mileage-up and mileage-down prices; $P_{t,k}, r_{t,k}^{up}$ and $r_{t,k}^{dn}$ are the energy, regulation capacity-up and capacity-down offers made by DER aggregator k with corresponding prices $\pi_{t,k}^e, \pi_{t,k}^{cap,up}, \pi_{t,k}^{cap,dn}$, respectively; μ_t^{up} and μ_t^{dn} are historical scores for providing regulation mileage-up and mileage-down services; S_t^{up} and S_t^{dn} are the regulation mileage-up and mileage-down ratios (the expected mileage for $1MW$ provided regulation capacity); P_{a,t,k_1} and π_{a,t,k_1}^e are the power consumption and the corresponding energy price at each demand block.

3.2.2 Constraints for Demand Response Aggregators (DRAGs)

The operating constraints for DRAGs are as follows:

$$\sum_{a\in A} P_{a,t,k_1} - r_{t,k_1}^{cap,dn} \geq 0; \quad \forall t \in T, \forall k_1 \in K_1 \tag{3.2}$$

$$\sum_{a\in A} P_{a,t,k_1} + r_{t,k_1}^{cap,up} \leq \sum_{a\in A} P_{a,k1}^{max}; \quad \forall t \in T, \forall k_1 \in K_1 \tag{3.3}$$

$$0 \leq P_{a,t,k_1} \leq P_{a,k1}^{max}; \quad \forall a \in A, \forall t \in T, \forall k_1 \in K_1 \tag{3.4}$$

$$0 \leq r_{t,k_1}^{cap,up} \leq r_{t,k_1}^{cap,up,max}; \quad \forall t \in T, \forall k_1 \in K_1 \tag{3.5}$$

$$0 \leq r_{t,k_1}^{cap,dn} \leq r_{t,k_1}^{cap,dn,max}; \quad \forall t \in T, \forall k_1 \in K_1 \tag{3.6}$$

where $P_{a,t,k1}^{max}$ is the maximum power consumption at each demand block; $r_{t,k1}^{cap,up,max}$ and $r_{t,k1}^{cap,dn,max}$ are the maximum allowed regulation capacity-up and capacity-down offers.

Equations (6.2) and (8.2a) limit the DRAG's offers to energy, regulation capacity-up and capcity-down markets. Equation (8.2b) ensures that the real power offered at each demand block is within its permitted range. Equations (8.3) and (7.9a) ensure that the regulation capacity-up and capacity-down offers are lower than their maximum permitted values.

3.2.3 Constraints for Energy Storage Aggregators (ESAGs)

The operating constraints for ESAGs are as follows:

$$P_{t,k_2} = E_{t-1,k_2} - E_{t,k_2} + (1/\eta_{k_2}^{di}) r_{t,k_2}^{cap,up} \mu_t^{up} - (\eta_{k_2}^{ch}) r_{t,k_2}^{cap,dn} \mu_t^{dn}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{3.7}$$

$$P_{t,k_2} = (1/\eta_{k_2}^{di}) P_{t,k_2}^{di} - (\eta_{k_2}^{ch}) P_{t,k_2}^{ch}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{3.8}$$

$$r_{t,k_2}^{cap,up} = r_{t,k_2}^{cap,up,di} + r_{t,k_2}^{cap,dn,ch}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{3.9}$$

$$r_{t,k_2}^{cap,dn} = r_{t,k_2}^{cap,dn,di} + r_{t,k_2}^{cap,up,ch}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{3.10}$$

$$E_{k_2}^{min} \leq E_{t,k_2} \leq E_{k_2}^{max}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{3.11}$$

$$0 \leq P_{t,k_2}^{di} \leq b_{t,k_2} DR_{k_2}^{max}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{3.12}$$

$$0 \leq r_{t,k_2}^{cap,up,di} \leq b_{t,k_2} DR_{k_2}^{max}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{3.13}$$

$$0 \leq r_{t,k_2}^{cap,dn,di} \leq b_{t,k_2} DR_{k_2}^{max}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{3.14}$$

$$0 \leq P_{t,k_2}^{ch} \leq (1 - b_{t,k_2}) CR_{k_2}^{max}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{3.15}$$

$$0 \leq r_{t,k_2}^{cap,up,ch} \leq (1 - b_{t,k_2}) CR_{k_2}^{max}; \forall t \in T, \forall k_2 \in K_2 \tag{3.16}$$

$$0 \leq r_{t,k_2}^{cap,dn,ch} \leq (1 - b_{t,k_2}) CR_{k_2}^{max}; \forall t \in T, \forall k_2 \in K_2 \tag{3.17}$$

$$r_{t,k_2}^{cap,dn,di} \leq P_{t,k_2}^{di} \leq DR_{k_2}^{max} - r_{t,k_2}^{cap,up,di}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{3.18}$$

$$r_{t,k_2}^{cap,dn,ch} \leq P_{t,k_2}^{ch} \leq CR_{k_2}^{max} - r_{t,k_2}^{cap,up,ch}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{3.19}$$

where E_{t,k_2} is the charging level; $\eta_{k_2}^{ch}$ and $\eta_{k_2}^{di}$ are the charging and discharging efficiencies; P_{t,k_2}^{di} is the discharging power; P_{t,k_2}^{ch} is the charging power; $r_{t,k_2}^{cap,up,di}$ and $r_{t,k_2}^{cap,dn,di}$ are the regulation capacity-up and capacity-down offers in the discharging mode; $r_{t,k_2}^{cap,dn,ch}$ and $r_{t,k_2}^{cap,up,ch}$ are the regulation capacity-up and capacity-down offers in the charging mode; $CR_{k_2}^{max}$ and $DR_{k_2}^{max}$ are the maximum charging and discharging rates; b_{t,k_2} is a binary variable indicating the charging ($b_{t,k_2} = 0$) and discharging ($b_{t,k_2} = 1$) modes.

Equation (7.9b) represents ESAG's power injection. ESAG's offers to the energy, regulation capacity-up and capacity-down markets are decomposed into charging and discharging terms by Equations (7.9c)-(7.9e). Equation (9.11) limits the charge level of ESAGs. Equations (9.10)-(5.3k) ensure that ESAG's offers to the energy, regulation capacity-up and capacity-down markets are in their permitted ranges. Equations (5.3l)-(5.3m) limit ESAG's offers to the energy, regulation capacity-up and capacity-down markets with respect to the charging and discharging rates.

3.2.4 Constraints for EV Charging Stations (EVCSs)

EVCSs are modeled as EV charging aggregators and are assumed to have unidirectional power flow as assumed in [6]. Constraints related to the operation of EVCSs are as follows:

$$0 \leq P_{t,k_3} \leq ER_{k_3}^{max} b_{k_3}; \quad \forall t \in T^{'}, \forall k_3 \in K_3 \tag{3.20}$$

$$0 \leq r_{t,k_3}^{cap,up} \leq ERR_{k_3}^{max} b_{k_3}; \quad \forall t \in T^{'}, \forall k_3 \in K_3 \tag{3.21}$$

$$0 \leq r_{t,k_3}^{cap,dn} \leq ERR_{k_3}^{max} b_{k_3}; \quad \forall t \in T^{'}, \forall k_3 \in K_3 \tag{3.22}$$

$$P_{t,k_3} + r_{t,k_3}^{cap,up} \leq ER_{k_3}^{max}; \quad \forall t \in T^{'}, \forall k_3 \in K_3 \tag{3.23}$$

$$P_{t,k_3} - r_{t,k_3}^{cap,dn} \geq 0; \quad \forall t \in T^{'}, \forall k_3 \in K_3 \tag{3.24}$$

$$\begin{aligned} 0.9CL_{k_3}^{max} b_{k_3} \leq E_{k_3}^{int} b_{k_3} + \sum_{t \in T^{'}} [P_{t,k_3} + r_{t,k_3}^{cap,up} \mu_t^{up} \\ - r_{t,k_3}^{cap,dn} \mu_t^{dn}] \gamma_{k_3}^{ch} \leq CL_{k_3}^{max} b_{k_3}; \; \forall k_3 \in K_3 \end{aligned} \tag{3.25}$$

where $T^{'} \subseteq T$ is the set of hours when EVs are available; $ER_{k_3}^{max}$ is the maximum charging rate; $ERR_{k_3}^{max}$ is the maximum permitted value for regulation capacity offers,

$CL_{k_3}^{max}$ is the maximum charge level; $E_{k_3}^{int}$ is the initial charge level; $\gamma_{k_3}^{ch}$ is the charging efficiancy; 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 (4.20)-(5.4b) limit EVCS's offers to the energy, regulation capacity-up and capacity-down markets. Equation (5.4d) ensures that the charge level of EVs is full.

3.2.5 Constraints for Dispatchable DG Aggregators (DDGAGs)

The operating constraints for DDDAGs are as follows:

$$P_{t,k_4} + r_{t,k_4}^{cap,up} \leq P_{k_4}^{max}; \quad \forall t \in T, \forall k_4 \in K_4 \tag{3.26}$$

$$P_{t,k_4} - r_{t,k_4}^{cap,dn} \geq P_{k_4}^{min}; \quad \forall t \in T, \forall k_4 \in K_4 \tag{3.27}$$

$$0 \leq r_{t,k_4}^{cap,up} \leq RU_{k_4}; \quad \forall t \in T, \forall k_4 \in K_4 \tag{3.28}$$

$$0 \leq r_{t,k_4}^{cap,dn} \leq RD_{k_4}; \quad \forall t \in T, \forall k_4 \in K_4 \tag{3.29}$$

where $P_{k_4}^{max}$ and $P_{k_4}^{min}$ are the maximum and minimum power generations; RU_{k_4} and RD_{k_4} are the maximum ramp-up and ramp-down rates.

Equations (5.4e) and (5.4f) limit DDDAG's offers to the energy, regulation capacity-up and capacity-down markets. Equations (5.5a) and (5.5b) ensure the regulation capacity-up/capacity-down offers are lower than maximum ramp-up/ramp-down rates.

3.2.6 Distribution Power Flow Equations

The linearized power flow equations are adopted from [28]:

$$\begin{aligned}
&\sum_{k_1 \in K_1} \sum_{a \in A} H_{n,k_1} P_{a,t,k_1} + \sum_{k_3 \in K_3} H_{n,k_3} P_{t,k_3} + P_{t,n}^D \\
&- \sum_{k_2 \in K_2} H_{n,k_2} P_{t,k_2} - \sum_{k_4 \in K_4} H_{n,k_4} P_{t,k_4} \\
&+ H_n^{sub} P_t^{sub} + \sum_{j \in J} Pl_{j,t} A_{j,n} = 0; \quad \forall t \in T, \forall n \in N
\end{aligned} \tag{3.30}$$

$$\begin{aligned}
&\sum_{k_1 \in K_1} \sum_{a \in A} H_{n,k_1} P_{a,t,k_1} tan\phi_{k_1} + Q_{t,n}^D \\
&- \sum_{k_4 \in K_4} H_{n,k_4} P_{t,k_4} tan\phi_{k_4} \\
&+ H_n^{sub} Q_t^{sub} + \sum_{j \in J} Ql_{j,t} A_{j,n} = 0; \quad \forall t \in T, \forall n \in N
\end{aligned} \tag{3.31}$$

$$\begin{aligned}
&V_{m,t} = V_{n,t} - (r_j Pl_{j,t} + x_j Ql_{j,t}); \quad \forall t \in T, \forall m \in N, \\
&\qquad \forall n \in N, \, C(m,n) = 1, \, A(j,n) = 1
\end{aligned} \tag{3.32}$$

$$V^{min} \leq V_{n,t} \leq V^{max}; \quad \forall t \in T, \forall n \in N \tag{3.33}$$

$$-Pl^{max} \leq Pl_{j,t} \leq Pl^{max}; \quad \forall t \in T, \forall j \in J \tag{3.34}$$

$$-Ql^{max} \leq Ql_{j,t} \leq Ql^{max}; \quad \forall t \in T, \forall j \in J \tag{3.35}$$

$$\begin{aligned}
r_t^{sub,up} &= \sum_{k_2 \in K_2} r_{t,k_2}^{cap,up} + \sum_{k_4 \in K_4} r_{t,k_4}^{cap,up} \\
&\quad + \sum_{k_1 \in K_1} r_{t,k_1}^{cap,dn} + \sum_{k_3 \in K_3} r_{t,k_3}^{cap,dn}; \quad \forall t \in T
\end{aligned} \tag{3.36}$$

$$\begin{aligned}
r_t^{sub,dn} &= \sum_{k_2 \in K_2} r_{t,k_2}^{cap,dn} + \sum_{k_4 \in K_4} r_{t,k_4}^{cap,dn} \\
&\quad + \sum_{k_1 \in K_1} r_{t,k_1}^{cap,up} + \sum_{k_3 \in K_3} r_{t,k_3}^{cap,up}; \quad \forall t \in T
\end{aligned} \tag{3.37}$$

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; $Pl_{j,t}$ and $Ql_{j,t}$ are the active and reactive power flow at branch j; $A_{j,n}$ is the incidence matrix of branches and buses; ϕ is the phase angle; $C_{m,n}$ is the connecting nodes matrix.

Equations (5.5c) and (5.5d) represent the active and reactive power flow. Voltage drop at each line is represented by equation (5.7) and is limited by equation (3.33). Active and reactive power limits at each line are represented by (3.34) and (5.8). Equations (3.36) and (5.10) represent DSO's aggregated offers for participating in the wholesale energy, regualtion capacity-up and capacity-down markets.

3.3 Market settlement

The DSO trades with the wholesale market on one side and deals with DERs aggregators on the other side. The best way of clearing the market is using a market-clearing price. However, the DSO is unable to use market-clearing prices for dealing with the wholesale market. However, the price in the distribution system is always the same as the price of the wholesale market. In the following, it has been proved. By writing the Lagrangian of the optimization problem proposed in the previous section:

Assume continuous relaxation of the problem in Section 3.2. Let $\mathbf{x}^{dr}$, $\mathbf{x}^{es}$, $\mathbf{x}^{ev}$, $\mathbf{x}^{ddg}$, and $\mathbf{x}^{pf}$ be the sets with all decision variables related to DRAGs, ESAGs, EVCSs, DDGAGs, and power flow equations, with corresponding constraints $\mathbf{g}(\mathbf{x}^{dr})$, $\mathbf{g}(\mathbf{x}^{es})$, $\mathbf{g}(\mathbf{x}^{ev})$, $\mathbf{g}(\mathbf{x}^{ddg})$, $\mathbf{g}(\mathbf{x}^{pf})$, and corresponding dual variables $\boldsymbol{\lambda}^{dr}$, $\boldsymbol{\lambda}^{es}$, $\boldsymbol{\lambda}^{ev}$, $\boldsymbol{\lambda}^{ddg}$, and $\boldsymbol{\lambda}^{pf}$, respectively. The Lagrangian function can be set up as:

$$\begin{aligned}\mathbf{L} =& f(\mathbf{x}^{dr}, \mathbf{x}^{es}, \mathbf{x}^{ev}, \mathbf{x}^{ddg}) + (\boldsymbol{\lambda}^{dr})^{\mathsf{T}}\mathbf{g}(\mathbf{x}^{dr}) \\ &+ (\boldsymbol{\lambda}^{es})^{\mathsf{T}}\mathbf{g}(\mathbf{x}^{es}) + (\boldsymbol{\lambda}^{ev})^{\mathsf{T}}\mathbf{g}(\mathbf{x}^{ev}) \\ &+ (\boldsymbol{\lambda}^{ddg})^{\mathsf{T}}\mathbf{g}(\mathbf{x}^{ddg}) + (\boldsymbol{\lambda}^{pf})^{\mathsf{T}}\mathbf{g}(\mathbf{x}^{pf})\end{aligned} \tag{3.38}$$

Based on the KKT conditions, partial derivative of the Lagrangian function with respect to P_t^{sub} must be zero at the optimum point. P_t^{sub} only exists in terms $f(\mathbf{x}^{dr}, \mathbf{x}^{es}, \mathbf{x}^{ev}, \mathbf{x}^{ddg})$ and $(\boldsymbol{\lambda}^{pf})^{\mathsf{T}}\mathbf{g}(\mathbf{x}^{pf})$. Hence, the partial derivative of the other terms in the Lagrangian function with respect to P_t^{sub} would be null.

$$\frac{\partial \mathbf{L}}{\partial P_t^{sub}} = \frac{\partial f(\mathbf{x}^{dr}, \mathbf{x}^{es}, \mathbf{x}^{ev}, \mathbf{x}^{ddg})}{\partial P_{t,\phi}^{sub}} + \frac{\partial((\boldsymbol{\lambda}^{pf})^{\intercal}\mathbf{g}(\mathbf{x}^{pf}))}{\partial P_{t,\phi}^{sub}} = -\pi_t^e + \lambda_{1,t}^P = 0 \tag{3.39}$$

$$LMP_{n,t} = \frac{\partial \mathbf{L}}{\partial P_{n,t}^D} = \lambda_{n,t}^P \tag{3.40}$$

Suppose there are no congestion and voltage issues. Hence, the LMP at all nodes are the same as follows:

$$LMP_{1,t} = LMP_{2,t} = ... = LMP_{n,t} = \lambda_{1,t}^P = \pi_t^e \tag{3.41}$$

As a result, the market-clearing price of the DSO is the same as the market-clearing price in the wholesale market which is operated by the ISO. In the same way, by taking the first derivative of the Lagrangian function with respect to the capacity-up and capacity-down, the prices of capacity-up and capacity-down markets of the DSO will be the same as market-clearing prices of capacity markets in the wholesale market.

When congestions and voltage violations happen in the DSO, distribution LMPs across the distribution system will be different, and the DSO will receive a surplus. This surplus is conceptually similar to the ISO's congestion revenue rights (CRRs) [29, 27] and can be returned to the distribution utilities who are responsible for operating and upgrading the distribution circuits, reactive power compensations, and meters.

In order to investigate the effectiveness of the proposed method, some case studies have been carried out.

3.4 Simulation results

Case studies are performed on the small distribution network shown in Fig.4.1. The system contains 5 nodes, where $N = \{1, 2, 3, 4, 5\}$; 4 lines, where $J = \{1, 2, 3, 4\}$;

Table 3.1: Market participants prices (\$/MW) and regulation signals ($P.U.$).

t	Wholesale		ESAG		DDGAG		EVCS		DRAG		Regulation	
	E	C	E	C	E	C	E	C	E	C	up	dn
1	24.3	14.7	25	23	28	27	29	30.5	29	30	0.45	0.42
2	23.7	17.3	25	23	28	27	29	30.5	29	30	0.45	0.42
3	23	16.6	25	23	28	27	29	30.5	29	30	0.45	0.42
4	23	16.6	25	23	28	27	29	30.5	29	30	0.45	0.42
5	23.7	17.3	25	23	28	27	29	30.5	29	30	0.45	0.42
6	25.9	22.7	28	25	29	28	29.5	31	30	31	0.48	0.48
7	29.4	30.4	28	25	29	28	29.5	31	30	31	0.48	0.48
8	30.7	33.6	28	25	29	28	29.5	31	30	31	0.48	0.48
9	30.1	33.6	28	25	29	28	29.5	31	30	31	0.48	0.48
10	29.1	31.4	28	25	29	28	29.5	31	30	31	0.48	0.48
11	28.8	30.4	28	25	29	28	29.5	31	30	31	0.48	0.48
12	28.2	24.3	28	25	29	28	29.5	31	30	31	0.48	0.48
13	27.5	24.3	27	24	28.5	27.5	29	30.5	29	30	0.5	0.51
14	27.2	24.3	27	24	28.5	27.5	29	30.5	29	30	0.5	0.51
15	27.2	24.3	27	24	28.5	27.5	29	30.5	29	30	0.5	0.51
16	27.5	24.3	27	24	28.5	27.5	29	30.5	29	30	0.5	0.51
17	28.2	28.2	30	27	29	28	29.5	31	30	31	0.5	0.51
18	30.4	28.8	30	27	29	28	29.5	31	30	31	0.5	0.51
19	32	33.6	30	27	29	28	29.5	31	30	31	0.5	0.51
20	32	33.6	30	27	29	28	29.5	31	30	31	0.5	0.5
21	31	32	30	27	29	28	29.5	31	30	31	0.5	0.5
22	29.4	32	28	25	29	28	29.5	31	30	31	0.5	0.5
23	27.5	25.6	28	25	28	27	29	30.5	29	30	0.42	0.45
24	25.3	22.4	28	25	28	27	29	30.5	29	30	0.42	0.45

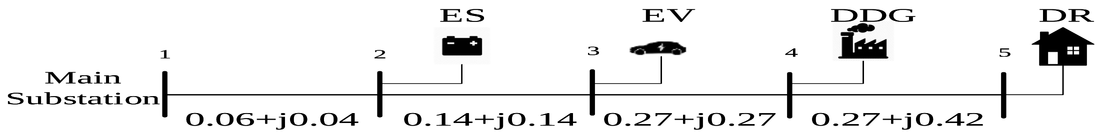


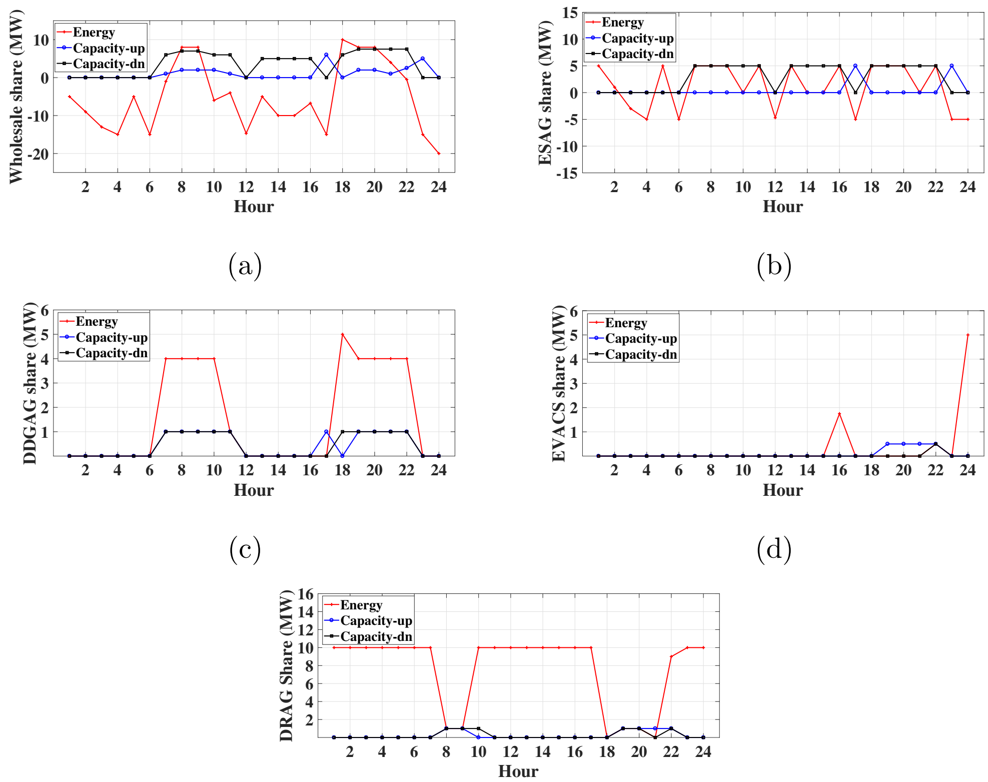
Figure 3.2: The small distribution network for case studies.

a DRAG, where $k_1 = \{1\}$; an ESAG, where $k_2 = \{2\}$; an EVCS, where $k_3 = \{3\}$; a DDGAG, where $k_4 = \{4\}$. The studies are performed over 24 hours, $T = \{1, 2, ..., 24\}$. EVs are available between hour 16 and hour 24, $T^{'} = \{16, 17, ..., 24\}$. Initial charge level of ESAG is $8MW$. The following parameters are assumed: $\eta_{k_2}^{ch} = \eta_{k_2}^{di} = 1$, $E_{k_2}^{min} = 2MW$, $E_{k_2}^{max} = 10MW$, $DR_{k_2}^{max} = CR_{k_2}^{max} = 5MW$, $E_{k_3}^{int} = 2MW$, $ER_{k_3}^{max} = 5MW$, $ERR_{k_3}^{max} = 0.5MW$, $P_{k_4}^{min} = 0$, $P_{k_4}^{max} = 5MW$, $RU_{k_4} = RD_{k_4} = 1MW$, $P_{a,t,k_1}^{max} = 10MW$, $r_{k_1}^{cap,up,max} = r_{k_1}^{cap,dn,max} = 1MW$.

The energy and regulation capacity prices in [5] are considered. The hourly factors in [30] 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 7.1, where E denotes energy price, C denotes regulation capacity price.

Market outcomes

The outcomes of DSO market coordination are presented in Fig. 3.3. The trades between the DSO and the wholesale market are shown in Fig. 3.3a. The awarded energy and regulation market shares of ESAG, DDGAG, EVCS, and DRAG are shown in Fig. 3.3b-Fig. 3.3e, 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.



(a) (b) (c) (d) (e)

Figure 3.3: Hourly awarded energy, regulation capacity-up/capacity-down services of (a) wholesale market (b) ESAG (c) DDGAG (d) EVCS (e) DRAG.

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 at hours 13, 14, 15, 16, when the regulation capacity-dwon price is lower than the energy price in the wholesale market.

The DDGAG offers energy to the wholesale market at peak hours 7, 8, 9, 10, 11, 18, 19, 20, 21, 22. During these peak hours, the wholesale regulation capacity price is higher than the wholesale energy price. Hence, the DDGAG offers regulation capacity-up service at its maximum ramping rate ($1\,MW$). During peak hours, the DDGAG's remaining capacity ($4\,MW$) is offered to the wholesale energy market.

However, at hour 18, the DDGAG assigns all its capacity for energy provision, since the wholesale regulation capacity price is lower than the wholesale energy price at this moment.

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.

Sensitivity analysis

Sensitivity analysis is performed to study the impacts of ESAG's and DDAG's energy price offers on their revenue. For each study case $i\,(i = 1, 2, ..., 40)$, the market participants' energy price offers are modified from their base case values (in Table I) by a multiplier $i/10$.

ESAG Energy Price Offers: Fig. 3.4 shows the sensitivity of ESAG's total revenue with respect to its energy price offers. In Case 1 with the lowest ESAG energy price offer, the ESAG offers regulation capacity-down service at all times even when its price offer for regulation capacity-down service is lower than the wholesale regulation capacity-down price. This is because ESAG can increase its charging level by providing regulation capacity-down service, and the energy gained during this charg-

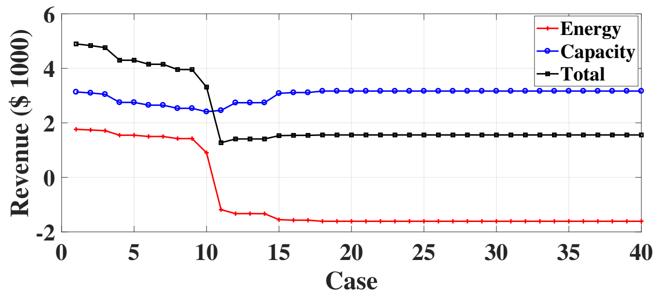


Figure 3.4: Variation of revenue of ESAG.

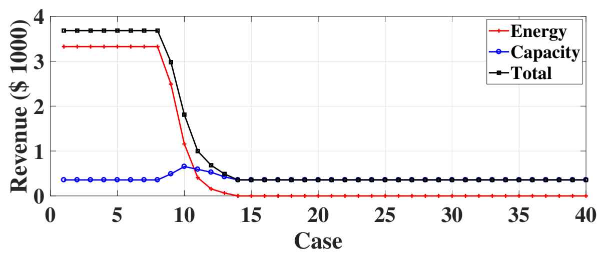


Figure 3.5: Variation of revenue of DDGAG.

ing period can be offered to the energy market. Hence, the ESAG gains the highest total revenue in this case. As the ESAG's energy price offer increases (from Case 2 to Case 11), its total revenue decreases. In Case 11, the ESAG gains the lowest total revenue. This is beacuse in Case 11, the ESAG's revenue from regulation capacity market is the lowest, as ESAG only offers regulation capacity service at peak hours when the wholesale regulation capacity price is high. After Case 11, the ESAG's energy price offer is higher than the wholesale energy price. This causes the ESAG to act as demand and also offer regulation capacity-up service. By offering regulation capacity-up service, the ESAG decreases its charging level and increases its energy purchase from the energy market. Therefore, the ESAG's revenue from regulation capacity market increases after Case 11 and becomes constant after Case 17.

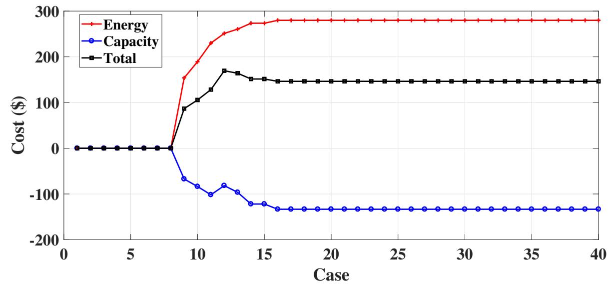


Figure 3.6: Variation of cost of EVCS.

DDGAG Energy Price Offers: Fig. 3.5 shows the sensitivity of DDGAG's total revenue with respect to its energy price offers. Before Case 8, the DDGAG's energy price offer is lower than the wholesale energy price at all the simulated hours. Hence, the DDGAG sells all the energy to the wholesale market while also providing regulation capacity-down service. In Cases 9 and 10, the DDGAG's energy price offer is lower than the wholesale energy price at some (not all the) simulated hours. Hence, it sells energy and provides capcaity-up service during these hours. This causes its energy revenue to decrease and regulation capacity revenue to increase. After Case 15, the 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.

EVCS energy price: In order to investigate the influence of energy price submitted by the EVCS, a sensitivity analysis is performed and its result is shown in Fig. 3.6. Before the case 8, the energy price submitted by the EVCS is lower than that of the wholesale market. As a result, the energy will not be sold to the EVCS. However, after case 8, at some hours, the price of EVCS is higher than the price of energy at the wholesale market. Hence, the EVCS buys energy from the wholesale market

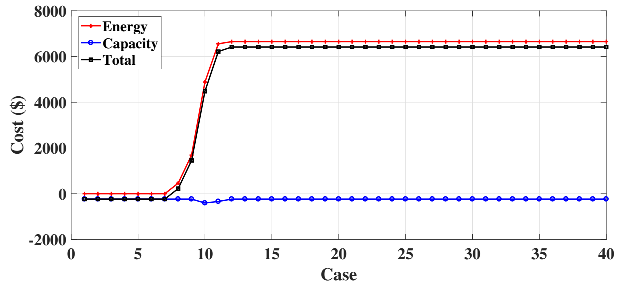


Figure 3.7: Variation of cost of DRAG.

and make profit by providing regulation for wholesale market. As its offering price increases, its total cost increases until the case 15 in which its offering price is higher than the wholesale market at all hours.

DRAG energy price: The effect of the offering price of DRAG is investigated by performing a sensitivity analysis on this parameter. The result is shown in Fig. 3.7. Before the case 8, the offering energy price of the DRAG is lower than that of the wholesale market. As a result, the energy will not be sold to the DRAG. However, it makes a profit by providing capacity-up for the wholesale market. After case 8, as the offering energy price of DRAG increases, its energy cost and total cost increase. However, after case 11 its cost becomes constant due to the fact that its offering energy price is higher than that of the wholesale market at all hours. In the case 10, the profit of DRAG for providing capacity is maximum since, in this case, it provides both capacity-up and capacity-down.

Distribution system line congestion

In order to investigate the impact of line congestion on the DSO market, the maximum permitted flow of line 1, which connects the distribution network to the substation, is limited to $7\,MW$. The LPM of the substation is always equal to the price of the

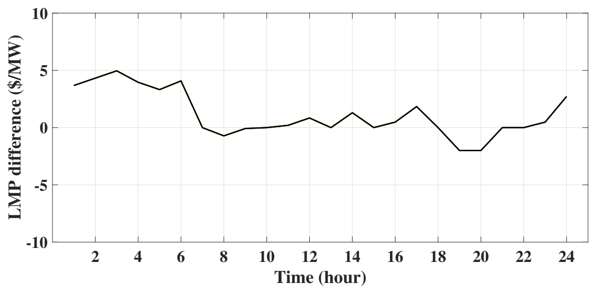


Figure 3.8: LMP difference of nodes from the base LMP when the maximum flow of line 1 is $7\,MW$

wholesale market. Hence, the LMP of this node is considered as the base LMP and the difference of LMP of other nodes from the base LMP is determined which is shown in Fig. 3.8. The LMP differences of all other 4 nodes are equal since there is no congestion on the lines connecting these nodes. In the hours that the LMP difference is zero, the congestion has not occurred. Congestion causes the node which is upstream of the congested line to have lower LMP than the node which is downstream of the congested line (in the radial networks). In hours $8, 19, 20$, the DSO sells energy to the wholesale market. Hence, the wholesale market is downstream of the congested line. As a result, the LMP at other nodes is lower than the LMP of node 1. This is the reason that the LMP difference is negative at hours $8, 19, 20$. On the other side, at hours 1-6, 11, 12, 14, 16, 17, 23, 24, the wholesale market sells energy to the DSO. Hence, the distribution system is downstream of the congested line and the LMP difference at other nodes is positive. At other remaining hours, which the LMP difference is zero, the congestion does not occur.

To investigate the influence of congestion of other lines on the DSO market, the maximum permitted flow of all lines is limited to $7\,MW$. The LMP difference from the base LMP at all nodes is shown in Fig.3.9. The LMP difference in node 5 is higher than other nodes since node 5 is at the end of the downstream flow of the congested

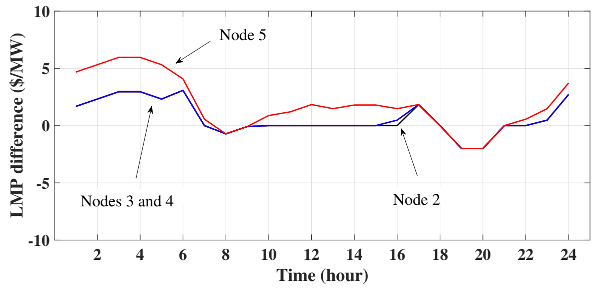


Figure 3.9: LMP difference of nodes from the base LMP when maximum flow of lines is 7 MW

Table 3.2: Comparison of profit from energy market of market participants in different congestion scenarios

Profit ($)	Market participant					AGGs
	WM	ESAG	DDGAG	EVCS	DRAG	
Base case	3016.672	902.208	1156.16	-189.28	-4885.76	-3016.672
Congestion 1	1844.16	1245.445	2140.148	-219.86	-5268.735	-2103.002
Congestion 2	1125.44	1104.013	1520.087	-219.86	-3913	-1508.76
Congestion 3	0	1326.6	3266	-234.145	-4358.455	0

lines. At hours $8, 19, 20$, the LMP difference is negative. This is due to the fact that in these hours, the wholesale market buys energy from the DSO. Hence, the wholesale market is at the end of the downstream flow of congested lines. As a result, the LMP difference from the base LMP at these hours is negative.

The revenues of all market participants in congestion scenarios are given in Table 3.2. The base case is the case that no congestion occurs, *congestion 1* is the case that maximum flow of line 1 is limited to 7 MW, the congestion 2 is the case that flow of all lines are limited to 7 MW, and congestion 3 is the case that maximum permitted flow of line 1 is limited to 0 MW. In congestion 1, the energy trade between the DSO

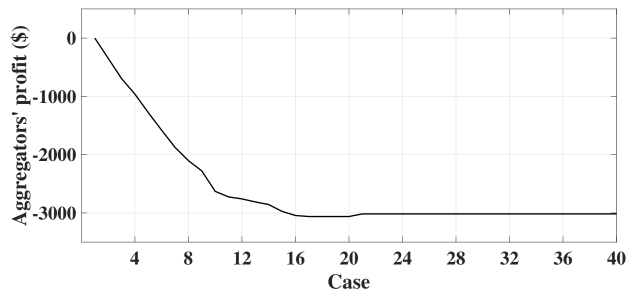


Figure 3.10: Variation of total aggregators' profit with respect to maximum permitted flow of line 1

and the wholesale market has significantly decreased since the line 1 is congested. The EVCS and DRAG have to provide their demand from DDGAG and ESAG in the hours that line 1 are congested. Hence, the cost of EVCS and DRAG has increased and the profit of ESAG and DDGAG from the energy market has increased. In congestion 2, the energy trade between the DSO and the wholesale market has decreased compared to congestion 1 since all lines have been congested. The EVCS cost is the same as congestion 1 since the LMP of node 3, where the EVCS is located, is the same as the one in congestion 1. The cost of DRAG has decreased significantly since the line 4 is congested. As a result, the profit of ESAG and DDGAG have decreased significantly.

In congestion 3, DSO does not have any energy trade with the wholesale market. By comparing congestion 1 and congestion 3, one can observe that revenues of the DDGAG and ESAG and cost of EVCS have increased. However, the cost of DRAG has increased which is due to the fact that DRAG consumes more than that of congestion 3. Another interesting issue is investigating the summation of aggregators' profit which is given in Table. 3.2. This is as same as the case that there is a distribution company that owns all of the aggregators and lets them independently participate in the market operated by the DSO. Variation of total aggregators' profit with respect to the variation of the maximum permitted flow of line 1 is depicted in Fig. 3.10. The permitted flow of line 1 varies from 0 MW to 40 MW by the step-size of 1 MW. By comparing the congestion scenarios, one can see that the total cost of summation of aggregators has increased when they trade with the wholesale market. This is due to the fact that the effect of DRAG is more than the effect of other aggregators. In other words, totally, summation of aggregators buy energy from the wholesale market. However, if sizes of ESAG and DDGAG were more than DRAG such that the summation of aggregators sells energy to the wholesale market, the total aggregators' profit would be more than that of the case that they do not trade with the wholesale market.

3.4.1 Investigating the role of the DSO

An interesting case study is investigating the effect of our DSO framework on market participants to observe how a participant's share changes when it directly participate in the wholesale market. Suppose the DDGAG wants to directly participate in the wholesale market. It is assumed that the offering price of the DDGAG in the market operated by the DSO is its marginal cost. The DDGAG aggregator needs to solve the following optimization problem in order to determine its share.

$$max \sum_{t\in T}[P_{t,k_4}\pi^{e}_{t} + r^{up}_{t,k_4}\pi^{cap,up}_{t} + r^{dn}_{t,k_4}\pi^{cap,dn}_{t} + r^{up}_{t,k_4}S^{up}_{t}\mu^{up}_{t}\pi^{mil,up}_{t} + r^{dn}_{t,k_4}S^{dn}_{t}\mu^{dn}_{t}\pi^{mil,dn}_{t}$$
$$- P_{t,k_4}\pi^{e}_{t,k_4} - r^{up}_{t,k_4}\pi^{cap,up}_{t,k_4} - r^{dn}_{t,k_4}\pi^{cap,dn}_{t,k_4} - r^{up}_{t,k_4}S^{up}_{t}\mu^{up}_{t}\pi^{mil,up}_{t,k_4} - r^{dn}_{t,k_4}S^{dn}_{t}\mu^{dn}_{t}\pi^{mil,dn}_{t,k_4}] \tag{3.42}$$

$s.t.$

$$P_{t,k_4} + r^{cap,up}_{t,k_4} \leq P^{max}_{k_4}; \quad \forall t \in T, \forall k_4 \in K_4 \tag{3.43}$$

$$P_{t,k_4} - r^{cap,dn}_{t,k_4} \geq P^{min}_{k_4}; \quad \forall t \in T, \forall k_4 \in K_4 \tag{3.44}$$

$$0 \leq r^{cap,up}_{t,k_4} \leq RU_{k_4}; \quad \forall t \in T, \forall k_4 \in K_4 \tag{3.45}$$

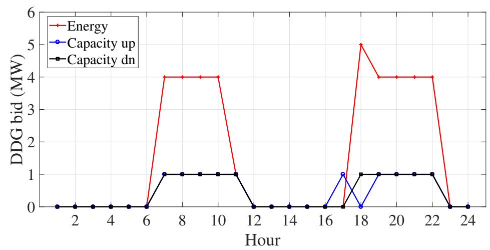


Figure 3.11: DDG bid to the wholesale market

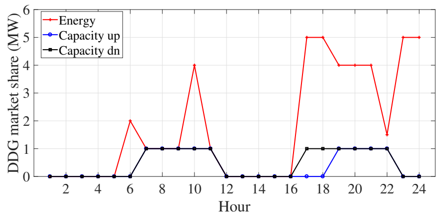
$$0 \leq r_{t,k_4}^{cap,dn} \leq RD_{k_4}; \quad \forall t \in T, \forall k_4 \in K_4 \tag{3.46}$$

The DDG bid to the wholesale market is shown in Fig. 3.11 which is the exact same figure as depicted in Fig. 3.3c. Hence, the revenue of the DDG is the same as its revenue when participating in the market operated by the DSO.

In the proposed formulation, the distribution network was neglected. However, the DDGAG is located in the distribution system. Therefore, distribution network constraints should be considered. Let us suppose the DDGAG accesses the distribution network data. For participating in the wholesale market, the DDGAG should assure that its awarded share is available at the substation. Hence, the objective function should be changed as follows:

$$\begin{aligned} max \sum_{t \in T} [& P_t^{sub} \pi_t^e + r_t^{sub,up} \pi_t^{cap,up} + r_t^{sub,dn} \pi_t^{cap,dn} + r_t^{sub,up} S_t^{up} \mu_t^{up} \pi_t^{mil,up} \\ & + r_t^{sub,dn} S_t^{dn} \mu_t^{dn} \pi_t^{mil,dn} - P_{t,k_4} \pi_{t,k_4}^e - r_{t,k_4}^{up} \pi_{t,k_4}^{cap,up} - r_{t,k_4}^{dn} \pi_{t,k_4}^{cap,dn} \\ & - r_{t,k_4}^{up} S_t^{up} \mu_t^{up} \pi_{t,k_4}^{mil,up} - r_{t,k_4}^{dn} S_t^{dn} \mu_t^{dn} \pi_{t,k_4}^{mil,dn}] \end{aligned} \tag{3.47}$$

Constraints (5.5c)-(5.10), as power flow equations, and constraints (5.11j)-(3.46), as operational constraints of the DDGAG, should be considered. Two cases have been defined. *Case* 1 is the case that the DDGAG participates in the market operated by the DSO. *Case* 2 is the case that the DDGAG directly participates in the wholesale



(a) (b)

Figure 3.12: (a) DDG market share in the DSO market (b) DDG bid for directly participating in the wholesale market.

market. In order to investigate the effect of distribution network constraints, the maximum permitted flow of line 1 is limited to 3 MW.

The result has been shown in Fig. 3.12a and Fig. 3.12b. In case 1, the revenue of DDGAG is 3101.7 \$. In case 2, the revenue of DDGAG is 722.9 \$. In case 2, the DDGAG just can participate in the wholesale market. As a result, when the permitted flow of line 1 is limited to 3 MW, the maximum bid of the DDGAG is limited to 3 MW and its total revenue has decreased. However, in case 1, in addition to participating in the wholesale market, the DDGAG participates in the retail market operated by the DSO. Hence, the revenue of the DDGAG in case 1 is increased and that of case 2 has decreased.

3.5 Conclusion

This chapter proposed a DSO framework for coordinating DER aggregators to participate in the wholesale energy/regulation markets and retail energy market. Various types of aggregators were 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. The effect of congestion on the proposed framework has been investigated.

Chapter 4

TWO-STAGE STOCHASTIC PROGRAMMING FOR DSO DESIGN

In this chapter, a distribution system operator (DSO) framework is proposed for comprehensive retail and wholesale markets participation of distributed energy resource (DER) aggregators under uncertainty based on two-stage stochastic programming. Different kinds of DER aggregators including energy storage aggregators (ESAGs), demand response aggregators (DRAGs), electric vehicle (EV) aggregating charging stations (EVCSs), dispatchable distributed generation (DDG) aggregators (DDGAGs), and renewable energy aggregators (REAGs) are modeled. Distribution network operation constraints are considered using a linearized power flow. The problem is modeled using mixed-integer linear programming (MILP) which can be solved by using commercial solvers. Case studies are conducted to investigate the performance of the proposed DSO framework.

4.1 Introduction

The installed capacity of DERs is increasing, thanks to their low operational costs and growing demand. Being capable of providing fast ramping services, DER aggregators can effectively participate in the wholesale energy and regulation markets. However, uncontrolled participation of DER aggregators may cause security issues to distribution system operations. Hence, there is a need for an entity to enable DER aggregators to participate in the wholesale market and monitor the distribution system for secure and reliable operation.

Many topics have been examined in the context of market participation of DERs. In [3, 8], the concepts of DER aggregator and virtual power plant are introduced to enable DERs for wholesale market participation. A decentralized approach using Dantzig-Wolfe decomposition is presented for DER coordination in [7]. The proposed approach allows households to participate in the electricity market to minimize the total cost. In [9, 12], a microgrid is presented for wholesale market participation. The mentioned works ignore distribution grid operations. Hence, they neglect distribution grid security/reliability constraints which are necessary for DER's market participation. In [10], a biding strategy for market participation of a virtual power plant is proposed considering a demand response market which is considered as a stage between day-ahead and real-time markets. In [11], a bidding strategy is proposed for day-ahead and real-time markets participation of EV aggregators. In [10, 11], in order to consider power balance equations, DC load flow is proposed, which is inappropriate due to high impedances in distribution grids.

Inspired by the smart grid technologies and growing DER installed capacity, the system operators call for a distribution level electricity market in which DERs can easily participate while assuring distribution grid security/reliability. The concept of distribution system operator (DSO) is presented recently in order to integrate DERs while operating the distribution network based on a retail market framework [21, 20, 22]. In [21], a DSO is introduced for operating a day-ahead retail market. The distribution locational marginal price (D-LMP) is presented as a method for paying the market participants. However, the distribution network operation and corresponding security constraints are not included in the proposed model. In [20], the authors proposed a two-stage stochastic programming approach for a DSO to operate day-ahead energy and reserve markets. In [22], a distribution market operator (DMO) is proposed which collects offers from microgrids in order to participate in the wholesale market. To represent the relationship between D-LMP and transmission-level LMP, a penalty factor is defined. Both [20] and [22] adopt DC load flow, which is inappropriate for distribution grid modeling.

To the best of our knowledge, the DSO framework for comprehensive market participation of DER aggregators under uncertainty in the retail market as well as wholesale energy and regulation markets has not been studied yet. In this chapter, a two-stage stochastic programming DSO framework is proposed for comprehensive market participation of DER aggregators under uncertainty. Various DER aggregators, including Energy storage aggregators (ESAGs), demand response aggregators (DRAGs), electric vehicle (EV) aggregating charging stations (EVCSs), dispatchable distributed generation (DDG) aggregators (DDGAGs), and renewable energy aggregators (REAGs), are considered. The proposed DSO optimally coordinates these DER aggregators for their participations in the retail market and wholesale energy/regulation markets, while maintaining distribution grid security. Case studies verify the effectiveness of the proposed DSO framework.

4.2 Two-stage Stochastic DSO Market Formulation

In this chapter, the DSO is defined as an entity which interacts with DER aggregators and end-user customers on one side and trades with the wholesale market on the other side. The DSO collects offers from various types of DER aggregators and runs the retail market as well as coordinates the offers for constructing an aggregated offer for participating in the wholesale energy and regulation markets which is operated by the independent system operator (ISO) whose pay-for-performance regulation market is considered [27, 31].

The wholesale electricity market involves two stages: the day-ahead stage and balancing stage. For instance, California ISO (CAISO), which is adopted here, is a two-settlement market consisting of day-ahead and real-time markets, which is used for adjusting balance between supply and demand [27]. Market participants can participate in the day-ahead market and correct their share by participating in the real-time market in the case that their production or consumption has changed. In practice, usually, there is a difference between the offer of a participant and its production or consumption, especially for renewable energy producers. Hence, participation in the real-time market is necessary for them.

One important characteristic of a DSO is being capable of handling uncertainties in the system operation. An appropriate method for a market operator to cover uncertainties is using two-stage stochastic programming [32]. In this method, in the objective function, expected operational costs, including costs related to the day-ahead operation and costs related to the compensating actions in the real-time, is minimized. In this model, here-and-now variables are decisions related to the day-ahead market and wait-and-see variables are decisions related to the real-time market. Day-ahead market prices usually can be predicted with high accuracy [18]. Hence, sources of uncertainties are inelastic loads, renewable energy aggregator production, and real-time prices. The two-stage stochastic programming introduced in [33] is adopted here.

4.2.1 Objective Function

The DSO minimizes the distribution grid's total operational cost, considering 1) costs of buying/selling energy and selling regulation services to the wholesale energy and regulation markets; 2) costs of paying DER aggregators for their retail market participation. The objective function of the proposed two-stage stochastic programming is given by (9.1).

$$min \sum_{t \in T} [P_t^{sub} \pi_t^e - r_t^{sub,up} \pi_t^{cap,up} - r_t^{sub,dn} \pi_t^{cap,dn}$$

$$- r_t^{sub,up} S_t^{up} \mu_t^{up} \pi_t^{mil,up} - r_t^{sub,dn} S_t^{dn} \mu_t^{dn} \pi_t^{mil,dn}$$

$$
\begin{aligned}
&+ \sum_{k\in\{K2,K4\}} P_{t,k}\pi^{e}_{t,k} - \sum_{k_3\in K_3} P_{t,k_3}\pi^{e}_{t,k_3} \\
&+ \sum_{k\in K}[r^{up}_{t,k}\pi^{cap,up}_{t,k} + r^{dn}_{t,k}\pi^{cap,dn}_{t,k} \qquad (4.1)\\
&+ r^{up}_{t,k}S^{up}_{t}\mu^{up}_{t}\pi^{mil,up}_{t,k} + r^{dn}_{t,k}S^{dn}_{t}\mu^{dn}_{t}\pi^{mil,dn}_{t,k}] \\
&- \sum_{k_1\in K_1}\sum_{a\in A} P_{a,t,k_1}\pi^{e}_{a,t,k_1} \\
&+ \sum_{w\in W}\Omega_w(P^{sub,b,rl}_{t,w}\pi^{e,b,rl}_{t,w} - P^{sub,s,rl}_{t,w}\pi^{e,s,rl}_{t,w})]
\end{aligned}
$$

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 (K_1), k_2 (K_2), k_3 (K_3), k_4 (K_5), and a (A) are the indices (sets) for all DRAGs, ESAGs, EVCSs, DDGAGs, and demand blocks, respectively; $P^{sub}_t, r^{sub,up}_t$, and $r^{sub,dn}_t$ are the DSO's aggregated quantity offers to the wholesale energy, regulation capacity-up and capacity-down markets, respectively; $\pi^{e}_t, \pi^{cap,up}_t$ ($\pi^{cap,dn}_t$), and $\pi^{mil,up}_t$ ($\pi^{mil,dn}_t$) are the wholesale energy, regulation capacity-up (capacity-down), and regulation mileage-up (mileage-down) prices, respectively; $P_{t,k}, r^{up}_{t,k}$ and $r^{dn}_{t,k}$ are the energy, regulation capacity-up and capacity-down quantity offers made by DER aggregator k with corresponding prices $\pi^{e}_{t,k}, \pi^{cap,up}_{t,k}, \pi^{cap,dn}_{t,k}$, respectively; μ^{up}_t and μ^{dn}_t are historical scores for providing regulation mileage-up and mileage-down services; S^{up}_t and S^{dn}_t are the regulation mileage-up and mileage-down ratios (the expected mileage for $1MW$ provided regulation capacity); P_{a,t,k_1} and π^{e}_{a,t,k_1} are the power consumption and the corresponding energy price at each demand block; Ω_w is the probability of scenario w; $P^{sub,b,rl}_{t,w}$ is amount of power purchased from the wholesale real-time market with corresponding price $\pi^{e,b,rl}_{t,w}$; $P^{sub,s,rl}_{t,w}$ is amount of power sold to the wholesale real-time market with price $\pi^{e,s,rl}_{t,w}$.

In (9.1), the wholesale energy market is modeled as a producer in the DSO, while the wholesale regulation market is modeled as a consumer in the DSO. Therefore, cost terms related to the energy and regulation markets are associated with the positive and negative signs, respectively. The DSO is modeled as a price taker in the wholesale energy and regulation markets.

4.2.2 Constraints for Demand Response Aggregators (DRAGs)

The operating constraints for DRAGs are as follows:

$$\sum_{a\in A} P_{a,t,k_1} - r^{cap,dn}_{t,k_1} \geq 0; \quad \forall t \in T, \forall k_1 \in K_1 \tag{4.2}$$

$$\sum_{a\in A} P_{a,t,k_1} + r^{cap,up}_{t,k_1} \leq \sum_{a\in A} P^{max}_{a,k1}; \quad \forall t \in T, \forall k_1 \in K_1 \tag{4.3}$$

$$0 \leq P_{a,t,k_1} \leq P^{max}_{a,k1}; \quad \forall a \in A, \forall t \in T, \forall k_1 \in K_1 \tag{4.4}$$

$$0 \leq r^{cap,up}_{t,k_1} \leq r^{cap,up,max}_{t,k_1}; \quad \forall t \in T, \forall k_1 \in K_1 \tag{4.5}$$

$$0 \leq r^{cap,dn}_{t,k_1} \leq r^{cap,dn,max}_{t,k_1}; \quad \forall t \in T, \forall k_1 \in K_1 \tag{4.6}$$

where $P^{max}_{a,t,k1}$ is the maximum power consumption at each demand block; $r^{cap,up,max}_{t,k1}$ and $r^{cap,dn,max}_{t,k1}$ are the maximum allowed regulation capacity-up and capacity-down quantity offers, respectively.

Equations (6.2)-(8.2a) ensure the total power consumed by the DRAG for buying/selling energy and offering regulation service is less than the maximum power consumption across all demand blocks within the DRAG. Equation (8.2b) limits the amount of power offered by each demand block to its maximum value. Equations (8.3)-(7.9a) limit the regulation capacity-up and capacity-down quantity offers to their maximum values.

4.2.3 Constraints for Energy Storage Aggregators (ESAGs)

The operating constraints for ESAGs are as follows:

$$P_{t,k_2} = E_{t-1,k_2} - E_{t,k_2} + (1/\eta_{k_2}^{di}) r_{t,k_2}^{cap,up} \mu_t^{up} - (\eta_{k_2}^{ch}) r_{t,k_2}^{cap,dn} \mu_t^{dn}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{4.7}$$

$$P_{t,k_2} = (1/\eta_{k_2}^{di}) P_{t,k_2}^{di} - (\eta_{k_2}^{ch}) P_{t,k_2}^{ch}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{4.8}$$

$$r_{t,k_2}^{cap,up} = r_{t,k_2}^{cap,up,di} + r_{t,k_2}^{cap,dn,ch}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{4.9}$$

$$r_{t,k_2}^{cap,dn} = r_{t,k_2}^{cap,dn,di} + r_{t,k_2}^{cap,up,ch}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{4.10}$$

$$E_{k_2}^{min} \leq E_{t,k_2} \leq E_{k_2}^{max}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{4.11}$$

$$0 \leq P_{t,k_2}^{di} \leq b_{t,k_2} DR_{k_2}^{max}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{4.12}$$

$$0 \leq r_{t,k_2}^{cap,up,di} \leq b_{t,k_2} DR_{k_2}^{max}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{4.13}$$

$$0 \leq r_{t,k_2}^{cap,dn,di} \leq b_{t,k_2} DR_{k_2}^{max}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{4.14}$$

$$0 \leq P_{t,k_2}^{ch} \leq (1 - b_{t,k_2}) CR_{k_2}^{max}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{4.15}$$

$$0 \leq r_{t,k_2}^{cap,up,ch} \leq (1 - b_{t,k_2}) CR_{k_2}^{max}; \forall t \in T, \forall k_2 \in K_2 \tag{4.16}$$

$$0 \leq r_{t,k_2}^{cap,dn,ch} \leq (1 - b_{t,k_2}) CR_{k_2}^{max}; \forall t \in T, \forall k_2 \in K_2 \tag{4.17}$$

$$r_{t,k_2}^{cap,dn,di} \leq P_{t,k_2}^{di} \leq DR_{k_2}^{max} - r_{t,k_2}^{cap,up,di}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{4.18}$$

$$r_{t,k_2}^{cap,dn,ch} \leq P_{t,k_2}^{ch} \leq CR_{k_2}^{max} - r_{t,k_2}^{cap,up,ch}; \quad \forall t \in T, \forall k_2 \in K_2 \tag{4.19}$$

where E_{t,k_2} is the charging level; P_{t,k_2}^{ch} (P_{t,k_2}^{di}) and $\eta_{k_2}^{ch}$ ($\eta_{k_2}^{di}$) are the charging (discharging) power and charging (discharging) efficiencies, respectively; $r_{t,k_2}^{cap,up,ch}$ ($r_{t,k_2}^{cap,dn,ch}$) and $r_{t,k_2}^{cap,up,di}$ ($r_{t,k_2}^{cap,dn,di}$) are the regulation capacity-up (capacity-down) offers in charging and discharging modes, respectively; $CR_{k_2}^{max}$ and $DR_{k_2}^{max}$ are the maximum charging and discharging rates, respectively; b_{t,k_2} is a binary variable indicating the charging

($b_{t,k_2} = 0$) and discharging ($b_{t,k_2} = 1$) modes.

ESAG's power injection is given by (7.9b). ESAG's quantity offers for energy and regulation capacity-up/down markets are decomposed into charging and discharging terms by (7.9c)-(7.9e). The charge level of ESAGs is limited by (9.11). Equations (9.10)-(5.3k) assure that ESAG's offers to the energy and regulation capacity-up/down markets are lower than their maximum values. In equations (5.3l)-(5.3m), the total power offered by ESAG to the energy and regulation capacity-up/down markets lies within the charging and discharging rates.

4.2.4 Constraints for EV Charging Stations (EVCSs)

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

$$0 \leq P_{t,k_3} \leq ER_{k_3}^{max} b_{k_3}; \quad \forall t \in T^{'}, \forall k_3 \in K_3 \tag{4.20}$$

$$0 \leq r_{t,k_3}^{cap,up} \leq ERR_{k_3}^{max} b_{k_3}; \quad \forall t \in T^{'}, \forall k_3 \in K_3 \tag{4.21}$$

$$0 \leq r_{t,k_3}^{cap,dn} \leq ERR_{k_3}^{max} b_{k_3}; \quad \forall t \in T^{'}, \forall k_3 \in K_3 \tag{4.22}$$

$$P_{t,k_3} + r_{t,k_3}^{cap,up} \leq ER_{k_3}^{max}; \quad \forall t \in T^{'}, \forall k_3 \in K_3 \tag{4.23}$$

$$P_{t,k_3} - r_{t,k_3}^{cap,dn} \geq 0; \quad \forall t \in T^{'}, \forall k_3 \in K_3 \tag{4.24}$$

$$\begin{aligned} 0.9CL_{k_3}^{max} b_{k_3} \leq E_{k_3}^{int} b_{k_3} + \sum_{t \in T^{'}} [P_{t,k_3} + r_{t,k_3}^{cap,up} \mu_t^{up} \\ - r_{t,k_3}^{cap,dn} \mu_t^{dn}] \gamma_{k_3}^{ch} \leq CL_{k_3}^{max} b_{k_3}; \; \forall k_3 \in K_3 \end{aligned} \tag{4.25}$$

where $T^{'} \subseteq T$ is the set of hours when EVs are available at the charging station; $ER_{k_3}^{max}$ is the maximum charging rate; $ERR_{k_3}^{max}$ is the maximum allowed regulation capacity offers, $CL_{k_3}^{max}$ is the maximum charge level; $E_{k_3}^{int}$ is the initial charge level; $\gamma_{k_3}^{ch}$ is the charging 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.

In (4.20)-(4.22), EVCS's offers to the energy and regulation capacity-up/down markets are limited by their corresponding maximum values. In (5.4a)-(5.4b), the total power offered by EVCS to the energy and regulation capacity-up/down markets lies within the maximum charging rate. Equation (5.4d) assures the charge level of EVs is full.

4.2.5 Constraints for Dispatchable DG Aggregators (DDGAGs)

The operating constraints for DDGAGs are as follows:

$$P_{t,k_4} + r_{t,k_4}^{cap,up} \leq P_{k_4}^{max}; \quad \forall t \in T, \forall k_4 \in K_4 \tag{4.26}$$

$$P_{t,k_4} - r_{t,k_4}^{cap,dn} \geq P_{k_4}^{min}; \quad \forall t \in T, \forall k_4 \in K_4 \tag{4.27}$$

$$0 \leq r_{t,k_4}^{cap,up} \leq RU_{k_4}; \quad \forall t \in T, \forall k_4 \in K_4 \tag{4.28}$$

$$0 \leq r_{t,k_4}^{cap,dn} \leq RD_{k_4}; \quad \forall t \in T, \forall k_4 \in K_4 \tag{4.29}$$

where $P_{k_4}^{max}$ and $P_{k_4}^{min}$ are the maximum and minimum power generations, respectively; RU_{k_4} and RD_{k_4} are the maximum ramp-up and ramp-down rates, respectively.

In (5.4e)-(5.4f), the total power offered by DDGAG to the energy and regulation capacity-up/down markets lie within the DDGAG's maximum and minimum power generations. In (5.5a)-(5.5b), the DDGAG's regulation capacity-up/down offers are limited by its maximum ramp-up/down rates.

4.2.6 Distribution Power Flow Equations

The linearized power flow equations are adopted from [28]:

$$\begin{aligned}
&\sum_{k_1\in K_1}\sum_{a\in A} H_{n,k_1}P_{a,t,k_1} + \sum_{k_3\in K_3} H_{n,k_3}P_{t,k_3} + P_{t,n}^{D} \\
&-\sum_{k_2\in K_2} H_{n,k_2}P_{t,k_2} - \sum_{k_4\in K_4} H_{n,k_4}P_{t,k_4} \\
&-\sum_{k_5\in K_5} H_{n,k_5}P_{t,k_5} + H_n^{sub}P_t^{sub} + \sum_{j\in J} Pl_{j,t}A_{j,n} = 0; \\
&\forall t\in T,\, \forall n\in N
\end{aligned} \tag{4.30}$$

$$\begin{aligned}
&\sum_{k_1\in K_1}\sum_{a\in A} H_{n,k_1}P_{a,t,k_1}tan\phi_{k_1} + Q_{t,n}^{D} \\
&-\sum_{k_4\in K_4} H_{n,k_4}P_{t,k_4}tan\phi_{k_4} \\
&+H_n^{sub}Q_t^{sub} + \sum_{j\in J} Ql_{j,t}A_{j,n} = 0; \quad \forall t\in T,\, \forall n\in N
\end{aligned} \tag{4.31}$$

$$\begin{aligned}
&V_{m,t} = V_{n,t} - (r_j Pl_{j,t} + x_j Ql_{j,t}); \\
&\forall t\in T,\, \forall m\in N,\, \forall n\in N,\, C(m,n)=1,\, A(j,n)=1
\end{aligned} \tag{4.32}$$

$$V^{min} \le V_{n,t} \le V^{max}; \quad \forall t\in T,\, \forall n\in N \tag{4.33}$$

$$-Pl^{max} \le Pl_{j,t} \le Pl^{max}; \quad \forall t\in T,\, \forall j\in J \tag{4.34}$$

$$-Ql^{max} \le Ql_{j,t} \le Ql^{max}; \quad \forall t\in T,\, \forall j\in J \tag{4.35}$$

$$\begin{aligned}
&r_t^{sub,up} = \sum_{k_2\in K_2} r_{t,k_2}^{cap,up} + \sum_{k_4\in K_4} r_{t,k_4}^{cap,up} \\
&+\sum_{k_1\in K_1} r_{t,k_1}^{cap,dn} + \sum_{k_3\in K_3} r_{t,k_3}^{cap,dn}; \quad \forall t\in T
\end{aligned} \tag{4.36}$$

$$\begin{aligned}
&r_t^{sub,dn} = \sum_{k_2\in K_2} r_{t,k_2}^{cap,dn} + \sum_{k_4\in K_4} r_{t,k_4}^{cap,dn} \\
&+\sum_{k_1\in K_1} r_{t,k_1}^{cap,up} + \sum_{k_3\in K_3} r_{t,k_3}^{cap,up}; \quad \forall t\in T
\end{aligned} \tag{4.37}$$

$$
\begin{aligned}
&P^{D}_{t,n,w} - P^{D}_{t,n} - H^{sub}_{n}(P^{sub,RT}_{t,w} - P^{sub,b,RT}_{t,w}) \\
&- \sum_{k_5 \in K_5} H_{n,k_5}(P_{t,k_5,w} - P_{t,k_5} - P^{spill}_{t,k_5,w}) \\
&+ \sum_{j \in J} Pl_{j,t,w}A_{j,n} - \sum_{j \in J} Pl_{j,t}A_{j,n} = 0; \\
&\forall t \in T, \forall n \in N, \forall w \in W
\end{aligned} \tag{4.38}
$$

$$
\begin{aligned}
&Q^{D}_{t,n,w} - Q^{D}_{t,n} - H^{sub}_{n}Q^{sub,RT}_{t,w} + \sum_{j \in J} Ql_{j,t,w}A_{j,n} \\
&- \sum_{j \in J} Ql_{j,t}A_{j,n} = 0; \quad \forall t \in T, \forall n \in N, \forall w \in W
\end{aligned} \tag{4.39}
$$

$$
\begin{aligned}
&V_{m,t,w} - V_{m,t} = V_{n,t,w} - V_{n,t} - (r_j Pl_{j,t,w} - r_j Pl_{j,t} \\
&+ x_j Ql_{j,t,w} - x_j Ql_{j,t}); \forall t \in T, \forall m \in N, \forall n \in N, \\
&C(m,n) = 1, A(j,n) = 1, \forall w \in W
\end{aligned} \tag{4.40}
$$

$$
V^{min} \leq V_{n,t,w} \leq V^{max}; \quad \forall t \in T, \forall n \in N, \forall w \in W \tag{4.41}
$$

$$
-Pl^{max} \leq Pl_{j,t,w} \leq Pl^{max}; \forall t \in T, \forall j \in J, \forall w \in W \tag{4.42}
$$

$$
-Ql^{max} \leq Ql_{j,t,w} \leq Ql^{max}; \forall t \in T, \forall j \in J, \forall w \in W \tag{4.43}
$$

$$
P^{sub,b,rl}_{t,w}, P^{sub,s,rl}_{t,w} \geq 0; \forall t \in T, \forall w \in W \tag{4.44}
$$

where k_5 (K_5) are the indices (sets) for all REAGs; $P^{spill}_{t,k_5,w}$ is the power of REAGs curtailed in each scenario; $H_{n,k}$ is the mapping matrix of DER aggregator k to bus n; $P^{D}_{t,n}$ and $Q^{D}_{t,n}$ are the inelastic active and reactive power loads at each node; $Pl_{j,t}$ and $Ql_{j,t}$ are the active and reactive power flow at branch j; $A_{j,n}$ is the incidence matrix of branches and buses; ϕ is the phase angle; $C_{m,n}$ is the connecting nodes matrix.

Equations (4.30)-(4.37) are related to the power flow equations in the day-ahead stage. Specifically, active and reactive power flows are represented by (4.30)-(4.31); voltage drop at each line is represented by (4.32) and is limited by (4.33); active and reactive power limits at each line are represented by (4.34)-(4.35); DSO's aggregated

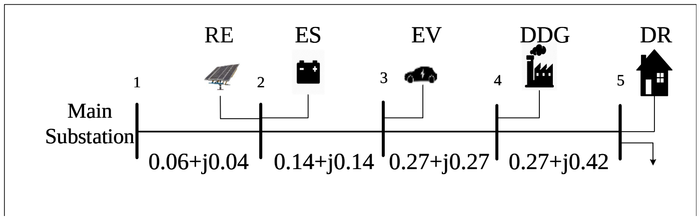


Figure 4.1: The small distribution network for case studies.

offers for participating in the wholesale energy and regulation capacity-up/down markets are represented by (4.36)-(4.37). Equations (4.38)-(8.13a) are related to adjustments in the real-time stage. Specifically, Equations (4.38)-(8.16a) are active power, reactive power, and voltage adjustments, respectively; Equations (4.41)-(8.13a) ensure that bus voltages, line active and reactive power flows lie within their limits in each scenario, respectively. Equation (5.11h) restricts the sign of trading power in the real-time stage.

4.3 Simulation results

In this section, two-stage stochastic programming introduced in Section 4.2 is used to obtain simulation results. Case studies are performed on the small distribution network in Fig.4.1. 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 DDGAG, where $k_4 = \{4\}$; a REAG, where $k_5 = \{5\}$, and an inelastic load. The studies are performed over 24 hours, $T = \{1, 2, ..., 24\}$. EVs are available during Hours 16~24, $T' = \{16, 17, ..., 24\}$. Initial charge level of ESAG is $8MW$. The following parameters are assumed: $\eta_{k_2}^{ch} = \eta_{k_2}^{di} = 1$, $E_{k_2}^{min} = 2MW$, $E_{k_2}^{max} = 10MW$, $DR_{k_2}^{max} = CR_{k_2}^{max} = 5MW$, $E_{k_3}^{int} = 2MW$, $ER_{k_3}^{max} = 5MW$, $ERR_{k_3}^{max} = 0.5MW$, $P_{k_4}^{min} = 0$, $P_{k_4}^{max} = 5MW$, $RU_{k_4} = RD_{k_4} = 1MW$, $P_{a,t,k_1}^{max} = 10MW$, $r_{k_1}^{cap,up,max} = r_{k_1}^{cap,dn,max} = 1MW$.

Table 4.1: REAG's production

Scenario Index	1	2	3	4	5
Production (MW)	1	1.5	3	2	2.5
Probability	0.1	0.1	0.6	0.1	0.1

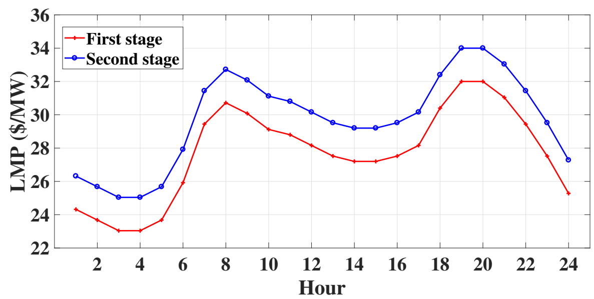
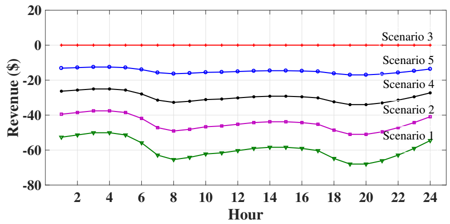


Figure 4.2: First-stage (day-ahead) and second-stage (real-time) LMPs under single source of uncertainty.

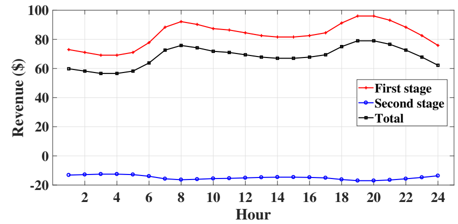
In the deterministic case, inelastic load is considered to be 3 MW at all times and is located at Node 5. Also, the maximum power production of REAG is considered to be 3 MW. Hourly energy prices, capacity up/down prices, and hourly regulation signals are generated by using hourly factors introduced in [30] and are given in [34]. Case studies below focus on uncertainty. Market outcomes in deterministic cases can be found in [34].

Single source of uncertainty

In this case, for simplicity, only one source of uncertainty is considered, which is the REAG production given in Table. 4.1. Wholesale real-time market prices are considered to be 2 $\$/MWh$ higher than the corresponding day-ahead market prices. It is assumed the DSO can only buy energy from the real-time market. In two-stage stochastic programming, the first-stage LMP corresponds to the day-ahead market



(a)



(b)

Figure 4.3: Under single source of uncertainty, (a) REAG's second-stage (real-time) revenue under each scenario; (b) REAG's first-stage (day-ahead) revenue, expected second-stage (real-time) revenue, and total expected revenue.

price, which is the dual variable of the power balance equation (4.30). The second-stage LMP corresponds to the real-time price, which is equal to the dual variable of power balance adjustment equation (4.38) divided by probability of occurrence of each scenario. Fig. 4.2 shows the first-stage (day-ahead) and second-stage (real-time) LMPs. Market participants are first settled by day-ahead LMPs. After that, market participants which need real-time compensation due to their uncertainties are settled by real-time LMPs.

Fig. 4.3a shows the REAG's second-stage (real-time) revenue in each scenario. In Scenario 3, REAG's scheduled power in the day-ahead stage is the same as that in the real-time stage. Hence, there is no need for real-time correction. In other scenarios, REAG's scheduled power in the day-ahead stage is higher than that in the real-time stage. This power deficiency should be compensated by purchasing from the wholesale real-time market. As a result, the REAG's second-stage (real-time) revenue is negative, which means it purchases power from the wholesale real-time market. Fig. 4.3b shows the REAG's first-stage (day-ahead) revenue, expected second-stage (real-time) revenue, and expected total revenue.

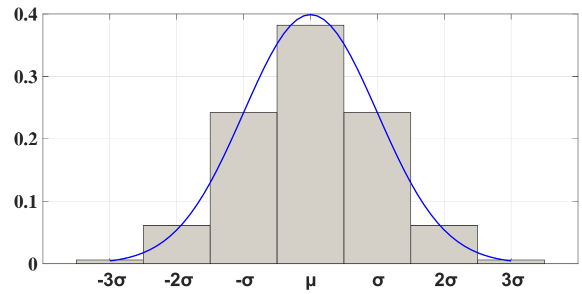


Figure 4.4: Normal distribution used under multiple sources of uncertainties.

Multiple sources of uncertainties

As mentioned above, there are three sources of uncertainties including REAG production, inelastic load, and real-time prices. Random scenarios can be generated using scenario generation methods based on the probability distribution function. Scenario reduction methods can be applied to reduce computation burden. In this case, for simplicity, normal distribution in Fig. 4.4 with mean value μ and standard deviation σ is considered as the probability distribution of random variables. Seven scenarios from -3σ to 3σ are considered. The mean value of each random variable is assumed to be the same as its value in the deterministic case. The standard deviation σ is considered to be 5%, 15%, and 8% for real-time prices, inelastic load, and REAG production, respectively. The REAG production scenarios are considered to change in the opposite direction of the real-time prices and inelastic load. In the second-stage (real-time), the price of selling energy to the wholesale market is considered to be 0.8 of the price of buying energy from it.

Fig. 4.5 shows the first-stage (day-ahead) LMPs and second-stage (real-time) LMPs in different scenarios. LMPs in Scenarios 1~3 equal the real-time prices of selling energy to the wholesale market, since in these scenarios, the demand is lower than the production in the retail market operated by the DSO. However, in Scenarios

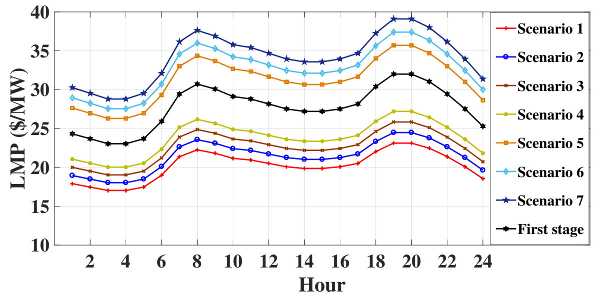


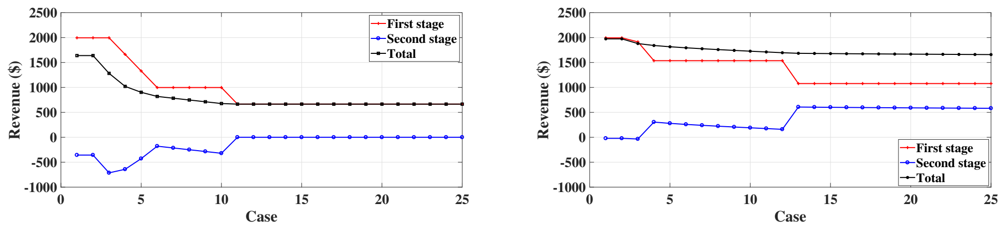
Figure 4.5: Under multiple sources of uncertainties, the REAG's first-stage (day-ahead) LMP and second-stage (real-time) LMPs in different scenarios.

5~7 the LMPs equal the real-time prices of buying energy from the wholesale market, since in these scenarios the demand is greater than the production.

Sensitivity analysis

Sensitivity analysis is carried out on the REAG's revenue with respect to changing the real-time prices in both previous case studies.

Fig. 4.6a shows the changes in REAG's first-stage (day-ahead) revenue, expected second-stage (real-time) revenue, and total revenue with respect to changes in the real-time prices under one source of uncertainty. 25 sensitivity cases are simulated. In each case, the base-case wholesale real-time market prices are multiplied by i, where i varies from 1 to 25. When $i = 1$, the REAG's second-stage (real-time) compensation cost is very low. Hence, its first-stage (day-ahead) revenue is high. Also, the REAG's second-stage (real-time) revenue is negative, which indicates the REAG buys power from the real-time market to compensate its power deficiency. Two factors affect the second stage revenues: 1) real-time prices; 2) amount of power deficiency that should be compensated in the real-time market. These two factors are negatively correlated with each other, which means when one factor increases the other factor decreases. The total effect of the two factors depends on the studied sensitivity case.



(a) (b)

Figure 4.6: Changes in REAG's first-stage (day-ahead) revenue, expected second-stage (real-time) revenue, and total revenue with respect to changes in the real time prices under (a) one source of uncertainty; (b) multiple sources of uncertainties.

For instance, when $i = 3$, effect of real-time price on second-stage revenue is higher than that of power deficiency, which decreases the second-stage revenue. However, when i increases, the effect of power deficiency grows. Hence, the second-stage revenue becomes zero after $i = 10$. Fig. 4.6b shows the changes in REAG's first-stage (day-ahead) revenue, expected second-stage (real-time) revenue, and total revenue with respect to changes in the real-time prices under multiple sources of uncertainties. To increase REAG's real-time compensation cost, REAG's real-time selling/purchasing prices are multiplied/divided by i, where i varies from 1 to 25. When i is small, the real-time compensation cost is low. Hence, the DSO schedules the REAG production at its mean value and covers the variations of inelastic load and REAG production by trading with the wholesale market. When i increases, the real-time compensation cost becomes expensive. As a result, the DSO schedules the REAG production at a lower level to avoid trading with the wholesale market and compensate inelastic load variation by REAG production. This causes the REAG's expected second-stage (real-time) revenue to increase when i becomes greater.

4.4 Conclusion

This chapter proposes a two-stage stochastic programming DSO framework for coordination of DER aggregators to participate in the retail market as well as wholesale energy and regulation markets. Various kinds of DER aggregators are modeled in the proposed DSO framework. Case studies carried out on a small distribution network show key factors between the first-stage (day-ahead) and second-stage (real-time) LMPs. The REAG participates in day-ahead and real-time markets with uncertainties. Sensitivity analysis shows as the real-time price increases, the DSO schedules less power production to REAG as an uncertain market participant.

Chapter 5

A DSO FRAMEWORK FOR MARKET PARTICIPATION OF DER AGGREGATORS IN UNBALANCED DISTRIBUTION NETWORKS

This chapter presents a distribution system operator (DSO) framework for wholesale and retail market participation of distributed energy resources (DERs) aggregators. The DSO coordinates aggregators' energy and regulation offers as well as end-users' energy consumption through the unbalanced retail market and submits balanced energy and regulation offers to the wholesale market on behalf of all the aggregators and end-users within its territory. Various kinds of DER aggregators including demand response aggregators (DRAGs), energy storage aggregators (ESAGs), electric vehicle (EV) charging stations (EVCSs), dispatchable distributed generation aggregators (DDGAGs), and renewable energy aggregators (REAGs) are modeled. To handle unbalanced distribution grids with single-phase aggregators, a linearized unbalanced power flow is tailored to model operating constraints of the distribution grid with various aggregators. A market settlement approach is proposed for the DSO, which coordinates with wholesale market clearing process and ensures the DSO's non-profit characteristic. It is proved that at the wholesale-DSO coupling substation, the total payment received/compensated by the DSO under the wholesale price is identical to that under three single-phase retail prices for each phase at the substation. Case studies are performed on the modified IEEE 33-node and 240-node distribution test systems to investigate the market outcomes of the proposed DSO.

5.1 Introduction

The Federal Energy Regulatory Commission (FERC) Order No. 2222 has required all the US independent system operators (ISOs) to completely open their wholesale markets for distributed energy resources (DERs) [1]. A huge number of DER aggregators are anticipated to enter the wholesale energy and ancillary services markets in the near future. This may cause significant challenges to transmission and distribution operations [2]: 1) These aggregators are modeled as small generators in the ISO's market system. Adopting a huge number of these small generators could cause a significant computational burden to the ISO's unit commitment and economic dispatch process. 2) To participate in the ISO's market, the aggregators need to control numerous DER outputs across the distribution system without any information on the operating constraints of the distribution grid, which could cause voltage and thermal violations in the distribution system. Therefore, there is a need for an entity to coordinate DER aggregators' market activities while assuring the secure and reliable operation of the distribution network and reducing the computational burden for the wholesale market clearing process [35].

Existing works on DER market participation fall into two categories. The first category considers DERs participating in the wholesale markets directly through aggregators [3, 8, 7, 9, 12, 4, 13, 10, 11]. In [3], the concept of the aggregator is defined to enable DERs to participate in the electricity market. In [8], the optimal operation of a virtual power plant is presented in order to participate in energy and reserve markets. In [7], a decentralized approach is proposed for coordinating DERs in which a numerous number of households interact with an aggregator to minimize the total cost of purchasing electricity. The presented decentralized model is based on Dantzig-Wolfe decomposition. In [9], the optimal bidding strategy of a microgrid in order to participate in the day-ahead and real-time markets is presented. In [12], optimal resource management of a microgrid in order to participate in the wholesale and local markets as well as transactive energy including the integration of these two markets is presented. In [4], an optimal bidding strategy problem of a load-serving entity (LSE) is proposed in order to participate in the wholesale energy and reserve markets. In [13], the optimal operation of a retailer in the day-ahead and real-time wholesale markets considering demand response (DR) is presented. Above previous works ignore distribution system power flow constraints. Hence, they neglect assuring secure and reliable operation of the distribution network while coordinating DER market participation. In [10], the bidding strategy problem of the virtual power plant considering the DR market is presented. The demand response market is defined as a stage between the day-ahead market and real-time market in which the virtual power plant is able to compensate the unbalance power between day-ahead market and real-time dispatch by purchasing flexibility from demand response providers. In [11], the optimal bidding strategy of EV aggregators for participating in day-ahead and the real-time markets is presented. A penalty cost is defined in order to avoid large difference between bidding of day-ahead and real-time markets. In [10, 11], DC power flow is used to model power balance constraints which is inappropriate due to high impedances in distribution network.

The second category of works defines the distribution system operator (DSO) to coordinate the DER market participation [21, 14, 19, 20, 22, 16, 23, 25, 26, 36, 37, 38, 39, 40, 41, 42, 43, 44, 45, 46, 47]. In [21], the day-ahead market framework operated by a DSO is presented. In [14], to meet DSO request, a local flexibility market is proposed for selling flexibility. In [21, 14], the distribution network and corresponding constraints are not modeled. In [19], a bi-level optimization is presented to model the DER aggregator's profit maximization problem and the DSO's market clearing process. In [20], the day-ahead energy and reserve markets are presented for a DSO. In [22], a local market operated by the distribution market operator (DMO) is presented. The proposed DMO gathers offers from microgrids and aggregates them to participate in the wholesale market. In [19, 20, 22], DC power flow is adopted to model power balance constraints which is inappropriate for distribution networks with high network resistances. In [16], a bilateral electricity market in the distribution system is proposed. In [23], a day-ahead market model operated by a DSO is presented. The DSO considers DERs offers as well as interaction with the wholesale market in order to clear the day-ahead market in the distribution system. In [25], a re-dispatch optimal power flow (OPF) is modeled as a congestion management method implemented by a DSO. In [26], a comprehensive congestion management method for a DSO is presented using dynamic tariff, network reconfiguration, and flexibility provided by aggregators. In [16, 23, 25, 26], wholesale market participation of DERs is not considered. In [36], a capacity limit offering curve, which reflects the opportunity cost of wholesale day-ahead and real-time markets participation for an aggregator, is proposed to avoid conflict between transmission system operator (TSO) and DSO. However, the market settlement procedure for the capacity limit market, operated by the DSO, is not proposed. The proposed method may impose additional costs on DER market participation. In [37], a bi-level programming approach is proposed for the management of active distribution networks with considering multiple virtual power plants. The upper-level problem minimizes the total operational cost in the distribution network. In the lower level problem, the profit of each virtual power plant is maximized. In [38], a bi-level robust economic dispatch model for the distribution system and micro-grids is proposed. In the upper level, the economic dispatch of the distribution network is modeled. In the lower level, each micro-grid optimizes its operation. The bi-level optimization, proposed in [37, 38], is hard to solve for large systems. In [39], the DSO is considered as a profit-seeking entity and the arbitrage opportunity between the day-ahead and real-time markets for the DSO is modeled. The authors have proposed a Nash bargaining equilibrium for coordination between TSO and DSO. In [40], the authors proposed an approach to reflect the uncertainty of the DERs production in distribution locational marginal prices (D-LMPs) by using conic duality. However, [39, 40] did not consider the wholesale market participation of DERs. Moreover, the proposed model in [40] is hard to solve for large distribution systems. In [41], a method for modeling the aggregation of flexibility from different types of DERs in an unbalanced distribution network is proposed. The feasible region of the injected power at the substation is approximated by an inner-box region. However, a market framework for DER market participation and appropriate settlement procedure is not proposed.

There are some works that deal with the TSO-DSO coordination [42, 43, 44, 45, 46**?**]. In [42], a bi-level optimization problem is proposed for the distribution market clearing process considering the interaction with the transmission wholesale market. The market-clearing conditions of the DSO and ISO are modeled in the upper-level and lower-level problems, respectively. The equilibrium problem with equilibrium constraints (EPEC) is used to find the equilibrium between DSOs and ISO. However, the proposed model is hard to solve for large systems. In [43], a bi-level optimization model is presented for siting and sizing of the energy storage systems in the coordinated transmission and distribution systems. In [44], a three-stage unit commitment problem is presented for coordinating the transmission and distribution system operation. In the first stage, the unit commitment problem of the ISO is modeled. In the second and third stages, transmission and distribution economic dispatch is modeled, respectively. The proposed model in [42, 43, 44] is hard to solve for large systems. In [45], a non-cooperative approach is proposed for coordinated operation of

TSO and DSO. The TSO and DSO are considered as entities that optimize their own operational cost based on the non-cooperative game. However, the optimal solution is not guaranteed and it is hard to solve for large distribution systems. In [46], a heterogeneous decomposition algorithm is proposed to solve the economic dispatch of coordinated transmission and distribution systems. In [47], an AC power flow model is proposed for coordinated transmission and distribution system operation and is solved using a heterogeneous decomposition algorithm. In [46, 47] wholesale market participation of DERs was not considered.

Several questions remain unexplored in existing literature. How to design a DSO to coordinate DER aggregators' wholesale market participation as well as operating the retail/local market? How does a DSO coordinate the DER aggregators' regulation market participation? What is the appropriate market settlement approach for the DSO in coordination with the wholesale market clearing process? How does the DSO operate the unbalanced retail/local market while submitting three-phase balanced offers to the wholesale market?

This chapter extends our prior works in [34] and [48] to further integrate single-phase DER aggregators for wholesale and retail markets participation considering a market settlement procedure. This study addresses the above questions with the following major contributions:

- A DSO framework is proposed to optimally coordinate various kinds of DER aggregators for the wholesale energy and regulation market participation while operating the unbalanced retail market and submitting balanced offer to the wholesale market.
- A market settlement approach is proposed for the DSO, which coordinates with the wholesale market clearing process and ensures the DSO's non-profit charac-

teristic. It is proved that at the wholesale-DSO coupling substation, the total payment received/compensated by the DSO under the wholesale price is identical to that under three single-phase D-LMPs for each phase at the substation.

- To handle the single-phase market participants while assuring three-phase balanced offers to the wholesale market, a linearized unbalanced power flow is tailored to model the operating constraints of the distribution grid with various aggregators.

- The DSO's market outcomes and market settlement process are investigated through case studies on the modified IEEE 33-node and 240-node distribution test systems.

The proposed DSO reduces the computational burden for wholesale market clearing by moving the DER-related market clearing computations to the DSO level, while satisfying distribution system operating constraints and being compatible with the current wholesale market structures.

The rest of the chapter is organized as follows. Section 7.2 presents the DSO framework and its interaction with the wholesale market. Section 5.3 presents the mathematical formulation of the DSO market. Section 5.5 proposes the market settlement approach for the DSO. Section 5.6 discusses the case studies. Section 5.7 presents the concluding remarks.

5.2 The DSO Framework

In this chapter, the DSO is considered as the non-profit distribution system and market operator. The DSO, shown in Fig. 5.1, serves as a mediator that trades with the wholesale market at the substation on one hand and interacts with DER aggregators and end-user customers on the other hand. The DER aggregators submit

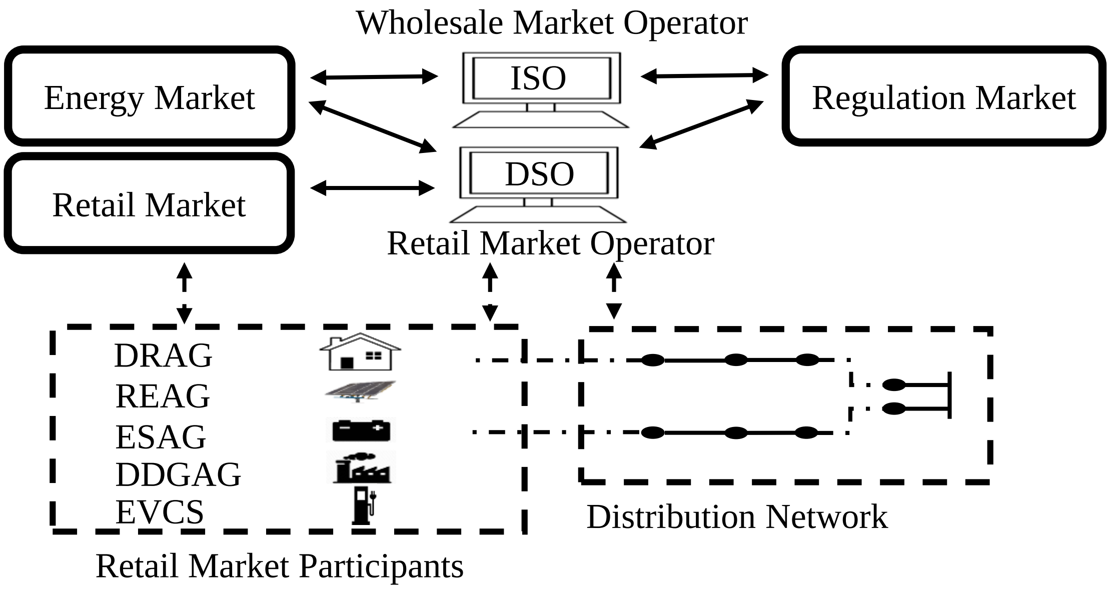


Figure 5.1: Framework of the DSO.

their energy and regulation offers to the DSO instead of to the wholesale market directly. The DSO collects the offers to operate the retail market and coordinate the retail offers to construct an aggregated bid for participating in the ISO's day-ahead wholesale energy and regulation markets. Once the day-ahead wholesale energy and regulation markets are cleared, the DSO's share in the wholesale market will be determined. The DSO will then distribute this awarded share to all the retail market participants.

The proposed DSO coordinates with the ISO to form a hierarchical wholesale/retail market mechanism. Compared to the existing mechanism which requires the modeling of a huge number of aggregators in the wholesale market clearing process, this hierarchical mechanism could significantly reduce the computational burden for wholesale market clearing while satisfying distribution system operating constraints.

On the wholesale market side, without loss of generality, this chapter adopts the market rules of California ISO (CAISO), whose pay-for-performance regulation market considers regulation capacity (capacity-up and capacity-down) and regulation mileage (mileage-up and mileage-down) [27]. However, the proposed model is capable of handling different wholesale markets clearing process for energy and regulation markets. For instance, in the PJM Interconnection and New York ISO wholesale regulation markets, the participants get cleared based on the regulation capability and regulation performance in one direction which means that a bid for regulation includes both regulation-up and regulation-down [49, 50].

5.3 Mathematical Model of The DSO Market

In this section, the optimization problem is formulated for the DSO which operates the retail market and aggregates the offers from DER aggregators for participating in the wholesale energy and regulation markets. The purpose of defining constraints for different kinds of aggregators is to leverage the participation of different technology in the wholesale market. As mentioned in FERC Order No. 2222, the ISOs must revise their tariffs to leverage the participation of different kinds of aggregators and accommodate their technical constraints. Here, by considering different kinds of aggregators and their corresponding technical constraints, the DSO handles the participation of different kinds of aggregators and removes the burden of defining different participation models for ISOs.

5.3.1 The Objective Function

The DSO minimizes the total operational cost across the distribution network, considering 1) costs of buying/selling energy in the wholesale energy and regulation markets; 2) costs of paying various types of DER aggregators for providing energy and regulation in the retail market. The DSO is assumed to be a price-taker in the wholesale market. The objective function of the proposed model is as follows:

$$
\begin{aligned}
Min \sum_{\phi\in\Phi}\sum_{t\in T}[&P_{t,\phi}^{sub}\pi_t^e - r_{t,\phi}^{sub,up}\pi_t^{cap,up} - r_{t,\phi}^{sub,dn}\pi_t^{cap,dn} \\
&- r_{t,\phi}^{sub,up}S_t^{up}\mu_t^{up}\pi_t^{mil,up} - r_{t,\phi}^{sub,dn}S_t^{dn}\mu_t^{dn}\pi_t^{mil,dn} \\
&+ \sum_{k\in\{K_2,K_4\}} P_{t,k,\phi}\pi_{t,k}^e - \sum_{k_3\in K_3} P_{t,k_3,\phi}\pi_{t,k_3}^e \\
&+ \sum_{k\in K}[r_{t,k,\phi}^{up}\pi_{t,k}^{cap,up} + r_{t,k,\phi}^{dn}\pi_{t,k}^{cap,dn} \\
&+ r_{t,k,\phi}^{up}S_t^{up}\mu_t^{up}\pi_{t,k}^{mil,up} + r_{t,k,\phi}^{dn}S_t^{dn}\mu_t^{dn}\pi_{t,k}^{mil,dn}] \\
&- \sum_{k_1\in K_1}\sum_{a\in A} P_{a,t,k_1,\phi}\pi_{a,t,k_1}^e] \qquad (5.1)
\end{aligned}
$$

In (9.1), the wholesale energy market is modeled as a producer for the DSO, while the wholesale regulation market is modeled as a consumer for the DSO. Therefore, cost terms corresponding to the wholesale energy market are associated with positive signs, while cost terms corresponding to the wholesale regulation market are associated with negative signs. The EVCSs and DRAGs are also modeled as consumers in the DSO's retail energy market, whose cost terms are associated with negative signs. Specifically, Equation (9.1) includes the terms related to the wholesale market (first and second lines of (9.1)) and terms related to the DER aggregators (the remaining lines of (9.1)). Terms related to the wholesale market include the cost of providing energy from the wholesale market, the benefit of selling regulation capacity-up/down to the wholesale market, and benefit of selling regulation mileage-up/down to the wholesale market which is calculated by using expected mileage for 1 MW regulation capacity, μ_t^{up}/μ_t^{dn}, and historical scores for providing regulation mileage, S^{up}/S^{dn}. Terms related to the DER aggregators include the cost of providing energy from producing DER aggregators, the benefit of selling energy to consuming DER aggregators, and the cost of providing regulation from DER aggregators.

5.3.2 Constraints for Demand Response Aggregators (DRAGs)

The DRAGs operating constraints are as follows:

$$\sum_{a \in A} P_{a,t,k_1,\phi} - r^{dn}_{t,k_1,\phi} \geq 0;\ \forall t \in T,\ \forall k_1 \in K_1,\ \forall \phi \in \Phi \tag{5.2a}$$

$$\sum_{a \in A} P_{a,t,k_1,\phi} + r^{up}_{t,k_1,\phi} \leq \sum_{a \in A} \overline{P}_{a,k_1,\phi}; \forall t \in T, \forall k_1 \in K_1 \\ , \forall \phi \in \Phi \tag{5.2b}$$

$$0 \leq P_{a,t,k_1,\phi} \leq \overline{P}_{a,k_1,\phi};\ \forall a \in A,\ \forall t \in T,\ \forall k_1 \in K_1 \\ , \forall \phi \in \Phi \tag{5.2c}$$

$$0 \leq r^{up}_{t,k_1,\phi} \leq \overline{r}^{up}_{t,k_1,\phi};\ \forall t \in T,\ \forall k_1 \in K_1,\ \forall \phi \in \Phi \tag{5.2d}$$

$$0 \leq r^{dn}_{t,k_{1,\phi}} \leq \overline{r}^{dn}_{t,k_1,\phi};\ \forall t \in T,\ \forall k_1 \in K_1,\ \forall \phi \in \Phi \tag{5.2e}$$

In (6.2)-(8.2a), DRAG's offers to energy, regulation capacity-up, and capacity-down markets are limited with respect to minimum and maximum power consumption. Equation (8.2b) ensures that the energy offer is lower than the corresponding maximum power consumption. In (8.3)-(7.9a), regulation capacity-up and capacity-down are limited with respect to their permitted values.

5.3.3 Constraints for Energy Storage Aggregators (ESAGs)

The operating constraints for ESAGs are as follows, for $\forall t \in T, \forall k_2 \in K_2, \forall \phi \in \Phi$:

$$P_{t,k_2,\phi} = E_{t-1,k_2,\phi} - E_{t,k_2,\phi} + (1/\eta^{di}_{k_2}) r^{up}_{t,k_2,\phi} \mu^{up}_t \\ - (\eta^{ch}_{k_2}) r^{dn}_{t,k_2,\phi} \mu^{dn}_t \tag{5.3a}$$

$$P_{t,k_2,\phi} = (1/\eta^{di}_{k_2}) P^{di}_{t,k_2,\phi} - (\eta^{ch}_{k_2}) P^{ch}_{t,k_2,\phi} \tag{5.3b}$$

$$r^{up}_{t,k_2,\phi} = r^{up,di}_{t,k_2,\phi} + r^{dn,ch}_{t,k_2,\phi} \tag{5.3c}$$

$$r^{dn}_{t,k_2,\phi} = r^{dn,di}_{t,k_2,\phi} + r^{up,ch}_{t,k_2,\phi} \tag{5.3d}$$

$$\underline{E}_{k_2,\phi} \leq E_{t,k_2,\phi} \leq \overline{E}_{k_2,\phi} \tag{5.3e}$$

$$0 \leq P^{di}_{t,k_2,\phi} \leq b_{t,k_2,\phi}\overline{D}_{k_2,\phi} \tag{5.3f}$$

$$0 \leq r^{up,di}_{t,k_2,\phi} \leq b_{t,k_2,\phi}\overline{r}^{up}_{k_2,\phi} \tag{5.3g}$$

$$0 \leq r^{dn,di}_{t,k_2,\phi} \leq b_{t,k_2,\phi}\overline{r}^{dn}_{k_2,\phi} \tag{5.3h}$$

$$0 \leq P^{ch}_{t,k_2,\phi} \leq (1 - b_{t,k_2,\phi})\overline{C}_{k_2,\phi} \tag{5.3i}$$

$$0 \leq r^{up,ch}_{t,k_2,\phi} \leq (1 - b_{t,k_2,\phi})\overline{r}^{dn}_{k_2,\phi} \tag{5.3j}$$

$$0 \leq r^{dn,ch}_{t,k_2,\phi} \leq (1 - b_{t,k_2,\phi})\overline{r}^{up}_{k_2,\phi} \tag{5.3k}$$

$$r^{dn,di}_{t,k_2,\phi} \leq P^{di}_{t,k_2,\phi} \leq \overline{D}_{k_2,\phi} - r^{up,di}_{t,k_2,\phi} \tag{5.3l}$$

$$r^{dn,ch}_{t,k_2,\phi} \leq P^{ch}_{t,k_2,\phi} \leq \overline{C}_{k_2,\phi} - r^{up,ch}_{t,k_2,\phi} \tag{5.3m}$$

Equation (7.9b) defines the injected power of ESAGs. Equations (7.9c)-(7.9e) decompose the energy, regulation capacity-up, and regulation capacity-down offers into their corresponding values in the charge and discharge modes. In (9.11), charge levels are limited within the upper and lower limits. Equations (9.10)-(5.3k) limit the injected power, regulation capacity-up offers, and capacity-down offers with respect to their maximum values in the charge/discharge modes. Equations (5.3l)-(5.3m) ensure the charged/discharged power is limited with respect to the maximum charge/discharge rate and the regulation capacity-up and capacity-down offers in the charge/discharge modes, respectively.

Note that the DER aggregators are required to submit their bidding/operating parameters to the DSO. These parameters are built upon the DER preferences. Hence, some of the DERs' preferences are reflected by these parameters.

5.3.4 Constraints for EV Charging Stations (EVCSs)

EVCSs are modeled as EV charging aggregators and are assumed to have unidirectional power flow [6]. Constraints related to the operation of EVCSs are as follows:

$$0 \leq P_{t,k_3,\phi} \leq \overline{R}^{c}_{k_3,\phi} b_{k_3,\phi}; \forall t \in T^{'}, \forall k_3 \in K_3, \forall \phi \in \Phi \tag{5.4a}$$

$$0 \leq r^{up}_{t,k_3,\phi} \leq \overline{r}^{up}_{k_3,\phi} b_{k_3,\phi};\ \forall t \in T^{'}, \forall k_3 \in K_3, \forall \phi \in \Phi \tag{5.4b}$$

$$0 \leq r^{dn}_{t,k_3,\phi} \leq \overline{r}^{dn}_{k_3,\phi} b_{k_3,\phi};\ \forall t \in T^{'}, \forall k_3 \in K_3, \forall \phi \in \Phi \tag{5.4c}$$

$$P_{t,k_3,\phi} + r^{up}_{t,k_3,\phi} \leq \overline{R}^{c}_{k_3,\phi};\ \forall t \in T^{'}, \forall k_3 \in K_3, \forall \phi \in \Phi \tag{5.4d}$$

$$P_{t,k_3,\phi} - r^{dn}_{t,k_3,\phi} \geq 0;\ \forall t \in T^{'}, \forall k_3 \in K_3, \forall \phi \in \Phi \tag{5.4e}$$

$$\begin{aligned} &0.9\overline{CL}_{k_3,\phi} b_{k_3,\phi} \leq E^{int}_{k_3,\phi} b_{k_3,\phi} + \sum_{t \in T^{'}} [P_{t,k_3,\phi} + r^{up}_{t,k_3,\phi} \mu^{up}_{t} \\ &- r^{dn}_{t,k_3,\phi} \mu^{dn}_{t}] \gamma^{ch}_{k_3} \leq \overline{CL}_{k_3,\phi} b_{k_3,\phi};\ \forall k_3 \in K_3, \forall \phi \in \Phi \end{aligned} \tag{5.4f}$$

Equations (5.4a)-(5.4c) limit EVCSs' energy, regulation capacity-up, and capacity-down offers within their maximum values. In (5.4d)-(5.4e), the energy offer is limited with respect to the maximum charge rate and the regulation capacity-up and capacity-down offers. Equation (5.4f) ensures the EVCSs are fully charged.

5.3.5 Constraints for Dispatchable DG Aggregators (DDGAGs)

The operating constraints for DDGAGs are as follows:

$$P_{t,k_4,\phi} + r^{up}_{t,k_4,\phi} \leq \overline{P}_{k_4,\phi}; \forall t \in T,\ \forall k_4 \in K_4, \forall \phi \in \Phi \tag{5.5a}$$

$$P_{t,k_4,\phi} - r^{dn}_{t,k_4,\phi} \geq \underline{P}_{k_4,\phi}; \forall t \in T,\ \forall k_4 \in K_4, \forall \phi \in \Phi \tag{5.5b}$$

$$0 \leq r^{up}_{t,k_4,\phi} \leq \overline{r}^{up}_{k_4,\phi}; \forall t \in T,\ \forall k_4 \in K_4, \forall \phi \in \Phi \tag{5.5c}$$

$$0 \leq r^{dn}_{t,k_4,\phi} \leq \overline{r}^{dn}_{k_4,\phi}; \forall t \in T,\ \forall k_4 \in K_4, \forall \phi \in \Phi \tag{5.5d}$$

Equations (5.5a)-(5.5b) limit the energy, regulation capacity-up, and capacity-down offers with respect to the minimum and maximum power generations, respectively. Equations (5.5c)-(5.5d) limit the regulation capacity-up and capacity-down offers within their permitted values, respectively.

5.4 The Linearized Three-Phase Power Flow

The distribution system operation is unbalanced due to single-phase loads. The linearized three-phase power flow is considered to model the unbalanced operation [51, 52]. Consider a branch $j \in J$ which connects node $n \in N$ to node $m \in N$. The voltage drop across a branch is defined as follows:

$$V_{m,\phi} = V_{n,\phi} - \sum_{\psi \in \Phi} Z_{j,\phi,\psi} I_{j,\psi} \tag{5.6}$$

Substituting $I_{j,\psi}$ by $I_{j,\psi} = S^*_{j,\psi}/V^*_{n,\phi}$, multiplying both sides of the resulting equation by their complex conjugates, and assuming 1) the branch losses are negligible (i.e., $|Z_{j,\phi,\psi}|^2 |S_{j,\psi}|^2 / |V_{n,\phi}|^2 \approx 0$), 2) the voltages are approximately balanced (i.e., $\frac{V_{n,a}}{V_{n,b}} \approx \frac{V_{n,b}}{V_{n,c}} \approx \frac{V_{n,c}}{V_{n,a}} \approx e^{j2\pi/3}$), the following equations are obtained:

$$U_{m,\phi} = U_{n,\phi} - \sum_{\psi \in \Phi} \alpha_{\phi,\psi} Z_{j,\phi,\psi} S^*_{j,\psi} - \sum_{\psi \in \Phi} \alpha^*_{\phi,\psi} Z^*_{j,\phi,\psi} S_{j,\psi} \tag{5.7}$$

$$U_{m,\phi} = |V_{m,\phi}|^2,\ U_{n,\phi} = |V_{n,\phi}|^2 \tag{5.8}$$

$$\alpha_{\phi,\psi} = \begin{bmatrix} 1 & e^{-i2\pi/3} & e^{i2\pi/3} \\ e^{i2\pi/3} & 1 & e^{-i2\pi/3} \\ e^{-i2\pi/3} & e^{i2\pi/3} & 1 \end{bmatrix} \tag{5.9}$$

In (5.7), substituting the complex variables by their real and imaginary parts (using $Z_{j,\phi,\psi} = r_{j,\phi,\psi} + ix_{j,\phi,\psi}$, $S_{j,\psi} = P_{j,\psi} + iQ_{j,\psi}$, $\alpha_{\phi,\psi} = \alpha^{re}_{\phi,\psi} + i\alpha^{im}_{\phi,\psi}$), the following equation is obtained as the DSO operating constraint:

$$\begin{aligned} U_{m,\phi} = U_{n,\phi} &- \sum_{\psi\in\Phi}(2\alpha^{re}_{\phi,\psi} r_{j,\phi,\psi} - 2\alpha^{im}_{\phi,\psi} x_{j,\phi,\psi})P_{j,\psi} \\ &- \sum_{\psi\in\Phi}(2\alpha^{re}_{\phi,\psi} x_{j,\phi,\psi} + 2\alpha^{im}_{\phi,\psi} r_{j,\phi,\psi})Q_{j,\psi} \end{aligned} \tag{5.10}$$

Using the voltage drop equation in (5.10) and considering power balance at each node, the following three-phase power flow model is obtained:

$$\begin{aligned} &- H^{sub}_{n} P^{sub}_{t,\phi} + P^{D}_{t,n,\phi} + \sum_{k_1\in K_1}\sum_{a\in A} H_{n,k_1} P_{a,t,k_1,\phi} \\ &+ \sum_{k_3\in K_3} H_{n,k_3} P_{t,k_3,\phi} - \sum_{k\in\{K_2\cup K_4\cup K_5\}} H_{n,k} P_{t,k,\phi} \\ &+ \sum_{j} Pl_{j,t,\phi} A_{j,n} = 0;\ \forall t\in T,\ \forall n\in N,\ \forall\phi\in\Phi \end{aligned} \tag{5.11a}$$

$$\begin{aligned} &- H^{sub}_{n} Q^{sub}_{t,\phi} + \sum_{k_1\in K_1}\sum_{a\in A} H_{n,k_1} P_{a,t,k_1,\phi} tan\phi_{k_1} \\ &+ Q^{D}_{t,n,\phi} - \sum_{k_4\in K_4} H_{n,k_4} P_{t,k_4,\phi} tan\phi_{k_4} \\ &+ \sum_{j} Ql_{j,t,\phi} A_{j,n} = 0;\quad \forall t\in T,\ \forall n\in N,\ \forall\phi\in\Phi \end{aligned} \tag{5.11b}$$

$$\begin{aligned} &U_{m,t,\phi} = U_{n,t,\phi} - \sum_{\psi\in\Phi}(2\alpha^{r}_{\phi,\psi} r_{j,\phi,\psi} - 2\alpha^{x}_{\phi,\psi} x_{j,\phi,\psi})Pl_{j,t,\psi} \\ &- \sum_{\psi\in\Phi}(2\alpha^{r}_{\phi,\psi} x_{j,\phi,\psi} + 2\alpha^{x} r_{j,\phi,\psi})Ql_{j,t,\psi};\ \ \forall t\in T, \\ &\forall(m,n)\in C_{mn},\ \forall(n,j)\in A_{j,n},\ \forall\phi\in\Phi \end{aligned} \tag{5.11c}$$

$$\underline{V}^2 \le U_{n,t,\phi} \le \overline{V}^2;\quad \forall t\in T,\ \forall n\in N,\ \forall\phi\in\Phi \tag{5.11d}$$

$$-\overline{Pl}_j \le Pl_{j,t,\phi} \le \overline{Pl}_j;\quad \forall t\in T,\ \forall j\in J,\ \forall\phi\in\Phi \tag{5.11e}$$

$$-\overline{Ql}_j \le Ql_{j,t,\phi} \le \overline{Ql}_j;\quad \forall t\in T,\ \forall j\in J,\ \forall\phi\in\Phi \tag{5.11f}$$

$$\begin{aligned} &r^{sub,up}_{t,\phi} = \sum_{k_2\in K_2} r^{up}_{t,k_2,\phi} + \sum_{k_4\in K_4} r^{up}_{t,k_4,\phi} + \\ &\sum_{k_1\in K_1} r^{dn}_{t,k_1,\phi} + \sum_{k_3\in K_3} r^{dn}_{t,k_3,\phi};\quad \forall t\in T,\ \forall\phi\in\Phi \end{aligned} \tag{5.11g}$$

$$r^{sub,dn}_{t,\phi} = \sum_{k_2 \in K_2} r^{dn}_{t,k_2,\phi} + \sum_{k_4 \in K_4} r^{dn}_{t,k_4,\phi} + \sum_{k_1 \in K_1} r^{up}_{t,k_1,\phi} + \sum_{k_3 \in K_3} r^{up}_{t,k_3,\phi}; \quad \forall t \in T, \forall \phi \in \Phi \tag{5.11h}$$

$$P^{sub}_{t,A} = P^{sub}_{t,B} = P^{sub}_{t,C}; \quad \forall t \in T \tag{5.11i}$$

$$r^{sub,up}_{t,A} = r^{sub,up}_{t,B} = r^{sub,up}_{t,C}; \quad \forall t \in T \tag{5.11j}$$

$$r^{sub,dn}_{t,A} = r^{sub,dn}_{t,B} = r^{sub,dn}_{t,C}; \quad \forall t \in T \tag{5.11k}$$

Equations (5.11a)-(5.11b) ensure the summation of active/reactive power at each node is zero. The voltage drop at each branch is defined by (5.11c). Equation (5.11d) ensures the voltage at each node remains within its upper/lower limits. In (5.11e)-(5.11f), the active/reactive power flow of each branch is limited within its maximum value in both directions. Equations (5.11g)-(5.11h) balance the regulation capacity-up/capacity-down offers from the aggregators and to the wholesale market. Equations (5.11i)-(5.11k) ensure the aggregated offers submitted by the DSO to the wholesale market are three-phase balanced.

Note that the main difference between the proposed power flow and DC power flow is that DC power flow assumes that voltages have a constant value and ignores reactive power and also assumes that all resistances are equal to zero while linearized power flow does not make these assumptions. Moreover, the proposed power flow is capable of handling multi-phase systems. In [51], the linearized power flow is used on IEEE 13, 34, 37, 123 bus networks and it is compared with the results of forward-backward sweep method. The results showed that voltage error does not exceed 0.0016 per unit which shows the accuracy of the linearized power flow.

5.5 The Market Settlement

The DSO trades with the wholesale market on one hand and coordinates the DER aggregators within the retail market on the other hand. Therefore, the market settlements for the DSO and ISO need to be coordinated. The ISO and DSO can be viewed as the market participant in each other's market. When the DSO market is cleared, the DSO determines distribution locational marginal prices, D-LMPs, at each phase across its territory. However, the DSO cannot determine the price for the ISO (which is assumed as a participant in the DSO market) at the DSO-ISO coupling point, since the price at this location is determined by the ISO's wholesale market clearing process.

Lemma 5.1 *At the wholesale-DSO coupling substation, the total payment received or compensated by the DSO under the wholesale price is identical to that under three single-phase D-LMPs for each phase at the substation.*

Proof. See Appendix 7.6

Lemma 1 is extendable to every balanced DSO market participant. When there is no congestion or voltage violation in the distribution system, a balanced three-phase aggregator will be paid at three single-phase D-LMPs. The average of these three D-LMPs is the same as the wholesale LMP at the ISO-DSO coupling substation. Therefore, when participating in the DSO market or in the existing ISO market directly, this three-phase aggregator will receive the same payment. When congestions and voltage violations happen in the DSO, D-LMPs across the distribution system will be different, and the DSO will receive a surplus. This surplus is conceptually similar to the ISO's congestion revenue rights (CRRs) [29, 27] and can be returned to the distribution utilities who are responsible for operating and upgrading the distribution circuits, reactive power compensations, and meters.

One of the important characteristics of an appropriate market design is being capable of avoiding price anticipatory behavior of the market participants. To achieve this, a pricing mechanism with incentive compatibility could be incorporated into the proposed DSO market. As a unified pricing mechanism, the D-LMP proposed in this chapter can prevent price anticipatory behavior under certain conditions, since this pricing mechanism pays the market participants using D-LMPs which are determined by the operating conditions of the entire distribution grid (not by the bid-in costs of individual market participants). Therefore, the impact of behavior from individual market participants on D-LMPs are limited [53, 54]. To further eliminate price anticipatory behavior of retail market participants, generally, the incentive compatibility constraints should be considered in the proposed optimization problem for retail market clearing. However, these incentive compatibility constraints makes the problem complex and hard to solve [55].

5.6 Case Studies

To investigate the market clearing performance and market outcomes of the proposed DSO, case studies are performed on 33-node and 240-node distribution systems. Studies are performed on a 24 hours operating timespan, where T=$\{1, 2, 3, ..., 24\}$. In all case studies, the energy and regulation capacity prices in [5] are considered. The hourly factors in [30] are used to generate hourly prices. Hourly energy prices, capacity up/down prices, and hourly regulation signals are given in [34], which are shown in Table. 7.1, where E denotes energy price, C denotes regulation capacity price. It is assumed that EVs are available between hours 16 to 24, where T'=$\{16, 17, 18, ..., 24\}$. S^{up} and S^{dn} are assumed to be equal to 1. Voltage limit is considered to be 5%. One

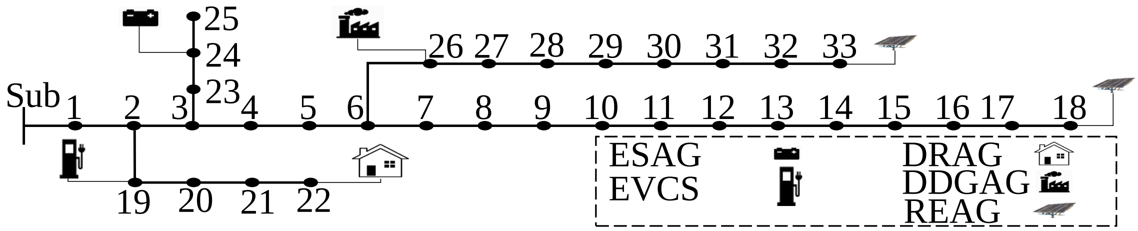


Figure 5.2: 33-nodes distribution system.

demand block is considered. For the sake of simplicity, the REAG production profile is considered deterministic with two production levels (high and low) and zero production cost. The probabilistic modeling of the REAG is out of scope of this chapter and is discussed in [48].

5.6.1 33-node Distribution System

The 33-node test system is a balanced radial network which is shown in Fig. 5.2. The system contains 33 nodes, N=$\{1,...,33\}$; 32 branches, J=$\{1,...,32\}$; a DRAG, K_1=$\{1\}$; an ESAG, K_2=$\{2\}$; an EVCS, K_3=$\{3\}$; a DDGAG, K_4=$\{4\}$; two REAGs, K_5=$\{5,6\}$. The test system data and load data are given in [56]. The two REAGs are considered to have identical energy production profile: 0.5 MW for hours 6-12 and 17-21; 0.4 MW for the remaining hours. The following parameters are assumed: $\eta^{ch}_{k_2}$=$\eta^{di}_{k_2}$=$\gamma^{ch}_{k_3}$=1, $\overline{P}_{k_1}$=1 MW, $\overline{r}^{up}_{k_1}$=$\overline{r}^{dn}_{k_1}$=0.1 MW, $\underline{E}_{k_2}$=0.5 MWh, $\overline{E}_{k_2}$=3 MWh, $\overline{D}_{k_2}$=$\overline{C}_{k_2}$=$\overline{r}^{up}_{k_2}$=$\overline{r}^{dn}_{k_2}$=1 MW, $E^{int}_{k_3}$=0.2 MWh, $\overline{R}^{c}_{k_3}$=0.5 MW, $\overline{r}^{up}_{k_3}$=$\overline{r}^{dn}_{k_3}$=0.2 MW, $\overline{CL}_{k_3}$=1 MWh, $\underline{P}_{k_4}$=0 MW, $\overline{P}_{k_4}$=3 MW, $\overline{r}^{up}_{k_4}$=$\overline{r}^{dn}_{k_4}$=0.5 MW.

Fig. 5.3 shows the share of each market participant. The amount of energy/regulation bought/sold by the DSO from/to the ISO is shown in Fig. 5.3(a). The awarded market share to the ESAG, EVCS, DRAG, and DDGAG is shown in Fig. 5.3(b)-Fig. 5.3(e), respectively. The DSO sells energy to the wholesale market at hours 8, 9, 18, 19, 20, and 21, during which the wholesale energy prices are high.

Table 5.1: Energy (E), Regulation Capacity (C) Prices ($/MWh) and Regulation-Up (up)/-Down (dn) Signals (p.u.) of Various Market Participants

t	Wholesale		ESAG		DDGAG		EVCS		DRAG		Regulation	
	E	*C*	*E*	*C*	*E*	*C*	*E*	*C*	*E*	*C*	*up*	*dn*
1	24.3	14.7	25	23	28	27	29	30.5	29	30	0.45	0.42
2	23.7	17.3	25	23	28	27	29	30.5	29	30	0.45	0.42
3	23	16.6	25	23	28	27	29	30.5	29	30	0.45	0.42
4	23	16.6	25	23	28	27	29	30.5	29	30	0.45	0.42
5	23.7	17.3	25	23	28	27	29	30.5	29	30	0.45	0.42
6	25.9	22.7	28	25	29	28	29.5	31	30	31	0.48	0.48
7	29.4	30.4	28	25	29	28	29.5	31	30	31	0.48	0.48
8	30.7	33.6	28	25	29	28	29.5	31	30	31	0.48	0.48
9	30.1	33.6	28	25	29	28	29.5	31	30	31	0.48	0.48
10	29.1	31.4	28	25	29	28	29.5	31	30	31	0.48	0.48
11	28.8	30.4	28	25	29	28	29.5	31	30	31	0.48	0.48
12	28.2	24.3	28	25	29	28	29.5	31	30	31	0.48	0.48
13	27.5	24.3	27	24	28.5	27.5	29	30.5	29	30	0.5	0.51
14	27.2	24.3	27	24	28.5	27.5	29	30.5	29	30	0.5	0.51
15	27.2	24.3	27	24	28.5	27.5	29	30.5	29	30	0.5	0.51
16	27.5	24.3	27	24	28.5	27.5	29	30.5	29	30	0.5	0.51
17	28.2	28.2	30	27	29	28	29.5	31	30	31	0.5	0.51
18	30.4	28.8	30	27	29	28	29.5	31	30	31	0.5	0.51
19	32	33.6	30	27	29	28	29.5	31	30	31	0.5	0.51
20	32	33.6	30	27	29	28	29.5	31	30	31	0.5	0.5
21	31	32	30	27	29	28	29.5	31	30	31	0.5	0.5
22	29.4	32	28	25	29	28	29.5	31	30	31	0.5	0.5
23	27.5	25.6	28	25	28	27	29	30.5	29	30	0.42	0.45
24	25.3	22.4	28	25	28	27	29	30.5	29	30	0.42	0.45

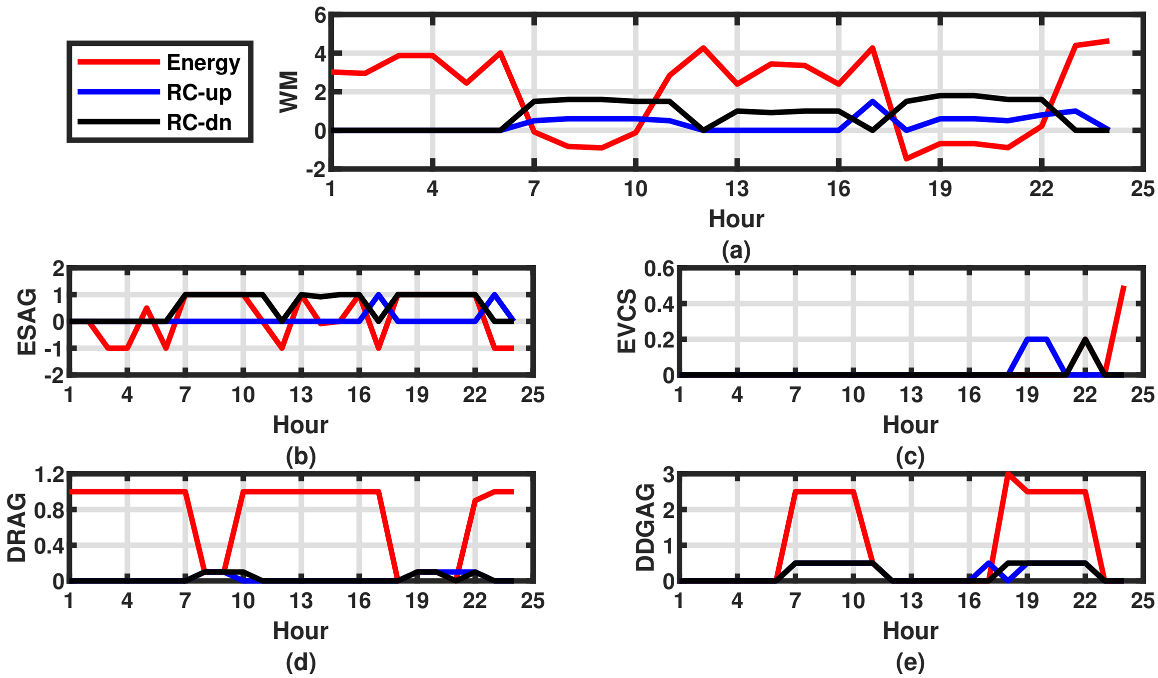


Figure 5.3: Hourly assigned energy, regulation capacity-up/-down services for the wholesale market (denoted by WM) and various aggregators for the 33-node system. The red, blue, and black curves denote awarded energy, regulation capacity-up/-down services, respectively. All Y-axis units are in MW.

The DSO intends to assign regulation capacity-down more than regulation capacity-up to the ESAG since this could increase the ESAG's charge level which eventually contributes to lowering the total DSO operating cost by purchasing extra low-cost energy service from the ESAG.

The EVCS is assigned to provide regulation capacity-up at hours 19-20 since: 1) the wholesale capacity-up price is higher than the EVCS's capacity-up offering price, and 2) providing regulation capacity-up increases the charge level of EVCS.

At peak hours 8-9 and 18-21, the DRAG's offering price for buying energy is lower than that of the wholesale market. As a result, the wholesale market wins all the energy at these hours. However, the DRAG's regulation capacity offering price is

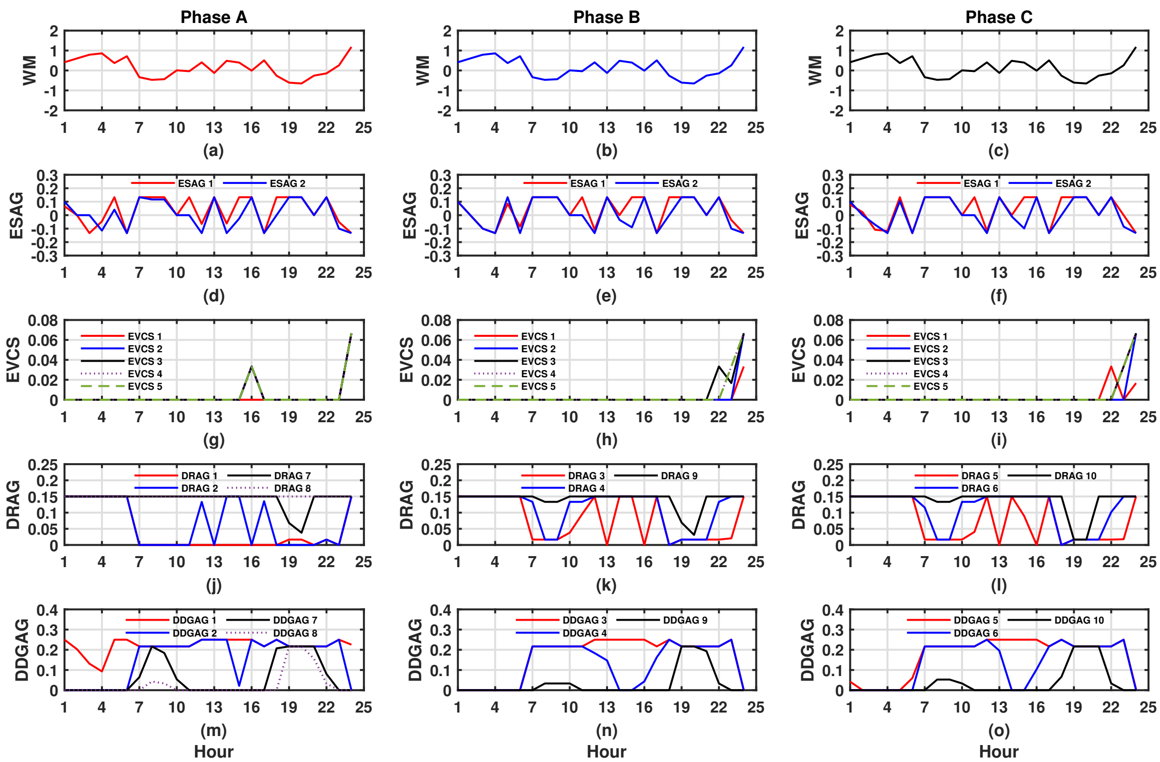


Figure 5.4: Hourly awarded quantities for the wholesale market (denoted by WM) and various aggregators for each phase in the wholesale and retail energy markets for the 240-node system. All Y-axis units are in MW.

lower than the wholesale market offering price for regulation capacity. Hence, the DSO assigns energy consumption equal to the regulation capacity-down provision to the DRAG that is necessary for providing regulation capacity-down.

The DSO assigns energy and regulation capacity provision to the DDGAG at peak hours 7-11 and 18-22, when the DDGAG's offering price is lower than wholesale price. The DSO intends to assign regulation capacity before assigning energy to the DDGAG at these hours since the wholesale regulation capacity price is higher than wholesale energy price. The DDGAG provides regulation at its maximum regulation capacity (0.5 MW). The DSO assigns its remaining capacity (2.5 MW) to energy provision. However, at hour 18, the DSO assigns energy provision to the DDGAG at its maximum capacity (3 MW), since at this hour, the wholesale energy price is higher than the wholesale regulation capacity price.

5.6.2 240-node Distribution System

The 240-node distribution test system is an unbalanced radial network in Midwest U.S. The system is fully observable with smart meters. The data of the system is given in [57].

The system contains 240 nodes, where N=$\{1, ..., 240\}$; 239 branches, where J=$\{1, ..., 239\}$. Multiple aggregators are considered as follows: ten DRAGs, where K_1=$\{1, ..., 10\}$; two ESAGs, where K_2=$\{11, 12\}$; five EVCSs, where K_3=$\{13, ..., 17\}$; ten DDGAGs, where K_4=$\{18, ..., 27\}$; six REAGs, where K_5=$\{28, ..., 33\}$.

Different offering prices are considered for individual aggregators of each type. In order to generate different prices for different aggregators, the data of the 33-node system is changed by using step size σ as follows: ESAGs' offering prices vary from 0σ to $+1\sigma$, where $\sigma = 3\%$; DRAGs' offering prices vary from -5σ to $+4\sigma$, where $\sigma = 2\%$; DDGAGs' offering prices vary from -5σ to $+4\sigma$, where $\sigma = 2\%$; EVCSs' offering price vary from 0σ to $+4\sigma$, where $\sigma = 3\%$;

The ESAGs and EVCSs are assumed to be identically allocated on each phase with the following parameters: $\eta_{k_2}^{ch}$=$\eta_{k_2}^{di}$=$\gamma_{k_3}^{ch}$=1, $\underline{E}_{k_2}$=0.1 MWh, $\overline{E}_{k_2}$=0.8 MWh, $\overline{D}_{k_2}$=$\overline{C}_{k_2}$=$\overline{r}_{k_2}^{up}$=$\overline{r}_{k_2}^{dn}$=0.4 MW, $E_{k_3}^{int}$=0.2 MWh, $\overline{R}_{k_3}^{c}$=0.2 MW, $\overline{r}_{k_3}^{up}$=$\overline{r}_{k_3}^{dn}$=0.1 MW, $\overline{CL}_{k_3}$ =0.5 MWh. The DDGAGs are assumed to be single phase with regulation limit of 0.1 MW and the following characteristics: the 1st, 2nd, 7th, and 8th DDGAGs have the capacity of 0.25 MW on phase A, the 3rd, 4th, and 9th DDGAGs have the capacity of 0.25 MW on phase B, and the 5th, 6th, and 10th DDGAGs have the capacity of 0.25 MW on phase C. The DRAGs are assumed to be single-phase with regulation limit of 0.05 MW and the capacity of 0.15 MW. The phase allocations of the ten DRAGs are the same as those of the ten DDGAGs. The REAGs are assumed to be single-phase with identical energy production profile of 0.15 MW for hours 6-12 and 17-21; 0.1 MW for remaining hours with the following phase allocation: the 1^{st} and 2^{nd} REAGs on phase A; the 3^{rd} and 4^{th} REAGs on phase B; and the 5^{th} and 6^{th} REAGs on phase C.

Fig. 5.4 shows the energy market outcomes of the 240-node system. Fig. 5.4(a), Fig. 5.4(b), and Fig. 5.4(c) show the DSO's wholesale market share on phases A, B, C, respectively. Although the DSO's retail market is unbalanced, the DSO's wholesale market share is three-phase balanced. By comparing market outcomes in the two test systems, one can see that the wholesale market buys less energy from the 240-node DSO than from the 33-node DSO, since retail market participants in the 240-node DSO have higher offering prices, therefore the 240-node DSO buys energy from the ISO during most hours.

The market share of ESAGs on phases A, B, and C is shown in Fig. 5.4(d), Fig. 5.4(e), and Fig. 5.4(f), respectively. The DSO assigns more charging states to the 2^{nd} ESAG than to the 1^{st} ESAG since the 2^{nd} ESAG's energy offering price is higher than that of the 1^{st} ESAG. This phenomenon can be observed by comparing their curves as the 2^{nd} ESAG's curve is under the 1^{st} ESAG's curve for most of the time.

The market share of EVCSs on phases A, B, and C is shown in Fig. 5.4(g), 5.4(h), and 5.4(i), respectively. The 5^{th} EVCS consumes more energy than other EVCSs, since its offering price for buying energy is the highest among all EVCSs.

The share of DRAGs on phases A, B, and C is shown in Fig. 5.4(j), Fig. 5.4(k), and Fig. 5.4(l), respectively. By comparing the share of 1^{st}, 2^{nd}, 7^{th}, 8^{th} DRAGs (all of which have demand response resources on phase A), one can see that the 8^{th} DRAG consumes energy more than the others since its offering price for buying energy is higher than that of the others. Hence, the DSO sells more energy to the 8^{th} DRAG.

Table 5.2: Settlement of retail market participants

Cost ($)	Market participant						
	WM	ESAGs	DDGAGs	EVCSs	DRAGs	REAGs	IL
33-node	-1192.2	-157.8	-715.2	18.5	488.6	-603.4	2161.5
240-node	-221.2	-122.0	-789.3	33.8	684.3	-505.9	920.3

Similarly, among all the DRAGs with resources on phase B (and C), the 9$^{\text{th}}$ (and 10$^{\text{th}}$) DRAG with the highest energy offering price on phase B (and C) consumes the most energy, respectively.

The market share of DDGAGs on phases A, B, and C is shown in Fig. 5.4(m), Fig. 5.4(n), and Fig. 5.4(o), respectively. The offering price of the 1$^{\text{st}}$ DDGAG is lower than other three DDGAGs on phase A. Hence, the DSO assigns the most energy provision to the 1$^{\text{st}}$ DDGAG among all DDGAGs on phase A. Fig. 5.4(n) (and Fig. 5.4(o)) shows similar results for the DDGAGs on phase B (and phase C).

5.6.3 Market Settlement

The costs of various market participants for buying/selling energy and regulation services in the DSO market in both 33-node and 240-node systems are given in Table. 5.2, where WM and IL denote the wholesale market and the inelastic load, respectively. In the 240-node system, the costs for aggregators of the same type are summed up together. It is clear that the summation of all the costs in each system is zero, leading to no surplus for the DSO when the retail market is cleared.

5.6.4 Voltage Profile

Voltage issue is one of important topics in the distribution network. As discussed earlier, DERs aggregators are located in the distribution system. In the current

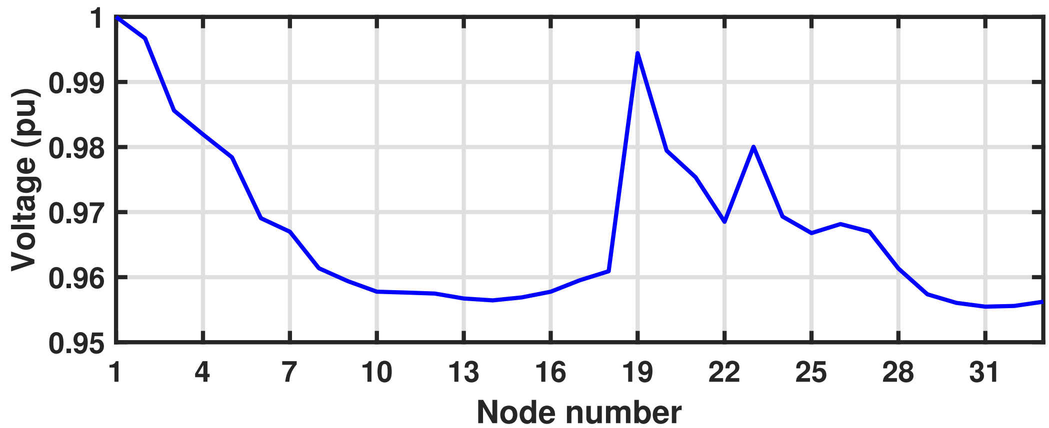


Figure 5.5: Voltage magnitudes for the 33-node test system

market framework, they participate in the wholesale market without investigating their impact on the distribution system. Hence, it is useful to investigate the voltage profile in our distribution network. Hour 24 is considered as the hour during which we have highest share of wholesale market which may cause voltage issues at the end of the feeders.

The voltage magnitudes of the 33-node distribution system are shown in Fig. 5.5. The voltage magnitudes lie within standard voltage limits (± 5 %). However, one can see that at Node 33, the end of the feeder, there is a potential for voltage violation if the load or DRAGs' capacity increases. Hence, uncontrolled participation of the DRAGs can cause voltage issues in the distribution network.

The voltage magnitudes of Feeders A, B, and C in the 240-node test system are shown in Fig. 5.6(a), Fig. 5.6(b), and Fig. 5.6(c), respectively. From each phase of these feeders, it is clear that the voltage magnitudes at all nodes remain in the range of ±1 % indicating healthy voltage profile for these feeders. By comparing these three feeders, it is obvious that Feeder C has the potential for voltage issues if DRAGs' capacity or load increases.

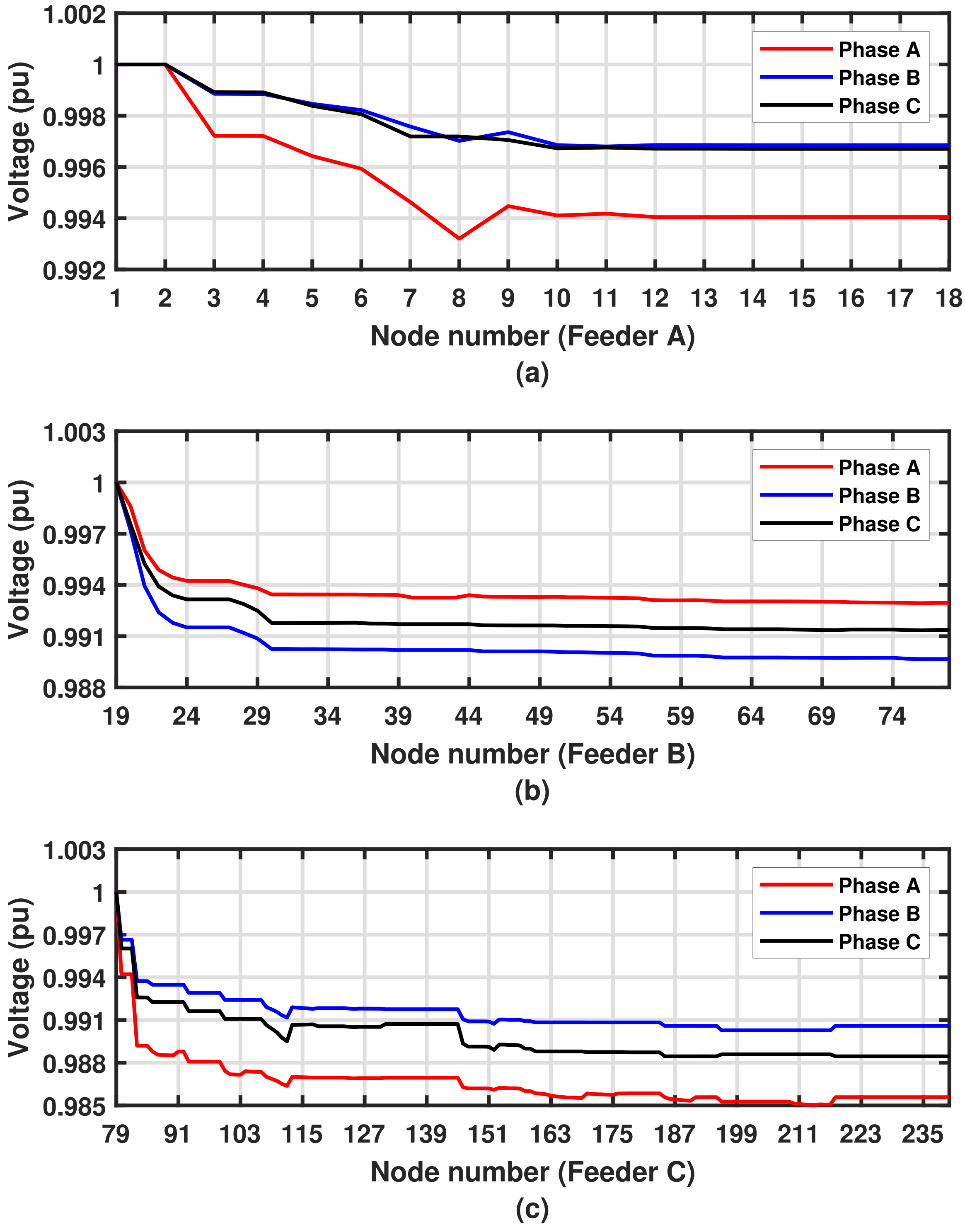


Figure 5.6: Voltage magnitudes of Feeders A, B, and C for the 240-node test system.

5.7 Conclusion

This chapter proposed a comprehensive DSO framework for market participation of DER aggregators in the three-phase unbalanced distribution network. Various kinds of DER aggregators were modeled. A three-phase unbalanced linearized power flow was introduced to consider unbalanced operating conditions in the distribution system. The retail market settlement procedure was discussed. At the wholesale-DSO coupling substation, the total payment received/compensated by the DSO under the wholesale price is identical to that under three single-phase D-LMPs for each phase at the substation.

Case studies were performed on the 33-node balanced distribution system and the 240-node unbalanced distribution system. The results in the balanced network show that the DSO sells energy to the wholesale market when the wholesale energy price is high. The DSO assigns regulation capacity-down services to the ESAG for increasing its charge level and decreasing DSO's operating cost. The DDGAG is cleared to sell energy during peak hours. There are opportunities for the EVCS to increase its charge level by providing regulation capacity-up. The DRAG purchases energy during off-peak hours. The results in the unbalanced system show that although the DSO's retail market is unbalanced, the DSO's share for participating in the wholesale market is three-phase balanced. The DSO assigns more charging states to the ESAGs with higher energy offering prices. In the unbalanced system, the DSO may buy energy from the DDGAG with higher energy offering price to submit a balanced offer to the ISO. The DSO sells energy to DRAGs and EVCSs considering achieving balanced operating conditions at the DSO-ISO coupling point. Voltage profile of the 33-node and 240-node distribution systems shows that some nodes may encounter potential voltage violation if the load or DERAG capacity increases which emphasizes the importance of controlled participation of DERAGs in the wholesale market.

5.8 Appendix

Proof of Lemma 1. Assume continuous relaxation of the problem in Section 5.3. Let $\mathbf{x}^{dr}$, $\mathbf{x}^{es}$, $\mathbf{x}^{ev}$, $\mathbf{x}^{ddg}$, and $\mathbf{x}^{pf}$ be the sets with all decision variables related to DRAGs, ESAGs, EVCSs, DDGAGs, and power flow equations, with corresponding constraints $\mathbf{g}(\mathbf{x}^{dr})$, $\mathbf{g}(\mathbf{x}^{es})$, $\mathbf{g}(\mathbf{x}^{ev})$, $\mathbf{g}(\mathbf{x}^{ddg})$, $\mathbf{g}(\mathbf{x}^{pf})$, and corresponding dual variables $\boldsymbol{\lambda}^{dr}$, $\boldsymbol{\lambda}^{es}$, $\boldsymbol{\lambda}^{ev}$, $\boldsymbol{\lambda}^{ddg}$, and $\boldsymbol{\lambda}^{pf}$, respectively. The Lagrangian function can be set up as:

$$\begin{aligned}\mathbf{L} =& f(\mathbf{x}^{dr},\mathbf{x}^{es},\mathbf{x}^{ev},\mathbf{x}^{ddg}) + (\boldsymbol{\lambda}^{dr})^{\mathsf{T}}\mathbf{g}(\mathbf{x}^{dr}) \\ &+ (\boldsymbol{\lambda}^{es})^{\mathsf{T}}\mathbf{g}(\mathbf{x}^{es}) + (\boldsymbol{\lambda}^{ev})^{\mathsf{T}}\mathbf{g}(\mathbf{x}^{ev}) \\ &+ (\boldsymbol{\lambda}^{ddg})^{\mathsf{T}}\mathbf{g}(\mathbf{x}^{ddg}) + (\boldsymbol{\lambda}^{pf})^{\mathsf{T}}\mathbf{g}(\mathbf{x}^{pf})\end{aligned} \tag{5.12}$$

Based on the KKT conditions, partial derivative of the Lagrangian function with respect to $P^{sub}_{t,\phi}$ must be zero at the optimum point, as shown in (13). $P^{sub}_{t,\phi}$ only exists in terms $f(\mathbf{x}^{dr},\mathbf{x}^{es},\mathbf{x}^{ev},\mathbf{x}^{ddg})$ and $(\boldsymbol{\lambda}^{pf})^{\mathsf{T}}\mathbf{g}(\mathbf{x}^{pf})$. Hence, the partial derivative of the other terms in the Lagrangian function with respect to $P^{sub}_{t,\phi}$ would be null.

$$\frac{\partial \mathbf{L}}{\partial P^{sub}_{t,\phi}} = \frac{\partial f(\mathbf{x}^{dr},\mathbf{x}^{es},\mathbf{x}^{ev},\mathbf{x}^{ddg})}{\partial P^{sub}_{t,\phi}} + \frac{\partial((\boldsymbol{\lambda}^{pf})^{\mathsf{T}}\mathbf{g}(\mathbf{x}^{pf}))}{\partial P^{sub}_{t,\phi}} = 0 \tag{5.13}$$

Let $\lambda^{(11a)}_{t,n,\phi}$ be the dual variable of (5.11a) and $\lambda^{(11i)_1}_{t}$, $\lambda^{(11i)_2}_{t}$, $\lambda^{(11i)_3}_{t}$ be corresponding dual variables of three sets of equations in (5.11i), where $\boldsymbol{\lambda}^{pf}$=$(\lambda^{(11a)}_{n,t,A},...,\lambda^{(11k)}_{t})^{\mathsf{T}}$. Substituting ϕ=$\{A,B,C\}$ in (5.13) results in (5.14)-(5.16):

$$\frac{\partial \mathbf{L}}{\partial P^{sub}_{t,A}} = \pi^{e}_{t} - \lambda^{(11a)}_{1,t,A} - \lambda^{(11i)_1}_{t} - \lambda^{(11i)_2}_{t} = 0 \tag{5.14}$$

$$\frac{\partial \mathbf{L}}{\partial P^{sub}_{t,B}} = \pi^{e}_{t} - \lambda^{(11a)}_{1,t,B} + \lambda^{(11i)_1}_{t} - \lambda^{(11i)_3}_{t} = 0 \tag{5.15}$$

$$\frac{\partial \mathbf{L}}{\partial P^{sub}_{t,C}} = \pi^{e}_{t} - \lambda^{(11a)}_{1,t,C} + \lambda^{(11i)_2}_{t} + \lambda^{(11i)_3}_{t} = 0 \tag{5.16}$$

By summating both sides of (5.14)-(5.16) and then dividing by 3, the following equation is obtained:

$$\begin{aligned}\pi_t^e &= \frac{\lambda_{1,t,A}^{(11a)} + \lambda_{1,t,B}^{(11a)} + \lambda_{1,t,C}^{(11a)}}{3} \\ &= \frac{LMP_{1,t,A} + LMP_{1,t,B} + LMP_{1,t,C}}{3}\end{aligned} \tag{5.17}$$

The ISO's payment, C^{WM}, is calculated as follows:

$$C^{WM} = (P_{t,A}^{sub} + P_{t,B}^{sub} + P_{t,C}^{sub})\pi_t^e \tag{5.18}$$

By using (5.11i) and (5.17):

$$C^{WM} = 3P_{t,A}^{sub} \frac{LMP_{1,t,A} + LMP_{1,t,B} + LMP_{1,t,C}}{3} \tag{5.19}$$

$$= P_{t,A}^{sub} LMP_{1,t,A} + P_{t,B}^{sub} LMP_{1,t,B} + P_{t,C}^{sub} LMP_{1,t,C} \tag{5.20}$$

Hence, ISO's payment using the wholesale market price is the same as using D-LMP for each phase at the substation. Following similar approaches, the ISO's capacity-up/down payment using wholesale prices are also proven to be the same as using DSO's single-phase retail market prices.

Chapter 6

ISO AND DSO COORDINATION: A PARAMETRIC PROGRAMMING APPROACH

In this chapter, a framework is proposed to coordinate the operation of the independent system operator (ISO) and distribution system operator (DSO) to leverage the wholesale market participation of distributed energy resources (DERs) aggregators while ensuring secure operation of distribution grids. The proposed coordination framework is based on parametric programming. The DSO builds the bid-in cost function based on the distribution system market considering its market player constraints and distribution system physical constraints including the power balance equations and voltage limitation constraints. The DSO submits the resulting bid-in cost function to the wholesale market operated by the ISO. After the clearance of the wholesale market, the DSO determines the share of its retail market participants (i.e., DER aggregators). Case studies are performed to verify the effectiveness of the proposed method.

6.1 Introduction

US Federal Energy Regulatory Commission issued Order No. 2222 to promote wholesale market competition by leveraging the market participation of distributed energy resources (DERs) [1]. Integrating numerous small DERs into today's wholesale market causes challenges for the independent system operators (ISOs) as 1) it imposes complexity and computational burden; and 2) it could cause distribution grid voltage/thermal violations if the aggregator-controlled DERs are not properly monitored by system operators. An effective solution to this problem is considering the distribution system operator (DSO) which runs the retail market to coordinate the DERs market participation while assuring the secure/reliable operation of the distribution grid [58]. However, there is a need for a coordination framework between the ISO and the DSO.

Recent works studied the ISO-DSO coordination problem [42, 43, 59, 60, 39, 44, 61, 62, 45]. They fall into two categories based on the solution method. The first category proposed bi-level and transformed the problem to single level optimization [42, 43]. In [42], a bi-level optimization model is proposed for DSO market clearing and pricing considering ISO-DSO coordination. The clearing conditions for the DSO and ISO markets are proposed in the upper-level and lower-level problems, respectively. The problem is converted to mixed-integer linear programming via an equilibrium problem with equilibrium constraints (EPEC) approach. In [43] a bi-level optimization model is proposed for the energy storage sizing and siting problem in the DSO-ISO coordination framework. However, bilevel optimization is hard to solve for large systems.

The second category of works uses decentralized and decomposition algorithms [59, 60, 39, 44, 61, 62, 45]. In [59], an extension of the decentralized market framework is proposed to consider loss allocation and its impact on the market outcome. However, the decentralized market framework is not compatible with the current market structures. In [60], a transactive market framework starting from the ISO to the DSO is proposed. The DSO runs the transactive market using an iterative method. However, the convergence of the proposed method is not guaranteed. In [39], a Nash bargaining-based method is proposed for the market-clearing process and the ISO-DSO coordination. However, there is no guarantee that the proposed algorithm converges especially when the number of DSOs increases. In [44], a three-stage unit commitment (UC) is proposed for the transmission-distribution coordination. A convex AC branch flow model is proposed to handle the distribution grid physical constraints. In [61], a distributed optimization algorithm is proposed for modeling the DSO retail market considering energy and ancillary services. However, the DSO's impact on wholesale market clearing is not considered. In [62], the optimal operation and coordination of the ISO-DSO is proposed. A decomposition algorithm is proposed and the original problem is decomposed to ISO and DSO sub-problems. In [45], a non-coopérative game approach is proposed for ISO-DSO coordination in which they optimize their own operational costs. The approaches in [44, 62, 45] are hard to solve for large systems.

This chapter proposes an ISO-DSO coordination framework based on parametric programming. The DSO builds the bid-in cost function (submitted to the ISO), considering its retail market participants' offering prices and their operational constraints as well as physical constraints of the distribution grid including power balance equations and voltage limitation constraints. To our best knowledge, this is the first attempt which shows the parametric programming based DSO offers optimal interactions with existing ISO markets. Different from existing approaches facing computational difficulties for large-scale ISO-DSO coordination, this work could lead to a coordinated ISO-DSO market clearing procedure which is computationally efficient and scalable toward large-scale systems with many DSOs and numerous DER aggregators. This work is an extension to our recent work [58] to present a coordination framework for the DSO and ISO which is practical with the current wholesale market structures.

6.2 DER Market Participation Framework

6.2.1 Direct Participation of the DERs in the ISO Market

This section presents the ideal case for DER market participation. This ideal case assumes the DERs participate in the ISO's wholesale market directly, and the ISO considers not only transmission-level operating constraints but also distribution grid physical constraints to ensure transmission and distribution security operations, since the DERs are located in the distribution grid. It is assumed that the ISOs have revised their tariffs such that DERs can participate in the wholesale market under one of the participation models. A unified formulation for the security constrained UC and economic dispatch (ED) problem of this ideal case is as follows:

$$\text{Min}_{x,q} \quad \sum_{t \in T} \sum_{i \in N} c_{i,t}(x_{i,t-1}, x_{i,t}, q_{i,t}) \tag{6.1}$$

$$\begin{aligned} \text{s.t.} \quad & (x, q) \in S^{Tra} \\ & (x, q) \in S^{Dis} \\ & (x_{i,t-1}, x_{i,t}, q_{i,t-1}, q_{i,t}) \in S_i^{player}, \forall i, t \\ & x_{i,t} \in \{0, 1\}, q_{i,t} \in \mathbb{R}^1, \forall i, t \\ & c_{i,t}(x_{i,t-1}, x_{i,t}, q_{i,t}) : \mathbb{R}^3 \mapsto \mathbb{R}^1, \forall i, t \end{aligned} \tag{6.2}$$

where t (T) and i (N) are the index (set) for the operating timespan and the market participants (generators/aggregators), respectively; $x_{i,t}$, $q_{i,t}$, and $c_{i,t}(x_{i,t-1}, x_{i,t}, q_{i,t})$ are the binary UC decision variable (start-up/shut-down), continuous ED decision variable (dispatched power), and bid-in cost function (with UCED decisions) of market participant i at time t, respectively; x and q denote the vectors of $x_{i,t}$ and $q_{i,t}$ for $t \in T$ and $i \in N$, respectively; S^{Tra}, S^{Dis}, and S_i^{player} denote the search space defined by the system-wide transmission grid constraints, system-wide distribution grid constraints, and operating constraints of the market participant i, respectively.

This is the ideal case for DERs' wholesale market participation. However, implementing this procedure is not possible for ISOs since 1) it adds many variables/constraints to the ISO problem from the distribution grids, making the ISO problem computationally expensive; and 2) it increases the ISO's burden on modeling the distribution-level constraints in its market clearing problem, while the distribution-level models/constraints are currently not available to ISOs.

6.2.2 Market Participation of the DERs through DSO and ISO Coordination Framework

This section presents our proposed ISO-DSO coordination framework. This framework decomposes the ideal case in Section II.A into an ISO sub-problem and several DSO sub-problems (one for each distribution system). This decomposition reduces the ISO's modeling and computation burdern by 1) considering distribution-level operating security in the DSO sub-problems; 2) considering distribution-level variables/constraints and optimization computations in the DSO sub-problems; and 3) introducing minimal changes to the existing ISO market structures. Without the DSO-level market, market participation of all the aggregators need to be handled by the ISO. These aggregators are modeled as numerous small generators in the ISO's UCED problem presented by (9.1)-(6.2). If locational marginal pricing (LMP) is adopted by the ISO and DSO markets, the market clearing outcomes of this ISO-DSO coordination framework are identical to those of the ideal case in Section II.A.

Each DSO is defined as a mediator which gathers offers from the DER aggregators to submit an aggregated bid to the wholesale energy market. The DER aggregators submit their offers to the DSO. The DSO gathers these offers and runs the retail market to build an aggregated offer to participate in the ISO wholesale market. Considering the DSOs as wholesale market participants, the wholesale market (ISO) security constrained UCED problem is as follows:

$$\text{Min}_{x,q} \quad \sum_{t \in T} \sum_{i \in N_{gen} \cup N_{dso}} c_{i,t}(x_{i,t-1}, x_{i,t}, q_{i,t}) \tag{6.3}$$

$$\begin{aligned} \text{s.t.} \quad & (x, q) \in S^{Tra} \\ & (x_{i,t-1}, x_{i,t}, q_{i,t-1}, q_{i,t}) \in S_i^{gen}, \forall i \in N_{gen}, \forall t \\ & (x_{i,t-1}, x_{i,t}, q_{i,t-1}, q_{i,t}) \in S_i^{dso}, \forall i \in N_{dso}, \forall t \\ & x_{i,t} \in \{0, 1\}, q_{i,t} \in \mathbb{R}^1, \forall i, t \\ & c_{i,t}(x_{i,t-1}, x_{i,t}, q_{i,t}) : \mathbb{R}^3 \mapsto \mathbb{R}^1, \forall i, t \end{aligned} \tag{6.4}$$

where N_{gen} and N_{dso} are the set of all generaors and DSOs in the wholesale market, respectively; S_i^{gen} and S_i^{dso} denote the search space defined by operating constraints of individual generators and DSOs, respectively; $N = N_{gen} \cup N_{dso}$.

Each DSO submits its bid-in cost function to the ISO's UCED problem in (8.2a)-(8.2b), following the ISO-defined non-convex cost function structure $c_{i,t}^{dso}(x_{i,t-1}, x_{i,t}, q_{i,t})$. Considering aggregator controlled DERs do not have start-up/no-load costs or binary UC decision variables, the bid-in cost function of aggregator j within DSO i at time t reduces to $c_{i,j,t}^{agg}(q_{i,j,t}^{agg})$, which is convex (piecewise linear/quadratic in many markets), where $q_{i,j,t}^{agg}$ is the bid-in power quantity of this aggregator to the DSO. The bid-in cost function of the DSO i, $c_{i,t}^{dso}(q_{i,t}^{dso})$ to be submitted to ISO (where $q_{i,t}^{dso}$ is the bid-in power quantity of this DSO to the ISO), is determined by following optimization problem (for single-period DSO markets):

$$\begin{aligned} c_{i,t}^{dso}(q_{i,t}^{dso}) = \text{Min}_{q^{agg}} & \sum_{j \in DSO_i} c_{i,j,t}^{agg}(q_{i,j,t}^{agg}) \\ \text{s.t.} \quad & q_{i,t}^{dso} \leq \sum_{j \in DSO_i} q_{i,j,t}^{agg} \\ & q_{i,j,t}^{agg} \in S_{i,j}^{agg}, \forall j \in DSO_i \\ & q^{agg} \in S_i^{Dis} \end{aligned} \tag{6.5}$$

where DSO_i is the set of all aggregators in i^{th} DSO; $S_{i,j}^{agg}$ is the search space defined by operational constraints of individual aggregators within each DSO; S_i^{Dis} is the search space defined by the physical constraints of each DSO (i.e., the distribution system); q^{agg} is the vector of $q_{i,j,t}^{agg}$ for $j \in DSO_i$.

For a single-period DSO market, Equation (8.3) is a parametric convex optimization problem parameterized by a single parameter $q_{i,t}^{dso}$, since its objective function is sum of convex bid-in cost functions from aggregators, and its constraints are all linear. The optimal solution of (8.3) is a function of parameter $q_{i,t}^{dso}$ which is the bid-in cost function of i^{th} DSO, $c_{i,t}^{dso}(q_{i,t}^{dso})$. Based on approximate multi-parametric convex programming [63], the optimal bid-in cost function from DSO to ISO, $c_{i,t}^{dso}(q_{i,t}^{dso})$, is also a convex function of parameter $q_{i,t}^{dso}$. If the aggregator bid-in cost functions are (piecewise) linear (following the cost function structure in existing ISOs), this problem reduces to a parametric linear optimization. Based on theories of multi-parametric linear programming [64, 65], the resulting $c_{i,t}^{dso}(q_{i,t}^{dso})$ is also (piecewise) linear, following the cost function structure in many existing ISO markets. The optimal outcomes of (8.3) determines: 1) the optimal bid-in cost function $c_{i,t}^{dso}(q_{i,t}^{dso})$ submitted from DSO to ISO (the minimal operating cost for DSO to offer $q_{i,t}^{dso}$ MW of generation/consumption in the ISO market); and 2) the optimal dispatch of total DSO generation/consumption $q_{i,t}^{dso}$ among all aggregators $q_{i,j,t}^{agg}$ to achieve minimal operating cost. Retail LMPs can be obtained by the dual model (not discussed in this chapter). If a multi-period DSO market is considered, this problem generalizes to a multi-parametric convex optimization problem and all the above discussions are still valid.

This convex (multi)-parametric-programming-based retail energy dispatch can be solved by existing multi-parametric programming solvers [66, 67, 68]. If single-period market clearing is considered (currently implemented by many real-world ISOs, as shown in (8.3)), this problem boils down to a convex parametric programming problem parameterized by a single parameter. To solve this single-period DSO market clearing problem, we have adopted sensitivity analysis procedure, in which we gradually adjust $q_{i,t}^{dso}$ by a pre-defined small step size and solve the optimization in (8.3) at each step to obtain $c_{i,t}^{dso}(q_{i,t}^{dso})$. The range for adjusting $q_{i,t}^{dso}$ is determined by upper/lower generation limits of individual DER aggregators.

The parametric programming in (8.3) is further expanded to obtain detailed formulation for the DSO market. The bid-in cost function of each DSO is determined by solving (7.9a)-(7.9i):

$$c^{dso}(P^{dso}) = Min \sum_{g\in G}\sum_{b\in B} P_{g,b}\pi_{g,b} - \sum_{d\in D}\sum_{b\in B} P_{d,b}\pi_{d,b} \tag{6.6}$$

s.t.

$$\begin{aligned}&\sum_{d\in D}\sum_{b\in B} H_{n,d}P_{d,b} + H_n^{sub}P^{dso} + L_n^P\\ &-\sum_{g\in G}\sum_{b\in B} H_{n,g}P_{g,b} + \sum_{j\in J} Pl_jA_{j,n} = 0; \quad \forall n\in N\end{aligned} \tag{6.7}$$

$$\begin{aligned}&\sum_{d\in D}\sum_{b\in B} H_{n,d}P_{d,b}tan\phi_d + H_n^{sub}Q^{dso} + L_n^Q\\ &-\sum_{g\in G}\sum_{b\in B} H_{n,g}P_{g,b}tan\phi_g + \sum_{j\in J} Ql_jA_{j,n} = 0; \forall n\in N\end{aligned} \tag{6.8}$$

$$0 \le P_{g,b} \le P_{b,g}^{max}; \quad \forall b\in B, \forall g\in G \tag{6.9}$$

$$0 \le P_{d,b} \le P_{d,g}^{max}; \quad \forall b\in B, \forall d\in D \tag{6.10}$$

$$\begin{aligned}&U_m = U_n - 2(r_jPl_j + x_jQl_j); \quad \forall m\in N,\\ &\qquad \forall n\in N,\, C(m,n)=1,\, A(j,n)=1\end{aligned} \tag{6.11}$$

$$\underline{U} \le U_n \le \overline{U}; \quad \forall n\in N \tag{6.12}$$

$$-Pl^{max} \le Pl_j \le Pl^{max}; \quad \forall j\in J \tag{6.13}$$

$$-Ql^{max} \leq Ql_j \leq Ql^{max}; \quad \forall j \in J \tag{6.14}$$

where t and T are the index and set for the entire operating timespan; g and G are the index and set for all generating aggregators; d and D are the index and set for all demand response aggregators; b and B are the index and set for all production/demand blocks; j and J are the index and set for all lines; n and N are the index and set for all nodes; P^{dso} is the DSO's aggregated offers (in MW) to ISO market; $P_{g,b}$ are $P_{d,b}$ are energy offer submitted by the generating aggregators and demand response aggregators, respectively with corresponding prices $\pi_{g,b}$ and $\pi_{d,b}$, respectively; $H_{n,d}$, $H_{n,g}$, and H_n^{sub} are mapping matrix of generating aggregators, demand response aggregators, substation to node n, respectively; Pl_j and Ql_j are the active and reactive power of branch j, respectively; $A_{j,n}$ is the incidence matrix of branches and nodes; ϕ_g and ϕ_d are the phase angle of the generating aggregators and demand response aggregators, respectively; Q_n^D is the reactive power of the firm load at each node; L_n^P and L_n^Q are the active and reactive power load at each node; $P_{g,b}^{max}$ and $P_{d,b}^{max}$ are the maximum production/consumption at each block of the generating aggregators and demand response aggregators, respectively; U is the square of voltage of each node; $\underline{U}$ and $\overline{U}$ are the square of minimum and maximum permitted voltage values, respectively; r_j and x_j are resistance and reactance of the branches; Pl^{max} and Ql^{max} are maximum active and reactive power of branches.

Equation (7.9a) defines the DSO's objective function to minimize the total system cost. Equations (7.9b)-(7.9c) define the active and reactive power balance equations, respectively. The produced/consumed power at each block of the generating aggregators and demand response aggregators are limited by (7.9d)-(7.9e), receptively. The price responsive demand is considered in this model. Voltage at each node is defined by (9.11). The minimum and maximum voltage limitations are met by (9.10). Constraints (7.9h)-(7.9i) limit the active and reactive power of each branch, respectively. More details for this DSO problem are in our prior work [58]. For simplicity, formulation (6)-(14) is presented for single-period markets and can be extended to consider multi-period markets.

The ISO gathers the bid-in cost function of the all DSOs and other market participants to run the wholesale market and determine the share of the all market participants including DSOs. Note that we need to determine the bid-in cost function for each DSO. Once we provide these cost functions, we can submit them to the ISO. Then ISO will clear the wholesale market and determine the share of each DSO in the ISO market. The merit of this procedure is that the ISO does not need to know the inner (distribution-level) constraints of the DSOs. This means that ISO does not need to consider a lot of variables and constraints to ensure the DERs' wholesale bidding activities do not cause voltage/thermal violations in the distribution grids. If LMP is adopted in the ISO-DSO markets, market clearing outcomes of this framework are the same as those of the ideal case in Section II.A, as the ISO is considering market participation of the small DER aggregators in the wholesale market (through the DSO). This is due to the fact that every share that ISO determines for each DSO lies on the best response function of that DSO (already submitted to the ISO). Hence, the results are the same as those in the ideal case when DERs participate in the ISO market directly. Due to space limitation, mathematical proofs are not included.

In the DSO problem, a parameter P^{dso} determines the amount of the power imported/exported from/to the ISO. In other words, the DSO is considered as a unit that is going to determine the cost function or demand function based on its generating units and demand response units as well as physical constraints of the distribution network. Indeed, the resulting cost function determines the true value cost of the energy consumed or produced in the distribution network considering all the physical

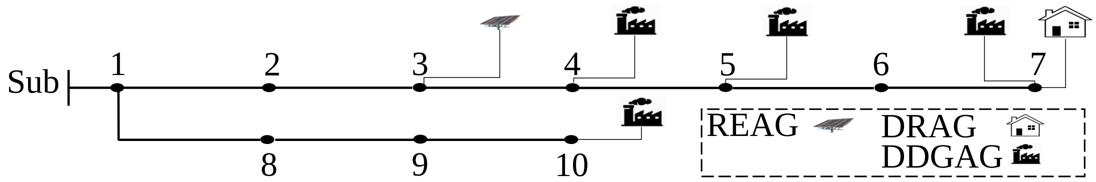


Figure 6.1: The small distribution network for case studies.

Table 6.1: Wholesale market participants information

Participant	Pmin (MW)	Pmax (MW)	Offering price ($/MWh)
Gen 1	0	10	8
Gen 2	0	20	20
Gen 3	0	30	22
DR 1	0	10	30
DR 2	0	20	32
DR 3	0	20	34

constraints of the distribution network.

6.3 Simulation Results

The case studies are implemented on a small system containing the ISO running wholesale-level ED and a small distribution network operated by the DSO shown in Fig. 6.1. In the wholesale-level ED, three generating units, three demand response units, and a firm load of 5 MW is considered. The generating units (Gen) and demand response (DR) units information is in Table. 7.1. The distribution system in Fig. 6.1 includes 10 nodes, 9 lines, 4 dispatchable distributed generation aggregators (DDGAG), 1 renewable energy aggregators (REAG), and 1 demand response aggregator (DRAG). The distribution system market participants' information is in Table.

Table 6.2: DSO market participants information

Participant	Pmin (MW)	Pmax (MW)	Offering price ($/MWh)
DDGAG 1	0	0.5	20
DDGAG 2	0	1	10
DDGAG 3	0	1.2	15
DDGAG 4	0	2	24
DRAG	0	20	28

Table 6.3: ISO market outcomes in the ideal case

Participant	Share (MW)	Participant	Share (MW)
Gen 1	10	DDGAG 1	0.5
Gen 2	20	DDGAG 2	1
Gen 3	13.8	DDGAG 3	1.2
DR 1	10	DDGAG 4	0
DR 2	20	DRAG	2.5
DR 3	10		

6.2. The REAG production is considered to be 1 MW with no cost. It is assumed that REAG production is constant.

6.3.1 The Ideal Case

In this section, the simulation results are obtained using the model presented by (9.1) and (6.2). In this case, the DERs participate in the wholesale market directly and submit their offering bids directly to the ISO. This case is ideal since the ISO oversees all the market participants' operation constraints as well as transmission and

Table 6.4: ISO market outcomes in the ISO-DSO coordination case

Participant	Share (MW)	Participant	Share (MW)
Gen 1	10	DR 1	10
Gen 2	20	DR 2	20
Gen 3	13.8	DR 3	10
DSO	1.2		

distribution network constraints. This case is the best case for secure and optimal market participation of the DERs. However, this is not implementable with the current wholesale market structures. The market share of each market participant in this model is given in Table. 6.3.

6.3.2 Participation through the DSO

In this case, the bid-in cost function of the DSO is first determined based on the formulation in (8.3). The DSO's total (minimal) operating costs at different output power levels are shown in Fig. 6.2. The breakpoints in Fig. 6.2 are determined by the retail market participants' minimum and maximum output power. The bid-in marginal cost function (price-quantity pairs offered by the DSO to ISO, which is the derivative of the DSO operating cost curve in Fig. 6.2) is in Fig. 6.3. The bid-in marginal cost function starts with the output power of -1.5 MW which means that DSO can consume energy of 1.5 MW since the DRAG has the (consumption) capability of 2.5 MW and the REAG produces 1 MW. The bid-in price of this consumption is 10 $/MWh. This is due to the fact that the cheapest unit's price in the DSO market is 10 $/MWh which means that the wholesale market price should be lower than this value in order for the DSO to buy energy from the wholesale market otherwise

Table 6.5: DSO market outcomes in the ISO-DSO coordination case

Participant	Share (MW)	Participant	Share (MW)
DDGAG 1	0.5	DDGAG 3	1.2
DDGAG 2	1	DDGAG 4	0
DRAG	2.5		

it provides that energy from the DDGAG 2. The DSO buys energy with this cost until the capacity of the DDGAG 2 is reached. Then, DDGAG 3, which is the next cheapest generating unit starts to be dispatched. This procedure continues until the last (most expensive) DDGAG is dispatched, which occurs at 3.2 MW. In the end, the DSO sells energy to the wholesale market at the price of 28 $/MWh which is actually the offering price of the DRAG (for energy consumption). This is due to the fact that if the offering price of the wholesale market is greater than 28 $/MWh, the DSO sells the energy to the ISO instead of to the DRAG.

The DSO submits this bid-in marginal cost function to the ISO. Then, ISO runs the wholesale market and determines the wholesale market share of the DSO and other participants. The ISO market outcomes are shown in Table. 6.4. By comparing Tables. 6.3 and 6.4, it is clear the market outcomes for generating units (Gen) and demand response units (DR) directly participating in the ISO market are identical in the ideal case and the ISO-DSO coordination case. The share of the DSO is 1.2 MW. In order to determine the share of the market participants in the DSO market, we need to substitute the parameter in the parametric optimization given in (8.3) which results in a simple optimization problem. The results of this optimization problem are given in Table. 6.5. By comparing Tables. 6.3 and 6.5, it is obvious the market outcomes for various aggregators are identical in the ideal case (when participating

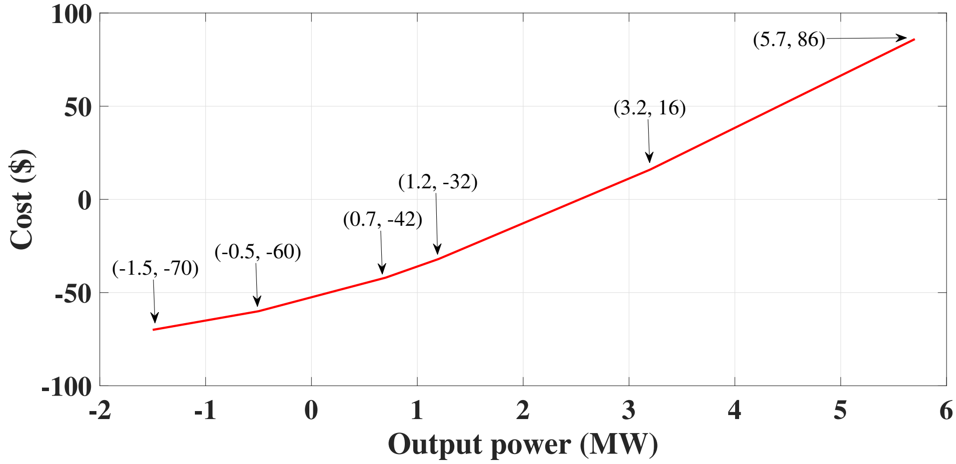


Figure 6.2: DSO total (minimal) operating cost

in the ISO market directly) and the ISO-DSO coordination case (when participating in the ISO market through the DSO).

6.4 Conclusion

In this chapter, an ISO-DSO market coordination framework is proposed to leverage the wholesale market participation of DER aggregators based on parametric programming. The DSO builds the bid-in cost function based on the DSO market participants' offering prices considering their operational constraints and the physical constraints of the distribution network including the power balance equations and voltage limitation constraints. The simulation results performed on the small system indicate the proposed coordination model will result in the same market outcomes as the ideal case in which the DER aggregators directly participate in the wholesale market.

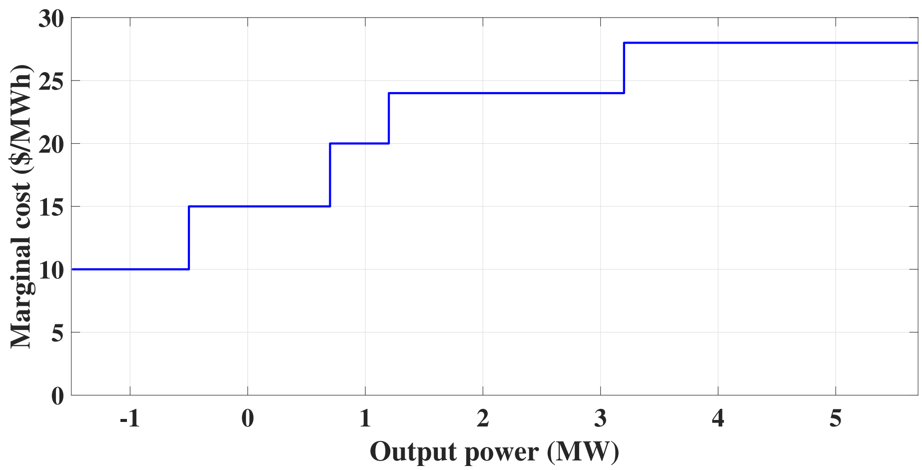


Figure 6.3: DSO marginal cost function (price-quantity pairs) submitted to ISO

Chapter 7

TRANSMISSION AND DISTRIBUTION COORDINATION FOR DER-RICH ENERGY MARKETS: A PARAMETRIC PROGRAMMING APPROACH

In this chapter, a framework is proposed to coordinate the operation of the independent system operator (ISO) and distribution system operator (DSO). The framework is compatible with current practice of the U.S. wholesale market to enable massive distributed energy resources (DERs) to participate in the wholesale market. The DSO builds a bid-in cost function to be submitted to the ISO market through parametric programming. Once the ISO clears the wholesale market, the dispatch and payment of the DSO are determined by ISO. Then, the DSO determines the dispatch and payment of the DER aggregators. To compare the proposed framework, an ideal case is defined in which DER aggregators can participate in the wholesale market directly and ISO overseas operation of both transmission and distribution systems. We proved 1) the dispatches of the proposed ISO-DSO coordination framework are identical to those of the ideal case; 2) the payments to each DER aggregator are identical in the proposed framework and in the ideal case. Case studies are performed on a small illustrative example as well as a large test system which includes IEEE 118 bus transmission system and two distribution systems - the IEEE 33 node and IEEE 240 node test systems.

7.1 Introduction

The Federal Energy Regulatory Commission (FERC) issued Order No. 2222 which requires all the US independent system operators (ISOs) to open their wholesale energy and ancillary service markets to the distributed energy resources (DER) aggregators market participation [1]. However, the uncontrolled participation of DER aggregators in the wholesale market may cause security and reliability issues in the distribution system. To overcome this issue, designing a distribution system operator (DSO) for coordinating the DER aggregators has been proposed [58]. However, the operation of the DSO should be compatible with the current practice of the wholesale markets operated by independent system operators (ISOs). Hence, the operation of the DSO and ISO should be coordinated.

Recently, several works have studied the coordination of the ISO and DSO [42, 43, 69, 70, 71, 72, 59, 60, 39, 44, 61, 62, 45, 73, 74, 75, 76, 77, 78, 79, 80]. They fall into three categories based on the modeling and solution method. The first category proposed bi-level models with the ISO and DSO markets modeled at two levels. The problem is transformed to single level optimization [42, 43, 69, 70, 71, 72]. In [42], a bi-level optimization model is proposed for DSO market clearing and pricing considering ISO-DSO coordination. The clearing conditions for the DSO and ISO markets are proposed in the upper-level and lower-level problems, respectively. The problem is converted to mixed-integer linear programming via an equilibrium problem with equilibrium constraints (EPEC) approach. In [43], a bi-level optimization model is proposed for the energy storage sizing and siting problem in the DSO-ISO coordination framework. In [69], a bi-level optimization model is proposed for the energy and flexibility market in which, the upper-level models the clearing conditions of the transmission level market while, in the lower level, clearing conditions of the distribution level market are modeled. In [70], a coordination scheme is proposed for energy service providers, transmission system operator (TSO), and DSO for DER planning while coordinating the operation of the TSO and DSO based on bi-level optimization. In the upper-level problem, the DSO cost is minimized and the profit of the energy service providers is ensured while the lower-level problem models the transmission level constraints and wholesale market. In [71], a bi-level optimization model is proposed for the coordinated operation of active distribution networks with multiple virtual power plants in joint energy and reserve markets operated by the DSO. At the upper level, the DSO minimizes the total operational cost of the distribution system while in the lower level problem, virtual power plants maximize their profit. In [72] a tri-level coordinated scheme for transmission and distribution (T&D) systems expansion planning is proposed. In the first and second levels, the expansion planning of T&D systems operated by the TSO and DSO are proposed, respectively. The third level is the economic dispatch problem performed by the ISO. The multi-parametric programming approach is used to convert the multi-level optimization problem into a single-level optimization problem. Bi-level optimization models are computationally expensive and hard to solve especially for large systems. These approaches place a high computation burden on the wholesale market and is not compatible with the current practice of the wholesale market.

The second category of works uses decentralized models and some of them use decomposition algorithms to decouple the ISO and DSO markets [59, 60, 39, 44, 61, 62, 45, 73, 74, 75, 76]. In [59], an extension of the decentralized market framework is proposed to consider loss allocation and its impact on the market outcome. However, the decentralized market framework is not compatible with the current market structures. In [60], a transactive market framework starting from the ISO to the DSO is proposed. The DSO runs the transactive market using an iterative method. However, the convergence of the proposed method is not guaranteed. In [39], a Nash bargaining-based method is proposed for the market-clearing process and the ISO-DSO coordination. The proposed model requires high ISO-DSO communication burden within each wholesale market clearing interval. In [44], a three-stage unit commitment (UC) is proposed for transmission-distribution coordination based on stochastic programming. A convex AC branch flow model is proposed to handle the distribution grid's physical constraints. However, stochastic programming is not compatible with the current practice of the wholesale market. In [61], a distributed optimization algorithm is proposed for modeling the DSO retail market considering energy and ancillary services. However, the DSO's impact on wholesale market clearing is not considered. In [62], the optimal operation and coordination of the ISO-DSO are proposed. A decomposition algorithm is proposed and the original problem is decomposed into ISO and DSO sub-problems. In [45], a non-cooperative game approach is proposed for ISO-DSO coordination in which they optimize their operational costs. The approaches in [62, 45] are hard to solve for large systems. In [73], a coordination framework for coordinating the economic dispatch of the TSO and DSO is proposed. Benders' decomposition is used for solving the proposed problem. In [74], a coordination framework is proposed for the dynamic economic dispatch problem of the ISO and DSO. A decentralized approach is proposed to solve this problem. Nevertheless, References [73, 74] do not propose any market framework or settlement. In [75], an economic dispatch for co-optimization of T&D systems is proposed. Primal-dual gradient algorithm based on the Lagrangian function is proposed to solve the co-optimization problem. However, the proposed method is not appropriate for a large number of DERs in the distribution system as it places so much computation burden on the economic dispatch of the wholesale market.

The third group of works proposed equivalent models for T&D coordination [77, 78, 79, 80]. In [77], a feasible region-based approach is proposed for the integration of DERs into the wholesale market considering the physical constraints of the distribution system operated by the DSO. In [78], a multi-port power exchange model is proposed to integrate the high penetration of the DERs into the wholesale market considering the physical constraints of the distribution network. The approaches in

[77] and [78] require modeling a transformed version of the distribution level constraints in the ISO market clearing problem, which significantly increases the modeling and computational complexity for the ISO. In [79], a unified equivalent model for external power networks based on multi-parametric programming is proposed for determining the transfer capacity of tie lines. However, they have not considered the distribution system and the market settlement of these external power networks. In [80], a coordinated economic dispatch is proposed for a multi-area power system based on parametric programming. However, no market framework is proposed. Besides, this approach requires iterative communications beteween the coordinator and each economic dispatch sub-area before reaching convergence for the overall coordinated problem. This places very high communication burden between the market operators which is difficult to be implemented in real world applications.

Ideally speaking, the ISO-DSO coordination for DER integration in the wholesale market should satisfy the following requirements: 1) There should be no exchange of grid models between T&D systems, in order to eliminate data confidentiality/privacy issues and avoid additional modeling/computational burden for ISO or DSO. 2) The coordination procedure should introduce no or minimal change to existing ISO wholesale market clearing procedure. 3) The coordination procedure should minimize the communication burden between ISO and DSO, by exchanging the minimal amount of public data and also by avoiding iterative T&D communications within each wholesale market clearing interval.

So far, there is no existing ISO-DSO coordination which fully satisfies the above requirements. Existing works either 1) exchange T&D grid models [42, 43, 69, 70, 71, 72]; 2) introduce significant changes to existing ISO market clearing [59, 60, 44, 62, 45, 73, 74, 75]; or 3) introduce high ISO-DSO communication burden and iterative ISO-DSO communications within each wholesale market clearing interval

[39, 61, 75, 76, 77, 78].

This paper proposes an ISO-DSO coordination framework which satisfies all the above requirements. The proposed framework coordinates the operation of ISO and DSO to leverage the wholesale market participation of DER aggregators while ensuring the secure operation of distribution grids. The proposed coordination framework is based on parametric programming. The DSO builds the bid-in cost function based on the distribution system market considering its market participants' constraints and distribution system physical constraints including the power balance equations and voltage limitation constraints. The DSO submits the resulting bid-in cost function to the wholesale market operated by the ISO. After the clearance of the wholesale market, the DSO determines the share of its DSO market participants (i.e., aggregators). Case studies are performed to verify the effectiveness of the proposed method.

This paper extends our prior works in [58, 34, 48, 81]. To the best of our knowledge, this is the first ISO-DSO coordination framework which fully satisfies all the above performance requirements for ideal and practical ISO-DSO coordination. This is achieved by the following major contributions:

- A framework is proposed to coordinate the operation of the DSO and ISO which is compatible with the current structure of the wholesale market without introducing additional changes to existing wholesale market clearing procedure.

- In this coordination framework, the DER aggregators participate in the wholesale market through the coordination of the DSO, which ensures the secure operation of the distribution grid. A parametric programming approach is proposed to construct the bid-in cost function of the DSO (to be submitted to the ISO) and run the DSO-level market clearing procedure, which is built upon the offers collected from the DER aggregators.

- A market settlement approach is proposed for the DSO, which coordinates with the wholesale market clearing process and ensures the DSO's non-profit characteristic. It is proved that under the proposed ISO-DSO coordination framework, each DER aggregator will receive identical dispatch signals and payments when they participate in the wholesale market through the coordination of the DSO and when they participate in the wholesale market directly with the ISO overseeing all the transmission-level and distribution-level operating constraints.

- The parametric-programming-based ISO-DSO coordination enables complete decoupling between the solution process of the ISO and DSO optimization subproblems. This avoids iterative ISO-DSO communications within each wholesale market clearing interval and allows the ISO and DSO to exchange the minimal amount of public data only after each entity reaches its optimal solution. The proposed approach requires no exchange of private/confidential ISO or DSO grid model data.

- The DSO's market outcomes and market settlement process are investigated through case studies on the modified IEEE 33-node and 240-node distribution test systems.

The rest of the paper is organized as follows. Section 7.2 presents general idea of the DSO and ISO coordination framework. Section 7.3 presents the mathematical formulation of ISO-DSO coordination framework. Section 7.4 proposes the market settlement approach for the ISO-DSO coordination framework. Section 7.5 discusses the case studies. Section 7.6 presents the concluding remarks.

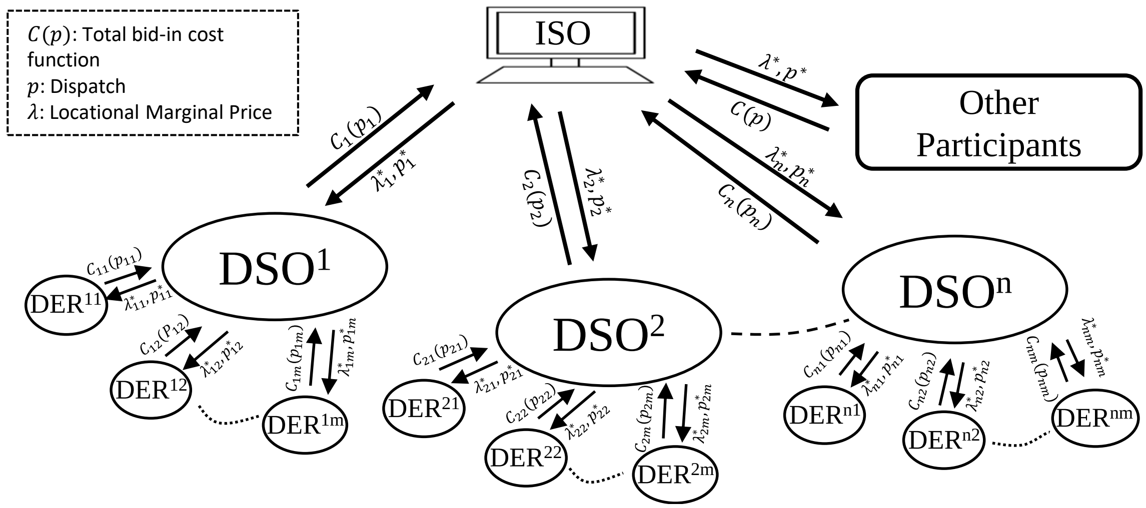


Figure 7.1: The framework of the ISO-DSO coordination.

7.2 The ISO-DSO Coordination Framework

In this section, the proposed ISO-DSO coordination framework, which is shown in Fig. 7.1, is explained. In this work, the DSO is defined as a non-profit entity that deals with the wholesale market on one side and coordinates the DER aggregators on the other side. The DER aggregators participate in the wholesale market through the coordination of the DSO, instead of directly participating in the wholesale market. The DER aggregators submit their offers to the DSO. The DSO gathers all these aggregated DER offers and runs the DSO market at the distribution level to construct the bid-in cost function of the DSO using a parametric programming approach. Then, the DSO submits that bid-in cost function to the wholesale market operated by the ISO. The ISO gathers the bid-in cost functions from all the DSOs as well as from other market participants and clears the wholesale market. Then, the ISO sends the dispatches and loactional marginal prices (LMPs) to the DSOs and other market participants. Once each DSO receives the wholesale-level dispatch and LMP from the ISO, the DSO will determine the optimal operating point of the DSO market and determine the optimal dispatches of the DER aggregators in the DSO territory. Then, each DSO will determine the distribution LMPs (D-LMPs) in the distribution system based on the wholesale-level dispatch and LMP received by the DSO from the ISO at the coupling substation. The DSO will also settle the DSO market participants (i.e., DER aggregators) based on these D-LMPs. Following this procedure, the optimal dispatches and LMPs for all the ISO-level and DSO-level market participants determined by this ISO-DSO coordination framework will be identical to those determined by the ideal case in which the ISO oversees all the T&D-level operating constraints. This procedure eliminates the ISO's modeling/computation burden since it avoids sending the distribution grid model data to the ISO by allowing the distribution-level operating constraints and computations to be handled by each DSOs (instead of the ISO).

7.3 ISO-DSO Coordination Formulation

In this section, the mathematical formulation of the proposed ISO-DSO coordination framework is presented. In order to evaluate the proposed ISO-DSO coordination, an ideal case in which the ISO can oversee all the T&D-level operating constraints and the DER aggregators can participate in the wholesale market directly is defined and formulated. Then, the formulation of the ISO-DSO coordination is proposed.

7.3.1 Ideal Case

To perform market clearing computations for generating resources in both transmission-level and distribution-level systems (i.e., the conventional generators and DERs), as well as ensuring the secure operation of both T&D systems, an ideal market framework will be letting one single entity (the ISO) 1) collect both T&D-level offers/bids (i.e., the bid-in cost functions) from all the conventional generators and DER aggregators; 2) oversee both T&D-level operating constraints; and 3) optimally dispatch both T&D-level resources (conventional generators and DER aggregators). However, this ideal case is not implementable with the current practice of the wholesale market since 1) the distribution system is not observable to the ISO 2) considering all these small DER aggregators and all the distribution-level constraints in the wholesale market increases the computation burden of the ISO problem. This paper addresses this implementability issue by decomposing this ideal case into one ISO and multiple DSO sub-problems. This decomposition allows the distribution-level modeling and computation burden to be handled by each DSO, such that the ISO only needs to handle transmission-level modeling and computation while coordinating with the DSOs. The following sections prove that the proposed ISO-DSO coordination framework and this ideal case achieve identical optimal dispatches and LMPs for all the T&D-level market participants (generators and DER aggregators).

This ideal case is formulated as follows.

$$\text{Min}_{\boldsymbol{p}} \quad \sum_{i\in\mathcal{N}_{gen}} c_i^g(p_i^g) + \sum_{j\in\mathcal{N}_{dis}} \sum_{i\in\mathcal{N}_{agg}} c_{i,j}^{agg}(p_{i,j}^{agg}) \tag{7.1a}$$

$$\begin{aligned} \text{s.t.} \quad & \boldsymbol{p}^g \in S^{Tra} \\ & \boldsymbol{p}_j^{agg} \in S_j^{Dis}, \forall j \in \mathcal{N}_{dis} \\ & p_i^g \in S_i^{gen}, \forall i \in \mathcal{N}_{gen} \\ & p_{i,j}^{agg} \in S_{i,j}^{agg}, \forall i \in \mathcal{N}_{agg}, j \in \mathcal{N}_{dis} \end{aligned} \tag{7.1b}$$

where i and j are indices for market participants (generators/aggregators) and distribution grids in the ISO territory, respectively; p_i^g, $p_{i,j}^{agg}$ and $c_i^g(p_i^g)$, $c_{i,j}^{agg}(p_{i,j}^{agg})$ are the dispatched power and bid-in cost functions of generators in the transmission system and aggregators in various distribution systems under the ISO territory, respectively; $\boldsymbol{p}$ is the vector of p_i; S^{Tra}, S_j^{Dis}, S_i^{gen}, and $S_{i,j}^{agg}$ are the search space defined by the system-wide transmission grid constraints, system-wide distribution grid constraints, operating constraints of generators, and operating constraints of aggregators, respectively; $\mathcal{N}_{gen}$ is the set of all generators; $\mathcal{N}_{dis}$ is the set of all distribution systems; $\mathcal{N}_{agg}$ is set of all aggregators.

Equation (7.1a) minimizes the total cost function of the wholesale market considering all the generators and DER aggregators. Equation (7.1b) presents the operating constraints of all market participants (generators and DER aggregators) as well as the physical constraints of the T&D systems.

7.3.2 ISO-DSO Coordination

In this section, the mathematical formulation of the proposed ISO-DSO coordination framework is presented. This framework decomposes the above ideal case into one ISO sub-problem and multiple DSO sub-problems. Each DSO sub-problem can be solved independently. This framework and the ideal case will result in identical optimal dispatch and payment/LMP to each of the T&D-level market participants. However, the decomposition in this framework reduces the computation and modeling burden of the ISO by moving all the distribution-level decision variables and constraints to each DSO's sub-problem.

The ISO sub-problem is formulated as follows:

$$\text{Min}_{\boldsymbol{p}} \quad \sum_{i \in \mathcal{N}_{gen}} c_i^g(p_i^g) + \sum_{j \in \mathcal{N}_{dis}} c_j^{dso}(p_j^{dso}) \tag{7.2a}$$

$$\begin{aligned} \text{s.t.} \quad & \boldsymbol{p} \in S^{Tra} \\ & p_i \in S_i^{gen}, \forall i \in \mathcal{N}_{gen} \\ & p_j \in S_j^{dso}, \forall j \in \mathcal{N}_{dis} \end{aligned} \tag{7.2b}$$

where p_j^{dso} is the output power of each DSO; $c_j^{dso}(p_j^{dso})$ is the bid-in cost function of each DSO; S_j^{dso} is the search space defined by the operating constraints of each DSO.

Equation (7.2a) minimizes the total cost in the wholesale market, after collecting the bid-in cost functions from all the wholesale market participants (including conventional generators and DSOs). Equation (7.2b) models all the operating constraints of the DSOs and other wholesale market participants as well as the physical constraints of the transmission system. This ISO sub-problem is compatible with the current wholesale market clearing practice.

Each DSO j needs to determine its bid-in cost function $c_j^{dso}(p_j^{dso})$ and the corresponding DSO operating constraints S_j^{dso} to be submitted to the wholesale market (the above ISO sub-problem). We propose the following parametric programming approach for each DSO j to determine these data.

$$
\begin{aligned}
c_j^{dso}(p_j^{dso}) = \mathrm{Min}_{\boldsymbol{p}^{agg}} & \sum_{i \in \mathcal{N}_{agg}} c_{i,j}^{agg}(p_{i,j}^{agg}) \\
\text{s.t.} \quad & p_j^{dso} = \sum_{i \in \mathcal{N}_{agg_k}} p_{i,j}^{agg} + \sum_{l \in \mathcal{N}_{f_k}} f_{l,j} - L_{k,j} \\
& p_{i,j}^{agg} \in S_{i,j}^{agg}, \forall i \in \mathcal{N}_{agg} \\
& \boldsymbol{p}_j^{agg} \in S_j^{Dis}
\end{aligned}
\tag{7.3}
$$

where k is the substation node of DSO j; l is the index for branches; $\mathcal{N}_{f_k}$ is the set of all branches connected to node k; $f_{l,j}$ is the flow on branch l of DSO j; $L_{k,j}$ is the firm load of node k in DSO j.

Equation (7.3) defines a parametric programming problem, where p_j^{dso} is treated as a parameter in the minimization problem. Note that while the power balance equation at the substation is explicitly presented as the equality constraint, the power balance constraints in other nodes are incorporated in S_j^{Dis}. After collecting bid-in cost functions from all the DSO-level market participants (i.e., DER aggregators), for every possible p_j^{dso} value, this problem minimizes the total generation cost in the DSO-level market while satisfying the following constraints: 1) power balance constraint at each node; 2) the operating constraints of DER aggregators; and 3) the system-wide distribution grid constraints. Linearized three-phase power flow is considered which ignores losses [51].

Before the ISO market clearing run, each DSO collects the bid-in cost functions from all the DSO-level market participants (i.e., the DER aggregators) in its territory and solves (7.3) to determine its DSO bid-in cost function $c_j^{dso}(p_j^{dso})$ and the corresponding DSO operating constraints S_j^{dso} (i.e., the upper/lower limits for the DSO bid-in cost function) to be submitted to the wholesale market in the ISO sub-problem. The ISO collects the bid-in cost functions from all the DSOs and other ISO-level market participants (such as conventional generators), which allows the ISO to clear the wholesale market by solving (7.2a)-(7.2b).

Lemma 7.1 *The optimal bid-in cost function from DSO to ISO, $c_j^{dso}(p_j^{dso})$, is a convex function of parameter p_j^{dso}, if the following conditions are all satisfied: 1) the bid-in cost function submitted by each aggregator $c_{i,j}^{agg}(p_{i,j}^{agg})$ is a convex function; 2) the operating constraints of each DER aggregator define a convex set $S_{i,j}^{agg}$; and 3) the system-wide distribution grid constraints define a convex set S_j^{Dis}.*

Proof of Lemma 7.1. See Reference [64].

The convexity of the optimal DSO bid-in cost function $c_j^{dso}(p_j^{dso})$ ensures that our proposed ISO-DSO coordination is compatible with the current wholesale market structure, by allowing each DSO to always submit a convex bid-in cost function to the ISO. The ISO can then directly clear the wholesale market following its current market clearing procedure without introducing any additional change.

After the ISO clears the wholesale market, the dispatch and LMP data is distributed to all the DSOs. Each DSO utilizes the LMP of the coupling substation, as determined by the ISO, and employs it as the wholesale market price in the subsequent proceedings.

$$
\begin{aligned}
&\text{Min}_{\boldsymbol{p}^{agg}, p_j^{dso}} \sum_{i \in \mathcal{N}_{agg}} c_{i,j}^{agg}(p_{i,j}^{agg}) - LMP_j^* p_j^{dso} \\
&\text{s.t.} \quad p_j^{dso} = \sum_{i \in \mathcal{N}_{agg_k}} p_{i,j}^{agg} + \sum_{l \in \mathcal{N}_{f_k}} f_{l,j} - L_{k,j} \\
&\qquad\ p_{i,j}^{agg} \in S_{i,j}^{agg}, \forall i \in \mathcal{N}_{agg} \\
&\qquad\ \boldsymbol{p}_j^{agg} \in S_j^{Dis}
\end{aligned}
\tag{7.4}
$$

where LMP_j^* is the optimal wholesale LMP determined by the ISO market clearing at the bus where the DSO j is located.

Section 7.4 presents the detailed DSO market settlement procedure for each DSO to utilize (7.3) and (7.4) to determine the optimal dispatch and distribution LMPs (D-LMPs) for all the aggregators in the DSO territory.

A detailed formulation for the above DSO sub-problem in (7.3)-(7.4) which considers the real/reactive power flow limits and voltage limits using the linearized three-phase distribution power flow [51] is presented in Appendix A.

7.4 Market Settlement

In our proposed ISO-DSO coordination framework, the DSO is a nonprofit mediator that deals with the DER aggregators on one hand and trades with the wholesale market on the other hand. The DSO gathers the offers from all the DER aggregators and constructs the DSO bid-in cost function and submits it to the ISO based on the parametric programming procedure in (7.3). Once the ISO receives the bid-in cost functions from all the DSOs and other wholesale market participants, the ISO clears the wholesale market by solving (7.2) and determines the power dispatch p_j^{dso*} and LMP at the ISO-DSO coupling substation for each DSO. The DSO then needs to clear the DSO-level market with p_j^{dso*} and the wholesale-level LMP it receives at the

ISO-DSO coupling substation. Each DSO performs this market settlement procedure by 1) letting $p_j^{dso} = p_j^{dso*}$ in (7.3) and solving (7.3) for the optimal dispatch of all the aggregators in the DSO territory when $p_j^{dso} = p_j^{dso*}$; 2) solving (8.4) and obtaining the dual variables of (8.4) as the optimal D-LMPs of all the aggregators in the DSO territory. We prove the theorems below which guarantees that following the above market settlement procedure, the optimal dispatches, LMPs (or D-LMPs), and payments received by all the ISO-level and DSO-level market participants under the proposed ISO-DSO coordination framework will be identical to those under the ideal case where the ISO serves as the single entity overseeing all the T&D-level market participants and operating constraints.

Theorem 7.1 *The optimal dispatches for all the ISO-level and DSO-level market participants under the ISO-DSO coordination framework in (7.2)-(7.3) are identical to those under the ideal case in (7.1).*

Proof of Theorem 7.1. See Appendix B.

Theorem 7.2 *The optimal payments and LMPs (or D-LMPs) for all the ISO-level and DSO-level market participants under the ISO-DSO coordination framework in (7.2)-(7.4) are identical to those under the ideal case in (7.1).*

Proof of Theorem 7.2. See Appendix C.

The above theorems further guarantee: 1) Our proposed ISO-DSO coordination framework completely decouples the optimization problem in the ideal case into one ISO and multiple DSO sub-problems. 2) After this decoupling, at each market clearing run, each DSO only needs to submit its convex bid-in cost function $c_j^{dso}(p_j^{dso})$ and the corresponding DSO operating constraints (upper/lower limits) of this cost function S_j^{Dis} to the ISO, and the ISO only needs to send the optimal wholesale-level dispatch p_j^{dso*} and wholesale LMP back to each DSO. There is no data exchange between different DSOs and no exchange of confidential ISO or DSO grid models. This data exchange procedure is compatible with the current wholesale market clearing practice. It will result in the minimal amount of ISO-DSO data exchange without changing the existing wholesale market clearing procedure. Besides, this data exchange procedure also allows the ISO and DSO to exchange data only after each entity reaches its optimal solution. There is no iterative ISO-DSO data exchange during the iterative solution process of the ISO and DSO sub-problems. This ensures a complete decouple between the iterative solution process of the ISO and DSO sub-problems and eliminates the need for iterative ISO-DSO communications within each market clearing run.

7.5 Case Studies

In this section, case studies have been implemented to verify the effectiveness of the proposed ISO-DSO coordination model. First, a small illustrative example is studied to clearly describe our proposed approach. Then, a large system is studied which includes an IEEE 118-bus test system in the wholesale market and two distribution systems - the IEEE 33-node balanced and 240-node unbalanced distribution systems.

7.5.1 Illustrative Example

In this section, in order to understand the proposed ISO-DSO coordination clearly, a small illustrative example is given. The system consists of a generating unit (G) and a firm load (L) on the transmission side, as well as two dispatchable distributed generations (DDGs) on the distribution side. The system and its corresponding data are provided in Figure 7.2. The DSO parametric programming problem is as follows:

$$c^{dso}(P_{dso}) = \text{Min}_{\boldsymbol{P}_{ddg}} \quad 25P_{ddg_1} + 15P_{ddg_2} \tag{7.5a}$$

$$\text{s.t.} \quad P_{ddg_1} + F_{ds} = P_{dso} \tag{7.5b}$$

$$P_{ddg_2} - F_{ds} = 0 \tag{7.5c}$$

$$0 \leq P_{ddg_1} \leq 0.5 \tag{7.5d}$$

$$0 \leq P_{ddg_2} \leq 0.5 \tag{7.5e}$$

$$-0.1 \leq F_{ds} \leq 0.1 \tag{7.5f}$$

where $c^{dso}(P_{dso})$ is the bid-in cost function of the DSO; P_{dso} is the output power of the DSO injected; P_{ddg_1} is the active power provided by DDG 1; P_{ddg_2} is the active power provided by DDG 2; F_{ds} is the distribution line flow.

The problem described above is simple enough that we can determine the bid-in cost function by the following straightforward approach. We simply need to increase the P_{dso} and determine which DDG will provide power and at what cost. As we begin to increase P_{dso}, DDG 2 will be the cheaper option, so we can continue to increase

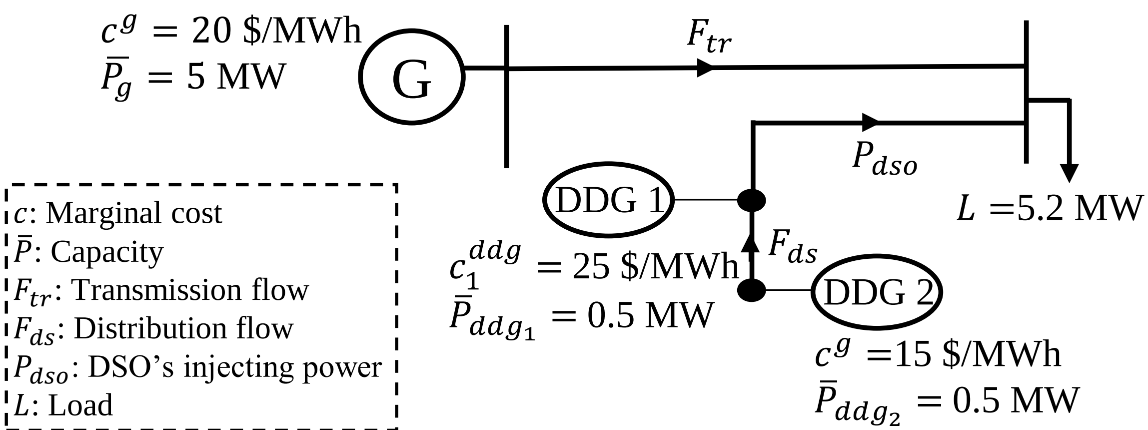


Figure 7.2: Illustrative example system. The minimum active power for all units is zero.

P_{dso} until DDG 2 reaches its maximum output or until line F_{ds} becomes congested. Since the capacity of F_{ds} is 0.1 MW, which is lower than the capacity of DDG 2, we can increase P_{dso} up to 0.1 MW, and the cost function would be $c^{dso}(P_{dso}) = 15P_{dso}$, which is determined by DDG 2. If we need to increase P_{dso} beyond 0.1 MW, we must use DDG 1. We can increase P_{dso} until DDG 1 reaches its maximum output of 0.5 MW. Thus, we can increase P_{dso} up to 0.6 MW, and the total cost function would be $c^{dso}(P_{dso}) = 15 \times 0.1 + 25(P_{dso} - 0.1)$. Therefore, the total cost function is as follows:

$$c^{dso}(P_{dso}) = \begin{cases} 15P_{dso}, & P_{dso} \in [0, 0.1) \\ 15 \times 0.1 + 25(P_{dso} - 0.1), & P_{dso} \in [0.1, 0.6] \end{cases}$$

Hence, the bid-in total cost function and marginal cost function which is derivative of the total cost function are determined as shown in Fig. 7.3(a) and Fig. 7.3(b), respectively.

The DSO submits this marginal cost function in Fig. 7.3(b) to the wholesale market and then, the wholesale market runs the following ISO-level economic dispatch

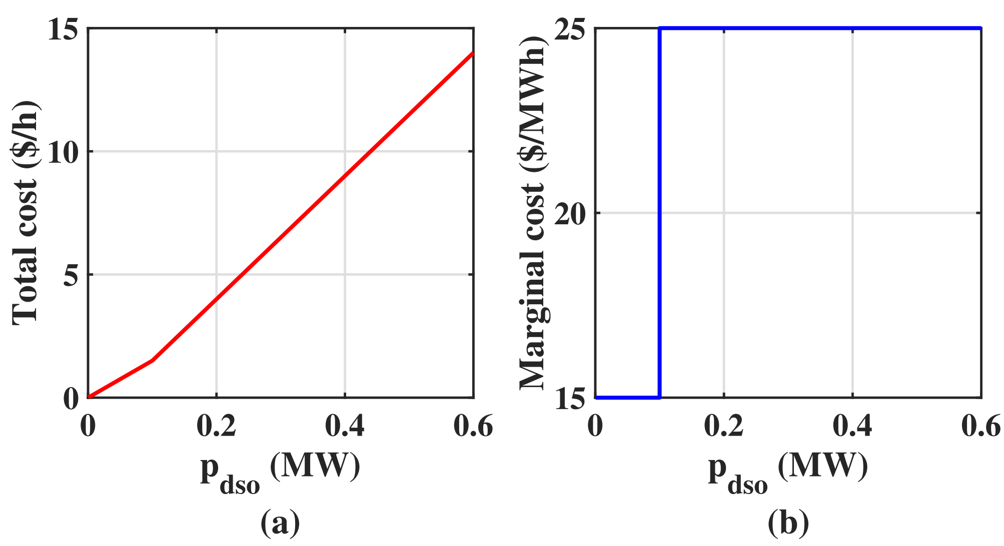


Figure 7.3: DSO bid-in total (left) and marginal (right) cost functions in the illustrative example.

problem:

$$\text{Min}_{\boldsymbol{P}} \quad 20P_g + 15P_{dso,1} + 25P_{dso,2} \tag{7.6a}$$

$$s.t. \quad P_g - F_{tr} = 0 \qquad [\lambda_1^{WM}] \tag{7.6b}$$

$$F_{tr} + P_{dso,1} + P_{dso,2} = 5.2 \qquad [\lambda_2^{WM}] \tag{7.6c}$$

$$0 \leq P_g \leq 5 \tag{7.6d}$$

$$0 \leq P_{dso,1} \leq 0.1 \tag{7.6e}$$

$$0 \leq P_{dso,2} \leq 0.5 \tag{7.6f}$$

where P_g is the power provision from the transmission side unit; $P_{dso,1}$ and $P_{dso,2}$ are the power provision of the first and second segments of the DSO bid-in cost function shown in Fig. 7.3(b), respectively; F_{tr} is the transmission line flow; λ_1^{WM} and λ_2^{WM} are the dual variables corresponding to the transmission-level power balance constraints, respectively.

The optimal solution to the above ISO problem is: $P_g = 5$ MW, $P_{dso,1} = 0.1$ MW, $P_{dso,2} = 0.1$ MW, and the DSO has dispatched $0.1 + 0.1 = 0.2$ MW and the wholesale LMP at the ISO-DSO coupling bus is 25 \$/MWh. The DSO substitutes the parameter $P_{dso} = 0.2$ in (7.5) and determines the DDGs' optimal dispatches, $P_{ddg_1} = 0.1$ MW, $P_{ddg_2} = 0.1$ MW. Then, the DSO solves the following problem to determine optimal D-LMPs:

$$\text{Min}_{\boldsymbol{P}} \quad 25P_{ddg_1} + 15P_{ddg_2} + 25P_{dso} \tag{7.7a}$$

$$\text{s.t.} \quad P_{ddg_1} + F_{ds} = P_{dso} \qquad [\lambda_1] \tag{7.7b}$$

$$P_{ddg_2} - F_{ds} = 0 \qquad [\lambda_2] \tag{7.7c}$$

$$0 \leq P_{ddg_1} \leq 0.5 \tag{7.7d}$$

$$0 \leq P_{ddg_2} \leq 0.5 \tag{7.7e}$$

$$-0.1 \le F_{ds} \le 0.1 \tag{7.7f}$$

where λ_1, λ_2 are the dual variables corresponding to the distribution-level power balance constraints (i.e., the D-LMPs). The solution to this DSO problem determines the following D-LMPs: $\lambda_1 = 25$ \$/MWh, and $\lambda_2 = 15$ \$/MWh.

The following equations describe the ideal case in which the ISO can oversee both T&D-level operations and DER aggregators directly participate in the ISO market:

$$\text{Min}_{\boldsymbol{P}} \quad 20P_g + 15P_{ddg1} + 25P_{ddg2} \tag{7.8a}$$

$$s.t. \quad P_g - F_{tr} = 0 \qquad [\lambda_1^{WM}] \tag{7.8b}$$

$$F_{tr} + P_{dso} = 5.2 \qquad [\lambda_2^{WM}] \tag{7.8c}$$

$$P_{ddg_1} + F_{ds} = P_{dso} \qquad [\lambda_1] \tag{7.8d}$$

$$P_{ddg_2} - F_{ds} = 0 \qquad [\lambda_2] \tag{7.8e}$$

$$0 \le P_g \le 5 \tag{7.8f}$$

$$0 \le P_{ddg1} \le 0.5 \tag{7.8g}$$

$$0 \le P_{ddg2} \le 0.5 \tag{7.8h}$$

$$-6 \le F_{tr} \le 6 \tag{7.8i}$$

$$-0.1 \le F_{ds} \le 0.1 \tag{7.8j}$$

The solution (including optimal dispatch and prices for all the T&D-level resources) to the above ideal case is the same as the ISO-DSO coordination framework. However, upon comparing formulations (7.6) and (7.8), it can be observed that constraints (7.8d), (7.8e), and (7.8j) are no longer necessary, which reduces the problem size and computational burden for the ISO, as well as avoids sending DSO-level modeling details to the ISO.

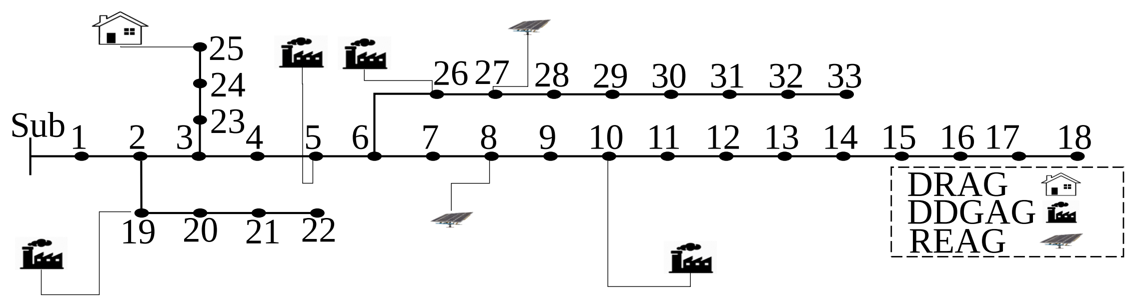


Figure 7.4: 33-node test system.

7.5.2 Large Test System

In this section, simulation studies are implemented in a large test system containing ISO running the wholesale-level economic dispatch on an IEEE 118-bus test system. We have also considered two DSOs running the DSO-level market in the IEEE 33-node balanced and 240-node unbalanced distribution systems, respectively. YALMIP [67] is utilized to solve parametric programming problems for DSOs.

118-bus Test System Data

The IEEE 118-bus test system is considered as the transmission system operated by the ISO. The system data is given in [82]. The system contains 118 buses, 186 transmission lines, and 54 generators.

33-node Test System Data and Results

The 33-node test system is a balanced radial network which is shown in Fig. 7.4. The system contains 33 nodes, 32 branches, a demand response aggregator (DRAG), four dispatchable distributed generation aggregators (DDGAGs), and two renewable energy aggregators (REAGs). The test system data and load data are given in [56].

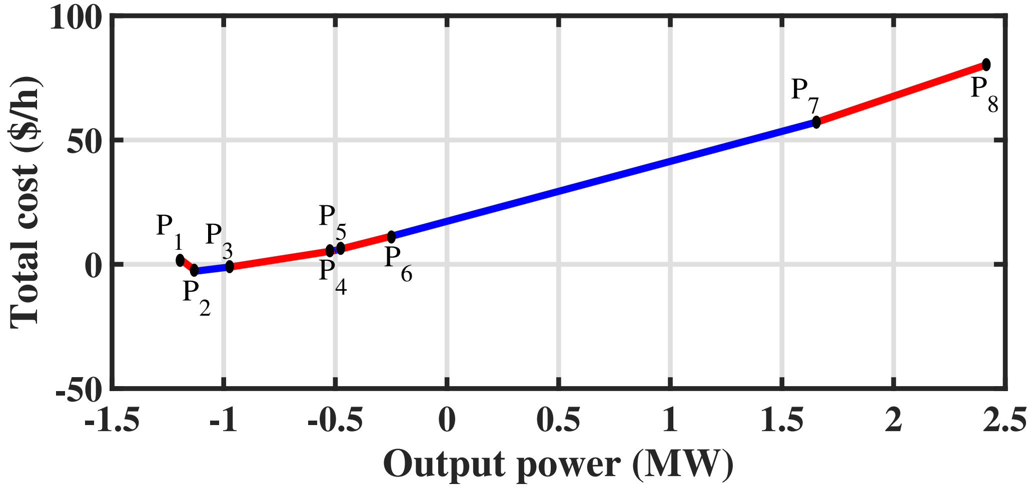


Figure 7.5: Total cost function of the 33 node test system.

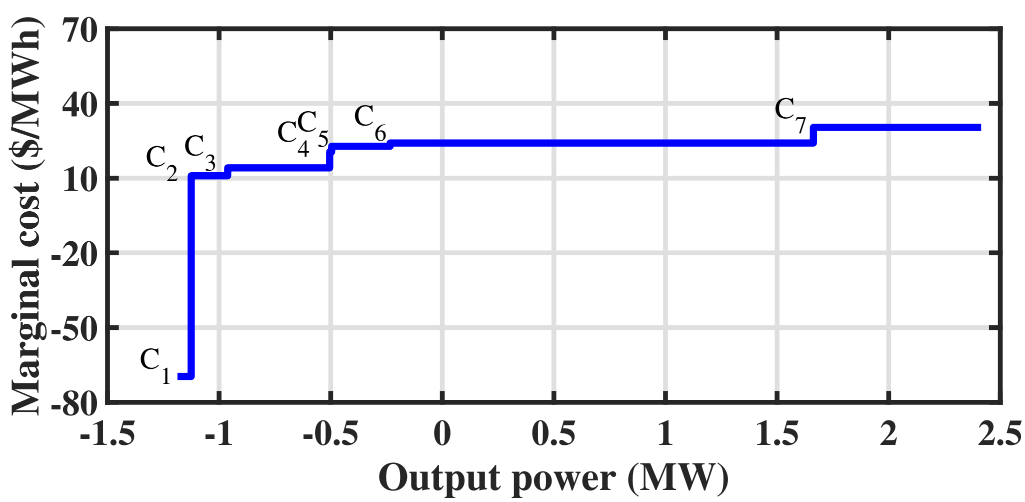


Figure 7.6: Bid-in marginal cost function of the 33 node test system.

Table 7.1: DSO market participants data for the 33-node test system

Participant	Pmin (MW)	Pmax (MW)	Offering price ($/MWh)
DDGAG 1	0	0.5	20
DDGAG 2	0	1	10
DDGAG 3	0	1.2	15
DDGAG 4	0	2	24
DRAG	0	2	28

Table 7.2: 33-node test system breakpoints and marginal costs data

Breakpoint index	Breakpoint coordinate value (MW,$/h)	Marginal cost index	Marginal cost value ($/MWh)
P_1	(-1.18654,1.54166)	C_1	-69.6072
P_2	(-1.12498, -2.74336)	C_2	10.9555
P_3	(-0.961451, -0.951813)	C_3	14.1388
P_4	(-0.504623, 5.50717)	C_4	20.5587
P_5	(-0.495727, 5.69006)	C_5	22.8007
P_6	(-0.233645, 11.6657)	C_6	24.1164
P_7	(1.66269, 57.3985)	C_7	30.3739
P_8	(2.4175, 80.325)		

The two REAGs are considered to have identical energy production profiles of 1 MW. The other aggregators' data is given in Table. 7.1. Pmin and Pmax are the minimum and maximum generating power, respectively. It is assumed that the 33-node test system is connected to the 118-bus test system trough bus 87 on the transmission side.

The total cost function of the DSO is determined based on (7.9). The DSO's total (minimal) operating costs at different output power levels are shown in Fig. 7.5. This is a piecewise linear function with eight breakpoints separating the seven linear segments. The breakpoints in Fig. 7.5 are determined by the DSO-level market participants' minimum and maximum output power considering the network's physical constraints. The bid-in marginal cost function which is the derivative of the total bid-in cost function in Fig. 7.5 is shown in Fig. 7.6. This marginal cost function consists of seven levels of marginal costs corresponding to the seven linear segments in the piecewise linear total cost function in Fig. 7.5.

The coordinates of the breakpoints in Fig. 7.5 and the values of the marginal costs in Fig. 7.6 are given in Table 7.2.

The bid-in marginal cost function starts with the output power of -1.18654 MW which means that DSO can consume the energy of -1.18654 MW due to the capability of the DRAG and inelastic load to consume power in the distribution system. The bid-in price of this consumption is -69.6072 $/MWh. The negative value indicates that if the wholesale market dispatches this consumption value to the DSO, the DSO should be paid at this price. This indicates the DSO prefer not purchasing energy from the ISO at this segment, since this may increase the total DSO-level generation cost. This is because it may violate certain voltage constraints that require the DSO to provide energy from its costly units. When the price of the wholesale market increases, the DSO starts selling energy to the wholesale market because the price

Table 7.3: DSO market participants information for 240-node test system

Participant	Capacity (MW)	Price ($/MWh)	Participant	Capacity (MW)	Price ($/MWh)
DDGAG 1	0.25 A	20	DRAG 1	0.15 A	28
DDGAG 2	0.25 A	10	DRAG 2	0.15 A	29
DDGAG 3	0.25 B	15	DRAG 3	0.15 B	30
DDGAG 4	0.25 B	24	DRAG 4	0.15 B	27
DDGAG 5	0.25 C	14	DRAG 5	0.15 C	26
DDGAG 6	0.25 C	15	DRAG 6	0.15 C	25
DDGAG 7	0.25 A	16	DRAG 7	0.15 A	24
DDGAG 8	0.25 B	17	DRAG 8	0.15 B	22
DDGAG 9	0.25 C	18	DRAG 9	0.15 C	22
DDGAG 10	0.25 A	19	DRAG 10	0.15 A	23

in the wholesale market is higher than the offering prices of the DDGAGs in the distribution system. In the end, the DSO sells energy to the wholesale market at the price of 30.3739 $/MWh. This is due to the fact that if the offering price of the wholesale market is greater than 30.3739 $/MWh, the DSO sells the energy to the ISO instead of to the DRAG. The DSO submits its marginal cost function, shown in Fig. 7.6, to the ISO and waits for the ISO to clear the wholesale market.

240-node Distribution System Data and Results

The 240-node distribution test system is an unbalanced radial network in Midwest U.S. The data of the system is given in [57]. The system contains 240 nodes and 239 branches. Multiple aggregators are considered as follows: ten DRAGs, ten DDGAGs,

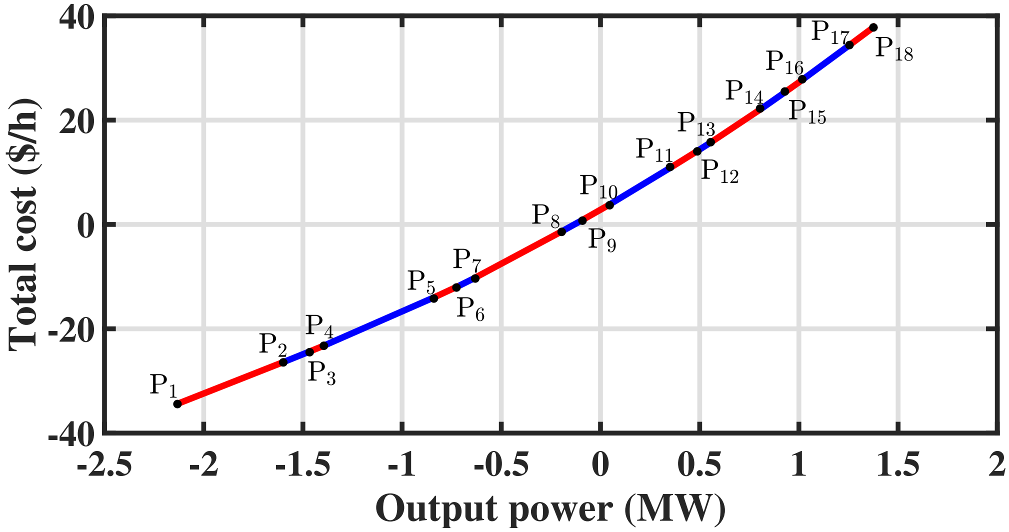


Figure 7.7: Total cost function of the 240 node test system.

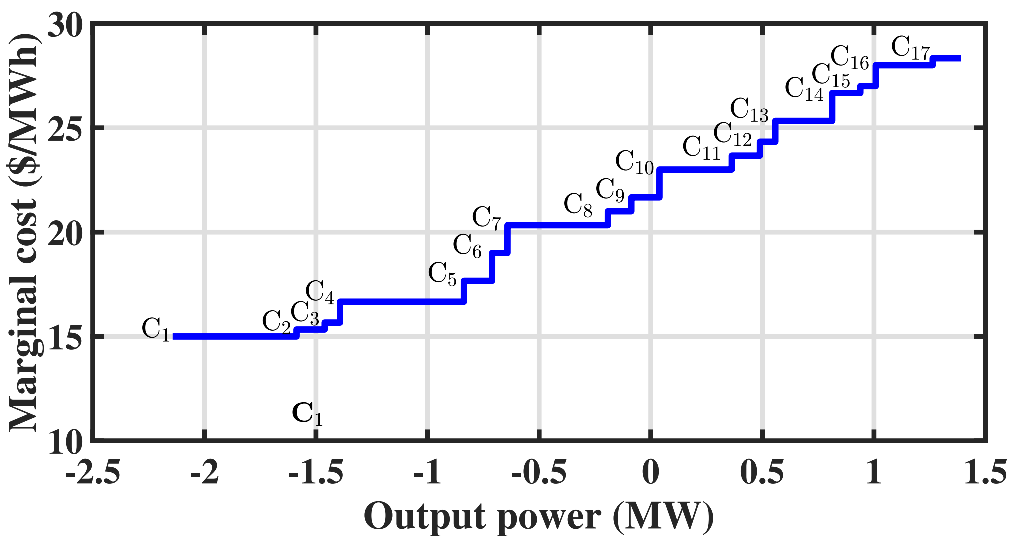


Figure 7.8: Bid in marginal cost function of the 240 node test system.

Table 7.4: 240 node breakpoints and marginal costs data

Breakpoint index	Breakpoint coordinate value (MW,$/h)	Marginal cost index	Marginal cost value ($/MWh)
P_1	(-2.142,-34.538)	C_1	15
P_2	(-1.587, -26.213)	C_2	15.333
P_3	(-1.461, -24.281)	C_3	15.667
P_4	(-1.392, -23.2)	C_4	16.667
P_5	(-0.837, -13.95)	C_5	17.667
P_6	(-0.711, -11.724)	C_6	19
P_7	(-0.642, -10.413)	C_7	20.333
P_8	(-0.192,-1.263)	C_8	21
P_9	(-0.087, 0.942)	C_9	21.667
P_{10}	(0.039, 3.672)	C_{10}	23
P_{11}	(0.363, 11.124)	C_{11}	23.667
P_{12}	(0.489, 14.106)	C_{12}	24.333
P_{13}	(0.558, 15.785)	C_{13}	25.333
P_{14}	(0.813, 22.245)	C_{14}	26.667
P_{15}	(.939,25.605)	C_{15}	27
P_{16}	(1.008, 27.468)	C_{16}	28
P_{17}	(1.263, 34.608)	C_{17}	28.333
P_{18}	(1.389, 38.178)		

and four REAGs. The data of the DER aggregators are given in Table 7.3. It is assumed that the 240-node system is connected to the 118-bus system through bus 27 of the transmission system.

The bid-in cost function of the DSO is determined based on (7.9). The formulation is extended to handle the single-phase aggregators and unbalanced distribution system physical constraints based on our prior work in [34].

The DSO's total bid-in cost function of the 240-node test system is shown in Fig. 7.7. The breakpoints in Fig. 7.7 are determined by the DSO market participants' minimum and maximum output power as well as the physical constraints of the distribution system. There are 18 breakpoints including the beginning and ending points. The bid-in marginal cost function of the DSO which is the derivative of the total bid-in cost function in Fig. 7.7 is given in Fig. 7.8. The data of the breakpoints and the marginal costs are given in Table 7.4.

In Fig. 7.8, the bid-in marginal cost function starts with -2.14 MW with the price of 15 $/MWh which means that if the price of the wholesale market is lower than or equal to this value the DSO operating the 240-node test system buys energy from the wholesale market for consumption in the distribution system. As the wholesale market price increases, the energy consumption in the DSO decreases until it reaches 23 $/MWh at which the DSO sells energy to the wholesale market for any price greater than this value. The amount of energy provision of the DSO for the ISO increases as the price in the wholesale market increases until it reaches its maximum capacity which is 1.39 MW.

Market Clearing Results

This section compares the market clearing results of the ideal case in (7.1) and our proposed ISO-DSO coordination case. In the ideal case, the ISO is the single entity

Table 7.5: Ideal case and ISO-DSO coordination case dispatch

Total wholesale market generators' dispatch			
6601.1 MW			
33 node test system dispatches			
Participant	Dispatch (MW)	Participant	Dispatch (MW)
DDGAG 1	0	DDGAG 3	1.2
DDGAG 2	0.7102	DDGAG 4	0
DRAG	0.6998		
240 node test system dispatches			
Participant	Dispatch (MW)	Participant	Dispatch (MW)
DDGAG 1	0.065 A	DRAG 1	0.15 A
DDGAG 2	0.25 A	DRAG 2	0.15 A
DDGAG 3	0.25 B	DRAG 3	0.15 B
DDGAG 4	0 B	DRAG 4	0.15 B
DDGAG 5	0.25 C	DRAG 5	0.15 C
DDGAG 6	0.25 C	DRAG 6	0.15 C
DDGAG 7	0.25 A	DRAG 7	0.15 A
DDGAG 8	0.25 A	DRAG 8	0.15 A
DDGAG 9	0.25 B	DRAG 9	0.15 B
DDGAG 10	0.023 C	DRAG 10	0.15 C

which oversees all the market participants and operating constraints in the transmission system and in both distribution systems. In our proposed ISO-DSO coordination case, both 33-node and 240-node DSOs submit their marginal bid-in cost functions in Figs. 7.6 and 7.8 to the ISO. Then, ISO clears the wholesale market based on (7.2). Table 7.5 shows the market dispatch results of the ideal case and the ISO-DSO coordination case for this large test system. Since these two cases share identical market dispatch results for all the T&D-level market participants (generators and DER aggregators), we only used one table to present these identical results for both cases. Table 7.5 shows the total dispatch in the wholesale market and the individual DER aggregators' dispatches in both 33-node and 240-node distribution systems. In the ISO-DSO coordination case, the total dispatches for the 33-node and 240-node DSOs are -0.5046 MW and -0.642 MW, respectively.

Market Settlements

In this section, we compare the market settlements of the ideal case and ISO-DSO coordination case. In the ideal case, the LMP on the transmission side is 20.24 $/MWh, which remains the same throughout the transmission system, as there is no transmission-level congestion. Therefore, the LMPs at the coupling points of the 33 node system and 240-node system are also 20.24 $/MWh. The 240-node system is unbalanced, resulting in different D-LMPs for each phase, namely 20 $/MWh, 21.71 $/MWh, and 19 $/MWh for phase A, phase B, and phase C, respectively. The average of the three-phase D-LMPs is 20.24 $/MWh. More detailed information on determining LMP in an unbalanced system can be found in our previous work [58].

In the ISO-DSO coordination case, the LMP on the transmission side is obtained by (7.2) and remains identical to the ideal case (20.24 $/MWh). Each DSO then determines its own D-LMPs based on (8.4), by letting $LMP_j^* = 20.24$ $/MWh. The

D-LMPs of the 33 node test system and 240-node system obtained from the ISO-DSO coordination case are identical to those obtained from the ideal case.

7.6 Conclusion

In this paper, an ISO-DSO coordination framework is proposed based on parametric programming, which ensures distribution grid operating security while allowing wholesale market participation of DER aggregators. Each DSO runs the DSO-level market in the distribution system and gathers offers from all the market participants (DER aggregators) in its territory and build the bid-in cost function for submission to the ISO. Then, the ISO gathers all these bid-in cost functions from all the DSOs and from other wholesale market participants to clear the wholesale market. Once the ISO clears the wholesale market, the dispatch and payment of each DSO are determined. Then, DSOs determine the DSO-level dispatch and D-LMPs in their territories based on the ISO-cleared market. A market settlement approach is presented and proved that each market participant (generator or aggregator) will receive identical compensation and dispatch under the proposed ISO-DSO coordination framework and under the ideal case where the DER aggregators can participate in the wholesale market directly and the ISO is the single entity overseeing both T&D-level operating constraints. This ISO-DSO coordination framework is compatible with today's wholesale market structure without introducing additional changes to existing wholesale market clearing procedure. It only exchanges minimal amount of public data between the ISO and DSO without exchanging any confidential grid models between the T&D operations. It also completely decouples the solution process of the ISO and DSO optimization sub-problems, which allows the ISO and DSO to exchange data only after each entity converges to its optimal solution.

Case studies were implemented on a small illustrative example and a large system to investigate the proposed ISO-DSO coordination framework. The small illustrative example shows that, compared to the ideal case, the proposed model significantly removes the variables and constraints for the wholesale market while resulting in the same market clearing outcomes. The large system contains the IEEE 118-bus transmission system connected to two DSO operated distribution systems including the 33-node balanced 240-node unbalanced distribution systems. The bid-in cost functions of the DSOs were developed based on parametric programming and submitted to the ISO. The dispatches and payments to the DER aggregators are identical under the ISO-DSO coordination framework and under the ideal case.

Appendix A

Following is the detailed formulation of (7.3).

$$c^{dso}(P^{dso}) = Min \sum_{g\in G}\sum_{b\in B} P_{g,b}\pi_{g,b} - \sum_{d\in D}\sum_{b\in B} P_{d,b}\pi_{d,b} \tag{7.9a}$$

s.t.

$$\begin{aligned}&\sum_{d\in D}\sum_{b\in B} H_{n,d}P_{d,b} + H_n^{sub}P^{dso} + L_n^P\\ &-\sum_{g\in G}\sum_{b\in B} H_{n,g}P_{g,b} + \sum_{j\in J} Pl_j A_{j,n} = 0; \quad \forall n \in N\end{aligned} \tag{7.9b}$$

$$\begin{aligned}&\sum_{d\in D}\sum_{b\in B} H_{n,d}P_{d,b}tan\phi_d + H_n^{sub}Q^{dso} + L_n^Q\\ &-\sum_{g\in G}\sum_{b\in B} H_{n,g}P_{g,b}tan\phi_g + \sum_{j\in J} Ql_j A_{j,n} = 0; \forall n \in N\end{aligned} \tag{7.9c}$$

$$0 \le P_{g,b} \le P_{b,g}^{max}; \quad \forall b \in B, \forall g \in G \tag{7.9d}$$

$$0 \le P_{d,b} \le P_{d,g}^{max}; \quad \forall b \in B, \forall d \in D \tag{7.9e}$$

$$\begin{aligned}&U_m = U_n - 2(r_jPl_j + x_jQl_j); \quad \forall m \in N,\\ &\qquad \forall n \in N,\ C(m,n) = 1,\ A(j,n) = 1\end{aligned} \tag{7.9f}$$

$$\underline{U} \leq U_n \leq \overline{U}; \quad \forall n \in N \tag{7.9g}$$

$$-Pl^{max} \leq Pl_j \leq Pl^{max}; \quad \forall j \in J \tag{7.9h}$$

$$-Ql^{max} \leq Ql_j \leq Ql^{max}; \quad \forall j \in J \tag{7.9i}$$

where g and G represent the index and set of all generating aggregators; d and D represent the index and set of all demand response aggregators; b and B represent the index and set of all production/demand blocks; j and J represent the index and set of all lines; n and N represent the index and set of all nodes; P^{dso} represents the DSO's aggregated offers to the ISO market; $P_{g,b}$ and $P_{d,b}$ represent the energy offers submitted by the generating aggregators and demand response aggregators, respectively, with corresponding prices $\pi_{g,b}$ and $\pi_{d,b}$; $H_{n,d}$, $H_{n,g}$, and H_n^{sub} represent the mapping matrices of generating aggregators, demand response aggregators, and substations to node n, respectively; Pl_j and Ql_j represent the active and reactive power of branch j, respectively; $A_{j,n}$ represents the incidence matrix of branches and nodes; ϕ_g and ϕ_d represent the phase angle of the generating aggregators and demand response aggregators, respectively; Q_n^D represents the reactive power of the firm load at each node; L_n^P and L_n^Q represent the active and reactive power load at each node; $P_{g,b}^{max}$ and $P_{d,b}^{max}$ represent the maximum production/consumption at each block of the generating aggregators and demand response aggregators, respectively; U represents the square of the voltage of each node; $\underline{U}$ and $\overline{U}$ represent the square of the minimum and maximum permitted voltage values, respectively; r_j and x_j represent the resistance and reactance of the branches; Pl^{max} and Ql^{max} represent the maximum active and reactive power of the branches.

The objective function of the DSO which minimizes the total cost over the system is defined in (7.9a). Equations (7.9b) and (7.9c) define active and reactive power balances, respectively. The generating power of each DDG is limited by (7.9d). The

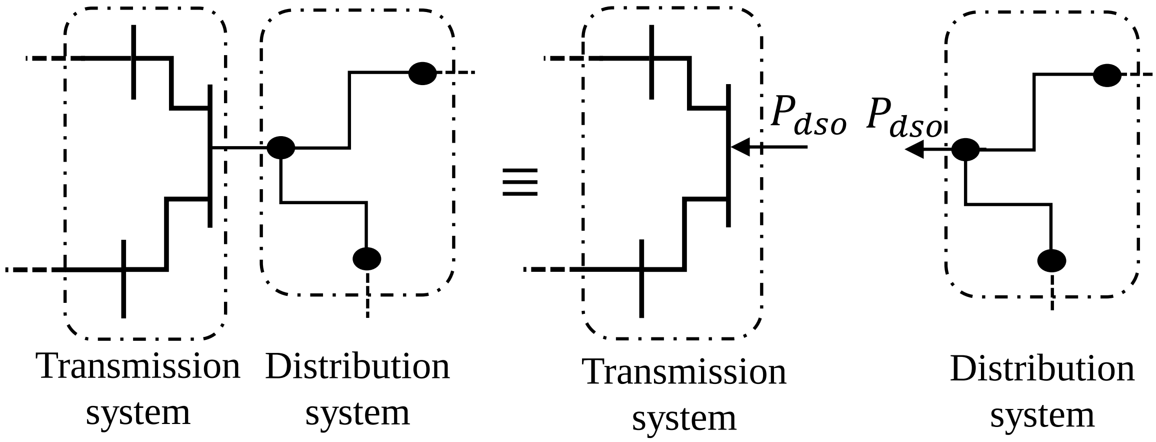


Figure 7.9: Transmission-distribution decomposition.

power consumption by the demand response is limited with respect to the maximum value in (7.9e). The voltage of each branch is defined in (9.11) and is limited with respect to the allowed voltage range in (9.10). The active and reactive flow of each branch is limited in (7.9h) and (7.9i), respectively.

Appendix B: Proof of Theorem 2

Let the ideal case in (7.1) be written in the short form as follows:

$$\begin{aligned} &\text{Min } f(X) \\ &s.t. \\ &\mathbf{X} \in S \end{aligned} \tag{7.10}$$

where $\mathbf{X}$ is the vector of all decision variables; f is the objective function; and S is the feasible region. This ideal case includes both T&D-level constraints and market participants (decision variables). For each coupling substation between the T&D systems, we introduce an ancillary variable P_{dso} to decompose the T&D systems as shown in Fig. 7.9. By introducing a vector of auxiliary variables $\mathbf{P}_{dso} = [P_{dso_1}, P_{dso_2}, ..., , P_{dso_n}]$

for different coupling substations between the transmission system and different distribution systems, Equation (7.10) can be written as follows:

$$\begin{aligned}
&\text{Min} f(\mathbf{X}, \mathbf{P}_{dso}) \\
&s.t. \\
&\quad \mathbf{X} \in S \\
&\quad \mathbf{P}_{dso} \in S^{P_{dso}}
\end{aligned} \tag{7.11}$$

By partitioning $\mathbf{S}$, we can separate transmission side constraints and all the distribution side constraints. Then, Equation (7.11) becomes:

$$\begin{aligned}
&\text{Min} f[f_1(\mathbf{X}^{iso}, \mathbf{P}_{dso}), f_2(\mathbf{X}^{dso_1}, \mathbf{P}_{dso}), ..., f_{n+1}(\mathbf{X}^{dso_n}, \mathbf{P}_{dso})] \\
&s.t. \\
&\quad \mathbf{X}^{iso} \in S^{ISO}(\mathbf{P}_{dso}) \\
&\quad \mathbf{X}^{dso_1} \in S^{DSO_1}(\mathbf{P}_{dso}) \\
&\quad \mathbf{X}^{dso_2} \in S^{DSO_2}(\mathbf{P}_{dso}) \\
&\quad \vdots \\
&\quad \mathbf{X}^{dso_n} \in S^{DSO_n}(\mathbf{P}_{dso}) \\
&\quad \mathbf{P}_{dso} \in S^{P_{dso}}
\end{aligned} \tag{7.12}$$

The meaning of (7.12) is that we present f (total cost function) as some function of $N+1$ components f_1 (terms of the total cost function related to the transmission side) f_2 (terms of the total cost function related to the DSO 1) ... f_{n+1} (terms of the total cost function related to the DSO n) where f_k depends on $\mathbf{X}^k$, where $k \in \{iso, dso_1, dso_2, ..., dso_n\}$, and auxiliary variables $\mathbf{P}_{dso}$. The optimization problem in (7.12) can be solved by a two-level solution using decomposition if: 1) $\mathbf{X}^k$ are mutually exclusive subsets of $\mathbf{X}$; 2) The problem in (7.12) can be formulated in a way that allows disjoint extermination [83]. the first condition holds since $\mathbf{X}^k$ are partitioned in such a way that just includes the local variables in that area. A purely additive function allows for disjoint extermination [83]. f is purely additive function. Hence, the second condition also holds. Therefore, the problem in (7.12) can be written as:

$$\begin{aligned} \text{Min} f(\mathbf{X}) = \underset{\mathbf{P}_{dso} \in S^{P_{dso}}}{\text{Min}} f[& \underset{\mathbf{X}^{iso} \in S^{ISO}(\mathbf{P}_{dso})}{\text{Min}} f_1(\mathbf{X}^{iso}, \mathbf{P}_{dso}), \\ & \underset{\mathbf{X}^{dso_1} \in S^{DSO_1}(\mathbf{P}_{dso})}{\text{Min}} f_2(\mathbf{X}^{dso_1}, \mathbf{P}_{dso}) \\ & \vdots \\ & \underset{\mathbf{X}^{dso_n} \in S^{DSO_n}(\mathbf{P}_{dso})}{\text{Min}} f_{n+1}(\mathbf{X}^{dso_n}, \mathbf{P}_{dso})] \end{aligned} \tag{7.13}$$

Each sub-system optimization $\underset{\mathbf{X}^{dso_i} \in S^{DSO_i}(\mathbf{P}_{dso})}{\text{Min}} f_i(\mathbf{X}^{dso_i}, \mathbf{P}_{dso})$ is parametric in $\mathbf{P}_{dso}$ which represents the parametric programming problem of each DSO. Let the optimal solution of each sub-system optimization be denoted as $f_i^*(\mathbf{P}_{dso})$, which is the parametric solution of the bid-in cost function of each DSO. These sub-system optimization problems are exactly the DSO sub-problems in our ISO-DSO coordination framework. The ideal case problem can be further written as:

$$\begin{aligned} \text{Min} f(\mathbf{X}) = \underset{\mathbf{P}_{dso} \in S^{P_{dso}}}{\text{Min}} f[& \underset{\mathbf{X}^{iso} \in S^{ISO}(\mathbf{P}_{dso})}{\text{Min}} f_1(\mathbf{X}^{iso}, \mathbf{P}_{dso}), \\ & f_1^*(\mathbf{P}_{dso}) \\ & \vdots \\ & f_n^*(\mathbf{P}_{dso})) \end{aligned} \tag{7.14}$$

The above problem is exactly the ISO sub-problem in our ISO-DSO coordination framework, after each DSO solves its DSO sub-problem and sends its optimal DSO bid-in cost function $f_i^*(\mathbf{P}_{dso})$ to the ISO. The above procedure demonstrates that our ISO-DSO coordination framework is an exact decomposition of the ideal case through parametric programming. Therefore both the ideal case and the ISO-DSO coordination framework will lead to identical optimal dispatch solutions for all the T&D-level market participants.

Appendix C: Proof of Theorem 2

Consider the following detailed formulation for the ideal case which is the detailed version of formulation (7.1).

$$\text{Min}_{\boldsymbol{p}} \quad \sum_{i\in\mathcal{N}_{gen}} c_i^g p_i^g + \sum_{j\in\mathcal{N}_{dis}} \sum_{i\in\mathcal{N}_{agg}} c_{i,j}^{agg} p_{i,j}^{agg} \tag{7.15a}$$

s.t.

$$\sum_{i\in\mathcal{N}_{gen_n}} p^g + \sum_{k\in\mathcal{N}_{.,n}} F_k - \sum_{k\in\mathcal{N}_{n,.}} F_k - L_n = 0; \quad [\lambda_i^w] \tag{7.15b}$$

$$\underline{p_i^g} \leq p_i^g \leq \overline{p_i^g}; \quad [\alpha_i^g] \tag{7.15c}$$

$$-\overline{F_k} \leq F_k \leq \overline{F_k}; \quad [\beta_i^{w^-}, \beta_i^{w^+}] \tag{7.15d}$$

$$\sum_{i\in\mathcal{N}_{agg_n}} p_{i,j}^{agg} + \sum_{k\in\mathcal{N}_{j_{n,.}}^d} f_{k,j} - \sum_{k\in\mathcal{N}_{j_{n,.}}^d} f_{k,j} - l_{n,j} = 0; \quad [\lambda_i^d] \tag{7.15e}$$

$$\underline{p_{i,j}^{agg}} \leq p_{i,j}^{agg} \leq \overline{p_{i,j}^{agg}}; \quad [\alpha_i^{agg}] \tag{7.15f}$$

$$-\overline{f_{k,j}} \leq f_{k,j} \leq \overline{f_{k,j}}; \quad [\beta_i^{d^-}, \beta_i^{d^+}] \tag{7.15g}$$

$$U_{m,j} = U_{n,j} - 2(r_{k,j} f_{k,j} + x_{k,j} q_{k,j}); \quad [\gamma_i^d] \tag{7.15h}$$

$$\underline{U} \leq U_n \leq \overline{U}; \quad [\zeta_i^{d^-}, \zeta_i^{d^+}] \tag{7.15i}$$

(7.15j)

In equations (7.15b) and (7.15e), there will be an equation where connects substation to the transmission system bus. let us introduce a new variable p^{dso} in the substation node as shown in Fig. 7.9 and decompose this equation to the following equations:

$$f_m + p^{dso} = 0; \quad [\lambda_m^d] \tag{7.16}$$

$$F_m + p^{dso} = 0; \quad [\lambda_m^w] \tag{7.17}$$

Let us derive the dual of the formulation (7.15) as follows:

$$\begin{aligned} \text{Max} \quad & \sum_{i \in \mathcal{N}_{gen}} \alpha_i^g (\overline{p_i^g}) + \sum_{i \in \mathcal{N}_{fl_w}} (\beta_i^{w+} - \beta_i^{w-})(\overline{F_i}) \\ & \sum_{i \in \mathcal{N}_{agg}} \alpha_i^{agg} (\overline{p_i^{agg}}) + \sum_{i \in \mathcal{N}_{fl_d}} (\beta_i^{d+} - \beta_i^{d-})(\overline{f_i}) \\ & + \sum_{i \in \mathcal{N}_{pf_w}} \lambda_i^w (L_i^w) + \sum_{j \in \mathcal{N}_{pf_d}} \lambda_i^d (L_i^d) \\ & - \sum_{n \in \mathcal{N}_{pf_d}} \zeta_i^{d^-} \underline{U} + \sum_{n \in \mathcal{N}_{pf_d}} \zeta_i^{d^+} \overline{U} \end{aligned} \tag{7.18a}$$

$$\lambda_i^w + \alpha_i^g \le c_i^g; \quad [p_i^g] \tag{7.18b}$$

$$\lambda_i^d + \alpha_i^{agg} \le c_i^{agg}; \quad [p_i^{agg}] \tag{7.18c}$$

$$\lambda_k^w - \lambda_n^w + \beta_j^{w+} - \beta_j^{w-} = 0; \quad [F_k] \tag{7.18d}$$

$$\lambda_k^d - \lambda_n^d + \beta_j^{d+} - \beta_j^{d-} = 0; \quad [f_k] \tag{7.18e}$$

$$\gamma_i^d + \zeta_i^{d^-}, \zeta_i^{d^+} = 0; \quad [U_n] \tag{7.18f}$$

$$\lambda_m^w + \lambda_m^d = 0; \quad [p^{dso}] \tag{7.18g}$$

With the same procedure explained in proof of Theorem 1, we can decompose each DSO dual problem considering λ_m^w as a parameter.

$$\begin{aligned} \text{Max} \quad & \sum_{i \in \mathcal{N}_{agg}} \alpha_i^{agg} (\overline{p_{agg}}) + \sum_{i \in \mathcal{N}_{fl_d}} (\beta_i^{d+} - \beta_i^{d-})(\overline{f_i^d}) \\ & + \sum_{j \in \mathcal{N}_{pf_d}} \lambda_i^d (L_i^d) \\ & - \sum_{n \in \mathcal{N}_{pf_d}} \zeta_i^{d^-} \underline{U} + \sum_{n \in \mathcal{N}_{pf_d}} \zeta_i^{d^+} \overline{U} \end{aligned} \tag{7.19a}$$

$$\lambda_i^d + \alpha_i^{agg} \leq c_i^{agg}; \quad [p_i^{agg}] \tag{7.19b}$$

$$\lambda_k^d - \lambda_n^d + \beta_j^{d+} - \beta_j^{d-} = 0; \quad [f_k] \tag{7.19c}$$

$$\gamma_i^d + \zeta_i^{d^-}, \zeta_i^{d^+} = 0; \quad [U_n] \tag{7.19d}$$

$$\lambda_m^w + \lambda_m^d = 0; \quad [p^{dso}] \tag{7.19e}$$

Considering λ_m^w as a parameter, we can derive the dual of formulation (7.19).

$$\text{Min}_{\boldsymbol{p}} \quad \sum_{j \in \mathcal{N}_{dis}} \sum_{i \in \mathcal{N}_{agg}} c_{i,j}^{agg} p_{i,j}^{agg} - \lambda_m^w p_j^{dso} \tag{7.20a}$$

s.t.

$$\sum_{i \in \mathcal{N}_{aggn}} p_{i,j}^{agg} + \sum_{k \in \mathcal{N}_{jn,.}^d} f_{k,j} - \sum_{k \in \mathcal{N}_{jn,.}^d} f_{k,j} - l_{n,j} = 0; \quad [\lambda_i^d] \tag{7.20b}$$

$$\underline{p_{i,j}^{agg}} \leq p_{i,j}^{agg} \leq \overline{p_{i,j}^{agg}}; \quad [\alpha_i^{agg}] \tag{7.20c}$$

$$-\overline{f_{k,j}} \leq f_{k,j} \leq \overline{f_{k,j}}; \quad [\beta_i^{d^-}, \beta_i^{d^+}] \tag{7.20d}$$

$$U_{m,j} = U_{n,j} - 2(r_{k,j} f_{k,j} + x_{k,j} q_{k,j}); \quad [\gamma_i^d] \tag{7.20e}$$

$$\underline{U} \leq U_n \leq \overline{U}; \quad [\zeta_i^{d^-}, \zeta_i^{d^+}] \tag{7.20f}$$

Formulation (7.20) is identical as the pricing problem presented in formulation (7.4)

Chapter 8

TRANSMISSION AND DISTRIBUTION COORDINATION FRAMEWORK USING PARAMETRIC PROGRAMMING: OPTIMAL PRICING IN THE DISTRIBUTION SYSTEMS

A parametric-programming-based framework was previously proposed to coordinate the market operations of the independent system operator (ISO) and the distribution system operator (DSO). This chapter extends this framework by investigating optimal DSO pricing in addition to the ISO-DSO coordinated dispatch. In our DSO pricing problem, after ISO clears the wholesale market, the locational marginal price (LMP) of the ISO-DSO coupling substation is determined, the DSO utilizes this price to solve the DSO pricing problem. The DSO pricing problem determines the distribution LMP (D-LMP) in the distribution system and calculate the payment to each aggregator. Proofs are provided to 1) demonstrate the D-LMP at the ISO-DSO coupling substation from this DSO pricing problem always aligns with the wholesale LMP from the ISO; and 2) demonstrate the relationship between the DSO pricing and dispatch models. Case studies on a small illustrative example verify the performance of the proposed pricing model.

8.1 Introduction

In 2020, Federal Energy Regulation Commission (FERC) Order No. 2222 [1] required all the independent system operators (ISOs) to fully unlock their wholesale markets for the aggregated distributed energy resources (DERs). This paves the path toward operating future electricity markets with significant DER participation. Ideally speaking, operating the wholesale markets with massive DERs requires coordinated operations between the transmission and distribution (T&D) systems, since the ISOs can only model, observe, and dispatch transmission-level networks and resources, while the DERs are physically located across the distribution feeders and cannot be directly monitored by the ISOs. However, T&D coordination is very limited in today's power industry practice. Without effective T&D coordination, many industry practitioners have expressed excessive concerns on both operational reliability and economic efficiency of the T&D systems when significant number of DERs are being aggregated and integrated into the wholesale markets. There is a growing industry need for enabling effective T&D coordination for reliably and economically integrating massive DERs into the wholesale markets.

Existing works on T&D coordination for DER market integration can be categorized into three groups. The first group of works model the ISO and the distribution system operation (DSO) with aggregated DERs using bi-level or tri-level optimization and then convert the multi-level optimization problem into a single-level optimization problem for obtaining solutions [42, 43, 69, 70, 71, 72]. These multi-level optimization models require a single entity to solve the converted single-level optimization problem. This single entity therefore needs to access the modeling details of the entire multi-level problem (including the ISO and DSO models and constraints). Such a single entity violates the data and model ownership in today's T&D system operation practices, and may degrade the model confidentiality for the T&D systems. Moreover, these converted single-level optimization problems can be computationally intensive, since they include optimization models for the transmission system and all the connected distribution systems, which will introduce high computation burden for the market clearing entity. The above disadvantages prevent this set of approaches from being adopted in real-world market operations.

The second group of works leverage distributed or decentralized optimization algorithms to decompose the entire ISO-DSO coordination problem into one ISO and several DSO sub-problems [59, 60, 39, 44, 61, 62, 45, 73, 74, 75, 76]. These existing distributed/decentralized optimization approaches cannot completely decouple the modeling and solution process of the ISO and DSO optimization sub-problems. Without complete decoupling, these approaches have to either require fully/partially exchanging the confidential T&D system models between the ISO and DSOs, or require intensive communication between the ISO and DSOs, in order to solve the ISO-DSO coordination problem in a partially decoupled way. The above technical obstacles significantly limit the real-world applicability of these approaches.

Another set of works coordinate the T&D operations through various equivalent models [77, 78, 79, 80]. The feasible region based approach in [77] and the multi-port exchange model in [78] need to convert the distribution system operating constraints into another form and then integrate them into the wholesale market model. Such approaches place extra modeling and computation burden to the wholesale market clearing process. The equivalent models proposed in [79] and [80] coordinate the operation of different systems based on parametric programming. However, the approach in [79] focuses on tie line transfer capacity without considering the distribution system operation; the approach in [80] suffers from intensive communication between the T&D systems, which degrades its real-world applicability.

To ensure real-world applicability and overcome the above disadvantages of existing works, in our recent work [84], a parametric programming based T&D coordination framework is proposed for reliably and economically integrating DERs into the wholesale market operation. This framework have several desired characteristics toward real-world application: 1) it completely avoids the exchange of confidential T&D system models, which eliminates extra modeling or computation efforts for the T&D operations; 2) it only requires minimal communications between the T&D operations; and 3) it highly complies with today's wholesale market operation which can enable smooth transition from the current ISO market clearing practice. However, the work in [84] focuses on completely decomposing the T&D economic dispatch process which can lead to 1) zero T&D model exchange, which signifies that the ISO is not required to possess any information about the distribution system model, and correspondingly, the DSO need not have any knowledge about the transmission side model; and 2) minimal T&D communications, which means that DSOs, like any other market participants, are only required to submit bids based on their cost functions and receive cleared dispatch and price signals from the ISO without exchanging any extra data between ISO and DSO. It does not clearly discuss the coordination of T&D pricing process which should be established to ensure all the T&D-level market participants receive fair compensation through the T&D-coordinated market.

The objective of this paper is to extend the T&D coordination framework in [84] by developing theoretical justifications and thorough discussions for the T&D-coordinated pricing problem. Specifically, we prove and discuss 1) the relationship between the T&D-coordinated dispatch model and T&D-coordinated pricing model, which together guarantee the T&D operation optimality for both dispatch and pricing process; and 2) the non-profit characteristics of the DSO under the proposed T&D-coordinated pricing model. One interesting finding is that, in order to ensure zero T&D model exchange and minimal T&D communication for the parametric programming based T&D coordination framework in [84], the optimal prices for aggregated DERs in the distribution systems cannot be directly obtained from the dual problem of the DSO economic dispatch problem. Instead, a separate DSO pricing model is needed to derive the correct price signals for DSO-level resources and coordinate with the ISO-level pricing and dispatch process.

8.2 Mathematical Formulation

In this section, we first present an ideal case formulation where the ISO oversees both the transmission and distribution systems, as described in [84]. This ideal case formulation serves as a benchmark to compare the results of the proposed ISO-DSO coordination problem. Next, we present the formulation of the ISO-DSO coordination framework proposed in [84]. Finally, we formulate and discuss the pricing problem for the proposed ISO-DSO coordination.

8.2.1 Ideal Case

The ideal case refers to a scenario where DER aggregators can directly participate in the wholesale market, even if they are located within the distribution system. In this case, the ISO oversees both the distribution system constraints and transmission system constraints. However, it is important to note that the ideal case is not currently implementable within the existing practices of the wholesale market. The purpose of considering the ideal case is to compare its results with the outcomes of our proposed ISO-DSO coordination problem. The general formulation of the ideal case is presented in the following formulation:

$$\text{Min}_{\boldsymbol{p}} \quad \sum_{i \in \mathcal{N}_{gen}} c_i^g(p_i^g) + \sum_{j \in \mathcal{N}_{dis}} \sum_{i \in \mathcal{N}_{agg}} c_{i,j}^{agg}(p_{i,j}^{agg}) \tag{8.1a}$$

$$\begin{aligned} \text{s.t.} \quad & \boldsymbol{p}^g \in S^{Tra} \\ & \boldsymbol{p}_j^{agg} \in S_j^{Dis}, \forall j \in \mathcal{N}_{dis} \\ & p_i^g \in S_i^{gen}, \forall i \in \mathcal{N}_{gen} \\ & p_{i,j}^{agg} \in S_{i,j}^{agg}, \forall i \in \mathcal{N}_{agg}, j \in \mathcal{N}_{dis} \end{aligned} \tag{8.1b}$$

where $\boldsymbol{p}$ is the vector of all decision variables (generating powers of all conventional generators and DER aggregators), i is the index for generating units, j is the index for distribution systems, $\mathcal{N}_{gen}$ is the set of conventional generating units in the transmission system, $c_i^g(p_i^g)$ is the bid-in cost function of the conventional generating units in the transmission system, $\boldsymbol{p}^g$ is the generating power of the conventional generating units in the transmission system, $\mathcal{N}_{dis}$ is the set of all distribution systems, $\mathcal{N}_{agg}$ is the set of all aggregators in the distribution system, $c_{i,j}^{agg}(p_{i,j}^{agg})$ is the bid-in cost function of the DER aggregators, $p_{i,j}^{agg}$ is the generating power of the DER aggregator in the distribution system, $\boldsymbol{p}^g$ is the vector of all generating powers provided by the conventional generating units in the transmission system, S^{Tra} is the search space defined by system-wide transmission constraints, $\boldsymbol{p}_j^{agg}$ is the vector of all generating powers of the DER aggregator in the distribution system, S_j^{Dis} is the search space defined by system-wide distribution system constraints, S_i^{gen} is the search space defined by operating constraints of the conventional generating units in the transmission system, and $S_{i,j}^{agg}$ is the search space defined by operating constraints of the DER aggregators in the transmission system.

In this ideal case, one single entity (i.e., the ISO) minimizes the total generation cost of all the T&D-level resources (conventional generators and DER aggregators), by determining the real power dispatch of all the T&D-level resources, while satisfying all the T&D-level system operating constraints.

8.2.2 ISO-DSO Coordination Dispatch Problem

In this section, we present the ISO-DSO coordination dispatch problem proposed in [84]. The process begins with all DER aggregators submitting their bid-in cost functions to the DSO. The DSO collects these bid-in cost functions and conducts a market operation at the distribution level. Using parametric programming, the DSO constructs its bid-in cost function, which is then submitted to the ISO. Subsequently, the ISO clears the wholesale market and transmits the dispatch signals to the DSO.

The DSO utilizes these dispatch signals in the parametric programming problem to determine the dispatch for each DER aggregator. The general formulation of the ISO dispatch problem in the ISO-DSO coordination framework is as follows:

$$\text{Min}_{\boldsymbol{p}} \quad \sum_{i \in \mathcal{N}_{gen}} c_i^g(p_i^g) + \sum_{j \in \mathcal{N}_{dis}} c_j^{dso}(p_j^{dso}) \tag{8.2a}$$

$$\begin{aligned} \text{s.t.} \quad & \boldsymbol{p} \in S^{Tra} \\ & p_i \in S_i^{gen}, \forall i \in \mathcal{N}_{gen} \\ & p_j \in S_j^{dso}, \forall j \in \mathcal{N}_{dis} \end{aligned} \tag{8.2b}$$

where $c_j^{dso}(p_j^{dso})$ denotes the bid-in cost function submitted by the DSO to the ISO; p_j^{dso} corresponds to the generating power injected by the DSO to the ISO at the ISO-DSO coupling point; S_j^{dso} defines the search space determined by the minimum and maximum allowable power generation levels of the DSO at each section of the DSO multi-segment bid-in cost function.

In the above ISO dispatch problem, the ISO only determines the optimal dispatch of transmission-level resources (conventional generators and DSOs) which will minimize the transmission-level total generation cost, while satisfying all the transmission-level system operating constraints. Since there is no distribution-level operating constraints or distribution-level resources (DER aggregators) involved in this ISO problem, there is no need to submit confidential distribution system models to the ISO. The only data submitted from the DSO to the ISO is the DSO's multi-segment bid-in cost function $c_j^{dso}(p_j^{dso})$ and its corresponding multi-segment upper/lower generation limits, which, as defined in today's wholesale market clearing rules, has to be reported to the ISO by each market participant.

The DSO constructs its bid-in cost function $c_j^{dso}(p_j^{dso})$ for participating in the ISO market by formulating the following parametric programming problem:

$$
\begin{aligned}
& c_j^{dso}(p_j^{dso}) = \\
& \quad \text{Min}_{\boldsymbol{p}^{agg}} \sum_{i \in \mathcal{N}_{agg}} c_{i,j}^{agg}(p_{i,j}^{agg}) \\
& \quad \text{s.t.} \quad p_j^{dso} = \sum_{i \in \mathcal{N}_{agg_k}} p_{i,j}^{agg} + \sum_{l \in \mathcal{N}_{f_k}} f_{l,j} - L_{k,j} \\
& \qquad\quad p_{i,j}^{agg} \in S_{i,j}^{agg}, \forall i \in \mathcal{N}_{agg} \\
& \qquad\quad \boldsymbol{p}_j^{agg} \in S_j^{Dis}
\end{aligned}
\tag{8.3}
$$

where $\mathcal{N}_{agg_k}$ denotes the set of all DER aggregators located at node k; $\mathcal{N}_{f_k}$ denotes the set of all branches connected to node k; $f_{l,j}$ denotes the flow of branch l; $L_{k,j}$ denotes the firm load situated at node k.

In equation (8.3), the parameter p_j^{dso} introduces a parametric aspect to the formulation. The solution to this problem yields the lowest generation costs for the DSO at all possible generation levels $c_j^{dso}(p_j^{dso})$, by optimally dispatching all the DSO-level resources (DER aggregators), while satisfying all the DSO-level system operating constraints (including distribution load balancing constraints, voltage/thermal constraints, etc.). Assuming the DSO is a non-profit entity, this lowest generation cost function is the bid-in cost function of the DSO, which is a piecewise linear function if (8.3) is a linear parametric programming problem with linearized distribution load flow as the operating constraints and piecewise linear bid-in cost functions from the DER aggregators. The DSO then submits this bid-in cost function to the ISO. Once the ISO clears the wholesale market, the dispatch of the DSO (p_j^{dso}) in the wholesale market is determined. Subsequently, the DSO incorporates this dispatch into (8.3), transforming it into a regular linear optimization problem. By solving this resulting problem, the DSO determines the dispatch for each individual DER aggregator within its territory. It has been mathematically proven in [84] that following the ISO-DSO coordination dispatch problem in (8.2)-(8.3), the dispatch of each individual aggregator or conventional generator is equivalent to the ideal case where the DER aggregator directly participates in the wholesale market and the ISO oversees all the T&D-level system operating constraints.

In the above DSO bidding and dispatch problem defined by (8.3), the DSO only determines the optimal dispatch of distribution-level resources (DER aggregators) which will minimize the distribution-level total generation cost at all possible generation levels, while satisfying all the distribution-level system operating constraints. Since there is no transmission-level operating constraints or transmission-level resources (conventional generators) involved in this DSO problem, there is no need to submit confidential transmission system models to the DSO. The only data submitted from the ISO to the DSO is the DSO's wholesale dispatch cleared by the ISO, which fully complies with today's wholesale market clearing rules. Moreover, the solution process of the ISO and DSO optimization problems in (8.2) and (8.3) is completely decoupled. The ISO and DSO only exchange data with each other once its own optimal dispatch solution is obtained. There is no exchange of intermediate solution data between ISO and DSO during the ISO and DSO optimization process.

8.2.3 ISO-DSO Coordination Pricing Problem

In the ISO-DSO coordination framework, after the ISO clears the wholesale market, the Locational Marginal Price (LMP) is determined at the bus where the DSO is located, in addition to the dispatches of all DSOs. The DSO then determines the dispatch of each DER aggregator by incorporating the total dispatch determined by the ISO into the dispatch problem proposed in equation (8.3). However, using the dual variables of this problem does not accurately reflect the true cost of the system in the wholesale market, particularly when the marginal unit is in the wholesale market.

This is because the share of the wholesale market is modeled as a parameter p_j^{dso}. Under this parametric modeling, if the marginal unit is in the wholesale market, which means p_j^{dso} provides the next megawatt in the DSO, the dual variable of this node balance constraint will not reflect the corresponding price for that marginal unit in the wholesale market (out of the DSO territory). further discussion on this is provided in the simulation results section. Consequently, the DSO requires a pricing problem to clear the distribution market, ensuring price consistency with the ideal case and maintaining non-profitability. The following problem is proposed to facilitate market clearance in the distribution system.

$$\begin{aligned}
&\text{Min}_{\boldsymbol{p}^{agg}, p_j^{dso}} \sum_{i \in \mathcal{N}_{agg}} c_{i,j}^{agg}(p_{i,j}^{agg}) - LMP_j^* p_j^{dso} \\
&\text{s.t.} \quad p_j^{dso} = \sum_{i \in \mathcal{N}_{agg_k}} p_{i,j}^{agg} + \sum_{l \in \mathcal{N}_{f_k}} f_{l,j} - L_{k,j} \\
&\qquad p_{i,j}^{agg} \in S_{i,j}^{agg}, \forall i \in \mathcal{N}_{agg} \\
&\qquad \boldsymbol{p}_j^{agg} \in S_j^{Dis}
\end{aligned} \tag{8.4}$$

where p_j^{dso} represents the total generating power of the DSO and is a decision variable in this case (not a parameter), and LMP_j^* corresponds to the LMP at the bus where the DSO is located in the wholesale market, as determined by the ISO's market clearing process.

Lemma 8.1 *The price cleared by the DSO (i.e., the D-LMP) at the ISO-DSO coupling substation node in the distribution system (dual variable corresponding to substation node balance constraint) will always be equal to the price at the same node in the wholesale market cleared by the ISO (LMP_j^*). This equality implies that the DSO is always revenue adequate.*

Proof of Lemma 8.1. Let $\mathbf{p}$ denote the vector of all decision variables, $f(\mathbf{p})$ denote the objective function, and $\mathbf{g}(\mathbf{p})$ represent the constraints, along with their corresponding dual variables $\boldsymbol{\lambda}$ in equation (8.4). The Lagrangian function for equation (8.4) can be formulated as follows:

$$\mathcal{L} = f(\mathbf{p}) + (\boldsymbol{\lambda})^{\mathsf{T}}(\mathbf{g}(\mathbf{p})) \tag{8.5}$$

Based on the Karush-Kuhn-Tucker (KKT) conditions, the partial derivative of the Lagrangian function with respect to p_j^{dso} must be zero at the optimal point:

$$\frac{\partial \mathcal{L}}{\partial p_j^{dso}} = \frac{\partial f(\mathbf{p})}{\partial p_j^{dso}} + \frac{\partial (\boldsymbol{\lambda})^{\mathsf{T}}(\mathbf{g}(\mathbf{p}))}{\partial p_j^{dso}} = 0 \tag{8.6}$$

Let λ^s represent the dual variable corresponding to the node balance equation at the substation, which is the D-LMP at the ISO-DSO coupling substation node. Then, we can further simplify equation (9.6) as follows:

$$\frac{\partial \mathcal{L}}{\partial p_j^{dso}} = LMP_j^* - \lambda^s = 0 \tag{8.7}$$

Therefore, D-LMP at the substation node in the distribution system is always equal to the LMP cleared in the wholesale market. Following Lemma 1 in our previous work [84], it can also be concluded that such pricing characteristics will also imply revenue adequacy for the DSO.

Lemma 8.2 *If the marginal unit is located within the distribution system, at the ISO-DSO coupling substation, the DSO dispatch problem in (8.3) results in the same D-LMP as the wholesale LMP determined by the ISO, which is also the same D-LMP determined by the DSO pricing problem in (8.4). However, if the marginal unit is located in the transmission system, at the ISO-DSO coupling substation, the D-LMP determined by the DSO dispatch problem in (8.3) could be different from the wholesale LMP determined by the ISO, and also could be different from the D-LMP determined by the DSO pricing problem in (8.4).*

Proof of Lemma 8.2. This proof is built upon our previous work in [84], where we proved in the above ISO-DSO coordination dispatch problem, the optimal dispatches of all the T&D-level resources are identical to those in the ideal case. Also, in Lemma 1, we proved the wholesale LMP determined by the ISO problem and the D-LMP determined by the DSO pricing problem in (8.4) are always the same at the ISO-DSO coupling substation.

For the sake of simplicity and without sacrificing generality, let us consider a scenario where there are no congestion or voltage issues in the system. We will assume that the marginal unit, which is the unit that provides the last MW, is located in the transmission system. We will denote this generating unit as generator z. In the ISO problem, the LMP is $LMP_j^* = c_z^g$ (bid-in generation cost of marginal unit z at the ISO-dispatched generation level), and $p^{dso} = p^{dso^*}$ (optimal wholesale dispatch of the DSO).

In the ISO-DSO coordination problem, when the DSO substitutes $p^{dso} = p^{dso^*}$ into the DSO dispatch problem in (8.3), all the DER aggregators in the distribution system that are not more expensive than the marginal unit are dispatched fully, since the marginal unit is located in the transmission system. The D-LMP at the substation node in the distribution system can be expressed as follows:

$$DLMP_k = \frac{\partial L}{\partial L_{k,j}} = \frac{\partial L}{\partial p_j^{dso}} = \lambda^k \tag{8.8}$$

Let us consider the cheapest yet un-dispatched generating unit in the distribution system, which will provide the next MW, as aggregator m. We can then express the derivative of the Lagrangian function with respect to p_{ddg_m} as:

$$\frac{\partial L}{\partial p_{ddg_m}} = \alpha_m^+ - \alpha_m^- - \lambda^m = 0 \tag{8.9}$$

In the DSO dispatch problem in (8.3), aggregator m becomes the marginal unit, we have $\alpha_m^+ = \alpha_m^- = 0$. Therefore, $\lambda^m = c_{ddg_m}$ (bid-in generation cost of aggregator m at the DSO-dispatched generation level). Since there is no congestion, the D-LMP at node k is equal to $\lambda^k = c_{ddg_m}$, which is different from the price in the transmission side.

Now, if we assume that the marginal unit lies in the distribution system, both the generating unit z and aggregator m will be the same unit. In this scenario, the D-LMP and the LMP of the wholesale market will be the same.

Lemma 8.3 *If the marginal unit is located in the transmission system, at the ISO-DSO coupling substation, the DSO pricing problem in (8.4) results in the same dispatch as the wholesale dispatch determined by the ISO problem, which is also the same dispatch determined by the DSO dispatch problem in (8.3). However, if the marginal unit is located in the distribution system, at the ISO-DSO coupling substation, the dispatch determined by the DSO pricing problem in (8.4) could be different from the wholesale dispatch determined by the ISO problem, and also could be different from the dispatch determined by the DSO dispatch problem in (8.3).*

Proof of Lemma 8.3. This proof is built upon our previous work in [84], where we proved in the above ISO-DSO coordination problem, the optimal dispatches, prices and payments of all the T&D-level resources are identical to those in the ideal case.

To simplify the analysis and without loss of generality, let us consider a scenario where there are no congestion and voltage issues in the system. let us assume that the marginal unit is located in the distribution system. Specifically, let aggregator m be the marginal unit and it's dispatch level is $p_m^{ddg^*}$ MW. let us assume that the wholesale dispatch of the DSO determined by the ISO problem is p_{dso}^* MW. Since there are no active constraints related to congestion or voltage in the distribution system, we can rewrite the power balance constraint as follows:

$$p^{dso} = \sum_{i \in \mathcal{N}_{agg}} p_i^{ddg} - L \tag{8.10}$$

where L represents the total firm load in the system.

Considering that aggregator m is the marginal unit and there are no congestion or voltage issues, we can further simplify Equation (8.10) as:

$$p^{dso} = \sum_{i \in \mathcal{N}_{agg_m}} \overline{p_i^{ddg}} + p_m^{agg} - L \tag{8.11}$$

where $\mathcal{N}_{agg_m}$ represents the set of all aggregators that are cheaper than aggregator m, and $\overline{p_i^{ddg}}$ denotes the maximum generation output of the aggregators.

Then we can say that ISO problem yields $p^*_{dso} = \sum_{i \in \mathcal{N}_{agg_m}} \overline{p_i^{ddg}} + p_m^{ddg^*} - L$.

Now, let us determine the optimal value of p^{dso} for the DSO pricing problem in (8.4). Equation (8.11) is also valid in the DSO pricing problem. The only variable that needs to be determined in (8.11) is p_m^{agg}. To find the optimal value of p_m^{agg}, let us examine the objective function of the DSO pricing problem, which is formulated as follows:

$$\text{Min} \sum_{i \in \mathcal{N}_{agg}} c_i^{ddg} p_i^{ddg} - c_m^{ddg} p^{dso} \tag{8.12}$$

Note that we know that aggregator m is the marginal unit. Hence, $LMP_j^* = c_m^{ddg}$ in the DSO pricing problem. The term $-c_m^{ddg} p^{dso}$ in the objective function indicates that there is a demand response with a price equal to the price of aggregator m. Consequently, all aggregators cheaper than aggregator m will be dispatched at their maximum output. However, for aggregator m, it can be dispatched at any dispatch level, and its actual dispatch level does not affect the objective function. This leads to a problem of degeneracy, where the solution for p^{dso} can have any value within the range $[\sum_{i \in \mathcal{N}_{agg_m}} \overline{p_i^{ddg}} - L, \sum_{i \in \mathcal{N}_{agg_m}} \overline{p_i^{ddg}} + \overline{p_m^{agg}} - L]$, which means it is not necessarily equal to the dispatch obtained from the wholesale market.

Now, let us suppose that the marginal unit is in the transmission side. In this case, there is no partially-dispatched unit in the distribution system. Each aggregator is either fully dispatched or not dispatched. Then aggregator m becomes the cheapest un-dispatched unit. Any unit that is cheaper than aggregator m (i.e., within set $\mathcal{N}_{agg_m}$) should be fully dispatched, and $p^{dso} = \sum_{i \in \mathcal{N}_{agg_m}} \overline{p_i^{ddg}} - L$, which is equal to the value obtained from the ISO problem.

Lemma 2 and Lemma 3 demonstrate the following observations: 1) When coupled with the ISO dispatch/pricing model in (8.2), the DSO dispatch model in (8.3) consistently generates the correct dispatch signals for DSO-level resources; 2) The DSO pricing model in (8.4), also in conjunction with the ISO dispatch/pricing model, consistently produces the accurate price signals for DSO-level resources. However: 1) The dual variables of the DSO dispatch model do not always yield the correct D-LMPs; 2) Similarly, the primal solutions of the DSO pricing model do not always result in the correct DSO-level dispatches. In order to reserve the desired features of minimal T&D communications and zero T&D confidential model exchange in the parametric-programming-based ISO-DSO coordination framework, the DSO-level optimal dispatch and pricing need to be achieved through two separated models. This is different from the ISO market clearing which utilizes one economic dispatch model to obtain both the optimal dispatch and pricing results.

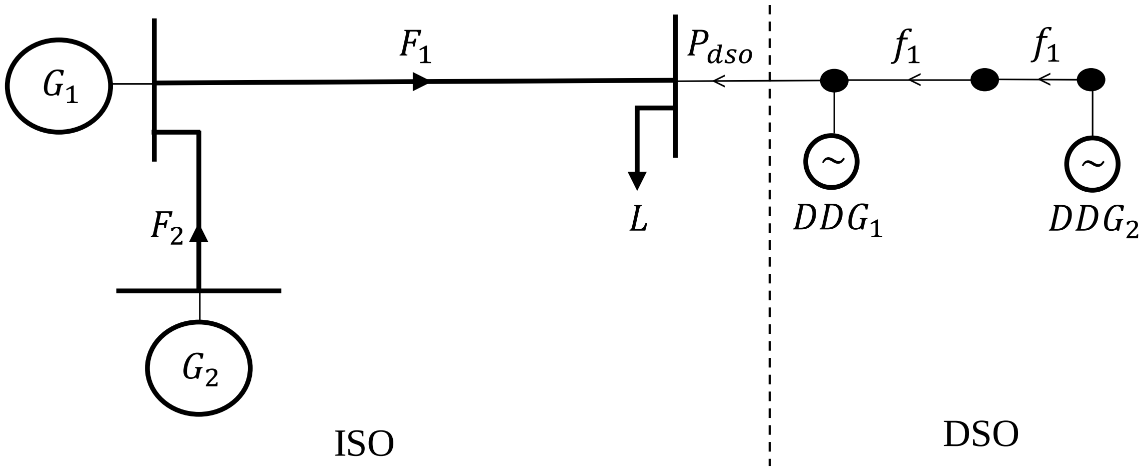


Figure 8.1: Illustrative example system.

8.3 Case Studies

In this section, case studies are conducted on a small illustrative example to validate the results of the proposed ISO-DSO pricing problem. The system, as depicted in Figure 8.1, consists of a three-node distribution system connected to a three-bus transmission system. The wholesale market is operated by the ISO in the transmission side, while the distribution-level market is managed by the DSO in the distribution side. The distribution system includes two dispatchable distributed generations (DDGs), while the transmission system comprises two conventional generating units.

In Case 1, the bidding data for the conventional generators and DDGs is provided in Table 8.1, and there is a firm load of 15 MW. This case has been designed in a manner where the marginal unit is located in the wholesale market.

On the other hand, Case 2 has been designed with the marginal unit located in the distribution system. The bidding data for the conventional generators and DDGs in this case can be found in Table 8.2, and there is a firm load of 11.5 MW.

Table 8.1: Bidding data for the conventional generators and DDGs in the illustrative example: Case 1

Participant	Pmin (MW)	Pmax (MW)	Offering price ($/MWh)
G_1	0	10	10
G_2	0	10	12
DDG_1	0	1	15
DDG_2	0	1	5

Table 8.2: Bidding data for the conventional generators and DDGs in the illustrative example: Case 2

Participant	Pmin (MW)	Pmax (MW)	Offering price ($/MWh)
G_1	0	10	10
G_2	0	10	20
DDG_1	0	1	15
DDG_2	0	1	5

8.3.1 Ideal Case

As mentioned previously, in the ideal case, it is assumed that DERs can directly participate in the wholesale market, and the ISO oversees both the transmission and distribution systems. The economic dispatch problem of the ISO in the ideal case can be formulated as follows:

$$\text{Min}_{\boldsymbol{P}} \quad c_1^g p_1^g + c_2^g p_2^g + c_1^{ddg} p_2^{ddg} + c_2^{ddg} p_2^{ddg} \tag{8.13a}$$

$$s.t. \quad p_1^g - F_1 + F_2 = 0 \qquad [\lambda_1^{WM}] \tag{8.13b}$$

$$p_2^g - F_2 = 0 \qquad [\lambda_2^{WM}] \tag{8.13c}$$

$$p^{dso} + F_1 - L = 0 \qquad [\lambda_3^{WM}] \tag{8.13d}$$

$$p_1^{ddg} + f_1 - p^{dso} = 0 \qquad [\lambda_1^D] \tag{8.13e}$$

$$f_1 - f_2 = 0 \qquad [\lambda_2^D] \tag{8.13f}$$

$$p_2^{ddg} - f_2 = 0 \qquad [\lambda_3^D] \tag{8.13g}$$

$$0 \leq p_1^g \leq 10 \tag{8.13h}$$

$$0 \leq p_2^g \leq 10 \tag{8.13i}$$

$$0 \leq p_1^{ddg} \leq 1 \tag{8.13j}$$

$$0 \leq p_2^{ddg} \leq 1 \tag{8.13k}$$

$$-20 \leq F_1 \leq 20 \tag{8.13l}$$

$$-20 \leq F_2 \leq 20 \tag{8.13m}$$

$$-2 \leq f_1 \leq 2 \tag{8.13n}$$

$$-2 \leq f_2 \leq 2 \tag{8.13o}$$

where p_1^g and p_2^g represent the power dispatched to the conventional units in the transmission system with corresponding prices c_1^g and c_2^g, respectively; p_1^{ddg} and p_2^{ddg} represent the power dispatched to the DDGs in the distribution system with corresponding prices c_1^{ddg} and c_2^{ddg}, respectively; F represents the transmission system line flow, f represents the distribution system line flow, $\lambda_\cdot^{WM}$ denotes the LMPs in the transmission system, and $\lambda_\cdot^D$ denotes the D-LMPs in the distribution system.

By substituting the values of c_1^g, c_2^g, c_1^{ddg}, and c_2^{ddg} from Table 8.1, we can construct the ideal case formulation for Case 1. The above problem is a simple linear program-

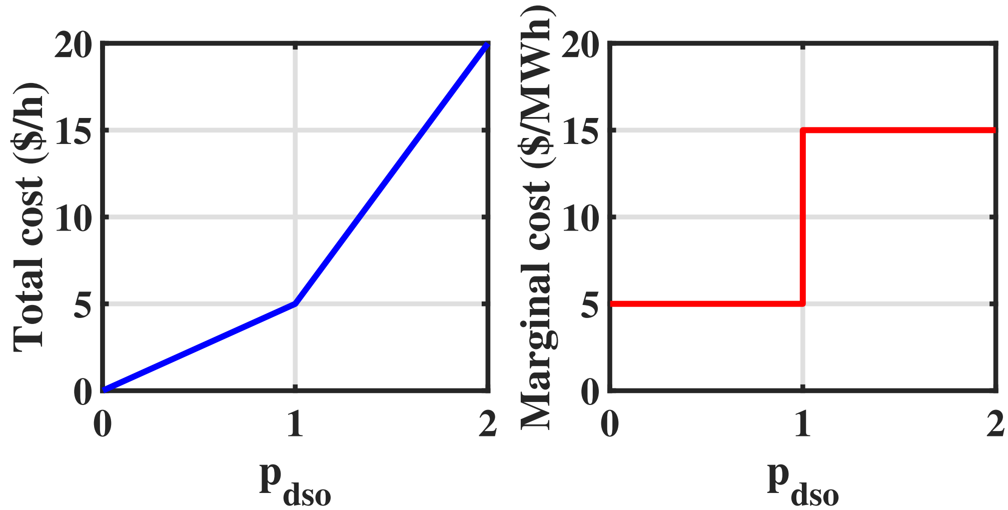


Figure 8.2: DSO bid-in total (left) and marginal (right) cost functions in the illustrative example.

ming that can be solved using power system insights and the solution is as follows: $p_1^g = 10$ MW, $p_2^g = 4$ MW, $p_1^{ddg} = 0$ MW, $p_2^{ddg} = 1$ MW,$\lambda_1^{WM} = \lambda_2^{WM} = \lambda_3^{WM} = \lambda_1^D = \lambda_2^D = \lambda_3^D = 12$ \$/MWh.

With the same procedure, by substituting the values of c_1^g, c_2^g, c_1^{ddg}, and c_2^{ddg} from Table 8.2, we can construct the ideal case formulation for Case 2, and the solution is as follows: $p_1^g = 10$ MW, $p_2^g = 0$ MW, $p_1^{ddg} = 0.5$ MW, $p_2^{ddg} = 1$ MW, $\lambda_1^{WM} = \lambda_2^{WM} = \lambda_3^{WM} = \lambda_1^D = \lambda_2^D = \lambda_3^D = 15$ \$/MWh.

8.3.2 ISO-DSO Coordination Framework

In this section, ISO-DSO coordination framework for the above example is formulated and investigated.

DSO's bid-in cost function.

In this framework, the DSO collects the offering prices of the DDGs and formulates the parametric programming dispatch problem in (8.3).

$$c^{dso}(p^{dso}) = \text{Min}_{\boldsymbol{p}^{ddg}} \quad 15p_1^{ddg} + 5p_2^{ddg} \tag{8.14a}$$

$$\text{s.t.} \quad p_1^{ddg} + f_1 - p^{dso} = 0 \tag{8.14b}$$

$$f_1 - f_2 = 0 \tag{8.14c}$$

$$p_2^{ddg} - f_2 = 0 \tag{8.14d}$$

$$0 \leq p_1^{ddg} \leq 1 \tag{8.14e}$$

$$0 \leq p_2^{ddg} \leq 1 \tag{8.14f}$$

$$-2 \leq f_1 \leq 2 \tag{8.14g}$$

$$-2 \leq f_2 \leq 2 \tag{8.14h}$$

Both Case 1 and Case 2 have the same DDG offering prices, resulting in the DSO's bid-in cost function formulation being identical. The above formulation considers p^{dso} as a parameter, making it a parametric programming problem. This problem can be solved by varying p^{dso} from 0 to its maximum possible value. The DSO's bid-in total and marginal cost functions for both Case 1 and Case 2 is depicted in Figure 8.2.

ISO problem.

The DSO submits its bid-in cost function to the ISO, and then the ISO proceeds to run and clear the wholesale market. The wholesale market problem can be formulated as follows:

$$\text{Min}_{\boldsymbol{P}} \quad c_1^g p_1^g + c_2^g p_2^g + 5p_1^{dso} + 15p_2^{dso} \tag{8.15a}$$

$$s.t. \quad p_1^g - F_1 + F_2 = 0 \qquad [\lambda_1^{WM}] \tag{8.15b}$$

$$p_2^g - F_2 = 0 \qquad [\lambda_2^{WM}] \tag{8.15c}$$

$$p_1^{dso} + p_2^{dso} + F_1 - L = 0 \qquad [\lambda_3^{WM}] \tag{8.15d}$$

$$0 \leq p_1^g \leq 10 \tag{8.15e}$$

$$0 \leq p_2^g \leq 10 \tag{8.15f}$$

$$-20 \leq F_1 \leq 20 \tag{8.15g}$$

$$-20 \leq F_2 \leq 20 \tag{8.15h}$$

$$0 \leq p_1^{dso} \leq 1 \tag{8.15i}$$

$$0 \leq p_2^{dso} \leq 1 \tag{8.15j}$$

where p_1^{dso}, p_2^{dso} are the variables used to model the two segment bid-in cost function of the DSO shown in Figure 8.2.

By substituting the values of c_1^g, c_2^g from Table 8.1, we can construct the ISO problem formulation for Case 1, and the solution is as follows: $p_1^g = 10$ MW, $p_2^g = 4$ MW, $p_1^{dso} = 1$ MW, $p_2^{dso} = 0$ MW,$\lambda_1^{WM} = \lambda_2^{WM} = \lambda_3^{WM} = 12$ \$/MWh.

With the same procedure, by substituting the values of c_1^g, c_2^g from Table 8.2, we can construct the ISO problem formulation for Case 2, and the solution is as follows: $p_1^g = 10$ MW, $p_2^g = 0$ MW, $p_1^{dso} = 1$ MW, $p_2^{dso} = 0.5$ MW,$\lambda_1^{WM} = \lambda_2^{WM} = \lambda_3^{WM} = 15$ \$/MWh.

DSO's dispatch problem.

We can construct the DSO dispatch problem by substituting the value of p^{dso} determined in the ISO problem above into equation (8.14). The dispatch problem for Case 1 can be derived by substituting $p^{dso} = 1$ MW, and similarly, the dispatch problem for Case 2 can be determined by setting $p^{dso} = 1.5$ MW.

Once the dispatch problem is constructed, the dual variable (8.14b) gives the D-LMP using the dispatch problem. Since there is no congestion, the D-LMP will be the same for all nodes. The resulting D-LMP for Case 1 is 15 \$/MWh, which is different from the price determined in the ISO problem since the marginal unit is not in the distribution system. On the other hand, for Case 2, the resulting D-LMP is 15 \$/MWh, which is the same as the LMP determined in the ISO problem since the marginal unit is in the distribution system.

DSO's Pricing Problem

Once the wholesale market is cleared by the ISO, the dispatch of the DSO is determined. The DSO then substitutes this dispatch into its dispatch problem to determine the dispatch of each DER aggregator in the distribution system.

The DSO utilizes the LMP at the corresponding bus to construct the pricing problem as follows:

$$\text{Min}_{\boldsymbol{P}} \quad 15p_1^{ddg} + 5p_2^{ddg} - LMP^* p^{dso} \tag{8.16a}$$

$$\text{s.t.} \quad p_1^{ddg} + f_1 - p^{dso} = 0 \tag{8.16b}$$

$$f_1 - f_2 = 0 \tag{8.16c}$$

$$p_2^{ddg} - f_2 = 0 \tag{8.16d}$$

$$0 \leq p_1^{ddg} \leq 1 \tag{8.16e}$$

$$0 \leq p_2^{ddg} \leq 1 \tag{8.16f}$$

$$-2 \leq f_1 \leq 2 \tag{8.16g}$$

$$-2 \leq f_2 \leq 2 \tag{8.16h}$$

By substituting LMP^* from the ISO problem, we can construct the pricing problem for Case 1 and Case 2. It should be noted that in the pricing problem, p^{dso} is a decision variable that is determined by solving the optimization problem.

Pricing problem for Case 1 is constructed by substituting LMP^* with 12 \$/MWh. By solving the constructed pricing problem, the value of p^{dso} for Case 1 is determined to be 1 MW, which is the same as the dispatch of the DSO determined in the ISO problem since the marginal unit is in the transmission system.

With the same procedure, the pricing problem for Case 2 can be constructed by substituting LMP^* with 15 \$/MWh. However, the resulting problem exhibits degeneracy, and p^{dso} can have any value in the range of [1 MW, 2 MW] since the marginal unit is in the distribution system.

8.4 Conclusion

In this paper, we further discuss the pricing and dispatch problem within the ISO-DSO coordination framework proposed in [84]. Specifically, we focus on the ISO-DSO coordination pricing problem, where the ISO clears the wholesale market and communicates the LMPs to the DSOs. The DSOs then utilize these LMPs to construct the pricing problem, enabling them to determine the distribution LMPs (D-LMPs) in the distribution system market. It is mathematically proven that the D-LMP at the substation node is always equal to the LMP determined in the wholesale market, ensuring consistency in pricing across the system. We also proved the relationship between the DSO dispatch and pricing problems in the ISO-DSO coordination framework, which shows the necessity of having a dedicated DSO pricing model for the determining the D-LMPs instead of obtaining the D-LMPs directly from the DSO dispatch model. Specifically, our studies show that, under the proposed ISO-DSO coordination framework which can guarantee optimal T&D-level dispatches and prices by only requiring minimal T&D communications and zero T&D confidential model exchange, each DSO needs a dedicated dispatch model and a dedicated pricing model toward obtaining the optimal DSO-level dispatches and prices, respectively. The DSO dispatch model will not always generate the correct D-LMPs, and the DSO pricing model will not always generate the correct DSO-level dispatch signals.

To validate our findings, we conducted case studies on a small illustrative example. The results demonstrate that the DSO is revenue adequate in the ISO-DSO coordination framework. DSO's dispatch follows the ISO's dispatch by substituting ISO's dispatch signal in the dispatch problem and there will be no physical conflict. Moreover, the DSO employs LMPs determined by the ISO to formulate the DSO-level pricing problem. We have demonstrated through mathematical derivation that this pricing problem ensures no financial conflict between the ISO's market clearing and the DSO's clearing process. Specifically, we observed that when the marginal unit is located in the transmission system, the dispatch of the pricing problem consistently matches the dispatch determined by the ISO problem. On the other hand, when the marginal unit is located in the distribution system, the dispatch problem consistently yields the same D-LMP as the LMP determined in the ISO problem. These findings further support the effectiveness of the coordination between the ISO and DSO in achieving efficient and consistent outcomes.

Chapter 9

AN EFFICIENT ALGORITHM FOR SOLVING ISO-DSO COORDINATION PARAMETRIC PROGRAMMING PROBLEM

A parametric programming approach for coordinating the operations of Independent System Operators (ISOs) and Distribution System Operators (DSOs) was previously proposed in the previous chapter. In this chapter, we introduce an efficient algorithm to solve the ISO-DSO coordination parametric programming problem. Notably, our proposed algorithm significantly improves the computational efficiency of solving the parametric programming DSO problem which is computationally intensive. We introduced two algorithms: the first algorithm addresses the DSO parametric programming problem without accounting for voltage constraints; the second algorithm accounts for the voltage constraints by adjusting the optimal solutions of the first algorithm through a cutting plane method. In these two algorithms, we leverage the radial structure of the distribution system to initially identify all the optimal solutions of the parametric DSO problem without considering voltage constraints. Subsequently, voltage constraints are dynamically incorporated to achieve the final optimal solutions. An analytical examination of the computational complexity of the problem has been conducted, revealing that the computational complexity of the algorithm is polynomial. Mathematical proofs have been presented to demonstrate the optimality of both algorithms. To validate our proposed method, we conducted tests on two small illustrative examples, comprising both a balanced and an unbalanced system, as well as two larger test systems, including a balanced test system (33-node) and an unbalanced test system (240 nodes). Our results affirm that our algorithms are not only efficient but also outperform the off-the-shelf parametric programming solver.

9.1 Introduction

The coordination of independent system operators and distribution system operators, as proposed in our prior work [84], relies on parametric programming. However, the solution of parametric programming is typically time consuming and challenging, especially for large-scale systems. Consequently, there is a need for an efficient algorithm capable of solving the parametric programming ISO-DSO coordination problem and identifying critical regions.

Many researchers have utilized parametric programming to address various issues within the field of power systems [85, 86, 87, 88, 89, 90, 91, 92]. In [85], a modified critical region projection approach was introduced to address the multi-area economic dispatch problem. The research presented an iterative algorithm designed to solve the decomposed problem, focusing on the optimal value function within critical regions. However, no specific algorithm was provided for the identification of critical regions, and as a result, solving the parametric programming problem was not addressed. In [86], a multi-parametric programming approach was introduced to examine the influence of energy storage systems on the economic dispatch of distribution systems. The research presented an approximate algorithm designed to identify critical regions within the multi-parametric programming problem, relying on a heuristic method. However, it's important to note that the proposed algorithm does not ensure the discovery of all critical regions and could potentially be computationally inefficient, particularly when applied to large test systems. In a [87], the authors employed parametric optimization techniques to investigate the effects of energy storage systems on renewable energy curtailment and system flexibility for addressing uncertainty. They introduced a ranking algorithm to identify critical regions, assuming the existence of predefined critical regions, which may not be generally accurate. In [88], a parametric programming approach is suggested for energy management in micro-grids. However, it's worth noting that the paper does not present a specific algorithm to solve the parametric programming problem. In [89], a multi-parametric programming approach is employed to define the unified power trading region. The paper introduces an algorithm for identifying the solution for parameters. Nevertheless, it's important to note that there's no guarantee that this algorithm can discover all the critical regions, and computational time might be a concern with this method as well. In [90], the impact of the transmission constraints penalty factor on the market solution is explored through parametric programming. Nevertheless, the paper does not put forward an algorithm for identifying critical regions. In [91], parametric programming is employed for energy management in coordinating Distributed Energy Resources (DERs) within a microgrid. Nevertheless, the paper does not introduce an algorithm to find the critical regions associated with the solution of the parametric programming problem. In [92], a dispatch optimization model is presented for coordinating the main grid and virtual power plants, and multi-parametric programming is applied to enhance convergence speed. Nevertheless, the paper does not introduce any algorithms to identify critical regions.

To the best of our knowledge, no prior work has proposed an efficient algorithm for solving the ISO-DSO coordination problem. In this paper, we introduce two algorithms for addressing the ISO-DSO coordination problem, as initially presented in our previous work [84]. The first algorithm focuses on solving the ISO-DSO coordination parametric programming problem without accounting for voltage constraints. The second algorithm builds upon the first by dynamically incorporating voltage constraints to determine a solution that adheres to all voltage constraints. We provide mathematical proofs to demonstrate the optimality of both algorithms. Furthermore, we extend the algorithms to accommodate unbalanced three-phase systems. To validate their effectiveness, we conduct case studies on two small illustrative examples, one balanced and one unbalanced. Additionally, we apply the algorithms to a 33-node test system, representing a balanced system, and a 240-node test system, reflecting an unbalanced system. The computational performance of both algorithms illustrates their efficiency.

9.2 ISO-DSO Coordination Problem Formulation

In this section, we introduced a general formulation of the ISO-DSO coordination problem. In the ISO-DSO coordination framework introduced in [84], The DSO needs to determine its bid in cost function to submit to the ISO. The general formulation for the DSO j to determine the bid in cost function is as follows:

$$c_j^{dso}(p_j^{dso}) = \text{Min}_{\boldsymbol{p}^{agg}} \sum_{i \in \mathcal{N}_{agg}} c_{i,j}^{agg} p_{i,j}^{agg} \tag{9.1a}$$

$$s.t.$$

$$\sum_{k \in \mathcal{N}^d_{jn,.}} f^p_{k,j} - \sum_{k \in \mathcal{N}^d_{jn,.}} f^p_{k,j} - p_j^{dso} = 0 \tag{9.1b}$$

$$\sum_{i \in \mathcal{N}_{aggn}} p_{i,j}^{agg} + \sum_{k \in \mathcal{N}^d_{jn,.}} f^p_{k,j} - \sum_{k \in \mathcal{N}^d_{j.,n}} f^p_{k,j} - l^p_{n,j} = 0 \tag{9.1c}$$

$$\sum_{i \in \mathcal{N}_{aggn}} q_{i,j}^{agg} + \sum_{k \in \mathcal{N}^d_{jn,.}} f^q_{k,j} - \sum_{k \in \mathcal{N}^d_{j.,n}} f^q_{k,j} - l^q_{n,j} = 0 \tag{9.1d}$$

$$\underline{p_{i,j}^{agg}} \leq p_{i,j}^{agg} \leq \overline{p_{i,j}^{agg}} \tag{9.1e}$$

$$-\overline{f^p_{k,j}} \leq f^p_{k,j} \leq \overline{f^p_{k,j}} \tag{9.1f}$$

$$U_{m,j} = U_{n,j} - 2(r_{k,j} f_{k,j} + x_{k,j} q_{k,j}) \tag{9.1g}$$

$$\underline{U} \leq U_n \leq \overline{U} \tag{9.1h}$$

where j is the index for each DSO; $\mathcal{N}_{agg}$ is the set of all aggregators; p_j^{dso} is the injected power of the DSO j to the substation which is a parameter for this parametric programming DSO problem; $\mathcal{N}_{j_{n,\cdot}}^d$ / $\mathcal{N}_{j_{\cdot,n}}^d$ are the set of lines leaving/coming node n in DSO j; $\boldsymbol{p}^{agg}$ is the vector of all decision variables; $p_{i,j}^{agg}$ is the power provided/consumed by aggregator i in DSO j with the offering cost of $c_{i,j}^{agg}$; $f_{k,j}^p/f_{k,j}^q$ is the active/reactive power flow of branch k in DSO j; $l_{k,j}^p/l_{k,j}^q$ is the active/reactive power load at node n in DSO j; $q_{i,j}^{agg}$ is the reactive power provided/consumed by aggregator i in DSO j;

Equation (9.1a) represents the objective function aimed at minimizing the total cost within the distribution system. Equation (9.1b) establishes the node balance constraint at the substation node. Equations (9.1c) and (9.1d) stand as the active and reactive power node balance constraints. Equation (9.1e) imposes limits on the active power of each aggregator in relation to their respective capacities. Equation (9.1f) sets restrictions on the flow along each branch, considering the branch capacity limits. Equation (9.1g) defines the voltage level at each node. Finally, Equation (9.1h) places constraints on the voltage at each node based on predefined voltage limits.

By defining p_j^{dso} is defined as a parameter, Problem (9.1) is a parametric linear programming (LP) problem [84], since 1) piecewise-linear cost functions are adopted in our proposed ISO-DSO coordination framework, which fully comply with today's wholesale market clearing rules in US; and 2) linearized distribution power flow [51] is adopted to model the real/reactive power balance constraints, line flow constraints, and voltage constraints.

Although off-the-shelf parametric LP solvers [64, 93, 94, 95, 96] can have polynomial ($O(n^k)$) time complexity in some special cases [93, 94], the worst-case time complexity of general large-scale parametric LP is still exponential ($O(2^n)$) [97]. As the DSO problem size grows significantly (when numerous DERs enter DSO), these off-the-shelf algorithms will be inefficient for online computations.

9.3 Algorithm Structure

In this section, the proposed algorithm is explained in detail. Generally, the algorithm consists of two parts. The first algorithm addresses the problem without considering any voltage constraints. Then, the second algorithm incorporates all the voltage constraints through cutting planes. Following this, we will elaborate on each algorithm in detail.

To start, we eliminate all the dependent decision variables in the DSO parametric LP problem. For each equality constraints in (9.1), we can eliminate one dependent decision variable. Let n denote the number of nodes in the distribution system. Considering radial feature of the distribution network, we'll have a total of $n-1$ lines, subsequently leading to $n-1$ active power flow variables. In parallel, we'll also have n active power balance constraints. This presents an opportunity to employ these equality constraints for substituting all the active power flow variables, along with utilizing one remaining equality constraint to eliminate one of the decision variables associated with the power provided/consumed by aggregators. Note that we have the same procedure for eliminating the reactive power flow variables. Consider the following representation of Problem (9.1):

$$\text{Min} \quad CX \tag{9.2a}$$

$$\text{s.t.} \quad AX = B \tag{9.2b}$$

$$DX \leq E \tag{9.2c}$$

To eliminate power flow variables, let us open up equation (9.2b):

$$\begin{bmatrix} A_1 & A_2 \\ A_3 & A_4 \end{bmatrix} \begin{bmatrix} X_1 \\ X_2 \end{bmatrix} = \begin{bmatrix} B_1 \\ B_2 \end{bmatrix} \tag{9.3}$$

If we multiply the first row of Equation (9.3), we obtain the following:

$$X_2 = A_4^{-1}(B_2 - A_3X_1) \tag{9.4}$$

Then we can substitute X_2 into the first row equation:

$$A_1X_1 + A_2A_4^{-1}(B_2 - A_3X_1) = B_1 \tag{9.5}$$

By utilizing Equation (9.5), we can proceed to eliminate an additional dependent decision variable. Ultimately, we can substitute all the flow variables and one of the decision variables ($p_{i,j}^{agg}$), and incorporate these replacements into Problem (9.2) which will lead to the following optimization problem:

$$\text{Min} \quad C_1X_1 + C_2A_4^{-1}(B_2 - A_3X_1) \tag{9.6a}$$

$$\text{s.t.} \quad D_1X_1 + D_2A_4^{-1}(B_2 - A_3X_1) \leq E_1 \tag{9.6b}$$

$$D_3X_1 + D_4A_4^{-1}(B_2 - A_3X_1) \leq E_2 \tag{9.6c}$$

Problem (9.6) does not include any flow variables and has one of the decision variables ($p_{i,j}^{agg}$) reduced compared to Problem (9.2).

9.3.1 Algorithm 1: ISO-DSO coordination problem without voltage constraints

In the proposed algorithm, initially, we eliminate all the voltage constraints and employ the following algorithm to determine the breakpoints.

Algorithm 1 consists of two main steps: Step 1 which includes lines lines 1-14; Step 2 which includes lines 15-23:

- **Step 1 (lines 1-14):** We begin by sorting DRs in decreasing order and DDGs in increasing order. The primary objective of this step is to identify the initial conditions for each aggregator's power injection or consumption value and for p^{dso}. In line 2, we determine the minimum value between the DR's capacity and

Algorithm 1: Solving problem (9.1) without voltage constraints

Sort DRs decreasing based on offering price.
Sort DDGs increasing based on offering price.
for $i \in \mathcal{N}^{dr}$ **do**
    Min $[\overline{f}_{k=n_i:n_s}, \overline{p}_i^{dr}]$
    Update p^{dso}, p_i^{dr} and $\overline{f}_{k=n_i:n_s}$
    Calculate $left_i = \overline{p}_i^{dr} - p_i^{dr}$
    if $left_i = 0$ **then**
        Continue;
    else
        Define $\mathcal{N}_i^c = \{j | j \in \mathcal{N}^{ddg}, c_j^{dr} \geq c_j^{ddg}\}$
        while $left_i, \mathcal{N}_i^c \neq 0$ **do**
            Min $[left_i, \overline{p}_z^{ddg}, \overline{f}_{k=n_i:n_z}]$
            Update $left_i$, p^{dso}, p_i^{dr}, p_z^{ddg} and $\overline{f}_{k=n_i:n_z}$
            $z \leftarrow z + 1$
$\mathcal{N}^{agg} \leftarrow \mathcal{N}^{ddg} \cup \mathcal{N}^{dr}$
$c^{agg} \leftarrow \text{sort}(c^{ddg} \cup c^{dr})$
for $i \in \mathcal{N}^{agg}$ **do**
    Calculate $left_i = \overline{p}_i^{agg} - p_i^{agg}$
    $left_i \leftarrow$ Min $[\overline{f}_{k=n_i:n_s}, left_i]$
    if $left_i$ =*0* **then**
        Continue
    Update p^{dso}, p_i^{agg}, and $\overline{f}_{k=n_i:n_s}$
    $c^{dso} \leftarrow c^{dso} \cup c_i^{agg}$

the capacities of all lines connecting the DR to the substation. Subsequently, we update the values in line 5 and compute the remaining capacity for the DR in line 6. If there is no capacity left, we move on to the next DR. Then, in line 10, we establish a set to collect all the DDGs with offering prices lower than that of the DR. In line 12, we choose the minimum capacity between the line connecting the DR to the DDG and the capacity of that DDG until there is no capacity left for the DR or the DDGs. This process is repeated for all DRs.

- **Step 2 (lines 15-23):** We unify all DRs and DDGs, sorting them in ascending order in lines 15-16. We then iterate through each of them to compute the available capacity in line 18. This is determined by selecting the minimum value between the remaining capacity of the aggregator and the capacity of all lines connecting that aggregator to the substation. If no capacity remains, we proceed to the next aggregator and update the values in line 22. At this stage, we also consider the aggregator's cost as the cost of the DSO. This process is repeated for all the aggregators.

Theorem 9.1 *Algorithm 1 yields optimal solutions (i.e., breakpoints in the piecewise-linear DSO bid-in cost function) and the optimal bid cost function for the parametric LP DSO in Problem (9.1) without voltage constraints.*

Proof of Theorem 10.1. See Appendix A.

9.3.2 ISO-DSO coordination problem considering voltage constraints

In the previous section, we determined all the breakpoints for the piecewise-linear DSO bid-in cost function by excluding voltage constraints and utilizing Algorithm 1. In this section, our focus shifts to reintroducing all voltage constraints and deriving breakpoints while taking these constraints into account.

Algorithm 2: Solving problem (9.1) considering voltage constraints

for $i \in Br$ **do**
  $B_i^f \leftarrow$ set of binding non voltage constants
  $B_i^v \leftarrow$ set of binding voltage constants
  $C \leftarrow$ total cost of Br_i
  if $B_i^v \neq 0$ & $B_{i-1}^v = 0$ **then**
    $CB_i \leftarrow B_{i-1}^f \cap B_i^f$
    for $j \in B_i^v$ **do**
      $A_j, B_j \leftarrow Eq(CB_j \cup B_j^v)$
      $X_j \leftarrow A_j^{-1} B_j, C_j(X_j)$
    if up:$Br_i \leftarrow \{X_j \,|\, C_j(X_j)\, \text{is minimum}\}$
    if dn:$Br_i \leftarrow \{X_j \,|\, C_j(X_j)\, \text{is maximum}\}$
    $BC \leftarrow B_j^v$
    $\Delta p^{dso} \leftarrow p_j^{dso}$-$p_i^{dso}$
    while $\Delta p^{dso} \neq 0$ **do**
      for $k \in CB_j$ **do**
        $Ml_k \leftarrow B_{i \neq k}^f \cup BC$
      for $j \in B_i^v$ **do**
        for k **do**
          $A_k, B_k \leftarrow Eq(Ml_j \cup B_j^v)$
          $X_k \leftarrow A_k^{-1} B_k, C_k(X_k)$
        if $B_{X_k}^f || B_{X_k}^v > 0$: delete X_k
        if up: $\tilde{B}r_j \leftarrow \{X_k \,|\, C_k(X_k)\, \text{is minimized}\}$
        if dn: $\tilde{B}r_j \leftarrow \{X_k \,|\, C_k(X_k)\, \text{is maximized}\}$
      for $j \in B^f$ **do**
        for k **do**
          $A_k, B_k \leftarrow Eq(Ml_j \cup B_j^v)$
          $X_k \leftarrow A_k^{-1} B_k, C_k(X_k)$
        if $B_{X_k}^f || B_{X_k}^v > 0$: delete X_k
        if up: $\tilde{B}r_j \leftarrow \{X_k \,|\, C_k(X_k)\, \text{is minimized}\}$
        if dn: $\tilde{B}r_j \leftarrow \{X_k \,|\, C_k(X_k)\, \text{is maximized}\}$
      if up:$Br_i \leftarrow \{\tilde{B}r_j \,|\, C_j(\tilde{B}r_j)$ is minimized$\}$
      if dn:$Br_i \leftarrow \{\tilde{B}r_j \,|\, C_j(\tilde{B}r_j)$ is maximized$\}$
      Update Ml, BC , Δp^{dso}

Algorithm 2 comprises the following steps:

- **Step 1 (lines 1-15):** For each breakpoint determined using Algorithm 1, we establish a set of binding voltage constraints and a set of binding non-voltage constraints in lines 2-3. Next, we compute the total cost for the current breakpoint in line 4. If it is the first breakpoint, we proceed to the next breakpoint and repeat the process. Following that, we check whether any voltage constraint is violated when transitioning from the previous breakpoint to the current breakpoint in line 5. If that's the case, we proceed to identify the line that connects the previous breakpoint to the current breakpoint in line 6. It's important to note that if we have n as the dimension, line 6 yields $n-1$ equations, which essentially determine a line in an n-dimensional space. Consequently, we can intersect this line with all the violated voltage constraints. For each violated voltage constraint, we combine the equations corresponding to the lines determined in line 6 with the violated voltage constraint, thereby deriving the coefficient matrices for these n sets of equations in line 8. In line 9, we determine the intersection point and calculate the total cost associated with this point. Once we have calculated all these intersection points for the violated voltages, we select the one with the minimum marginal cost if we are moving forward and the one with the maximum marginal cost if we are moving downward in lines 10-13. We store this point as the new breakpoint in line 14 and calculate the difference between the p^{dso} of the current breakpoint and the previous breakpoint in line 15.

- **Step 2 (lines 16-35):** We define Δp^{dso} and initiate a loop while Δp^{dso} has a positive value. When determining the new breakpoint, we also need to find the new marginal line to intersect with the subsequent voltage and non-voltage constraints. To achieve this, we generate all potential marginal lines in lines 17-18. These lines are derived by considering the previous marginal line and replacing one of them with the newly violated constraints from the previous breakpoint determination. Notably, this generates $n - 1$ potential marginal lines. We aim to intersect each set of these potential marginal lines with all the voltage constraints (lines 19-25) and non-voltage constraints (lines 26-32) and select the optimal one. In lines 21-22, we intersect these lines with the current voltage constraint within the loop, determine the intersection point, and calculate the total cost associated with this intersection point. In line 23, we conduct a feasibility test to ensure that none of the constraints are violated by this intersection point, removing it if necessary. For each voltage constraint in the loop, we select the intersection point that has the minimum marginal cost when moving forward and the maximum marginal cost when moving downward in lines 24-25. We repeat the same procedure for non-voltage constraints in lines 26-32. This results in having all the intersections for both voltage and non-voltage constraints. We then choose the one with the minimum marginal cost when moving forward and the maximum marginal cost when moving downward in lines 33-34. In line 35, we update the candidate marginal lines, breakpoint and the Δp^{dso}. To update the marginal lines, we substitute the new binding constraints with all the elements of the selected marginal line and generate the new set of marginal lines.

Theorem 9.2 *Algorithm 2 yields optimal breakpoints and the optimal bid cost function for Problem (9.1) after considering all the voltage constraints.*

Proof of Theorem 10.2. See Appendix B.

9.4 Algorithm Extensions for Unbalanced Systems

The algorithm explained in the previous section is extended to accommodate unbalanced distribution systems. The formulation for unbalanced distribution systems was introduced in our prior work [58].

9.4.1 Extension of Algorithm 1

Consider the unbalanced DSO formulation proposed in our previous work [58]. When we eliminate all the voltage constraints, each of the three phases becomes independent of the others, as no constraints or equations connect them. We can then employ Algorithm 1 to determine the breakpoints and bid in cost function independently for each phase.

The objective function for the parametric programming dispatch problem in a three-phase unbalanced system is as follows:

$$\text{Min} \quad p_A^{dso}\pi_A + p^{dso}\pi_B + p_C^{dso}\pi_C \tag{9.7}$$

On the transmission side, everything must be balanced ($p_A^{dso} = p_B^{dso} = p_C^{dso} = \frac{p^{dso}}{3}$). Therefore, we can reformulate the objective function as follows:

$$\text{Min} \quad p^{dso}\frac{\pi_A + \pi_B + \pi_C}{3} \tag{9.8}$$

This implies that to find the total bid in cost function of the distribution system, we must intersect all the bid cost functions from each phase along the p^{dso} axis. Regarding the price axis, it needs calculating the average of the bid cost functions from the three phases. This process in shown in Algorithm 3

9.4.2 Extension of Algorithm 2

Once we've utilized Algorithm 1 to calculate the bid in cost function for the unbalanced distribution system, the next step involves incorporating all the voltage

Algorithm 3: Extension to Algorithm 1 for unbalanced systems.

p_A^{dso}, c_A^{dso} $\leftarrow$ Algorithm 1 on phase A

p_B^{dso}, c_B^{dso} $\leftarrow$ Algorithm 1 on phase B

p_C^{dso}, c_C^{dso} $\leftarrow$ Algorithm 1 on phase C

$p^{dso} \leftarrow p_A^{dso} \cup p_B^{dso} \cup p_C^{dso}$

$c^{dso} \leftarrow \frac{1}{3}(c_A^{dso} + c_B^{dso} + c_C^{dso})$

constraints to determine the actual breakpoints. Algorithm 2 can be effectively employed for this purpose while considering all the voltage constraints. However, a problem can occur in some rare conditions in the case of the three-phase unbalanced system.

In the generation of marginal lines, we previously assumed that one voltage constraint could be added at a time. This assumption holds true for balanced test systems because in such systems, the voltage at each node is a function of the voltage at previous nodes, and there exists a recursive relationship between them. However, in three-phase transmission systems, there may be rare instances where three voltage constraints jointly contribute to generating new marginal lines. This scenario might lead us to identify a breakpoint that is not valid. Nevertheless, we have demonstrated that this does not pose a significant issue because we can readily identify the invalid breakpoint through a post-processing procedure.

In this post-processing step, we use monotonically increasing feature of the bid in cost function to pinpoint breakpoints where the marginal cost is not monotonically increasing. This indicates that the breakpoint is not on the optimal path and should be discarded. This allows us to efficiently remove redundant breakpoints and retain only the optimal ones. This extension is given in Algorithm 4

Algorithm 4: Extension to Algorithm 2 for unbalanced systems.

$Br \leftarrow$ Algorithm 2
for $i \in Br$ **do**
    $MC \leftarrow$ marginal cost of Br_{i-1} to Br_i
    if $MC_i \leq MC_{i-1}$ **then**
        delete Br_i

9.5 Case Studies

In this section, case studies have been conducted. Initially, a detailed study is implemented on two illustrative small example to gain a deeper understanding of the proposed algorithms. Subsequently, two case studies were performed on larger test cases, comprising a balanced test system consisting of 33 nodes and an unbalanced test system with 240 nodes.

9.5.1 Illustrative examples

We use two illustrative examples here to provide a simple explanation of the algorithms and formulation. We have employed one balanced test system and one unbalanced test system.

A balanced illustrative example

The system is depicted in Fig. 9.1, which comprises three nodes and three DDGs. The system's data is also presented in Fig. 9.1. The system's formulation is as follows.

$$\text{Min}_{\boldsymbol{p}^{ddg}} \quad 20p_1^{ddg} + 40p_2^{ddg} + 10p_3^{ddg} \tag{9.9a}$$

$$\text{s.t.} \quad p_1^{ddg} - f_2^p = 0 \tag{9.9b}$$

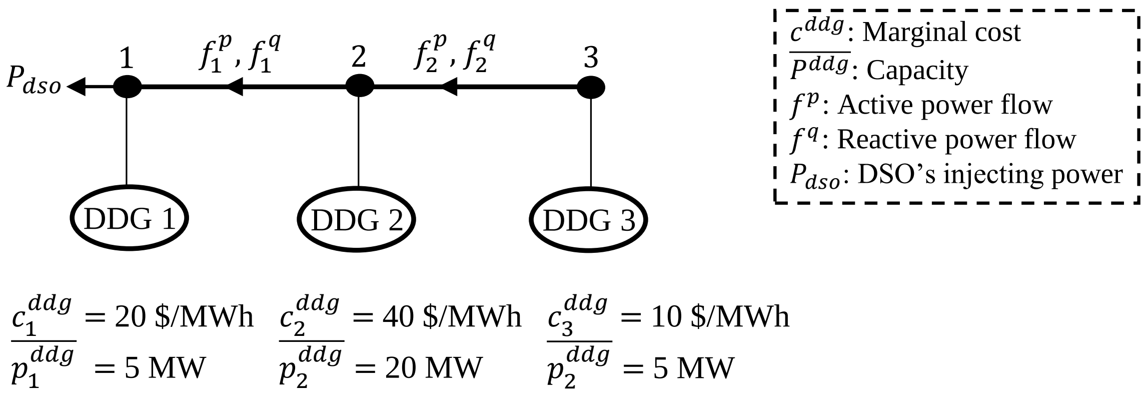


Figure 9.1: A balanced illustrative example system.

$$p_2^{ddg} + f_2^p - f_1^p = 0 \tag{9.9c}$$

$$p_3^{ddg} + f_1^p - p^{dso} = 0 \tag{9.9d}$$

$$0 \leq p_1^{ddg} \leq 5 \tag{9.9e}$$

$$0 \leq p_2^{ddg} \leq 20 \tag{9.9f}$$

$$0 \leq p_3^{ddg} \leq 5 \tag{9.9g}$$

$$-50 \leq f_1^p, f_2^p, f_3^p \leq 50 \tag{9.9h}$$

$$0.95^2 \leq U_1, U_2, U_3 \leq 1.05^2 \tag{9.9i}$$

The formulation, after removing all the flow variables and substituting the voltage constraints, is as follows:

$$\text{Min}_{\boldsymbol{p}^{ddg}} \quad 10p_1^{ddg} + 30p_2^{ddg} + 10p^{dso} \tag{9.10a}$$

$$\text{s.t.} \quad p_1^{ddg} - 5 \leq 0, -p_1^{ddg} \leq 0 \tag{9.10b}$$

$$p_2^{ddg} - 20 \leq 0, -p_2^{ddg} \leq 0 \tag{9.10c}$$

$$p_3^{ddg} - 5 \leq 0, -p_3^{ddg} \leq 0 \tag{9.10d}$$

$$p_1^{ddg} + p_2^{ddg} - 50 \leq 0 \tag{9.10e}$$

Table 9.1: Breakpoints using Algorithm 1 for the balanced illustrative example

p_1^{ddg} (MW)	p_2^{ddg} (MW)	p_3^{ddg} (MW)	p^{dso} (MW)
0	0	0	0
0	0	5	5
5	0	5	10
5	20	5	30

Table 9.2: Breakpoints using Algorithm 2 for the balanced illustrative example

p_1^{ddg} (MW)	p_2^{ddg} (MW)	p_3^{ddg} (MW)	p^{dso} (MW)
0	0	0	0
0	0	5	5
5	0	5	10
5	12.5	5	22.5
2	20	5	27

$$p_1^{ddg} - 50 \leq 0 \tag{9.10f}$$

$$-p_1^{ddg} - p_2^{ddg} - 50 \leq 0 \tag{9.10g}$$

$$-p_1^{ddg} - 50 \leq 0 \tag{9.10h}$$

$$0.125p_1^{ddg} + 0.1p_2^{ddg} - 0.025 \leq 0 \tag{9.10i}$$

$$-0.125p_1^{ddg} - 0.1p_2^{ddg} - 0.025 \leq 0 \tag{9.10j}$$

$$0.25p_1^{ddg} + 0.1p_2^{ddg} - 0.025 \leq 0 \tag{9.10k}$$

$$-0.25p_1^{ddg} - 0.1p_2^{ddg} - 0.025 \leq 0 \tag{9.10l}$$

The breakpoints using Algorithm 1 are provided in Table 9.1, and the breakpoints using Algorithm 2 are presented in Table 9.2. Upon comparing Table 9.1 and Table

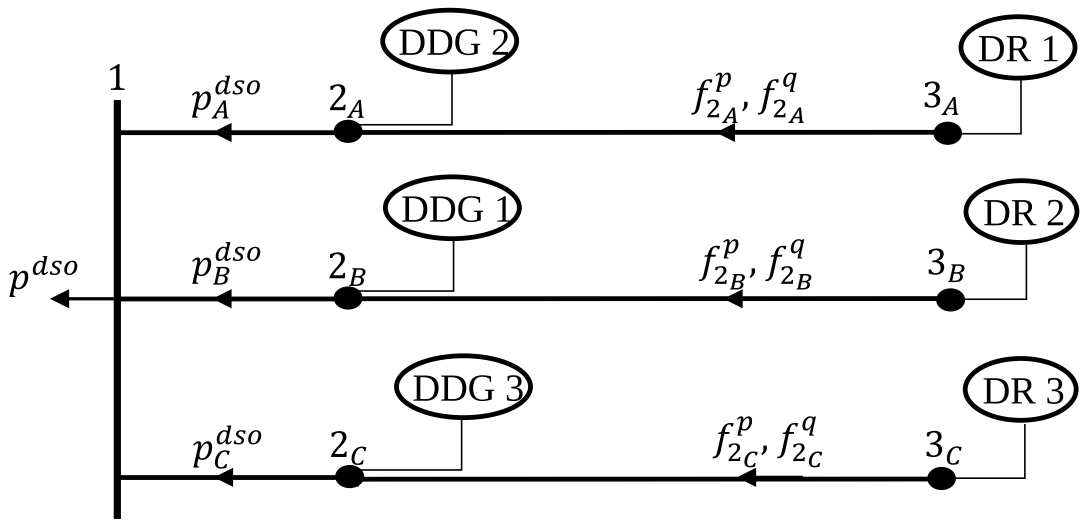


Figure 9.2: A unbalanced illustrative example system.

9.2, it is obvious that the first three breakpoints do not violate any voltage constraints. However, the fourth breakpoint results in a voltage violation, which results in new breakpoints.

An unbalanced illustrative example

The unbalanced illustrative example is depicted in Fig. 9.2. System data is provided in the Table 9.3. The formulation for the DSO bid in cost function is as follows:

$$\begin{aligned} \text{Min}_{\boldsymbol{p}^{ddg}}\ & 20p_1^{ddg} + 40p_2^{ddg} + 10p_3^{ddg} + 15p_4^{ddg} \\ & - 50p_1^{dr} - 50p_2^{dr} - 50p_3^{dr} \end{aligned} \tag{9.11a}$$

$$\text{s.t. } p_2^{ddg} + f_A^p - p_A^{dso} = 0 \tag{9.11b}$$

$$p_1^{ddg} + f_B^p - p_B^{dso} = 0 \tag{9.11c}$$

Table 9.3: Data of the units of the system shown in Fig. 9.2

Unit	Capacity (MW)	Offering price ($/MWh)
DDG 1	30	20
DDG 2	40	40
DDG 3	25	10
DDG 4	35	15
DR1	25	50
DR 2	20	50
DR 3	20	50

$$p_3^{ddg} + f_C^p - p_C^{dso} = 0 \tag{9.11d}$$

$$f_A^p + p_1^{dr} = 0 \tag{9.11e}$$

$$f_B^p + p_2^{dr} = 0 \tag{9.11f}$$

$$f_C^p + p_3^{dr} - p_4^{ddg} = 0 \tag{9.11g}$$

$$0 \leq p_1^{ddg} \leq 30 \tag{9.11h}$$

$$0 \leq p_2^{ddg} \leq 40 \tag{9.11i}$$

$$0 \leq p_3^{ddg} \leq 25 \tag{9.11j}$$

$$0 \leq p_3^{ddg} \leq 35 \tag{9.11k}$$

$$0 \leq p_1^{dr} \leq 25 \tag{9.11l}$$

$$0 \leq p_2^{dr} \leq 20 \tag{9.11m}$$

$$0 \leq p_3^{dr} \leq 20 \tag{9.11n}$$

$$-50 \leq f_A^p, f_B^p, f_C^p \leq 50 \tag{9.11o}$$

$$0.95^2 \leq U_2^A, U_2^B, U_2^C \leq 1.05^2 \tag{9.11p}$$

Table 9.4: Breakpoints using Algorithm 1 for the unbalanced illustrative example

p_1^{ddg}	p_2^{ddg}	p_3^{ddg}	p_4^{ddg}	p_1^{dr}	p_2^{dr}	p_3^{dr}	p^{dso}
0	5	0	0	-25	-20	-20	-60
25	30	25	0	-25	-20	-20	15
30	35	25	5	-25	-20	-20	30
30	40	25	10	-25	-15	-20	45
30	40	25	25	-10	0	-20	90

$$0.95^2 \leq U_3^A, U_3^B, U_3^C \leq 1.05^2 \tag{9.11q}$$

$$p_A^{dso} = p_B^{dso} = p_C^{dso} \tag{9.11r}$$

We need to follow the same procedure to eliminate all the active flow variables, as previously demonstrated in the illustrative example and is not included here because of space limitation. It is worth noting that in an unbalanced system, we have two additional equality constraints, as shown in (9.11r), which can be used to further eliminate two decision variables. The results of Algorithm 1 and Algorithm 2 are provided in Table 9.4 and Table 9.5, respectively. Upon comparing these two tables, it is evident that the first two breakpoints are infeasible when considering the voltage constraints. However, by utilizing Algorithm 2, four new breakpoints have been identified.

9.5.2 Computational performance: 33 node test system and 240 node test system

In our prior work [84], we conducted simulations using a 33-node test system and a 240-node test system, employing the YALMIP parametric programming solver [96]. Here, we applied our proposed algorithm to determine the DSO's bid-in cost function for both of these systems and compared the solution times of our algorithm

Table 9.5: Breakpoints using Algorithm 2 for the unbalanced illustrative example

p_1^{ddg}	p_2^{ddg}	p_3^{ddg}	p_4^{ddg}	p_1^{dr}	p_2^{dr}	p_3^{dr}	p^{dso}
0	0	0	11.1	-8.9	-8.9	-20	-26.8
22.1	22.1	22.1	0	-20	-20	-20	6.4
25	27.7	25	0	-22.7	-20	-20	15
27.8	32.8	25	2.8	-25	-20	-20	23.3
30	35	25	5	-25	-20	-20	30
30	40	25	10	-25	-15	-20	45
30	40	25	25	-10	0	-20	90

and YALMIP. It's important to note that both our algorithm and YALMIP yield the same results as previously proposed in [84], and these results are not reiterated here.

The simulation results were generated using a computer equipped with a 2.3 GHz, 8-core CPU and 16 GB of RAM. The solution times are presented in Table 9.6. The table provides a breakdown of each algorithm's performance, as well as the total time consumed by both algorithms combined. In the case of the 33-node test system, voltage violations occurred, necessitating the use of Algorithm 2. However, for the 240-node test system, no voltage violations were encountered, explaining the "0" time in the table. A comparison of the computational performance of both algorithms and YALMIP reveals that these algorithms are significantly faster, particularly as the system scale increases.

9.6 Conclusion

We previously introduced an ISO-DSO coordination framework based on parametric programming. Solving parametric programming problems is generally time-

Table 9.6: Computational performance of the algorithms and YALMIP.

Method	33 node system	240 node system
Algorithm 1	0.02 s	0.02 s
Algorithm 2	0.37 s	0 s
Both Algorithms	0.39 s	0.02 s
YALMIP	0.77 s	30.91 s

consuming and challenging. In this paper, we present an efficient algorithm designed to address the ISO-DSO coordination framework by leveraging the characteristics of the distribution system. We propose two algorithms, one of which can be employed after removing all voltage constraints and is exceptionally swift in determining breakpoints. The other algorithm is intended for use when voltage constraints are added. Importantly, we provide mathematical proof that both algorithms yield optimal solutions for the DSO's bid cost function.

To validate our approach, we conducted case studies on two illustrative examples, comprising both balanced and unbalanced test systems, as well as two large test systems: a balanced 33-node test system and an unbalanced 240-node test system. Our results demonstrated the remarkable efficiency of both proposed algorithms, particularly when compared to the computation time of off-the-shelf parametric programming solver in YALMIP. It was evident that the algorithm's performance surpassed that of YALMIP, especially as the system's scale increased.

Appendix A: Proof of Theorem 1

Here, we show that Algorithm 1 is based on KKT conditions. Hence, it gives the optimal solution. Let's consider the parametric programming DSO dispatch problem in which the flow variables have been removed. The problem is as follows:

$$\text{Min} \sum_{i \in \mathcal{N}_{agg}} c_i^{agg} p_i^{agg} \tag{9.12a}$$

$$\text{s.t.} \sum p_i^{agg} - \sum l_n = p^{dso};\ [\lambda] \tag{9.12b}$$

$$0 \leq p_i^{agg} \leq \overline{p_i^{agg}};\ \forall i \in \mathcal{N}_{agg};\ [\alpha_i^-, \alpha_i^+] \tag{9.12c}$$

$$-\overline{f_k} \leq f_k(p_{1\ldots n}^{agg}) \leq \overline{f_k};\ \forall k \in \mathcal{N}_J;\ [\mu_k^-, \mu_k^+] \tag{9.12d}$$

We can write the Lagrangian function as follows:

$$\begin{aligned}\mathcal{L} = & \sum_{i \in \mathcal{N}_{agg}} c_i^{agg} p_i^{agg} + \sum_{i \in \mathcal{N}_{agg}} \alpha_i^- (-p_i^{agg}) \\ & + \sum_{i \in \mathcal{N}_{agg}} \alpha_i^+ (p_i^{agg} - \overline{p_i^{agg}}) \\ & + \sum_{\forall k \in \mathcal{N}_J} \mu_k^- (-\overline{f_k} - f_k(p_{1\ldots n}^{agg})) \\ & + \sum_{\forall k \in \mathcal{N}_J} \mu_k^+ (f_k(p_{1\ldots n}^{agg}) - \overline{f_k}) \\ & + \lambda(p^{dso} - \sum p_i^{agg} + \sum l_n)\end{aligned} \tag{9.13}$$

We can formulate the KKT conditions as follows:

$$\begin{aligned}& c_i^{agg} - \lambda - \alpha_i^- + \alpha_i^+ + \sum_{k \in \mathcal{K}_i} (\mu_k^+ - \mu_k^-) = 0; \\ & \forall i \in \mathcal{N}_{agg}\end{aligned} \tag{9.14a}$$

$$p^{dso} - \sum p_i^{agg} + \sum l_n = 0 \tag{9.14b}$$

$$\mu_k^- (-\overline{f_k} - f_k(p_{1\ldots n}^{agg})) = 0;\ \forall k \in \mathcal{N}_J \tag{9.14c}$$

$$\mu_k^+ (f_k(p_{1\ldots n}^{agg}) - \overline{f_k}) = 0;\ \forall k \in \mathcal{N}_J \tag{9.14d}$$

$$\alpha_i^- (-p_i^{agg}) = 0;\ \forall i \in \mathcal{N}_{agg} \tag{9.14e}$$

$$\alpha_i^+(p_i^{agg} - \overline{p_i^{agg}}) = 0;\ \forall i \in \mathcal{N}_{agg} \tag{9.14f}$$

The only unknown variable in the set of equations (9.14) is p^{dso}. A closed-loop solution to the KKT conditions is not possible.

To solve the system of equations in (9.14), we must partition the variable p^{dso} in a way that maintains the same marginal unit within each partition. This approach comes from the key features related to the structure of optimization problem (9.12) and insights from economic dispatch problems.

In optimization problem (9.12), the marginal unit is always a single generator, and there is no possibility of a combination of multiple generators acting as the marginal unit. This feature comes from the fact that coefficients of all the constraints being either +1 or -1. When we successfully partition p^{dso} and identify a specific unit as the marginal unit, it leads to conditions such as $\alpha_1^- = \alpha_1^+ = \sum_{k \in \mathcal{K}i}(\mu k^+ - \mu_k^-) = 0$. Using equation (9.14a), it implies that $c_i^{agg} = \lambda$ in this case, indicating that the price of the DSO within that partition is equal to the offering price of the corresponding aggregator.

The process begins with the search for the minimum value of p^{dso} and progressively increasing it while monitoring changes in the group of generators. Each transition in this group marks the occurrence of a breakpoint, signifying a shift in the cost associated with providing the next megawatt (MW).

To determine the lowest value of p^{dso}, we maximize the dispatch of DRs up to the constraints imposed by line capacity. This process allows us to identify the minimum value of p^{dso}. The limiting factors in this process include the capacity of the DR or the capacity of the lines connecting the DR to the substation. This approach is implemented in step 1 of Algorithm 1, as outlined in lines 3-6.

Additionally, we need to determine the minimum value for DDGs. Here, we draw from the intuition derived from economic dispatch. When the offering price of DR is higher than the offering price of DDG, redirecting power from DDG to DR reduces the objective function. This insight guides the sorting of DRs and DDGs. The approach in Algorithm 1, detailed in lines 7-14, incorporates this logic.

With the minimum value of p^{dso} identified and the initial values of other aggregators established, we proceed to increase p^{dso} incrementally, adhering to the sorted list of aggregators. Beginning with the aggregator offering the lowest price, we determine the capacity of the lines connecting this aggregator to the substation, denoted as $\overline{f}k = n_i : n_s$. This information allows us to increase p^{dso} from its minimum to $min\{\overline{p_1^{agg}}, \overline{f}k = n_i : n_s\}$ while keeping the first aggregator as the marginal unit. This is the logic used in lines 18-19 of Algorithm 1. Utilizing complementary slackness, resulting in conditions such as $\alpha_1^- = \alpha_1^+ = \sum_{k \in \mathcal{K}i}(\mu k^+ - \mu_k^-) = 0$. Consequently, we determine that $\lambda = c_1^{agg}$, which is indicated in line 23 of Algorithm 1.

To further increase p^{dso}, we must move beyond this value and employ the next cheapest aggregator, which is the second aggregator. We apply the same principles to this partition of p^{dso}, resulting in $\lambda = c_2^{agg}$. This process continues until all aggregators are fully utilized or the line limit is reached, as described in the second step of Algorithm 1.

Appendix B: Proof of Theorem 2

In the preceding section, we established that all the breakpoints determined using Algorithm 1 are optimal and aligned with the KKT conditions. In Algorithm 2, we initiate our analysis with the breakpoints identified through Algorithm 1. Consequently, as long as there are no voltage constraints being violated, we remain on the optimal route. However, if a voltage violation occurs, we pinpoint all potential candidates by intersecting it with all the breakpoints, and we select the breakpoint for which $\frac{\Delta Cost}{\Delta p^{dso}}$ is minimized.

Drawing upon the Lagrangian function and employing the Envelope theorem, we recognize that $\frac{\partial Cost}{\partial p^{dso}}$ is equivalent to $\frac{\partial \mathcal{L}}{\partial p^{dso}}$, and we further know that $\frac{\partial \mathcal{L}}{\partial p^{dso}} = \lambda$. Hence, our selection process focuses on the partition of p^{dso} with the minimum marginal cost, which aligns with the ultimate goal of determining the bid-in cost function.

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