MODELS FOR THE INTEGRATION OF LOCAL ENERGY COMMUNITIES IN ENERGY MARKETS

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ABSTRACT

This paper presents two models for the integration of Distributed Energy Resources (DERs) in the electricity markets. The first one assumes a centrally organized market, where the DERs participate by providing bids like the rest of the conventional units. The second one assumes the existence of Local Energy Communities (LEC) coordinated by an independent entity (e.g. Aggregator) representing the DERs in the market procedures. The two models are formulated as mixed-integer linear programming problems. Three scenarios pertaining to the cost of the DERs are examined and conclusions are drawn regarding the impact of the two models in the operation and costs of the electricity system.

NOMENCLATURE

Indices and Sets

$t \in \mathcal{T}$	Dispatch periods.
$u \in \mathcal{U}$	Conventional production units.
$s \in \mathcal{S}$	Blocks of Generation Offers/Demand Bids.
$pb \in \mathcal{PB}$	Local producers with production bids.

Parameters

π_t	Load scenario frequency of dispatch period t.
$c_{u,s}$, $\bar{g}_{u,s}$	Price (€/MWh)-quantity (MWh) pair of the production bid for block s of conventional unit u.
$\bar{P}_{pb,s,t}$, $\bar{Q}_{pb,s,t}$	Price (€/MWh)-quantity (MWh) pair at dispatch period t and block s of local producer pb.
GP^{min}, GP^{max}	Minimum and maximum price for LEC Production Offers (€/MWh).
GQ^{max}	Maximum quantity for LEC Production Offer (MW).
LP^{max}	Maximum price for LEC Demand Bids (€/MWh).
LQ^{max}	Maximum quantity for LEC Demand Bids (MW).
d_t	Forecasted load of LEC during dispatch period t (MW).
D_t	Forecasted system load during dispatch period t (MW).
L_t	Total forecasted load during dispatch period t (MW).
M	Big positive number.

Variables

$\overline{LP}_t$, $\overline{LQ}_t$	Price (€/MWh)-quantity (MWh) pair of LEC Demand Bid during dispatch period t.
$\overline{GP}_t$, $\overline{GQ}_t$	Price (€/MWh)-quantity (MWh) pair of LEC Production Offer during dispatch period t.
$g_{u,s,t}$	Production of block s of conventional unit u during dispatch period t (MW).
LQ_t	Dispatched quantity of LEC Demand Bid during dispatch period t (MW).
GQ_t	Dispatched quantity of LEC Generation during dispatch period t (MW).
λ_t	System marginal price during dispatch period t (€/MWh).
$Q_{db,s,t}$	Dispatched load of consumer db per block s during dispatch period t (MW).
$Q_{pb,s,t}$	Dispatched production of local producer pb per block s during dispatch period t (MW).

INTRODUCTION

During the last years, the focus in the production of the energy systems is gradually shifted towards distributed energy resources, as opposed to larger central generation units. Moreover, customer empowerment is enhanced in order to achieve smooth integration of the new types of resources in the operation of the electricity systems through the formation of Local Energy Communities (LEC). According to the EU Electricity Directive COM(2016) 864 final/2, as part of the Winter Package, a LEC is defined as an association, a cooperative, a partnership, a non-profit organisation or other legal entity which is effectively controlled by local shareholders or members, generally value- rather than profit-driven, involved in distributed generation and in performing activities of a distribution system operator, supplier or aggregator at local level, including across borders. Although communities aiming to promote the production of RES and reduce energy consumption have existed for many years in Europe (e.g. Netherlands, wind cooperatives since the 1980s; Germany, more than hundred years old; Denmark, community-based district

heating systems and wind cooperatives since the 1970s oil crisis), their role to empower citizens collectively participating in electricity markets is now widely recognized. To this end, the national legislation in Greece has already established the legal framework for LECs (law 4513/2018) allowing also the use of net metering (virtual or not) (law 4414/2016 and relevant Ministerial Decree ΑΠΕΗΛ/Α/Φ1/οικ.175067).
At the same time, the complexity of managing the energy system with a high penetration of Distributed Energy Resources (DER) increases: the load is served increasingly by locally produced energy and the flexibility at the distribution grid increases, while the needs for central production of electricity reduce. Despite the existing regulatory framework in many countries, the largest part of the potential services offered by DER remains underutilized or fully unexploited. One of the main factors is the choice of the market model that maximizes the social benefit from the participation of DERs in the Energy Market.
This paper compares two models for integrating DERs participation in the overall electricity system. The first one simulates the integration of DERs in the market procedures as part of the day-ahead scheduling performed by the System Market Operator. The second one assumes that DERs' participation is organized locally, by an Aggregator representing one or more Local Energy Communities (LEC).
The paper is structured as follows: first, the two models are described; next, a specific case study is presented and relevant conclusions are drawn.

MODEL DESCRIPTION

Two schemes for incorporating DERs in the operations of the electricity systems are developed, each one characterized by a different market structure and mechanisms (Figure 1):

1. Centralized DER management: DERs are considered as usual resources; their dispatch is performed by the Market Operator through the market clearing process; their energy is remunerated at the market clearing price.
2. Decentralized DER management: DERs are considered as part of the portfolio of a LEC; the LEC participates in the Market procedures representing its DERs; dispatch of the DERs is performed by the LEC Operator through set-points.

The main difference of the two models concerns the existence (or not) of an intermediary representing the DERs: the centralized model assumes a centrally decided dispatch of the DERs; the decentralized model simulates the interdependence of the decision-making process of the LEC (Operator) and the market clearing process. To this end, the LEC is considered to represent a clientele of significant installed capacity – comparable to that of a conventional unit, thus capable of influencing the market outcome, i.e. the LEC is not a price-taker. Consequently, submitted demand bids and generation offers on the part

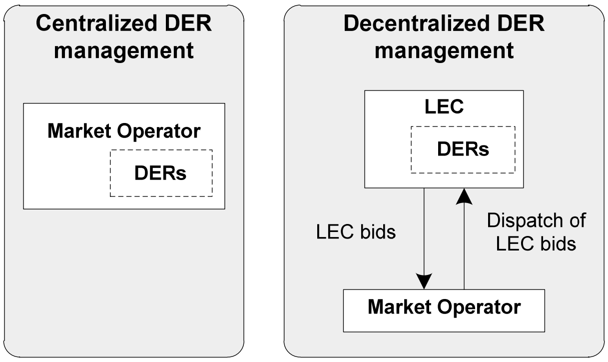

Figure 1: Conceptual framework of the interactions in the two models.

of the LEC affect the market prices, an effect that is taken into account in the LEC mathematical model.
These characteristics of the two schemes call for different modelling approaches: the centralized scheme is modelled as the usual market clearing problem, while the decentralized scheme is modelled as a bi-level programming problem. Both of them constitute mathematical programming problems, as presented next.

Centralized DER management

The centralized model is a mathematical programming problem that selects/decides the optimal dispatch of the various production resources (central or local generation units) that minimizes the total production cost (1) (or maximizes the social benefit) while observing the energy balance constraint (2) and the operational limits of the generation units (3), (4).

$$\min \pi_t\left(\sum_{u,s,t} c_{u,s} g_{u,s,t} + \sum_{pb,s,t} \bar{P}_{pb,s,t} Q_{pb,s,t}\right) \quad (1)$$

$$\sum_{u,s} g_{u,s,t} - L_t + \sum_{pb,s} Q_{pb,s,t} = 0, t \quad (2)$$

$$0 \le g_{u,s,t} \le \bar{g}_{u,s}, \forall u,s,t \quad (3)$$

$$0 \le Q_{pb,s,t} \le \bar{Q}_{pb,s,t}, \forall pb,s,t \quad (4)$$

Decentralized DER management

The decentralized model involves two interacting entities: the Market Operator and the LEC (Operator). In this model, the task of dispatching the DERs is undertaken by the LEC, an entity that possesses a portfolio of DERs and consumers and is responsible for representing them in the market procedures. The LEC participates in the Market by submitting properly defined generation offers or demand bids. The Market Operator receives the LEC generation offers or demand bids and decides their dispatch along with the dispatch of the central generation units and the satisfaction of the rest (non-LEC) of the demand, in order to maximize the social benefit.
This model describes a pay-as-bid compensation scheme, where the LEC Operator decides the actual quantity of the DERs to be dispatched, thus effectively simulating situations where the DERs are considered an asset for the LEC who is not seeking to make a profit, a case

characteristic of Local Energy Communities.
The interaction between the two entities is formulated as a bi-level programming problem with the decisions of the LEC constituting the upper-level problem and those of the Market Operator, the lower-level problem. The two levels of decision-making are interdependent: the LEC problem is affected by the market clearing prices; the market clearing problem is affected by the demand bids and generation offers of the LEC.

LEC Decision Model (Upper-Level Problem)
The LEC Operator, as responsible for managing and representing DERs in the market clearing process, aims at minimizing the total net energy procurement cost (cost for energy acquired from the grid minus the revenues from selling energy to the grid plus the local production cost) (5), subject to the energy balance constraint (6), while observing the operational limits of the local generation units (7), the Generation Offers and the Demand Bids(9)-(16). It should be noted that the LEC formulates only one bid or offer per dispatch period, i.e. constraint (16) assumes the application of net metering.
Decision variables are: the dispatch of local generation units ($Q_{pb,s,t}$), and price-quantity pairs of the Generation Offers ($\overline{GP}_t$, $\overline{GQ}_t$) and Demand Bids ($\overline{LP}_t$, $\overline{LQ}_t$) to be submitted to the Market Operator. Constraints are: the energy balance (6), the local generation operational limits (7) and conditions that ensure conformance of the submitted bids with the market rules (9)-(16).

$$\min \sum_t \pi_t \left[\lambda_t (LQ_t - GQ_t) + \sum_{pb,s,t} \bar{P}_{pb,s,t} Q_{pb,s,t} \right] \quad (5)$$

$$(LQ_t - GQ_t) + \sum_{pb,s} Q_{pb,s,t} = d_t, t \quad (6)$$

$$0 \le Q_{pb,s,t} \le \bar{Q}_{pb,s,t}, \forall pb, s, t \quad (7)$$

$$GP^{min} \le \overline{GP}_t \le GP^{max}, \forall t \quad (8)$$

$$0 \le \overline{LP}_t \le LP^{max}, \forall t \quad (9)$$

$$0 \le \overline{GQ}_t \le GQ_n^{max}, \forall t \quad (10)$$

$$0 \le \overline{LQ}_{n,t} \le LQ_n^{max}, \forall t \quad (11)$$

$$-\overline{GQ}_t M \le \overline{GP}_t \le \overline{GQ}_t M, \forall t \quad (12)$$

$$-\overline{GP}_t M \le \overline{GQ}_t \le \overline{GP}_t M, \forall t \quad (13)$$

$$-\overline{LQ}_t M \le \overline{LP}_t \le \overline{LQ}_t M, \forall t \quad (14)$$

$$-\overline{LP}_t M \le \overline{LQ}_t \le \overline{LP}_t M, \forall t \quad (15)$$

$$\overline{LQ}_t > 0 \ or \ \overline{GQ}_t > 0, \forall t \quad (16)$$

Market Clearing Problem (Lower-Level Problem)
The market clearing problem is again a social benefit maximization problem, where, instead of the production cost of the local generation units, the cost for compensating the LEC for energy injected into the grid minus the revenues from energy sales to the LEC for the energy absorbed from the grid by the LEC is included in the objective function (17).
The decision variables are: the conventional units' production ($g_{u,s,t}$), the dispatched quantities of Generation Offers (GQ_t) and Demand Bids (LQ_t) and the market clearing prices (λ_t). Constraints of the problem are: the energy balance (18) and the operational limits of conventional units, Generation Offers, Demand Bids (19)-(21).

$$\min \sum_{u,s,t} c_{u,s} g_{u,s,t} + \sum_t (\overline{GP}_t GQ_t - \overline{LP}_t LQ_t) \quad (17)$$

$$\sum_{u,s} g_{u,s,t} - D_t - (LQ_t - GQ_t) = 0 : \lambda_t, \forall t \quad (18)$$

$$0 \le g_{u,s,t} \le \bar{g}_{u,s}, \forall u, s, t \quad (19)$$

$$0 \le GQ_t \le \overline{GQ}_t, \forall n, t \quad (20)$$

$$0 \le LQ_t \le \overline{LQ}_t, \forall n, t \quad (21)$$

CASE STUDY

Scenarios

The IEEE 24-bus test system [1], [2] is used for the application of the two models. Input data can be found in [3], while load flexibility is ignored. Production comprises 26 conventional units with unit costs between 13,5€/MWh and 170,5€/MWh and total capacity of 3.105MW and 10 local generation units with unit costs between 33 and 45€/MWh and total capacity of 398,9MW. The simulations correspond to a one-year period, which is represented by 14 load scenarios, each weighted by its occurrence frequency. The LEC is considered to represent 818MWh of the load (corresponds to parameter d_t), while the rest of the load (D_t) amounts to 933MWh. Furthermore, a sensitivity analysis with respect to the local generation units cost is performed assuming intermediate prices (M), high (H) prices 67% higher than M, low (L) prices 67% lower than M.

Solution approach

The first model is a linear programming problem, while the second is equivalently transformed into a mixed-integer linear programming problem by replacing the lower-level problem by the respective Karush-Kuhn-Tucker conditions and applying proper linearization techniques for substituting the nonlinearities (bilinear products and complementarity slackness conditions) (i.e. Strong Duality Theorem [4], big-M formulation [5], equivalent expressions [6]). Both models are solved using CPLEX 12.5 under GAMS [7] running on an Intel®CoreTM i5 at 3,30GHz with 4GB RAM. The relative termination criterion is set to 10^{-8}. The decentralized model comprises 9.185 equations and 6.315 variables. The centralized model comprises 4.649 equations and 2.913 variables. Both models are solved within less than 1sec.

Results

The results for the centralized model are presented in TABLE 1 for the three scenarios of local generation units cost. The respective results for the decentralized model are presented in TABLE 2. In both models, expensive local generation units are dispatched less, thus increasing the dispatch of the conventional units and driving the total production cost to higher levels. The System Marginal Prices (SMPs) also increase, as well as the

Average Load Serving Cost (ALSC – calculated as the weighted average of the SMPs using the load as weight, i.e. $\frac{\sum_t \lambda_t L_t}{\sum_t L_t}$). The ALSC is used as an index representative of the average cost for serving the system load through the dispatch of the generation units, as it incorporates the SMPs, which reflect the influence of the dispatch of all energy resources.

When comparing the two models, significant changes are observed in the way the local generation units (and, by extension, the conventional units) are dispatched. From the results of the high cost scenario (H), it is seen that the dispatch of the local generation units in the decentralized model is higher than in the centralized model. This means that the energy needs of the LEC are covered mainly by the local production, while the conventional units are dispatched at lower levels, leading to reduced SMPs. Indeed, it is observed, that local generation units are more extensively used, even though their cost might be higher than the unit cost for importing energy from the grid. This choice, however, remains optimal for the LEC as the higher local production cost of the LEC's objective function is compensated by the reduced cost of the imported energy due to the lower SMPs and the lower quantities imported. In the low cost scenario (L), this effect is not observed. This is attributed to the fact that the dispatch of the local generation units increases anyway and the LEC's alternatives for a different dispatch of local generation are either too few or they have no impact.

TABLE 1: Centralized market results

	L	M	H
Production			
Conventional units (MWh)	*1.355*	*1.698*	*1.709*
Local generation units (MWh)	*396*	*53*	*42*
Social surplus (€)	-26.562	-30.082	-31.342
Production Costs (€)			
Local production units (€)	*5.136*	*1.951*	*2.508*
Conventional units (€)	*21.426*	*28.131*	*28.833*
Total cost(€)	26.562	30.082	31.341
Average SMP (€/MWh)	19,6	25,1	30,6
ALSC (€/MWh)	20,2	26,9	34,3

TABLE 2: Decentralized market results

	L	M	H
Production			
Conventional units (MWh)	*1.355*	*1.666*	*1.682*
Local generation units (MWh)	*396*	*85*	*69*
Dispatched Demand Bids (LB) (MWh)	488	743	754
Dispatched Generation Offers (GB) (MWh)	66	10	6
Social surplus (€)	121.974	158.444	165.133
Production Costs (€)			
Local production units (€)	*5.136*	*3.150*	*4.276*
Conventional units (€)	*21.426*	*27.347*	*27.778*
Total cost(€)	26.562	30.497	32.054
Average SMP (€/MWh)	19,6	20,5	20,9
ALSC (€/MWh)	20,2	21,1	21,5

CONCLUSIONS

The two models presented describe two different schemes for the integration of DERs in the electricity system: the centralized model corresponds to the case where DERs are managed centrally by the Market Operator; the decentralized model describes the case where DERs are represented in the market by a LEC. As shown in the study case results, the incorporation of the DERs via the LEC leads to reduced SMPs and reduced ALSC in the base case scenario (M), i.e. when the cost of local generation is comparable to that of the conventional units. Index ALSC is used as a measure for calculating the impact of the two schemes in the final electricity consumers, since it incorporates the SMPs and the influence of all energy resources, the dispatch of which aims at serving the entire load. The reduction of the ALSC in the presence of the LEC is much more pronounced in cases where the costs of the local generation units are high (scenarios M and H). In these cases, the local units are employed for serving the load locally, thus providing more flexibility on the part of the customers to cover their loads. By contrast, in case of low cost local units, the existence of LECs has no impact and the solutions of the two models are similar: the local generation units are dispatched first anyway, as they are less expensive, and there remain no flexible resources for the LEC to perform local management. Interestingly, in case local generation units are more expensive, the existence of LECs has positive impacts on the costs of all loads, either belonging to a LEC or not. On the other hand, conventional units are dispatched less and, as a result, their operation is less profitable.

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