A hybrid robust-stochastic approach to evaluate the profit of a multi-energy retailer in tri-layer energy markets

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Abstract

Nowadays, multi-energy consumers in the industrial sector have a significant contribution in exchange of different forms of energy such as electricity, heat, and natural gas. So, multi-energy consumers can provide excellent opportunities for market players to trade power in various energy markets. In this paper, a new entity called multi-energy retailer is introduced to simultaneously meet both flexible and non-flexible electrical, gas, and heat demands of multi-energy consumers, with a high level of supply reliability. The multi-energy retailer is equipped with cogeneration facilities and various storage technologies such as power-to-x storages to exploit the actual arbitrage opportunities in different layers of energy markets. The presented structure successfully models the behavior of multi-energy retailer entity and seeks to maximize its profit as well as increase the welfare level of the multi-energy consumers. The uncertainties associated with electricity market price and various demands of multi-energy consumers can affect the profit and optimal day-ahead scheduling of the multi-energy retailer. In order to accurately model such uncertainties, a hybrid robust-stochastic approach is utilized in this study. This approach helps the multi-energy retailer's operator to evaluate the worst-case of the scheduling process for the entity. Finally, the profit of the multi-energy retailer entity is estimated in the presence of conversion facilities, demand response programs, and various uncertainties based on actual energy market data.

Keywords: Energy markets, energy storage systems, multi-energy consumers (MEC), multi-energy retailer (MER), robust-stochastic model

Nomenclature

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A. Superscripts

b	Gas boiler.
ch	Charge.
dis	Discharge.
dr	Demand response programs (DRPs) execution.
e	Electricity market.
g	Gas market.
gm	Grid to MER.
h	Heat market.
i	CHP unit.

ini	Initial value (without participating in DRPs).
k	Tri-CAES system.
pg	Power-to-gas (P2G) storage.
ph	Power-to-heat (P2H) storage.
si	Simple cycle mode.
up, dw	Changes made during DRPs implementation.

B. Indices (sets)

m (NM)	Industrial consumers.
s (NS)	Scenarios.
t (NT)	Time intervals.

C. Parameters and variables

A	Reservoir energy level.
cop	Coefficient of the P2H performance.
EL	Electrical demand.
G	Gas energy.
GC	Gas consumption by facilities.
GL	Gas demand.
GP	Gas production by facilities.
H	Heat energy.
HL	Heat demand.
HP	Heat production by facilities.
IE	Rate of incentive for electrical demands variation.
IH	Rate of incentive for heat demands variation.
M	Sufficient large number.
P	Output power.
RU, RD	Ramp up/down rate limit.
sug, sdg	Start-up and shut-down cost.
SU, SD	Start-up and shut-down fuel consumption.
VOC	Operating and maintenance cost of compressor.
VOE	Operating and maintenance cost of expander.
I	Binary variable to indicate status of facilities.
Γ	Budget of uncertainty.
π	Probability of each scenario.
λ	Wholesale energy market price.
ζ	Contracted price between MER and MEC.
α	Participation rate of demands in DRPs.
η	Charge/discharge efficiency.
γ, β, m	Dual variables for the robust model.
τ_{loss}, τ_{gain}	Heat energy loss coefficients.
ΔE	Electrical demands change after execution of DRP.
ΔH	Heat demands change after execution of DRP.

1. Introduction

Retailers are an important part of the deregulated electricity market. They are responsible for supporting their clients based on pre-signed contracts with fixed selling prices. Nowadays, retailers face two major challenges in the upper and lower levels of the electricity market in order to increase their revenue [1]. In upper-level, retailers face with the challenge of reducing the difference between high and low electricity prices in many of the world's electricity markets, such as the Nordic energy market [2]. In lower-level, the emergence of new players as multi-energy consumers (MEC) in the energy markets has created some problems for retailers [3]. According to [4], it can be observed that about 54% of the total energy resources around the world are consumed by MEC, which are the main users of the industrial sector. Therefore, the high potential of MEC in advancing various electricity market programs, including demand response programs (DRPs) [5–9], cannot be ignored.

The best approach to solve the above-mentioned challenges is to change the traditional retailers' topology from one-dimensional to multidimensional mode. In this regard, traditional retailers can promote themselves by adopting emerging smart technologies such as power-to-x (P2X), combined heat and power (CHP), and tri-state compressed air energy storage (tri-CAES) conversions facilities to exploit arbitrage opportunities in different energy markets. These facilities, which improve the interdependencies between electricity, natural gas, and heat networks, can help retailers' owner to make more cost-effective decisions to supply the different demands in energy markets [10, 11]. Upgrading the existing retailers in the form of multi-energy retailer (MER) using the smart energy conversion technologies not only benefits retailers by boosting their operating income but also will benefit several other players in the energy networks. From the energy system operators' point of view, MER can reduce greenhouse gas emissions [7, 12], increase sustainable energy efficiency [13], and boost the resiliency of energy networks [14], whereas, from MEC point of view, MER can increase the welfare level of these subscribers. Therefore, this is crucial to determine the optimal operation of the MER in coordination with energy conversion facilities to reach the expected potentials of MER.

Our brief literature review reveals that the optimal operation of retailers in the presence of energy conversion facilities to meet various demands of customers has attracted much attention from researchers in recent years. Mainly, the shortcomings (**Sh**) of the existing studies about utilization of retailers in energy markets can be summarized as follows:

Sh1: The optimal day-ahead scheduling of electricity retailers has been evaluated in [15–22], considering flexible electrical demands. In [15, 16], the main goal is to maximize the short-term profit of the electricity retailer using stochastic programming to address the uncertainties of spot market price and consumer behavior. In [17], a single-leader multi-follower model between a retailer and subscribers has been presented to create an optimal pricing strategy for a pool-based electricity market. The main aim of this study is to maximize the profit of the price-maker retailer during the scheduling period. An optimization model has been proposed in [18, 19] for decreasing the customers' energy consumption cost and increasing the retailer's profit by utilizing short-term DRPs in the presence of renewable energy resources and stochastic decision-making model. Authors of [20] have suggested a fractile criterion optimization model for optimal operation of the electricity retailer by relying on the uncertainty of electricity market prices and DRPs. In [21], a two-stage robust model has been designed based on energy storage systems and DRPs to promote the performance of the electricity retailers in the deregulated electricity market. In this study, the effect of the capacity of the energy storage system to draw up a profitability strategy has also been investigated. Furthermore, a stochastic optimization approach has been used in [22] to minimize the retailer's energy procurement costs from wholesale electricity market by taking into account pool-order and forward/reward-based contracts options for implementing DRPs. Nevertheless, the effect of different energy carriers in the presented decision-making methods was not considered in any of the aforementioned studies.

Sh2: In [23], the role of electric power retailers in the form of the multi-carrier energy system has been investigated as a notable idea to increase the participation of MEC in the energy market programs. In this study, the integrated DRPs were applied only on the must-run electrical demand to increase the profit of the retailer as well as achieve high-level social welfare. Authors of [24] have presented a value-at-risk-based stochastic model for a multi-energy prosumer taking into account procurement strategies and various energy storage systems. In [25], a day-ahead energy trading model has been presented to deploy the regional integrated energy system with the aim of establishing an optimal connection between energy suppliers. Furthermore, in [26–28], several local energy systems have been equipped with the CHP unit, gas boiler (GB), and heat storage to meet the demands of electricity and heat. At the upper level of the scheduling, a multi-energy player buys energy from the electricity and gas markets and delivers them to local energy systems. In these studies, the main goal is to maximize the profit of local energy systems and multi-energy player at the lower and upper level of the day-ahead scheduling problem. Nevertheless,

(i) the role of the up-to-date facilities, such as P2X storages and tri-CAES system, was ignored in [23, 25–28].

(ii) the impact of DRPs on the profitability of the methods was not studied in [25–27].

(iii) the uncertainty associated with the electricity market price was not considered when determining the optimal scheduling of multiple energy suppliers in [23, 26–28], and

(iv) the impacts of the bilateral contract between the local energy system and MEC as well as the uncertainties of energy demands (contract violations) on the profit of multiple energy suppliers were not investigated in the relevant studies.

To overcome the above-mentioned shortcomings, in this paper the following research questions are addressed:

- How can retailers use existing opportunities in different energy markets to increase interactions with MEC?
- What are the positive effects of energy converting/storing facilities such as P2X and CAES on the retailer's profit?
- What is the impact of the uncertainties of electricity market price and energy demands on the retailer's scheduling?

A robust profit-maximization method is presented to evaluate the MER's profit as an arbitrator for participating in electricity, gas, and heat energy markets to cover the energy demands of MEC. Furthermore, the uncertainties associated with the MEC and electricity market price are addressed with a hybrid robust-stochastic approach. As such, the major contributions (**C**) of this paper are declared as follows.

C1: Developing a comprehensive model of traditional retailers as an MER using conversion facilities like CAES system, CHP unit, GB, power-to-gas (P2G) and power-to-heat (P2H) storages (to tackle **Sh1**).

C2: Incorporating uncertainties derived from electricity market price and electrical, gas, and heat demands into the optimal scheduling of MER using a hybrid robust-stochastic approach (to tackle **Sh1** and **Sh2**).

C3: Investigating the role of load shifting program in maximizing MER's profit, considering fair rewards (to tackle **Sh1** and **Sh2**).

The remainder of this paper is organized as follows. The structure of the proposed model and its mathematical formulation are presented in Section 2. The input data and numerical results are presented in Sections 3. Concluding remarks are drawn in Section 4.

2. Framework and Mathematical Formulation of The MER

2.1. Problem Description

This paper presents a comprehensive model for the optimal exploitation of the developed retailer as an MER to meet MEC by acting in the wholesale energy markets. To analyze the optimal performance of the proposed model, a robust energy management strategy is proposed for the electricity market with 24-hours scheduling interval (t=1,$\cdots$,24). Precise details of interactions among different players as well as the scheduling process of the MER are shown in Figure 1. As can be seen, the MER purchases various forms of energy from the electricity, gas, and district heat markets (tri-layer energy markets) and delivers them to MEC in the industrial sector. In other words, this agent participates in the energy markets based on the energy price signals and ultimately cooperates with MEC under the bilateral contracts. Furthermore, MEC can interact with the MER to implement DRPs based on fair rewards.

MER entity is equipped with CHP unit, GB unit, CAES system, power-to-gas (P2G), and power-to-heat (P2H) storages to meet the energy demands of MEC. Use of these facilities can offer many economic opportunities for the MER's operator in the energy markets and help the MER to fulfill its obligations at the lowest operating cost. Various demands under the contract with the MER can be supplied at a low energy cost as follows:

(i) **Electrical demands** of the MEC are met by CHP unit, tri-CAES facility, and also directly from the wholesale electricity market. CHP unit uses the gas market to supply electrical demands at intervals where energy prices in the gas market are lower than the electricity market. The tri-CAES system stores electrical energy into the reservoir during at low-price periods of the wholesale electricity market, and it uses discharging and simple cycle modes to meet electrical demands. Discharging and simple cycle modes act when the wholesale gas and electricity market prices are low and high, respectively [29].

(ii) **Gas demands** of the MEC are met by the wholesale gas market and P2G storage. When the electricity price is lower than the gas price, P2G can store electrical energy in the form of gas energy in its reservoir or use it to fulfill the gas demands.

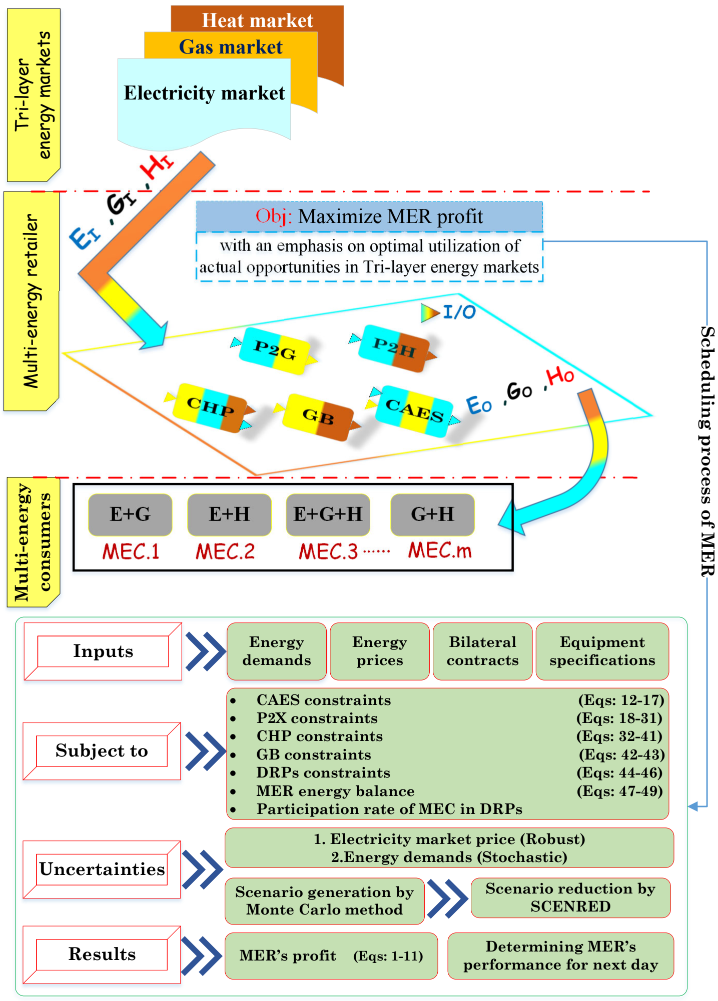

Fig. 1: Interactions among various players and scheduling process of the MER.

(iii) **Heat demands** of the MEC are met by the district heat market, GB unit, CHP unit, and P2H storage. It is critical to note that it is possible to use all three energy markets to fulfill heat demands.

Comprehensive mathematical descriptions of the introduced structure are provided in the following sub-sections.

2.2. Objective Function

In this sub-section, our model (with MER's profit as the objective function) is formulated as a hybrid robust-stochastic optimization problem. The goal of the MER entity is to maximize its profit by exploiting the economic opportunities available in various wholesale energy markets. As mentioned previously, the MER's income is earned from supplying the contracted MEC by utilizing various conversion facilities. Therefore, the MER's operator must decide on the performance of different equipment (such as the reservoir energy level, etc.) based on various uncertainties for the next day. The uncertainty parameters considered in the scheduling include the electricity market price and the MEC energy demands. To address these uncertainties, the robust optimization approach is used for the electricity market price and a scenario-based stochastic approach is applied for the demands of electrical, heat, and gas on the industrial consumers' side.

2.2.1. Stochastic programming

In the first step in the process, the mathematical formulation of the MER's profit function (PF) is presented based on the stochastic approach in Eqs. (1)-(5). It should be noted that in these equations, the uncertainty of the electricity market price is neglected.

$$Max: PF = \sum_{s=1}^{NS} \pi_s \left[\sum_{t=1}^{NT} \left(T_{t,s}^{1st} - T_{t,s}^{2nd} - T_{t,s}^{3rd} - T_{t,s}^{4th} \right) \right] \tag{1}$$

$$T_{t,s}^{lst} = \sum_{m=1}^{NM} \left(\zeta_t^e EL_{t,s,m} + \zeta_t^g GL_{t,s,m} + \zeta_t^h HL_{t,s,m} \right) \tag{2}$$

$$T_{t,s}^{2nd} = \lambda_t^e P_{t,s}^{gm} + \lambda_t^g G_{t,s}^{gm} + \lambda_t^h H_{t,s}^{gm} \tag{3}$$

$$T_{t,s}^{3rd} = VOC \left(P_{t,s}^{k,ch} + P_{t,s}^{k,si} \right) + VOE \left(P_{t,s}^{k,dis} + P_{t,s}^{k,si} \right) \tag{4}$$

$$T_{t,s}^{4th} = \sum_{m=1}^{NM} \left[\left(IE \times (\Delta E_{t,s,m}^{up} + \Delta E_{t,s,m}^{dw}) \right) + \left(IH \times (\Delta H_{t,s,m}^{up} + \Delta H_{t,s,m}^{dw}) \right) \right] \tag{5}$$

In Eq. (1), the first term represents the revenue obtained from selling electricity, gas, and heat demands to the MEC. All trading is done based on the contractual agreement between the MER's operator and MEC, where the agreed energy price and daily energy requirements are the two main components of the contracts. The amount of MER's revenue can be calculated by Eq. (2). The second term denotes the cost of purchasing power from the wholesale energy markets and is calculated by Eq. (3). The energy purchased is used to cover the hourly energy demands of the MEC and also delivered to the conversion facilities as a primary fuel. The third term of the objective function is related to the operating cost of the CAES system in charging, discharging, and simple cycle modes and is calculated by Eq. (4). Finally, the fourth term refers to the incentive compensation costs resulted from the execution of DRPs and is calculated by Eq. (5). This term is directly related to the applied changes in MEC's electricity and heat consumption load profile.

2.2.2. Hybrid robust-stochastic programming

In the next step of planning, the hybrid robust-stochastic optimization approach is applied to optimize the scheduling of the MER in coordination with CAES system, P2X storage, and cogeneration units. Because of the high importance of electrical energy, the robust optimization approach is utilized to tackle the uncertainty of the wholesale electricity market price. At the same time, the energy demands of the MEC is addressed by the scenario-based stochastic approach.

The general model of the robust optimization approach is presented in [30–33]. According to the mentioned studies, the developed hybrid robust-stochastic optimization approach to modeling the presented structure in this paper is formulated in Eqs. (6)-(11) as follows:

$$Min: -PF = -\sum_{s=1}^{NS} \pi_s \left[\sum_{t=1}^{NT} \left(T_{t,s}^{1st} - T_{t,s}^{2nd} - T_{t,s}^{3rd} - T_{t,s}^{4th} + \beta_{t,s} \right) + \gamma_s.\Gamma \right] \tag{6}$$

$$T_{t,s}^{2nd} = \lambda_t^g G_{t,s}^{gm} + \lambda_t^h H_{t,s}^{gm} + \lambda_t^{e,\min} P_{t,s}^{gm} \tag{7}$$

$$\text{Eqs.}(2), (4) \text{ and } (5) \tag{8}$$

$$\gamma_s + \beta_{t,s} \geq \left(\lambda_t^{e,\max} - \lambda_t^{e,\min} \right) .m_{t,s} \tag{9}$$

$$\gamma_s, \beta_{t,s}, m_{t,s} \geq 0 \tag{10}$$

$$P_{t,s}^{gm} \leq m_{t,s} \tag{11}$$

To solve the hybrid robust-stochastic problem, the mathematical formulation is reformulated as a minimization problem, which is shown in Eq. (6) ($Max : PF \rightarrow Min : -PF$). The decision variables of the MER are [$P_{t,s}^{gm}$, $G_{t,s}^{gm}$, $H_{t,s}^{gm}$, $P_{t,s}^{k,ch}$, $P_{t,s}^{k,dis}$, $P_{t,s}^{k,si}$, $\Delta E_{t,s,m}$, $\Delta H_{t,s,m}$]. The wholesale electricity market price as the uncertainty parameter is handled with the robust approach and may range from $\lambda_t^{e,\min}$ to $\lambda_t^{e,\max}$. The most important parameter in the robust approach is the budget of uncertainty (Γ). This parameter is used as an integer number to impose the lower and upper limitations on the uncertainty parameter (λ_t^e) during the scheduling period (t=1, 2,$\cdots$,NT) as well as to control the conservative level of the MER agent's operator. The amount assigned to the budget of uncertainty parameter can be equal to an integer value in the interval [0-NT]. If Γ is equal to NT, it means that the MER's operator has selected the most conservative state (worst-case) and the uncertainty of the electricity market price has considered in all periods of the scheduling problem. If Γ is zero, it means that the uncertainty of the electricity market price is ignored in the scheduling problem. Furthermore, γ, β, and m are dual variables of the constraints.

2.3. Problem Constraints

2.3.1. Tri-CAES constraints

Equation (12) indicates that the tri-CAES system can be utilized in one of the three modes of charging, discharging, and simple cycle. The amount of power exchanged in charging, discharging, and simple cycle modes should be between the minimum and maximum capacities of each mode which is presented in Eq. (13). The level of stored electrical energy in each hour and also the capacity limits of the reservoir are demonstrated by Eqs. (14) and (15). The level of the reservoir in the first and last scheduling period must be equal, which is shown in Eq. (16). The natural gas injected into tri-CAES in discharging and simple cycle modes is calculated using Eq. (17).

$$I_{t,s}^{k,ch} + I_{t,s}^{k,dis} + I_{t,s}^{k,si} \leq 1 \tag{12}$$

$$P^{k,X,\min} I_{t,s}^{k,X} \leq P_{t,s}^{k,X} \leq P^{k,X,\max} I_{t,s}^{k,X}; \quad X \in \{ch, dis, si\} \tag{13}$$

$$A_{t,s}^{k} = A_{t-1,s}^{k} + \eta^{k,ch} P_{t,s}^{k,ch} - \frac{P_{t,s}^{k,dis}}{\eta^{k,dis}} \tag{14}$$

$$A^{k,\min} \leq A_{t,s}^{k} \leq A^{k,\max} \tag{15}$$

$$A_{0,s}^{k} = A_{NT,s}^{k} \tag{16}$$

$$GC_{t,s}^{k} = \frac{P_{t,s}^{k,dis}}{\eta^{k,\mathrm{dis}}} + \frac{P_{t,s}^{k,si}}{\eta^{k,si}} \tag{17}$$

2.3.2. P2X storage constraints

The reserved natural gas in the P2G storage facility at any period of the scheduling horizon is expressed by Eq. (18). Equations (19)-(21) ensure that the stored gas energy in the reservoir, charging and discharging rates of the P2G do not exceed their permissible limits. In Eq. (22), it is assumed that the stored gas energy in the P2G storage is equal in the first and last periods of the scheduling. Equation (23) indicates that the produced natural gas by the P2G storage can be delivered to MEC or stored in the reservoir. The input power into the P2G storage should be lower than its maximum capacity which is given by Eq. (24).

$$A_{t,s}^{pg} = A_{t-1,s}^{pg} + G_{t,s}^{pg,ch} - G_{t,s}^{pg,dis} \tag{18}$$

$$0 \leq G_{t,s}^{pg,ch} \leq G^{pg,ch,max} \tag{19}$$

$$0 \leq G_{t,s}^{pg,dis} \leq G^{pg,dis,max} \tag{20}$$

$$A^{pg,min} \leq A_{t,s}^{pg} \leq A^{pg,max} \tag{21}$$

$$A_{0,s}^{pg} = A_{NT,s}^{pg} \tag{22}$$

$$G_{t,s}^{pg,ch} + GP_{t,s}^{pg} = \eta^{pg} P_{t,s}^{pg} \tag{23}$$

$$0 \leq P_{t,s}^{pg} \leq P^{pg,max} \tag{24}$$

P2H storage constraints are modeled similar to the P2G storage. Equations (25)-(31) show the relevant constraints.

$$A_{t,s}^{ph} = (1-\eta^{ph})A_{t-1,s}^{ph} + H_{t,s}^{ph,ch} - H_{t,s}^{ph,dis} - \tau_{loss}SU_{t,s}^{ph} + \tau_{gain}SD_{t,s}^{ph} \tag{25}$$

$$0 \leq H_{t,s}^{ph,ch} \leq H^{ph,ch,max} \tag{26}$$

$$0 \leq H_{t,s}^{ph,dis} \leq H^{ph,dis,max} \tag{27}$$

$$A^{ph,min} \leq A_{t,s}^{ph} \leq A^{ph,max} \tag{28}$$

$$A_{0,s}^{ph} = A_{NT,s}^{ph} \tag{29}$$

$$H_{t,s}^{ph,ch} + HP_{t,s}^{ph} = cop^{ph}P_{t,s}^{ph} \tag{30}$$

$$0 \leq P_{t,s}^{ph} \leq P^{ph,max} \tag{31}$$

2.3.3. CHP unit constraints

The heat and power outputs of the CHP units have an interdependent relationship and are expressed by a special feasible region [34]. The heat-power feasible region associated with the CHP unit used in this paper is shown in Figure 2 [34]. Indicators A, B, C, and D are four marginal points of the feasible region of the considered CHP unit. Linear inequalities to show the operational boundary of the CHP unit, are formulated by Eqs. (32)-(34). The heat and electricity energy provided by the CHP unit should not exceed the operational range of the unit. In this regard, Eqs. (35) and (36) are presented. The technical limitations associated with the ramp-up and ramp-down rate, are expressed by Eqs. (37) and (38), respectively. Start-up and shut-down costs of the CHP unit are presented in Eqs. (39) and (40). Finally, the amount of natural gas delivered to the CHP unit is calculated by Eq. (41).

$$P_{t,s}^{i} - P_{A}^{i} - \frac{P_{A}^{i} - P_{B}^{i}}{H_{A}^{i} - H_{B}^{i}} \times (H_{t,s}^{i} - H_{A}^{i}) \leq 0 \tag{32}$$

$$P_{t,s}^{i} - P_{B}^{i} - \frac{P_{B}^{i} - P_{C}^{i}}{H_{B}^{i} - H_{C}^{i}} \times (H_{t,s}^{i} - H_{B}^{i}) \geq -(1 - I_{t}^{i}) \times M \tag{33}$$

$$P_{t,s}^{i} - P_{C}^{i} - \frac{P_{C}^{i} - P_{D}^{i}}{H_{C}^{i} - H_{D}^{i}} \times (H_{t,s}^{i} - H_{C}^{i}) \geq -(1 - I_{t}^{i}) \times M \tag{34}$$

$$P^{i,\min} I_t^i \le P_{t,s}^i \le P^{i,\max} I_t^i \tag{35}$$

$$0 \le H_{t,s}^i \le H^{i,\max} I_t^i \tag{36}$$

$$P_{t,s}^i - P_{t-1,s}^i \le RU^i \tag{37}$$

$$P_{t-1,s}^i - P_{t,s}^i \le RD^i \tag{38}$$

$$SU_t^i \ge sug^i \left(I_t^i - I_{t-1}^i\right); SU_t^i \ge 0 \tag{39}$$

$$SD_t^i \ge sdg^i \left(I_{t-1}^i - I_t^i\right); SD_t^i \ge 0 \tag{40}$$

$$GC_{t,s}^i = \frac{P_{t,s}^i}{\eta^i} + SU_t^i + SD_t^i \tag{41}$$

2.3.4. GB constraints

The natural gas injected into GB is converted to the heat energy based on the thermal efficiency of the GB using the Eq. (42). The generation heat of GB should be in the admissible range presented in Eq. (43).

$$GC_{t,s}^b = \frac{HP_{t,s}^b}{\eta^B} \tag{42}$$

$$HP^{b,\min} \times I_{t,s}^b \le HP_{t,s}^b \le HP^{b,\max} \times I_{t,s}^b \tag{43}$$

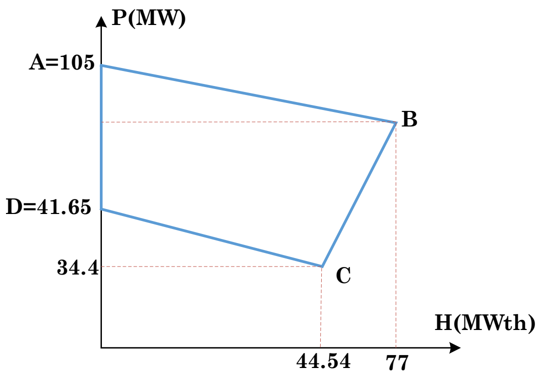

Fig. 2: Heat-power feasible region for the CHP unit [34].

2.3.5. Demand response program

The main target of using DRPs is to maximize MER's profit in day-ahead scheduling as well as in the presence of MEC. In this paper, load shifting program under incentive-based manner is utilized to manage the MEC's behavior [35]. To achieve the desired goal, MEC can modify or change their energy consumption patterns based on fair rewards received from the MER's operator. According to Eq. (44), the load shifting program will be implemented just on the electrical and heat demands of the MEC with regard to the participation rate of each demand. In addition, any decrement of the electrical and heat demands in peak periods should be compensated during the scheduling horizon in the valley and off-peak periods, as given in Eq. (45). The final electrical and heat demand profile of MEC after participating in load shifting program is calculated by Eq. (46).

$$\begin{cases} \Delta X^{up}_{t,s,m} \leq \alpha_X \times XL^{ini}_{t,s,m}; \quad X \in \{E, H\} \\ \Delta X^{dw}_{t,s,m} \leq \alpha_X \times XL^{ini}_{t,s,m}; \quad X \in \{E, H\} \end{cases} \tag{44}$$

$$\sum_{t=1}^{NT} \Delta X^{up}_{t,s,m} = \sum_{t=1}^{NT} \Delta X^{dw}_{t,s,m}; \; X \in \{E, H\} \tag{45}$$

$$XL^{dr}_{t,s,m} = \Delta X^{up}_{t,s,m} - \Delta X^{dw}_{t,s,m} + XL^{ini}_{t,s,m}; \quad X \in \{E, H\} \tag{46}$$

2.3.6. Energy balance

Constraints (47)-(49) guarantee the multi-energy balance in the MER based on the energy traded in wholesale energy markets, energy generated by self-production facilities, and the acquired energy of the load shifting program.

$$P^{gm}_{t,s} + P^{i}_{t,s} - P^{pg}_{t,s} - P^{ph}_{t,s} + P^{k,si}_{t,s} + P^{k.dis}_{t,s} - P^{k,ch}_{t,s} = \sum_m EL^{dr}_{t,s,m} \tag{47}$$

$$G^{gm}_{t,s} + G^{pg,dis}_{t,s} + GP^{pg}_{t,s} - GC^{i}_{t,s} - GC^{k}_{t,s} - GC^{b}_{t,s} = \sum_m GL_{t,s,m} \tag{48}$$

$$H^{gm}_{t,s} + HP^{i}_{t,s} + HP^{b}_{t,s} + HP^{ph}_{t,s} + H^{ph,dis}_{t,s} = \sum_m HL^{dr}_{t,s,m} \tag{49}$$

3. Simulation Results and Discussions

The performance of the MER under the uncertainty of the wholesale electricity market price and demands of MEC is investigated in the following sub-sections. The optimal scheduling scheme for MER was formulated in Eqs. (6)-(49) as a mixed integer linear programming (MILP) problem. The case studies are solved by CPLEX solver under GAMS software with CPU: 2.4 GHz and RAM: 6 GB. To assess the proposed model, the considered MER has been equipped with different conversion facilities, including CHP unit, GB, tri-CAES system, P2H, and P2G storages to meet the electrical, heat, and gas demands of MEC located in the industrial area.

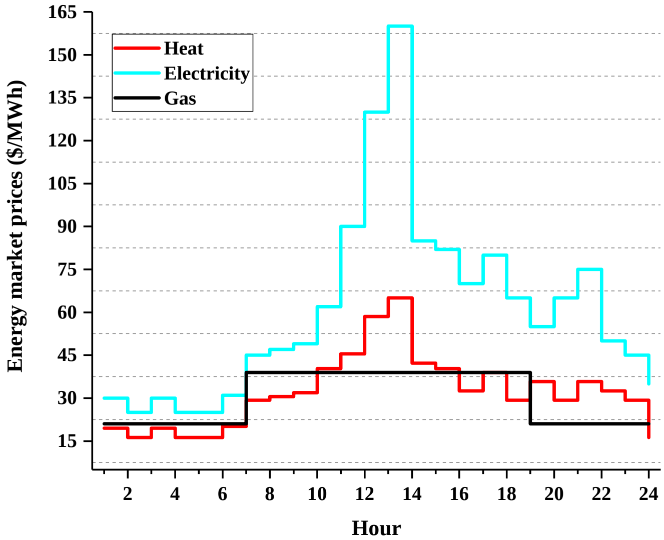

Fig. 3: Forecasted energy market prices.

3.1. Basic Data

The main basic data of the optimization problem are provided in the following. It should be noted that the modeling of MER's behavior has a close relationship with the rationality assumption. Hence, the data and rules of the Iberian market [36] are utilized to handle the optimization problem. According to the rules of the Iberian energy market, it is assumed that MEC have smart meters, so the cost of these facilities is not considered in the optimization model. Figure 3 depicts the forecasted wholesale energy market prices that the wholesale electricity market price is obtained from the Iberian market data [37] and the wholesale gas and district heating market prices are extracted from [38, 39]. The comprehensive data for elements of the MER are indicated in Table 1. The total energy consumption of the MEC under the pre-assumed hourly contractual agreement is shown in Figure 4. Moreover, the agreed price for delivering energy to each MEC is assumed to be constant within 24 hours, which is \$60/MWh, \$30/MWh and \$40/MWh for electric, gas, and heat carriers, respectively. According to [40, 41], the bilateral contract is concluded between MER and MEC based on the average day-ahead energy prices, which are presented in Figure 3.

Table 1: Data of the MER equipment.

Parameter	Amount	Parameter	Amount
η^i, η^b	0.35, 0.8	$P^{i,\min}, P^{i,\max}$(MW)	30, 100
η^{pg}	0.75	$A^{pg,\min}, A^{pg,\max}$(MWh)	50, 180
cop^{ph}	1.5	$A^{ph,min}, A^{ph,max}$(MWh)	0, 60
$\eta^{k,ch}, \eta^{k,dis}, \eta^{k,si}$	0.9, 0.9, 0.4	$A^{k,\min}, A^{k,\max}$(MWh)	50, 350
$\beta_{loss}, \beta_{gain}$	0.3, 0.6	$HP^{b,\min}, HP^{b,\max}$	0, 20
Ramp (MW/h)	55	$H^{i,\min}, H^{i,\max}$(MWth)	0, 72
$P^{ph,max}, P^{pg,max}(MW)$	20, 50	$H^{ph,ch,max}, H^{ph,dis,max}(MW)$	20, 20
$P^{k,x,\min}, P^{k,x,\max}$ $x \in \{ch, dis, si\}$	5, 50	$G^{pg,ch,max}, G^{pg,dis,max}$ (MW)	40, 40

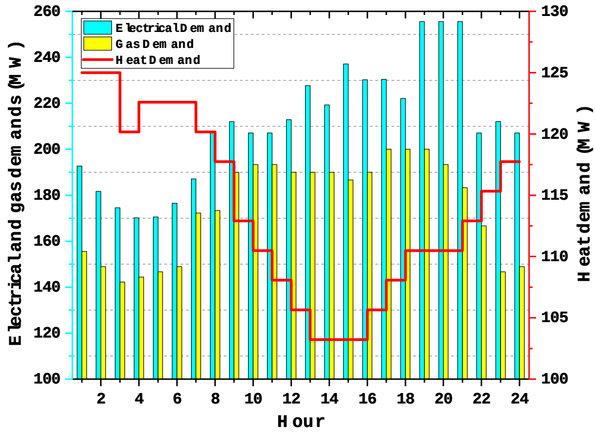

Fig. 4: The bilateral contract between MER and MEC.

3.2. Results

In this section, the impact of conversion facilities, load shifting program, and system uncertainties on the net profit earned by the retailer is examined.

3.2.1. Impact of conversion facilities

The effect of the multi-carrier storage systems, including P2G, P2H, and tri-CAES along with the CHP and GB units is investigated on the MER's profit. The results of this section are presented without uncertainty, and all technical constraints are entirely considered. The hourly scheduling of tri-CAES system, P2G, and P2H storages are shown in Figure 5. The positive amounts correspond to the intervals of discharge action and the negative amounts correspond to the intervals of charge operation. As can be seen in this figure, in the time interval [24-6], when the electricity market price is low, the MER's operator decides to use P2G, P2H, and CAES facilities in charging mode to convert energy into other forms or store it. On the contrary, when the electricity market price is high, these facilities are used in discharging mode. Also, in the time interval [19-21], it is more economical to operate the CAES system in simple cycle mode. During at high-price periods in the gas and heat markets, the MER's operator covers gas and heat demands by P2G and P2H facilities, and this way increases its profit.

The hourly scheduling of CHP and GB units are also presented in Figure 6. As can be seen, when the price of the electricity and heat markets is high, the MER's operator decides to use CHP and GB units to supply power and heat demands. Figure 7 shows the purchased electrical, heat, and gas energy from tri-layer energy markets. With regards to the corresponding contractual agreement, the MER tries to deliver the hourly energy to the MEC. Due to the sharp difference between the prices of the energy markets, the MER's operator is using all its capabilities to seize economic opportunities.

A comprehensive economic analysis of MER's operational profit is shown in Table 2. The first row demonstrates the initial state (traditional retailer), where no conversion facilities are applied. Table 2 shows that this case has the lowest net profit. In row 4, where CHP, GB, CAES, and P2X are implemented simultaneously, it can be seen that profit (32.05%) is increased in comparison with the initial state. So,

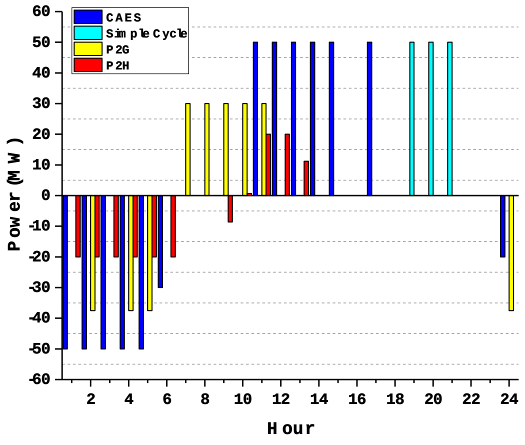

Fig. 5: Hourly Scheduling of CAES, P2G, and P2H systems.

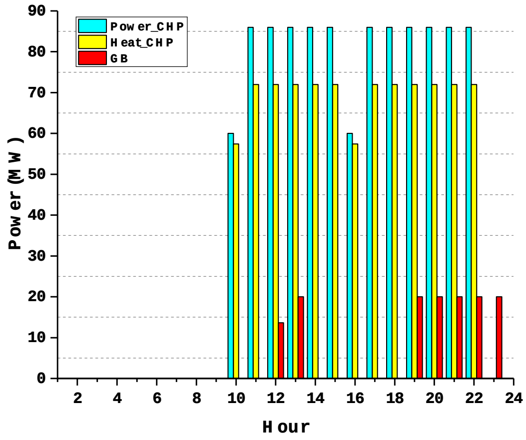

Fig. 6: Hourly Scheduling of CHP and GB units.

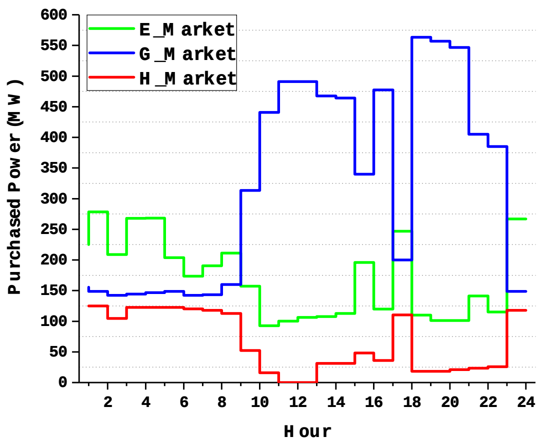

Fig. 7: The purchased power, gas, and heat from the energy markets.

Table 2: Economical compasion of case studies.

Various case studies		Profit ($)	Profit improvement
Initial state	Traditional retailer	39,417.56	-
MER (deterministic scheduling)	CHP+GB+CAES	49,837.56	26.43%
	CHP+GB+CAES+P2G	50,687.56	28.59%
	CHP+GB+CAES+P2X	52,053	32.05%
MER with load shifting program	5% both demand	57,398.38	45.61%
	6% both demand	58,461.59	48.31%
	8% both demand	60,548.85	53.60%
	10% both demand	62,555.1	58.69%
MER with uncertainties	Without DRP	48,448.02	-
	Considering DRP 5%	53,793.4	-

with energy conversion technologies, the retailer can achieve more profitable solutions to cover different customers.

3.2.2. *Impact of load shifting program*

In the second step, the impact of executing the load shifting program on the MER's profit is investigated by relying on fair rewards. The incentive fees for the electrical and heat demands are assumed to be \$30/MWh and \$10/MWh, respectively. Also, the load shifting program is implemented under various participation rates, which are set as 5%, 6%, 8%, and 10% for both types of demand. By implementing the load shifting program, the MER's operator can reduce the costs of purchasing electricity and heat energy from upstream networks. The results obtained from implementing the load shifting program by MER's operator under different participation rates are presented in Table 2. The economic results show that MER's profit increases by 58.69% compared to the initial state (for the participation rate of 10%). As can be anticipated, by increasing the participation rate of electrical and heat demands, the MER can obtain more profit.

3.2.3. *Sensitivity of MER's profit to the electricity price*

The conducted simulations in the previous sub-sections are based on three sets of forecasted energy market data for electricity, gas, and district heating. According to information presented in previous studies [42], wholesale gas and district heating market prices are almost constant throughout the year, but the wholesale electricity market prices change on a daily basis. Hence, in this sub-section, the sensitivity of the MER's profit to the electricity market prices is analyzed. To this end, 12 electricity market data are used to perform this analysis. The used day-ahead profiles are extracted from the Iberian market, which is shown in Figure 8 [37]. The obtained results for various case studies according to each daily electricity price profile are given in Table 3. This analysis is very useful for MER operators to achieve existing opportunities in the electricity market. As can be seen in this table, by promoting the electricity retailer in the form of an MER, the retailer's profit is increased dramatically in all case studies. In the meantime, the role of up-to-date energy conversion facilities such as the tri-CAES system, P2G

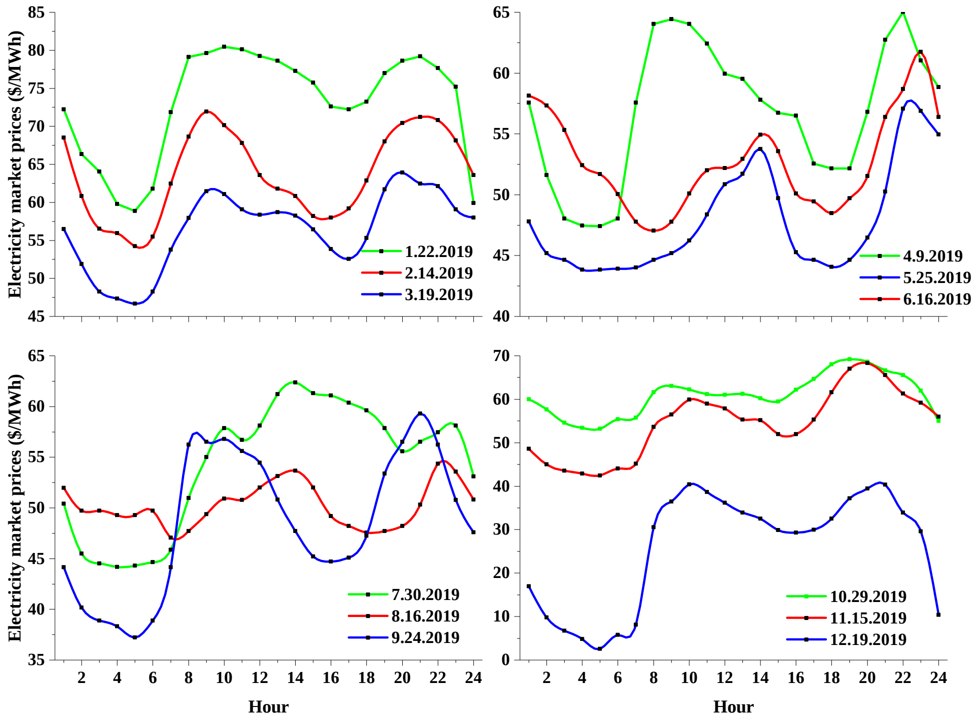

Fig. 8: Actual electricity market prices for different days based on Iberian market data [37].

Table 3: MER's profit for various actual electricity market prices.

Actual electricity market price for various days	**Profit ($)**			
	Traditional retailer	CHP+GB+CAES	CHP+GB+CAES+P2X	CHP+GB+CAES+P2X+DRP (5%)
1.22.2019	3,989.72	14,019.53	14,238.51	16,581.142
2.14.2019	38,510.03	45,191.96	46,371.64	48,543.35
3.19.2019	64,026.51	66,839.36	68,698.851	70,821.99
4.9.2019	61,979.73	64,330.07	66,060.79	68,183.19
5.25.2019	99,950.15	100,519.64	104,287.73	106,328.01
6.16.2019	83,680.613	85,504.36	88,505.98	90,613.15
7.30.2019	67,923.44	69,103.67	70,894.61	72,959.79
8.16.2019	90,805.41	90,951.16	94,105.097	96,178.71
9.24.2019	93,119.74	93,890.36	97,282.96	99,293.94
10.29.2019	46,333.18	50,894.87	52,304.08	54,454.104
11.15.2019	69,125.04	72,242.65	74,523.53	76,591.05
12.19.2019	190,928.12	199,378.68	211,738.83	214,435.83
Approximate profit for one year	**27,311,150.49**	**28,585,989.3**	**29,670,378.24**	**30,449,527.68**

storage, and P2H storage as well as DRP in accessing different energy markets and earning more profit is undeniable. According to the obtained results, the approximate annual profit of the retailer is increased by up to 8.63% in the presence of CHP, GB, CAES, and P2X facilities and up to 11.49% in the presence of the DRP compared to the initial state (traditional retailer).

3.2.4. Impact of various uncertainties

In this case, the uncertainties posed from electrical, heat, and gas demands as well as electricity market price are considered. The considered uncertainties are handled with the hybrid robust-stochastic model. Monte-Carlo (MC) method is used to address the uncertainty of energy demands. For this purpose, one-hundred scenarios were generated using a Normal distribution function with a deviation of 5% of the forecasted values. Then, the generated scenarios were reduced to ten scenarios by the GAMS/SCENRED tool. For the robust part of the optimization program, the deviation of electricity market price from forecasted value and the budget of uncertainty are considered to be 5% and 5, respectively. The MER's profit under system uncertainties in presence of all conversion facilities as well as with and without load shifting program is presented in Table 2. The MER's profit under the hybrid robust-stochastic approach has reduced to \$48,448.02 and \$53,793.4 compared with the deterministic scheduling results presented in the fourth and fifth rows of Table 2. Because in this approach, the MER's operator considers a more robust approach to manage the uncertainties of the system. Figure 9 demonstrates the relationships among the electricity market price variations, the budget of uncertainty, and the MER's profit in the energy markets. The variations of the electricity market price are from 5% to 20%, and the budget of uncertainty parameter (Γ) is considered to be from 1 to 11. For a fixed amount of the budget of uncertainty, MER's profit is monotonically decreasing as the price deviation increases.

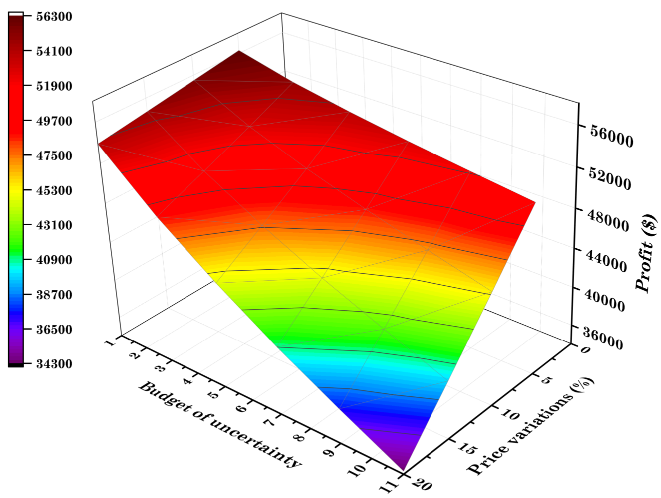

Fig. 9: Impact of budget of uncertainty and price deviations on MER's profit.

4. Conclusions and Future Work

This paper introduced a new entity called MER to develop the activities of traditional retailers by relying on emerging energy conversion technologies. The presented structure was formulated as a hybrid robust-stochastic model to maximize the MER's profit in a tri-layer energy market as well as handle the two key uncertainties, including energy demands of MEC and electricity market price. The main focus of this study was to implement a day-ahead scheduling process to maximize the MER's profit by relying on available opportunities in each energy market. Furthermore, the impacts of DRPs implementation on the

MER's profit were also investigated with the aim of increasing coordination between MER operators and MEC.

The key findings from the simulation results according to the presented profiles in Figure 3 can be summarized as follows:

1) Utilizing the conversion facilities such as CHP unit, GB unit, tri-CAES system, P2G, and P2H storages plays a crucial role in increasing MER's profit up to 32% compared to the traditional retailers.

2) Implementing the load shifting program, along with the conversion facilities helps the MER's operator to increase its profit up to \$62555.1 compared to the case without DRP, which had a total profit of \$52,053.

3) The performance of MER was evaluated in the worst-case scenario (Γ=11, price deviation=20%) to guarantee the agent's profit against uncertainties. In this case, MER's profit was reduced by 12% compared to deterministic scheduling.

In the future work, an investment cost recovery mechanism will be used to evaluate the impact of the investment and operation costs of various conversion facilities on the MER's performance over the long run (5 to 10 years).

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