Applied Energy 169 (2016) 324–340

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

Day-ahead resource scheduling of a renewable energy based virtual power plant

Ali Ghahgharaee Zamani, Alireza Zakariazadeh, Shahram Jadid *

Center of Excellence for Power System Automation and Operation, Dept. of Electrical Engineering, Iran University of Science and Technology, P. O. Box: 1684613114, Tehran, Iran

HIGHLIGHTS

- Simultaneous energy and reserve scheduling of a VPP.
- Aggregate uncertainties of electricity prices, renewable generation and load demand.
- Develop a stochastic scheduling model using the point estimate method.

ARTICLE INFO

Article history:
Received 4 June 2015
Received in revised form 4 November 2015
Accepted 2 February 2016

Keywords:
Virtual Power Plant (VPP)
Optimal energy and reserve scheduling
Demand Response Program (DRP)
Point Estimate Method (PEM)
Combined Heat and Power (CHP)

ABSTRACT

The evolution of energy markets is accelerating in the direction of a greater reliance upon distributed energy resources (DERs). To manage this increasing two-way complexity, virtual power plants (VPPs) are being deployed today all over the world. In this paper, a probabilistic model for optimal day ahead scheduling of electrical and thermal energy resources in a VPP is proposed where participation of energy storage systems and demand response programs (DRPs) are also taken into account. In the proposed model, energy and reserve is simultaneously scheduled considering the uncertainties of market prices, electrical demand and intermittent renewable power generation. The Point Estimate Method (PEM) is applied in order to model the uncertainties of VPP's scheduling problem. Moreover, the optimal reserve scheduling of VPP is presented which efficiently decreases VPP's risk facing the unexpected fluctuations of uncertain parameters at the power delivery time. The results demonstrated that implementation of demand response programs (DRPs) would decrease total operation costs of VPP as well as its dependency on the upstream network.

1. Introduction

The virtual power plant integrates and coordinates decentralized power-generating sites, storage facilities and controllable loads via a common intelligent control center. VPPs are not only used for marketing energy quantities produced by distributed generation systems but also play a part as regards the power systems. They enable the provision of system services in the distribution and transmission network such as operating reserve capacity. The VPP aggregates the electrical output from a multitude of distributed energy resources and makes this supply available to the system operator. If requested, the VPP controls the immediate dispatch of the connected plants, thus contributing to grid reliability. The aggregation of DERs aiming at providing reserve capacity is a suitable solution for compensating the unexpected power fluctuations of intermittent renewable generations.

Various literatures have already discussed VPPs and their challenges and opportunities in optimal scheduling issues or bidding strategies in markets. The literatures having some differences with the present work in terms of the possible embedded elements (e.g. storage or CHP, etc.) are investigated in the following. In [1,2], VPP is considered as a centralized entity containing some micro-CHP units connected to a low voltage distribution network. An optimal operation approach of a VPP composed of some CHP units is presented based on a decentralized control strategy [3]. In [1–3], however, the optimal usage of CHP systems has been defined as the main goal and the key role of electrical storages and demand response resources has not been taken into account. The impact of the use of flexibility at the demand side, also referred to as demand response, on power system operation is assessed in [4]. A two-stage modeling approach is used which combines a day-ahead deterministic unit commitment model and an hourly

* Corresponding author. Tel.: +98 21 77491223; fax: +98 21 77491242.
E-mail addresses: a_ghahgharaei@elec.iust.ac.ir (A.G. Zamani), zakaria@iust.ac.ir (A. Zakariazadeh), jadid@iust.ac.ir (S. Jadid).

http://dx.doi.org/10.1016/j.apenergy.2016.02.011
0306-2619/

Nomenclature

Sets

dg	set of DG units, running from 1 to N_{dg}
k	set of demand response program levels containing I (first level), II (second level) and III (third level)
t	set of time periods, running from 1 to 24.
z	set of zones, running from 1 to N_z.
ω	set of scenarios, running from 1 to N_ω

Binary variables

I, J, u	binary variables pertaining to startup, shutdown and unit commitment status of VPP's resources, respectively

Continuous variables

$P_{boil,zt}$	output power of boiler in period t and zone z
$P^{e}_{chp,zt}$ ($P^{t}_{chp,zt}$)	El. (Th.) output power of CHP in period t and zone z, respectively
$P^{s}_{dg,zt}$	scheduled power deployed by DG units in period t and zone z
$P^{k,s}_{drp,zt}$	scheduled power deployed by the kth level of demand response program in period t and zone z
$P^{s}_{ens,zt}$	scheduled involuntary electrical load curtailment in period t and zone z
$P^{s}_{line,zt}$	scheduled power flow through upstream line of zone z in period t
$P_{sh,zt}$	surplus heat power in period t and zone z
$P_{SR,t}$	VPP's bid to spinning reserve market in period t
$P^{e}_{st,zt}$, $P^{t}_{st,zt}$	exchanged power into/out of El. and Th. storages in period t and zone z, respectively
$R^{U,s}_{dg,zt}$, $R^{D,s}_{dg,zt}$	scheduled spinning reserve up and spinning reserve down deployed by DG units in period t and zone z, respectively
$R^{U,k,s}_{drp,zt}$, $R^{D,k,s}_{drp,zt}$	scheduled reserve up and reserve down deployed by the kth level of demand response program in period t and zone z, respectively

simulation in real-time. A detailed modeling approach of both the supply and demand side is taken, allowing to obtain a realistic quantification of DR benefits. The focus of [4] is on residential DR, including the scheduling of white goods appliances and battery electric vehicles (BEVs). With regard to the presented work in [4], the use of cogeneration systems has not been embedded in the model. A stochastic programming framework for solving the scheduling problem faced by an industrial customer with cogeneration facilities, conventional power production system, and heat only units is proposed in [5]. The power and heat demands of the customer are supplied considering demand response (DR) programs. Power demand and pool prices are considered as stochastic processes in the scheduling problem, however, the use of renewable energy sources has not been investigated in the model. Ref. [6] presents a stochastic profit-based model for day-ahead operational planning of a combined wind farm-cascade hydro system. The generation company (GenCo) that owns the VPP considers a portion of its hydro plants capacity to compensate the wind power forecast errors. The proposed optimization problem is a mixed integer linear programming (MILP), formulated as a two-stage stochastic programming model. In [6], however, the presence of energy storages, demand response programs and cogeneration systems has not been investigated. An optimization methodology is proposed in [7] based on a multi-objective approach to handle with day-ahead optimal resource scheduling of a VPP in a distribution network considering different reactive power management strategies. The proposed methodology determines an optimal resource scheduling considering two competing objective functions. One objective function is expressed as the minimization of the operation cost of all distributed energy resources managed by the VPP, and the other one as the minimization of the voltage magnitude differences in all buses of the distribution network. The main goal is helping the VPP's management of a distribution network with high penetration of several distributed energy resources, such as distributed generation units, electric vehicles, and capacitor banks. Despite of the comprehensive proposed model in [7], the presence of demand response programs and cogeneration systems has not been investigated. A weekly self-scheduling of a VPP based on stochastic programming has been tackled in [8] where intermittent renewable sources, storage system and a conventional power plant have been taken into account. In [9], a two-stage stochastic mixed-integer linear programming model for a VPP has been presented, where, the VPP tries to maximize its expected profit via participating in both the day-ahead and the balancing markets. In [8,9], however, the presence of cogeneration systems and demand response programs has not been investigated. In [10–12], a special price-based unit commitment method has been suggested as an appropriate solution for bidding strategies of VPPs in energy market but without considering the presence of renewable energy sources and demand response programs. In [13], a modified particle swarm optimization approach has been presented aiming at minimizing the day-ahead costs of VPP. Although the storages were modeled in [13], in the case study, these resources have been ignored and therefore, the impact of storages in VPPs has not been assessed. In [14], a full model of demand response in which demand flexibility is fully utilized by price responsive shiftable demand bids in energy market as well as spinning reserve bids in reserve market, is proposed. However, the presence of renewable energy sources has not taken into account.

The literatures having some differences with the present work in the modeling (e.g. modeling of resources, modeling of uncertainties, optimization approach, etc.) are investigated in the following. A new method to support VPP day-ahead resource scheduling in a smart grid context considering the intensive use of V2G and other distributed energy resources is proposed in [15]. The main objective is to minimize the operation costs considering all the available resources for each operation period. With full respect to the proposed method in [15] the uncertainties modeling of renewable energy sources in operation from VPPs has not been investigated. Authors in [16] propose a new market integration approach for responsive loads. Regional pockets of responsive loads are aggregated into models that describe population dynamics as an equivalent virtual power plant. This demand-side virtual power plant is then integrated into the market as a new source of spinning reserves. Despite of the comprehensive proposed model in [16], the modeling of uncertainties of renewable energy sources has not been taken into account. The economic operation of a hybrid system consisting of wind, solar, hydrogen and thermal power systems in the VPP structure is evaluated to participate in the electricity market with high levels of reliable power production [17]. An economic operation-based load dispatching strategy that can interactively adapt to the real measured wind and solar power production values is also proposed in [17]. The proposed forecasting approach, for wind and solar resources, is developed taking into account the components of the VPP concept, the required time horizon, the specifications of the site and the available data. In [17], however, the presence of uncertainties of market price and electrical demand has not been tackled. Authors in [18] propose a new framework for the operation of distribution companies (Discos) in the liberalized electricity market environment considering distributed generation (DG) units and carbon dioxide (CO_2) emission penalty cost. The proposed short-term framework is a two-stage model. The first stage, namely day-ahead stage, deals with the activities of discos. The results of the first stage are imposed as the boundary constraints in the second stage which deals with the activities of discos in an hour-ahead period. In the hour-ahead stage, the retailers determine the amount of purchased active and reactive power from the grid and the production of each DG unit in the energy and reserve market keeping in mind its day-ahead decision to maximize the desired short-term profit. With full respect to the proposed framework in [18], the modeling of existing uncertainties in operation from distribution networks has not been taken into account. A new algorithm has been proposed in [19] in order to optimize thermal and electrical scheduling of a large scale VPP containing cogeneration systems and energy storages. Despite of the accurate mathematic model in [19], no specific model for renewable energy sources and their corresponding uncertainties has been investigated. A stochastic bidding strategy of microgrid in a joint day-ahead market of energy and spinning reserve service is proposed in [20] taking into account of uncertainty of renewable DG unit's output power and load but without considering the price uncertainty.

This paper proposes a simultaneous energy and reserve scheduling method for a VPP considering demand response resources, energy storages and uncertainty parameters. Modeling of uncertainties in operational planning problems makes the scheduled result more realistic. The innovative contributions of the proposed method are highlighted as follows:

- Presenting a two-stage probabilistic model for simultaneous energy and reserve scheduling of a VPP.
- Aggregating uncertainties of electricity prices, renewable power generation and load demand in VPP's scheduling problem.
- Including load demand participation in both energy and reserve scheduling in a VPP.
- Aggregating various technologies of DERs (e.g. energy storages, cogeneration systems, DRPs, stochastic and dispatchable generation units) in VPP's territory.

The rest of the paper is organized as follows: Sections 2–4 provide the model description and formulation that completely delineates the VPP's framework and the proposed day-ahead probabilistic mixed-integer linear programming model of VPP; the simulation results of a typical case study are presented and analyzed in Section 5, and the paper is concluded in Section 6.

2. The VPP's framework

2.1. Concept of VPP

In this paper, the VPP's concept is developed for aggregating some DERs to coordinately operate for participating in both energy and spinning reserve markets. In general, two integration strategies are existed, including integration in a microgrid and in a VPP [21]. In [21], the integration of DERs, i.e. DGs, controllable loads and energy storages, into microgrid and Virtual Power Plant (VPP) has been investigated. As discussed in [22], VPP enables the integration of DERs (both generation and demand) into power system operation. So, energy storages and demand response resources are types of DERs and can be integrated in a VPP [21–23].

To compare a VPP with a microgrid, it can be noted that there are some conceptual differences between definitions of a VPP and a microgrid. The microgrid concept is based on the assumption that large numbers of micro generators are connected to a network aiming at reducing the requirement for transmission and high voltage distribution assets [21]. The microgrid is generally designed based on delivering local energy that meets the exact needs of the constituents being served almost independently [24–26]. So, the energy management system of a microgrid tries to operate the microgrid more independently. Similar to microgrids, VPP is a combination of DGs, controllable loads and energy storages; however, it is a wider concept than microgrids. In general, VPPs aggregate a number of DERs with various operating pattern that are connected to various points in the distribution network for the purpose of trading electrical energy or providing system support services [21].

According to Fenix definition [22], VPP aggregates the capacity of many diverse DER; it creates a single operating profile, at a single point of common coupling with the upstream network. Moreover, there are two types of VPP: the commercial VPP (CVPP) and technical VPP (TVPP). CVPPs perform commercial aggregation and do not take into consideration any network operation aspects that an active distribution network have to consider for a stable operation. TVPP consists of DER from the same geographic location and includes the real-time influence of the local network on DER aggregated profile as well as representing the cost and operating characteristics of the portfolio. These concepts are discussed in detail in [27].

Similar to [10], this paper considers VPP the same as TVPP defined in [22] as a comprehensive definition which takes into account the influence of local network on DER aggregated profile.

2.2. Control scheme of VPP

VPPs may be controlled in decentralized or centralized manner [28]. In decentralized control strategy, each DER is locally controlled by local controller (LC). Basically, the active power output of DER is controlled by distributed generation controller (DGC) and the DGC is controlled by LC. In order to achieve an integrated system, the LCs are linked to each other forming a ring network architecture through communication to allow signals exchange. On the other hand, in the centralized one, the DERs are centrally controlled by control coordination center (CCC). The requirement signals, e.g. loads signals, are transmitted to the CCC, and processed by means of logic algorithm. Thereafter the signals are dispatched to each DGC and then the active power output is produced according to the CCC signals. With the CCC it is able to execute both technical and economical functions, in order to gain benefits of aggregated DERs. Additional information about the control strategies of VPP has been addressed in detail in [28].

It this paper, VPP is controlled in the centralized form and the aim of CCC is to maximize the net profit of VPP by providing optimal bids to the electricity market.

2.3. Interaction strategy of VPP

The complete aggregation of DERs in a VPP can just be achieved within the smart grid scheme. By complete implementation of smart grid technologies, the passive participants in distribution systems are expected to convert to the active one and, as a result, they can mutually communicate with system operators and other players in order to incorporate in power balancing and energy trading activities. In this case, the VPP's operator is able to call on its own DERs (in its territory) and external entities to share some information based on its operational objective as shown in Fig. 1. According to this figure, the VPP's operator can mutually contact with energy/spinning reserve market for determining its optimal bidding strategies in these two markets. The market

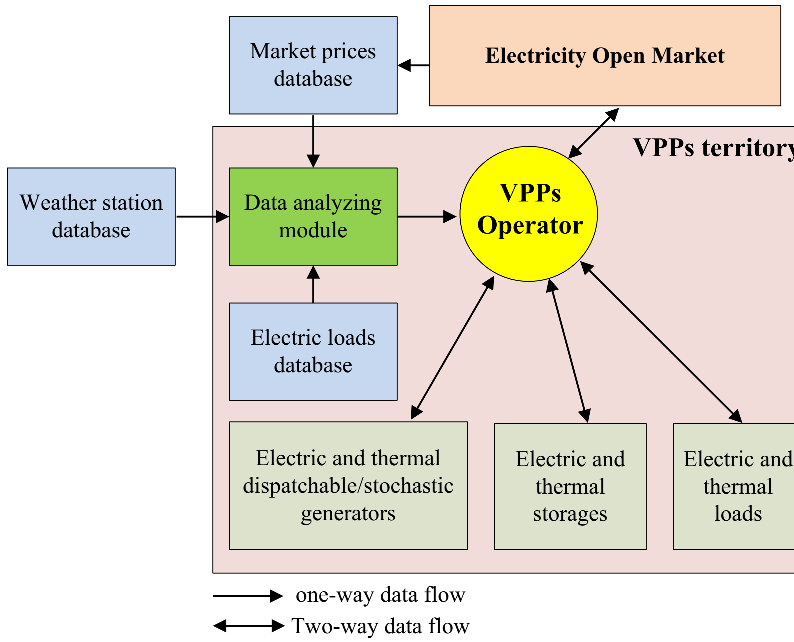

Fig. 1. The VPP's framework.

framework considered in this paper is the same as suggested in [10].

2.4. Local network of VPP

The VPP under investigation is a set of zones, individually connected to a typical radial network, which is fed by a substation transformer, as shown in Fig. 2. As thermal loads are locally fed by thermal suppliers, the overall network is split into a number of zones. Each zone is composed of two main parts: electrical and thermal. The resources available in electrical part consist of Photo Voltaic (PV), wind turbine, electrical link of CHP, DG units (fuel cells and micro turbines), electrical storage (electrochemical battery) as well as demand response resources for feeding electrical load demand or energy injecting to the upstream line. On the other hand, resources available in thermal part consist of boiler, thermal link of CHP and thermal storage for feeding thermal load demand. As the actual locations of DERs in the network are taken into account, thus the present work focuses on a large scale VPP.

In case of presence of some DERs inside the local network that are not included in the VPP's cluster, these resources can be considered as independent resources with known values (e.g. known active power). So, these resources can be embedded in the proposed model by their known values. Therefore, the values pertaining to the output power of these resources can be forecasted by VPP and have not been determined by optimization algorithm of VPP. However, these resources have not been considered in the local network of VPP and it is assumed that all resources (both generation and demand) in the local network are managed by VPP. With this assumption, the power flow through each line can completely be controlled by VPP.

3. Point estimate method

Optimal operation of power systems have always been faced with some uncertainties. That is due to some uncertain input parameters that extremely affect on performance of power systems. So far, many efforts have been made to identify and model these uncertainties (e.g. probabilistic models, robust optimization, interval arithmetic, etc.). There are two types of methods used for energy reserve scheduling in the literature: deterministic and stochastic methods. In the deterministic approach, the amount of reserve requirement in each period is determined before the energy and reserve scheduling [29] where in stochastic methods the probabilistic nature of parameters such as renewable generation or units failures are modeled within the scheduling optimization [30,31]. Studies evidenced that the stochastic scheduling methods properly model system situations if compared to deterministic method [32].

A new standard classification of uncertainty modeling techniques for renewable energy resource impact assessment under uncertainty has been proposed in [33]. These methods have been introduced and implemented and their strengths and weaknesses have been demonstrated. As discussed in [33], the probabilistic techniques are more appropriate for impact assessment of renewable energies. The main reason for this fact is that the output of renewable energy resources basically depends on the characteristics of their primary energy resources such as solar radiation, wind speed, and environmental temperature. The historic data of these parameters is usually available and they can be modeled using a probability density function (PDF). The main probabilistic models include Monte Carlo simulations, PEM, scenario-based decision making and Markov models, e.g. Discrete-time Markov chain model [34], Semi-Markov model [35], Markov-Chain Regime-Switching Autoregression (MS-AR) [36] and Markov-Chain Monte Carlo (MCMC) [37]. In [38], Different scenarios for modeling the output power of PVs and wind units as well as day-ahead energy prices are generated based on the Monte Carlo simulations for optimal daily operation of a VPP. Two probabilistic optimal operation management schemes of microgrid and Decision making of a VPP under uncertainties are proposed using PEM in [39–41], respectively.

The PEM, as a subcategory of probabilistic models, is a suitable tool for modeling of power system uncertainties [33]. Suppose that X and D are the vectors of input uncertain and deterministic parameters, respectively, and y is the output function of these

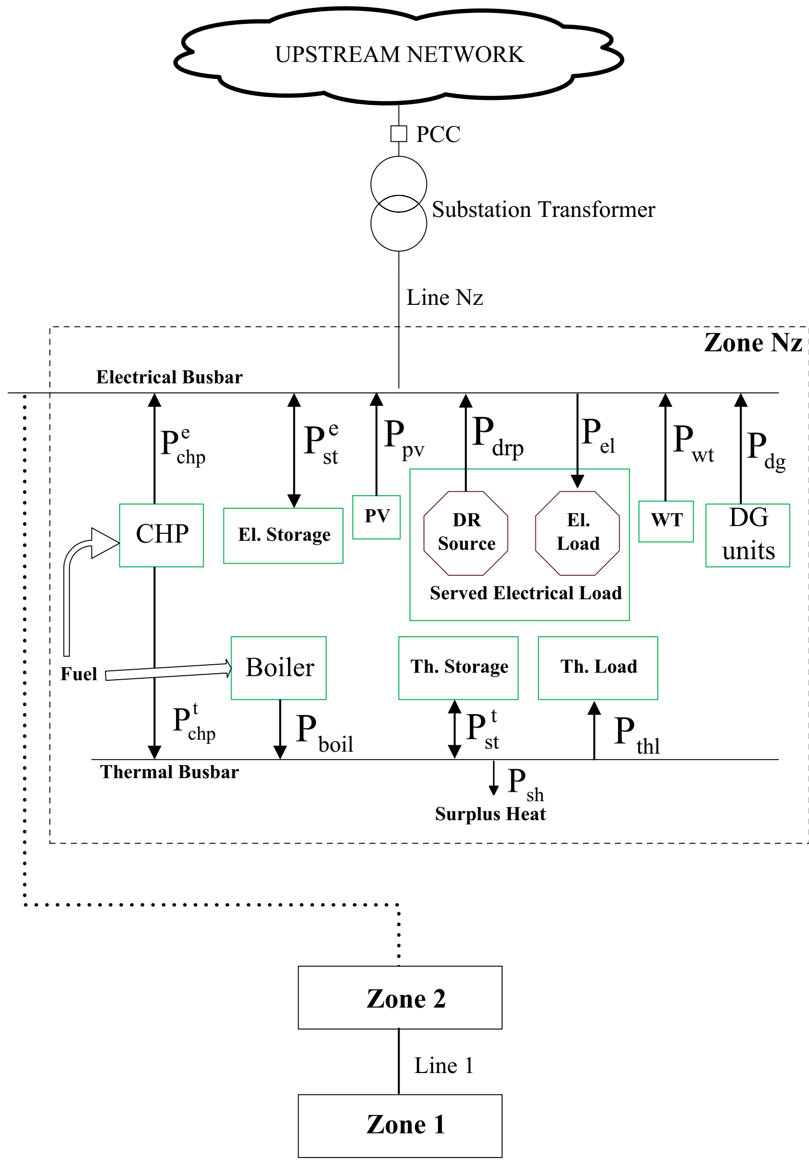

Fig. 2. The VPP's local network.

input parameters (e.g. objective function of VPP's scheduling problem) as given in (1). The vector X can adopt each ones of the considered uncertain parameters such as solar radiation, wind speed, energy market price and electric load demand.

$$y = f(D, X) \tag{1}$$

The PEM is a strong technique which approximately calculates the expected value and standard deviation of y based on the mean and standard deviation of X. If there are n uncertain parameters in vector X ($x_\tau, \tau = 1:n$) then this method performs $2n$ calculations to obtain the expected values of y ($E(y)$) and $y^2(E(y^2))$. The PEM is implemented through the following steps:

Step 1. Determine the locations and probabilities of concentrations $\varphi_{\tau,i}$ and $\pi_{\tau,i}$, respectively, as expressed in (2) and (3).

$$\varphi_{\tau,i} = \frac{M_3(x_\tau)}{2\sigma_{x_\tau}^3} + (-1)^{i+1}\sqrt{s + \frac{1}{2}\left(\frac{M_3(x_\tau)}{\sigma_{x_\tau}^3}\right)^2}, \quad \tau = 1:n, \quad i = 1,2 \tag{2}$$

$$\pi_{\tau,i} = (-1)^i \frac{\varphi_{\tau,3-i}}{2s\sqrt{s + \frac{1}{2}\left(\frac{M_3(x_\tau)}{\sigma_{x_\tau}^3}\right)^2}}, \quad \tau = 1:n, \quad i = 1,2 \tag{3}$$

where τ is the counter of uncertain parameters, σ_{x_τ} is standard deviation of x_τ and $M_3(x_\tau)$ is third moment of parameter x_τ that is illustrated by (4).

$$M_3(x_\tau) = E[(x_\tau - \mu_{x_\tau})^3], \quad \tau = 1:n \tag{4}$$

where μ_{x_τ} is the mean value of uncertain parameter x_τ.

Step 2. Determine the concentration points $x_{\tau,i}$, as given below:

$$x_{\tau,i} = \mu_{x_\tau} + \varphi_{\tau,i} * \sigma_{x_\tau}, \quad \tau = 1:n, \quad i = 1,2 \tag{5}$$

Step 3. Calculate $E(y)$ and $E(y^2)$ according to (6) and (7). If $\tau = p$ then the pth uncertain parameter in vector X must be replaced by $x_{\tau,i}$ (as obtained by (5)) and the other ones in X can be set by their mean values.

$$E(y) = \sum_{\tau=1}^{n}\sum_{i=1}^{2}\pi_{\tau,i} * f(D, \mu_{x_1}, \mu_{x_2}, \ldots, x_{\tau,i}, \ldots, \mu_{x_s}) \tag{6}$$

$$E(y^2) = \sum_{\tau=1}^{n}\sum_{i=1}^{2}\pi_{\tau,i} * f^2(D, \mu_{x_1}, \mu_{x_2}, \ldots, x_{\tau,i}, \ldots, \mu_{x_s}) \tag{7}$$

Step 4. Calculate the mean and the standard deviation of y as follows:

$$\mu_y = E(y) \tag{8}$$

$$\sigma_y = \sqrt{E(y^2) - E^2(y)} \tag{9}$$

In this paper, the PEM is applied in order to generate $2n$ scenarios with specific probabilities that would be called on the second stage of the objective function of VPP's scheduling problem.

4. Mathematical model

The mathematical model of the proposed method is investigated in this section. At first, the proposed objective function of VPP's scheduling problem, as the main part of this section, is introduced. Then, the constraints of mathematical model such as the relations pertaining to the VPP's resources, power balancing and exchanged power with electricity market are described.

4.1. Objective function

The objective function of the proposed energy and reserve scheduling method is the day-ahead expected net profit of VPP. The presented objective function is composed of two main stages; the upper and lower stages are, respectively, scenario-independent (first stage) and scenario-dependent (second stage) expressions. In fact, the first stage includes the values that do not depend on any particular scenario realization in each time period, that are named as scheduled variables; on the other hand, the second stage contains the values pertaining to each particular scenario in each time period. The distributed generation units and DRPs among all other VPP's resources have been considered to participate in each scenario and compensate the fluctuations of uncertain parameters. The superscripts s and ω are used to indicate the first stage and second stage variables, respectively. The different parts of the proposed objective function are described as follows:

The exchanged cash flow into/out of VPP pertaining to the first stage of the objective function:

- The scheduled exchanged cash flow between VPP and the electricity market (energy market and spinning reserve market); as line N_z is connected to point of common coupling (PCC) of VPP, the power flowing through this line ($P_{line,ts}^{N_z}$) is the same as offered to the energy market; positive and negative values of $P_{line,ts}^{N_z}$ indicate selling power to and purchasing power from energy market, respectively.
- The scheduled energy, spinning reserve up/down costs corresponding to the three-level DRP.
- The cost of fuel that is injected to boilers and CHP units as well as the startup and shutdown costs of CHP units.
- The operational cost of electrical and thermal storages; the related cost is generally concerned with maintenance costs, it is assumed to be a linear function of the absolute of its charged or discharged capacity at each hour [11].
- The scheduled energy, spinning reserve up/down costs of DG units.
- The scheduled penalty for not served electrical loads.
- The scheduled obtained revenue from end-consumers according to the hourly retail energy rates of VPP.

The exchanged cash flow into/out of VPP pertaining to the second stage of the objective function:

- The expected supplementary revenue in the exchanged cash flow between VPP and the electricity market.
- The expected supplementary energy costs of DG units and DRPs.
- The expected supplementary penalty for not served electrical loads.
- The expected supplementary revenue in the exchanged cash flow between VPP and end-consumers.

$$\begin{aligned} profit = max\sum_{t=1}^{24}\left\{\begin{array}{l} \rho_{EM,t}^{f} * P_{line,t}^{N_z,s} + \rho_{SR,t} * P_{SR,t} \\ +\sum_{z=1}^{N_z}\left\{\begin{array}{l} EC_{drp,zt}^{s} + RC_{drp,zt}^{U,s} + RC_{drp,zt}^{D,s} \\ +EC_{chp,zt} + EC_{boiler,zt} \\ +EC_{st,zt}^{e} + EC_{st,zt}^{t} \\ +\sum_{dg=1}^{N_{dg}}(EC_{dg,zt}^{s} + RC_{dg,zt}^{U,s} + RC_{dg,zt}^{D,s}) \\ +\rho_{ens,t} * P_{ens,zt}^{s} + P_{sel,zt}^{s} * \rho_{ret_{vpp},t} \end{array}\right\} \end{array}\right\} \\ +\sum_{\omega=1}^{N_\omega}\sum_{t=1}^{24}\pi_{\omega,t} * \left\{\begin{array}{l} \rho_{EM,t}^{\omega} * P_{line,t}^{N_z,\omega} - \rho_{EM,t}^{f} * P_{line,t}^{N_z,s} \\ +\sum_{z=1}^{N_z}\left\{\begin{array}{l} EC_{drp,zt}^{\omega} + \sum_{dg=1}^{N_{dg}} EC_{dg,zt}^{\omega} \\ +\rho_{ens,t} * (P_{ens,zt}^{\omega} - P_{ens,zt}^{s}) + (P_{sel,zt}^{\omega} - P_{sel,zt}^{s}) * \rho_{ret_{vpp},t} \end{array}\right\} \end{array}\right\} \end{aligned} \tag{10}$$

where $\pi_{\omega,t}$ is the occurrence probability of scenario ω in period t. $\rho_{EM,t}^{f}$ and $\rho_{EM,t}^{\omega}$ are the forecasted and scenario-dependent prices of energy market in period t. $\rho_{SR,t}$, $\rho_{ret_{vpp},t}$ and $\rho_{ens,t}$ indicate the spinning reserve market price, VPP's retail energy rate and the considered penalty for energy not-served in period t, respectively. $P_{sel,zt}^{\omega}$ and $P_{sel,zt}^{s}$ are, respectively, the scenario-dependent and scheduled served electrical demand in period t and zone z.

In stochastic methods the reserve requirement for each scenario are determined based on a trade-off between the costs due to the reserve and to the expected energy not served. The load shedding option is considered only for some scenarios with very low probability of occurrence [42]. In fact, in the operation of the real VPP, it is expected that no involuntary load shedding occurs due to renewable generation variations. When a low probability renewable power scenario happens, if the scheduled reserve is not enough for compensating the power deviation, the VPP operator can purchase the required power from hour-ahead or real-time market [43]. The energy not served term is embedded in the model to ensure that the power balance equation is always respected in each operational case of VPP. So, in normal operational cases of VPP, this energy not served variable would be set to zero by solving the model and because of parallel operation of VPP with the upstream network. On the other hand, in special operational cases where network limitations or generation unit outages, are emerged, the energy not served variable can be set to a non-zero value by solving the model. As in the model, VPP takes into account network operation aspects as well as all electrical loads in the local network in terms of providing their demand, so VPP is responsible for any blackout of these loads and must pay the penalty for such event. However, VPP can prevent from this event, by making some appropriate policies in its territory, e.g. implementing the demand response programs. The energy not served variable ($P_{ens,zt}^{\omega}$ and $P_{ens,zt}^{s}$) is penalized by a high value that is known as VOLL (Value Of Lost Load). The VOLL is an important measure in electricity markets. It represents customer's willingness to pay for electricity service (or avoid curtailment). In electricity markets, VOLL is usually measured in dollars per MWh. VOLL depends on multiple factors such as the type of customer affected, regional economic conditions and demographics, time and duration of outage, and other specific traits of an outage [44].

There are some mechanisms for estimating the fuel cost of CHP units. For instance, based on an Italian pricing framework, a gas volume (m^3) numerically correspondent to one fourth of produced electricity (kWh) is out of fiscal ruling, i.e., conventionally associated to electricity production; the remaining part is considered for heat generation purposes by assigning two rates to fuel dependent on the type of application (e.g. heat or electricity generation purposes) [19]. In this paper, the consumption fuel cost of CHP units ignoring the application type has been considered. Otherwise, some other mechanisms could be embedded in the presented model. Both CHPs and boilers are gas-fired. According to (10), 860 is kWh-to-kcal ratio and by using this coefficient and heating value of natural gas (HV_{NG}), the unit of $\rho_{NG,t}$ converts from dollars per cubic meter to dollars per kWh.

Each term of the objective function is described as follows:

$$EC^s_{drp,zt} = -\sum_{k=I}^{III}\left(\rho^{E,k}_{drp,t} * P^{k,s}_{drp,zt}\right), \quad \forall z, \quad \forall t \tag{11}$$

$$RC^{U,s}_{drp,zt} = -\sum_{k=I}^{III}\left(\rho^{R^U,k}_{drp,t} * R^{U,k,s}_{drp,zt}\right), \quad \forall z, \quad \forall t \tag{12}$$

$$RC^{D,s}_{drp,zt} = -\sum_{k=I}^{III}\left(\rho^{R^D,k}_{drp,t} * R^{D,k,s}_{drp,zt}\right), \quad \forall z, \quad \forall t \tag{13}$$

where $EC^s_{drp,zt}$, $RC^{U,s}_{drp,zt}$ and $RC^{D,s}_{drp,zt}$ are the scheduled energy, reserve up and reserve down costs of the three-level DRP in period t and zone z, respectively. $\rho^{E,k}_{drp,t}$, $\rho^{R^U,k}_{drp,t}$ and $\rho^{R^D,k}_{drp,t}$ are the price bids of energy, reserve up and reserve down pertaining to the kth level of DRP in period t, respectively.

$$\begin{aligned} EC^s_{dg,zt} &= -\left(EC_{dg}\left(P^s_{dg,zt}\right) + SC_{dg,z} * I^s_{dg,zt} + SHC_{dg,z} * J^s_{dg,zt}\right), \quad \forall z, \ \forall t, \ \forall dg \\ EC_{dg}(x) &= \alpha_{dg} * x + \beta_{dg} \end{aligned} \tag{14}$$

$$RC^{U,s}_{dg,zt} = -RC^U_{dg}\left(R^{U,s}_{dg,zt}\right), \quad \forall z, \ \forall t, \ \forall dg \Big| RC^U_{dg}(x) = \alpha^U_{dg} * x + \beta^U_{dg} \tag{15}$$

$$RC^{D,s}_{dg,zt} = -RC^D_{dg}\left(R^{D,s}_{dg,zt}\right), \quad \forall z, \ \forall t, \ \forall dg \Big| RC^D_{dg}(x) = \alpha^D_{dg} * x + \beta^D_{dg} \tag{16}$$

where $EC^s_{dg,zt}$, $RC^{U,s}_{dg,zt}$ and $RC^{D,s}_{dg,zt}$ are the scheduled energy, spinning reserve up and spinning reserve down costs of DG units in period t and zone z, respectively. $(\alpha_{dg}, \beta_{dg})$, $(\alpha^U_{dg}, \beta^U_{dg})$ and $(\alpha^D_{dg}, \beta^D_{dg})$ are positive coefficients of energy cost function, spinning reserve up cost function and spinning reserve down cost function of DG units, respectively. $SC_{dg,z}$ and $SHC_{dg,z}$ are, respectively, the startup and shutdown cost of DG units in zone z.

$$\begin{aligned} EC_{chp,zt} = \frac{-860 * \rho_{NG,t}}{HV_{NG}} * \left(\frac{P^e_{chp,zt}}{\eta_{chp,z}}\right) \\ - (SC_{chp,z} * I_{chp,zt} + SHC_{chp,z} * J_{chp,zt}), \quad \forall z, \ \forall t \end{aligned} \tag{17}$$

$$EC_{boiler,zt} = \frac{-860 * \rho_{NG,t}}{HV_{NG}} * \left(\frac{P_{boil,zt}}{\eta_{boil,z}}\right), \quad \forall z, \ \forall t \tag{18}$$

where $EC_{chp,zt}$ and $EC_{boiler,zt}$ are the energy costs of CHPs and boilers at period t and zone z, respectively. $\eta_{chp,z}$ and $\eta_{boil,z}$ indicate the electrical efficiency of CHP and efficiency of boiler in zone z, respectively. $SC_{chp,z}$ and $SHC_{chp,z}$ are, respectively, the startup and shutdown cost of CHP units in zone z. $\rho_{NG,t}$ is the natural gas price in period t.

$$EC^e_{st,zt} = -\left(a^e_{st,z}\left|P^e_{st,zt}\right| + b^e_{st,z}\right), \quad \forall z, \ \forall t \tag{19}$$

$$EC^t_{st,zt} = -\left(a^t_{st,z}\left|P^t_{st,zt}\right| + b^t_{st,z}\right), \quad \forall z, \ \forall t \tag{20}$$

where $EC^e_{st,zt}$ and $EC^t_{st,zt}$ are, respectively, the energy cost functions of electrical and thermal storages in period t and zone z. $(a^e_{st,z}, b^e_{st,z})$ and $(a^t_{st,z}, b^t_{st,z})$ are positive coefficients of energy cost functions of electrical and thermal storages in zone z, respectively.

$$EC^\omega_{drp,zt} = -\sum_{k=I}^{III}\left(\rho^{E,k}_{drp,t} * \left(P^{k,\omega}_{drp,zt} - P^{k,s}_{drp,zt}\right)\right), \quad \forall z, \ \forall t, \ \forall \omega \tag{21}$$

$$\begin{aligned} EC^\omega_{dg,zt} = -\Big(&EC_{dg}\left(P^\omega_{dg,zt}\right) - EC_{dg}\left(P^s_{dg,zt}\right) + SC_{dg,z} * I^\omega_{dg,zt} \\ &-SC_{dg,z} * I^s_{dg,zt} + SHC_{dg,z} * J^\omega_{dg,zt} - SHC_{dg,z} * J^s_{dg,zt}\Big), \\ &\forall z, \ \forall t, \ \forall \omega, \ \forall dg \end{aligned} \tag{22}$$

where $EC^\omega_{drp,zt}$ and $EC^\omega_{dg,zt}$ are the supplementary energy cost of the three-level DRP and DG units in period t, zone z and scenario ω, respectively.

4.2. DG units

4.2.1. Scenario-independent (scheduled) constraints

The scheduled power and spinning reserve up/down of DGs should meet the inequalities shown in (23) and (24) at each time period and each zone. the scheduled spinning reserve up/down provided by each DG unit should be bounded into DG's operational spinning reserve up/down limitations ($R^U_{dg\_max,z}$ and $R^D_{dg\_max,z}$) as given in (25) and (26). The inter-relationships of the three binary decision variables of DG units are given in (27)–(29).

$$R^{U,s}_{dg,zt} \leqslant u^s_{dg,zt} * P_{dg\_max,z} - P^s_{dg,zt}, \quad \forall z, \ \forall t, \ \forall dg \tag{23}$$

$$R^{D,s}_{dg,zt} \leqslant P^s_{dg,zt} - u^s_{dg,zt} * P_{dg\_min,z}, \quad \forall z, \ \forall t, \ \forall dg \tag{24}$$

$$0 \leqslant R^{U,s}_{dg,zt} \leqslant R^U_{dg\_max,z}, \quad \forall z, \ \forall t, \ \forall dg \tag{25}$$

$$0 \leqslant R^{D,s}_{dg,zt} \leqslant R^D_{dg\_max,z}, \quad \forall z, \ \forall t, \ \forall dg \tag{26}$$

$$u^s_{dg,zt} - u^s_{dg,zt-1} \leqslant I^s_{dg,zt}, \quad \forall z, \ \forall t, \ \forall dg \tag{27}$$

$$u^s_{dg,zt-1} - u^s_{dg,zt} \leqslant J^s_{dg,zt}, \quad \forall z, \ \forall t, \ \forall dg \tag{28}$$

$$u^s_{dg,zt} - u^s_{dg,zt-1} = I^s_{dg,zt} - J^s_{dg,zt}, \quad \forall z, \ \forall t, \ \forall dg \tag{29}$$

where $P_{dg\_max,z}$ and $P_{dg\_min,z}$ are the maximum and minimum operational power of DG in zone z, respectively. $R^U_{dg\_max,z}$ and $R^D_{dg\_max,z}$ are the maximum operational spinning reserve up and the maximum operational spinning reserve down of DG in zone z, respectively.

4.2.2. Scenario-dependent constraints

The scheduled spinning reserve up/down provided by each DG unit must cover the maximum difference between DG's scheduled power and the one produced in each scenario that can be expressed by (30)–(32). The DG's produced power at each scenario must be bounded by its minimum ($P_{dg\_min,z}$) and maximum ($P_{dg\_max,z}$) allowable power as given in (33).

$$P^\omega_{dg,zt} - P^s_{dg,zt} = R^{U,\omega}_{dg,zt} - R^{D,\omega}_{dg,zt}, \quad \forall z, \ \forall t, \ \forall \omega, \ \forall dg \tag{30}$$

$$0 \leqslant R^{U,\omega}_{dg,zt} \leqslant R^{U,s}_{dg,zt}, \quad \forall z, \ \forall t, \ \forall \omega, \ \forall dg \tag{31}$$

$$0 \leqslant R^{D,\omega}_{dg,zt} \leqslant R^{D,s}_{dg,zt}, \quad \forall z,\ \forall t,\ \forall \omega,\ \forall dg \tag{32}$$

$$u^{\omega}_{dg,zt} * P_{dg\_min,z} \leqslant P^{\omega}_{dg,zt} \leqslant u^{\omega}_{dg,zt} * P_{dg\_max,z}, \quad \forall z,\ \forall t,\ \forall \omega,\ \forall dg \tag{33}$$

$$u^{\omega}_{dg,zt} - u^{\omega}_{dg,zt-1} \leqslant I^{\omega}_{dg,zt}, \quad \forall z,\ \forall t,\ \forall \omega,\ \forall dg \tag{34}$$

$$u^{\omega}_{dg,zt-1} - u^{\omega}_{dg,zt} \leqslant J^{\omega}_{dg,zt}, \quad \forall z,\ \forall t,\ \forall \omega,\ \forall dg \tag{35}$$

$$u^{\omega}_{dg,zt} - u^{\omega}_{dg,zt-1} = I^{\omega}_{dg,zt} - J^{\omega}_{dg,zt}, \quad \forall z,\ \forall t,\ \forall \omega,\ \forall dg \tag{36}$$

4.3. Cogeneration systems (CHP)

The thermal output power of cogeneration systems is related to the electric one by multiplying the heat-to-electric power ratio (k) [45]. The output power of CHP units could be zero or between the technical minimum and maximum rates. The set of constraints shown in (39)–(41) ensure that the inter-relationships of the three binary decision variables of CHP units, $b_{chp,zt}$, $I_{chp,zt}$, and $J_{chp,zt}$, are in sequential logical order and there are no conflicting situations.

$$P^{t}_{chp,zt} = k_{chp,z} * P^{e}_{chp,zt}, \quad \forall z,\ \forall t \tag{37}$$

$$u_{chp,zt} * P^{e}_{chp\_min,z} \leqslant P^{e}_{chp,zt} \leqslant u_{chp,zt} * P^{e}_{chp\_max,z}, \quad \forall z,\ \forall t \tag{38}$$

$$u_{chp,zt} - u_{chp,z(t-1)} \leqslant I_{chp,zt}, \quad \forall z,\ \forall t \tag{39}$$

$$u_{chp,z(t-1)} - u_{chp,zt} \leqslant J_{chp,zt}, \quad \forall z,\ \forall t \tag{40}$$

$$u_{chp,zt} - u_{chp,z(t-1)} = I_{chp,zt} - J_{chp,zt}, \quad \forall z,\ \forall t \tag{41}$$

where $P^{e}_{chp\_min,z}$ and $P^{e}_{chp\_max,z}$ are the minimum and maximum operational power of CHP in zone z, respectively. $k_{chp,z}$ is heat-to-electricity ratio for CHP units in zone z.

4.4. Boiler

A boiler could be applied if the CHP unit and thermal storage are not able to cover thermal load, entirely, or when using them is not economical. The output power of each boiler is bounded by its operational constraint.

$$0 \leqslant P_{boil,zt} \leqslant P_{boil\_max,z}, \quad \forall z,\ \forall t \tag{42}$$

where $P_{boil\_max,z}$ is the rated power of boiler in zone z.

4.5. Storages

Energy storage devices can usually be modeled by their minimum and maximum allowable level of energy. The minimum allowable level of energy is detected by the Depth of Discharge (DoD) of storages that has a significant effect on their life cycle. To this end, the State of Charge (SoC) of each storage device must be bounded to the mentioned ranges as shown in (43)–(46) for electrical storages and (47)–(50) for thermal storages. $P^{e}_{st,zt}$ is assumed to be positive and negative if storage is in discharging and charging modes, respectively. It should be mentioned that $P^{e}_{st,zt}$ is assumed to remain constant during each time period (one hour in here); so, power and energy values of storages could be combined for each time period (as shown in (43) and (47)).

$$SoC^{e}_{st,zt} = SoC^{e}_{st,z(t-1)} - P^{e}_{st,zt}, \quad \forall z,\ \forall t \tag{43}$$

$$SoC^{e}_{st,zt} = E^{e}_{st,initial,z}, \quad \forall z,\ t = 0 \tag{44}$$

$$SoC^{e}_{st,zt} = E^{e}_{st,final,z}, \quad \forall z,\ t = 24 \tag{45}$$

$$E^{e}_{st,min,z} \leqslant SoC^{e}_{st,zt} \leqslant E^{e}_{st,max,z}, \quad \forall z,\ \forall t \tag{46}$$

$$SoC^{t}_{st,zt} = SoC^{t}_{st,z(t-1)} - P^{t}_{st,zt}, \quad \forall z,\ \forall t \tag{47}$$

$$SoC^{t}_{st,zt} = E^{t}_{st,initial,z}, \quad \forall z,\ t = 0 \tag{48}$$

$$SoC^{t}_{st,zt} = E^{t}_{st,final,z}, \quad \forall z,\ t = 24 \tag{49}$$

$$E^{t}_{st,min,z} \leqslant SoC^{t}_{st,zt} \leqslant E^{t}_{st,max,z}, \quad \forall z,\ \forall t \tag{50}$$

where $E^{e}_{st,initial,z}$, $E^{e}_{st,final,z}$, $E^{e}_{st,max,z}$ and $E^{e}_{st,min,z}$ are the initial, final, maximum and minimum level of energy in electrical storage in zone z, respectively. $SoC^{e}_{st,zt}$ is the state of charge in electrical storage in period t and zone z. The superscript t is used to model the thermal storages.

Another important characteristic of storages is the rate of charge and discharge at each time period. The input power to or output power from storage must be between the maximum charge and discharge power at each hour given as follows:

$$-P^{e}_{st,charge,z} \leqslant P^{e}_{st,zt} \leqslant P^{e}_{st,discharge,z}, \quad \forall z,\ \forall t \tag{51}$$

$$-P^{t}_{st,charge,z} \leqslant P^{t}_{st,zt} \leqslant P^{t}_{st,discharge,z}, \quad \forall z,\ \forall t \tag{52}$$

where $P^{e}_{st,charge,z}$ and $P^{e}_{st,discharge,z}$ are the maximum rechargeable and discharge power of electrical storage in zone z.

4.6. Electrical load curtailment

To implement DRPs in the proposed method, an incentive-based three-level DRP is modeled. The demand response resources are divided to three capacity programs, first, second and third level (I, II and III). A specified capacity with corresponding incentive payment is considered for each level of DRP.

4.6.1. Scenario-independent (scheduled) constraints

The scheduled power and reserve up/down of the three-level DRP should meet the inequalities shown in (53) and (54) at each time period and each zone. the scheduled reserve up/down provided by each level of DRP should be bounded into its operational reserve up/down limitations ($R^{U,k}_{drp\_max,zt}$ and $R^{D,k}_{drp\_max,zt}$) as given in (55) and (56). In (54), $PMAX^{k}_{drp,zt}$ is the maximum allowable curtailed power of kth level of DRP in period t and zone z.

$$0 \leqslant P^{k,s}_{drp,zt} - R^{D,k,s}_{drp,zt}, \quad \forall z,\ \forall t,\ k = I, II, III \tag{53}$$

$$R^{U,k,s}_{drp,zt} \leqslant PMAX^{k}_{drp,zt} - P^{k,s}_{drp,zt}, \quad \forall z,\ \forall t,\ k = I, II, III \tag{54}$$

$$0 \leqslant R^{U,k,s}_{drp,zt} \leqslant R^{U,k}_{drp\_max,zt}, \quad \forall z,\ \forall t,\ k = I, II, III \tag{55}$$

$$0 \leqslant R^{D,k,s}_{drp,zt} \leqslant R^{D,k}_{drp\_max,zt}, \quad \forall z,\ \forall t,\ k = I, II, III \tag{56}$$

4.6.2. Scenario-dependent constraints

Similar to the expressed relations for DG units, the scheduled reserve up/down provided by each level of DRP must cover the maximum difference between DG's scheduled power and the one produced in each scenario that can be expressed by (57)–(59). If it is not possible to meet the entire electricity demand, due to network constraints or inadequacy of the local production, a load curtailment, that is known as Energy Not Served (ENS), is scheduled, considering a share of the electric demand, up to a maximum value, $PMAX_{ens,zt}$, as given by (61):

$$P^{k,\omega}_{drp,zt} - P^{k,s}_{drp,zt} = R^{U,k,\omega}_{drp,zt} - R^{D,k,\omega}_{drp,zt}, \quad \forall z,\ \forall t,\ \forall\omega,\ k = I, II, III \tag{57}$$

$$0 \leqslant R^{U,k,\omega}_{drp,zt} \leqslant R^{U,k,s}_{drp,zt}, \quad \forall z,\ \forall t,\ \forall\omega,\ k = I, II, III \tag{58}$$

$$0 \leqslant R^{D,k,\omega}_{drp,zt} \leqslant R^{D,k,s}_{drp,zt}, \quad \forall z,\ \forall t,\ \forall\omega,\ k = I, II, III \tag{59}$$

$$0 \leqslant P^{k,\omega}_{drp,zt} \leqslant PMAX^{k}_{drp,zt}, \quad \forall z,\ \forall t,\ \forall\omega,\ k = I, II, III \tag{60}$$

$$\begin{aligned} &0 \leqslant P^{\omega}_{ens,zt} \leqslant PMAX_{ens,zt}, \quad \forall z,\ \forall t,\ \forall\omega \\ &0 \leqslant P^{s}_{ens,zt} \leqslant PMAX_{ens,zt}, \quad \forall z,\ \forall t \end{aligned} \tag{61}$$

4.7. Output power of PV modules and wind turbines

Once the wind speed and solar irradiation scenarios have been generated based on PEM, the mathematical model of wind turbines and PV modules must be applied to compute the output power of these units. The output power of the PV module is dependent on the solar irradiance and ambient temperature of the site as well as the characteristics of the module itself that is well addressed in [46]. There are some known approaches to determine the output power of wind turbines according to wind speed of the site. In this paper, a linear relation for modeling the performance of wind turbines has been used [46–48].

4.8. Exchanged reserve with spinning reserve market

The reserve concept is commonly defined as a power balancing source to improve the reliability margin of power system. The available reserve in each zone and each scenario (AR^{ω}_{zt}) can be attained by (62), in which, the total scheduled capacity (scheduled power plus scheduled reserve) minus the produced power of the reserve providing resources in each scenario is considered as available reserve provided by each zone. To accurate modeling, an auxiliary variable, named as feasible reserve (FR^{ω}_{zt}), is defined to take network limitations into account as shown in (63). To this end, a recurrence relation is considered to calculate the allowable reserve that can be crossed from each line of the radial network. As the plausible energy shortage in the scheduled bids of VPP to energy market ($P^{N_z,\omega}_{line,t} - P^{N_z,s}_{line,t}$) must be supported by reserve, this value is also embedded in the proposed model. Finally, the minimum obtained value of feasible reserve plus VPP's energy shortage through the all implemented scenarios is called as the amount of reserve offered from VPP to spinning reserve market as given in (64). It is assumed that the substation transformer capacity is restricted by the thermal limit of line N_z (P_{line_max,N_z}). The value of the exchanged power with spinning reserve market should meet the constraints expressed in (65) and (66).

$$\begin{aligned} AR^{\omega}_{zt} = &\sum_{dg=1}^{N_{dg}} \left(P^{s}_{dg,zt} + R^{U,s}_{dg,zt} - P^{\omega}_{dg,zt} \right) \\ &+ \sum_{k=I}^{III} \left(P^{k,s}_{drp,zt} + R^{U,k,s}_{drp,zt} - P^{k,\omega}_{drp,zt} \right), \quad \forall z,\ \forall t,\ \forall\omega \end{aligned} \tag{62}$$

$$\begin{aligned} FR^{\omega}_{zt} = &\min\left\{ (AR^{\omega}_{zt} + FR^{\omega}_{z-1t}), (P_{line\_max,z} - P^{\omega}_{line,zt}) \right\}, \\ &\forall z,\ \forall t,\ \forall\omega \middle| FR^{\omega}_{0t} = 0 \end{aligned} \tag{63}$$

$$P_{SR,t} = \min_{\omega}\left\{ FR^{\omega}_{N_z t} + (P^{N_z,\omega}_{line,t} - P^{N_z,s}_{line,t}) \right\}, \quad \forall t \tag{64}$$

$$P_{SR,t} \leqslant P_{line\_max,N_z} - P^{N_z,s}_{line,t}, \quad \forall t \tag{65}$$

$$-P_{line\_max,N_z} - P^{N_z,s}_{line,t} \leqslant P_{SR,t}, \quad \forall t \tag{66}$$

4.9. Thermal limit of power lines

The power flow through each line should be bounded by thermal limit of the line ($P_{line\_max,z}$). Because of radial topology of the network, this constraint is the only one that is considered to involve grid constraints. As this paper mainly focuses on optimal scheduling of VPP's resources for providing optimal bids to the electricity market and gaining to the maximum profit, thereby the role of reactive power for participating in the reactive power market or voltage control purposes and so on has not been investigated and the reactive power flow relationships are ignored. However, the proposed method is able to manage and schedule the active and reactive power equations, simultaneously.

$$\left| P^{s}_{line,zt} \right| \leqslant P_{line\_max,z}, \quad \forall t,\ z = 1 : N_z - 1 \tag{67}$$

$$|P^{\omega}_{line,zt}| \leqslant P_{line\_max,z}, \quad \forall z,\ \forall t,\ \forall\omega \tag{68}$$

4.10. Power balance

As the presented model is composed from two sections, the electrical and thermal parts, two power balance equations must be included for each zone as expressed by (69)–(75). In (69), $P^{s}_{sel,zt}$ is the scheduled served electrical load demand used in the objective function that is interpreted by (70). $P^{s}_{eq,zt}$, is an auxiliary variable that reflects the scheduled equivalent electric output power of each zone. The corresponding scenario-dependent expressions are shown in (72)–(74). The Eq. (75) indicates the thermal power balance of each zones of VPP.

$$P^{s}_{eq,zt} = P^{e}_{chp,zt} + P^{f}_{pv,zt} + \sum_{dg=1}^{N_{dg}} P^{s}_{dg,zt} + P^{e}_{st,zt} - P^{s}_{sel,zt} + P^{f}_{wt,zt}, \quad \forall z,\ \forall t \tag{69}$$

$$P^{s}_{sel,zt} = P^{f}_{el,zt} - \left(P^{I,s}_{drp,zt} + P^{II,s}_{drp,zt} + P^{III,s}_{drp,zt} + P^{s}_{ens,zt} \right), \quad \forall z,\ \forall t \tag{70}$$

$$P^{s}_{line,zt} = P^{s}_{eq,zt} + \sum_{i=1}^{z-1} P^{s}_{eq,it}, \quad \forall z,\ \forall t \tag{71}$$

$$\begin{aligned} P^{\omega}_{eq,zt} = &P^{e}_{chp,zt} + P^{\omega}_{pv,zt} + \sum_{dg=1}^{N_{dg}} P^{\omega}_{dg,zt} + P^{e}_{st,zt} - P^{\omega}_{sel,zt} \\ &+ P^{\omega}_{wt,zt}, \quad \forall z,\ \forall t,\ \forall\omega \end{aligned} \tag{72}$$

$$P^{\omega}_{sel,zt} = P^{\omega}_{el,zt} - \left(P^{I,\omega}_{drp,zt} + P^{II,\omega}_{drp,zt} + P^{III,\omega}_{drp,zt} + P^{\omega}_{ens,zt} \right), \quad \forall z,\ \forall t,\ \forall\omega \tag{73}$$

$$P^{\omega}_{line,zt} = P^{\omega}_{eq,zt} + \sum_{i=1}^{z-1} P^{\omega}_{eq,it}, \quad \forall z,\ \forall t,\ \forall\omega \tag{74}$$

$$P_{thl,zt} = k_{chp,z} * P^{e}_{chp,zt} + P_{boil,zt} + P^{t}_{st,zt} - P_{sh,zt}, \quad \forall z,\ \forall t \tag{75}$$

where $P^{f}_{pv,zt}$, $P^{f}_{wt,zt}$ and $P^{f}_{el,zt}$ are the forecasted (mean) values of PV's output power, wind turbine's output power and electrical load demand in period t and zone z, respectively. $P_{thl,zt}$ is the thermal load demand in period t and zone z.

The complete procedure of the proposed day-ahead Probabilistic Mixed-Integer Linear Programming (PMILP) model of VPP is shown in Fig. 3. The proposed model is solved using Mixed Integer Linear Programming (MILP) solver CPLEX under GAMS software.

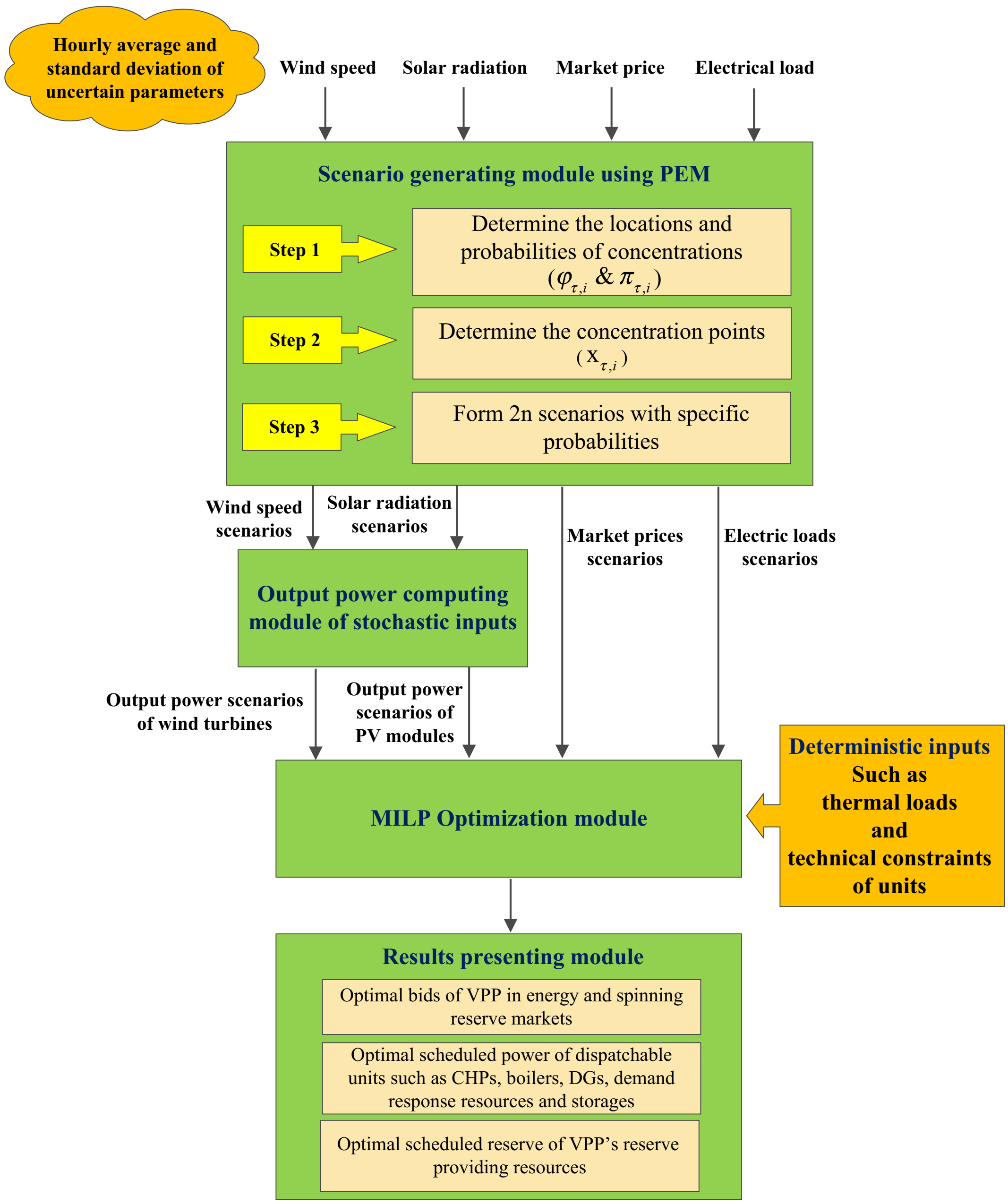

Fig. 3. The complete procedure of the proposed Probabilistic Mixed-Integer Linear Programming (PMILP) model using PEM.

5. Case study

The proposed method is tested on the typical network as introduced in Section 2 considering 4 zones for this study. Before presenting the simulation results, it is necessary to be expressed some important notes as follows:

- As the renewable energy plants are fed by no cost sources (solar and wind) and in support of clean energies, no charge is considered for these resources [49,50]. Otherwise, any other tariffs can be embedded in the proposed model.
- The considered VOLL in this paper ($\rho_{ens,t}$), is taken as 4000 $/MWh [44].
- The required technical input data for the generating units are provided in Table 1. The operational parameters of CHPs and DG units are taken from [19,20], respectively. Electrical and thermal storages data are taken from [11,19]. For gas-fired resources (boilers and CHPs), according to (10), $\rho_{NG,t}$ is chosen as 0.2623 dollars per cubic meter, based on reports of Ontario Energy Board (OEB) for winter 2014 [51]. Besides, the heating value of natural gas (HV_{NG}) equals 10,852 kcal/m^3 [52]. The values pertaining to prices and allowable curtailed load of the three-level DRP are shown in Fig. 4, as well.
- The data used for wind speed and solar radiation are taken from data archives of Waterloo university for one month (November 2014) to provide mean and standard deviation of these two parameters at each hour [53]. The applied mean data for uncertainty modeling of energy market price are derived from OEB, equal to 90% of the TOU prices announced for residential applications [54].
- The hourly mean (forecasted) values and estimated points of uncertain parameters by PEM are shown in Fig. 5.

Table 1
Input data for DGs, CHPs, boilers, storages and thermal limits of power lines.

Parameter	Zone 1	Zone 2	Zone 3	Zone 4	Parameter	Zone 1	Zone 2	Zone 3	Zone 4
α_{dg} ($/kWh)[a]	0.04	0.04	–	–	$k_{chp,z}$	0.9	0.7	1.1	1.5
$\alpha^U_{dg}, \alpha^D_{dg}$ ($/kWh)[a]	0.01	0.01	–	–	$\eta_{chp,z}$	0.33	0.25	0.25	0.33
β_{dg} ($/h)[a]	0.85	0.85	–	–	$SC_{chp,z}$ ($)	0.22	0.22	0.29	0.24
$\beta^U_{dg}, \beta^D_{dg}$ ($/h)[a]	0.21	0.21	–	–	$SHC_{chp,z}$ ($)	0.09	0.09	0.13	0.1
$P_{dg\_max,z}$ (kW)[a]	200	200	–	–	$\eta_{boil,z}$	0.85	0.95	0.9	0.85
$P_{dg\_min,z}$ (kW)[a]	50	50	–	–	$a^e_{st,z}$ ($/kWh)	8^*10^{-4}	8^*10^{-4}	10^{-3}	8^*10^{-4}
$R^U_{dg\_max,z}$ (kW)[a]	60	60	–	–	$a^t_{st,z}$ ($/kWh)	10^{-3}	8^*10^{-4}	10^{-3}	10^{-3}
$R^D_{dg\_max,z}$ (kW)[a]	60	60	–	–	$b^e_{st,z}$ ($/h)	0.01	0.02	0.02	0.015
$SC_{dg,z}$ ($)[a]	0.09	0.09	–	–	$b^t_{st,z}$ ($/h)	0.01	0.02	0.02	0.015
$SHC_{dg,z}$ ($)[a]	0.08	0.08	–	–	$E^e_{st,initial,z}$ (kWh)	18	60	0	20
$\#\alpha_{dg}$ ($/kWh)	–	–	0.03	0.03	$E^e_{st,final,z}$ (kWh)	20	50	10	40
$\#\alpha^U_{dg}, \alpha^D_{dg}$ ($/kWh)	–	–	0.01	0.01	$E^t_{st,initial,z}$ (kWh)	18	60	0	20
$\#\beta_{dg}$ ($/h)	–	–	2.5	2.5	$E^t_{st,final,z}$ (kWh)	20	50	10	40
$\#\beta^U_{dg}, \beta^D_{dg}$ ($/h)	–	–	0.63	0.63	$E^e_{st,max,z}$ (kWh)	30	60	10	20
$\#P_{dg\_max,z}$ (kW)	–	–	100	100	$E^t_{st,max,z}$ (kWh)	50	70	20	40
$\#P_{dg\_min,z}$ (kW)	–	–	20	20	$E^e_{st,min,z}$ (kWh)	10	20	0	0
$\#R^U_{dg\_max,z}$ (kW)	–	–	30	30	$E^t_{st,min,z}$ (kWh)	10	10	5	0
$\#R^D_{dg\_max,z}$ (kW)	–	–	30	30	$P^e_{st,charge,z}$ (kW)	7	5	1	10
$\#SC_{dg,z}$ ($)	–	–	0.16	0.16	$P^t_{st,charge,z}$ (kW)	7	5	1	10
$\#SHC_{dg,z}$ ($)	-	-	0.09	0.09	$P^e_{st,discharge,z}$ (kW)	5	10	5	5
$P^e_{chp\_max,z}$ (kW)	90	80	100	50	$P^t_{st,discharge,z}$ (kW)	5	10	5	5
$P^e_{chp\_min,z}$ (kW)	55	10	20	5	$P_{line\_max,z}$ (kW)	300	400	500	600

[a] First type DG: micro turbine. # second type DG: fuel cell.

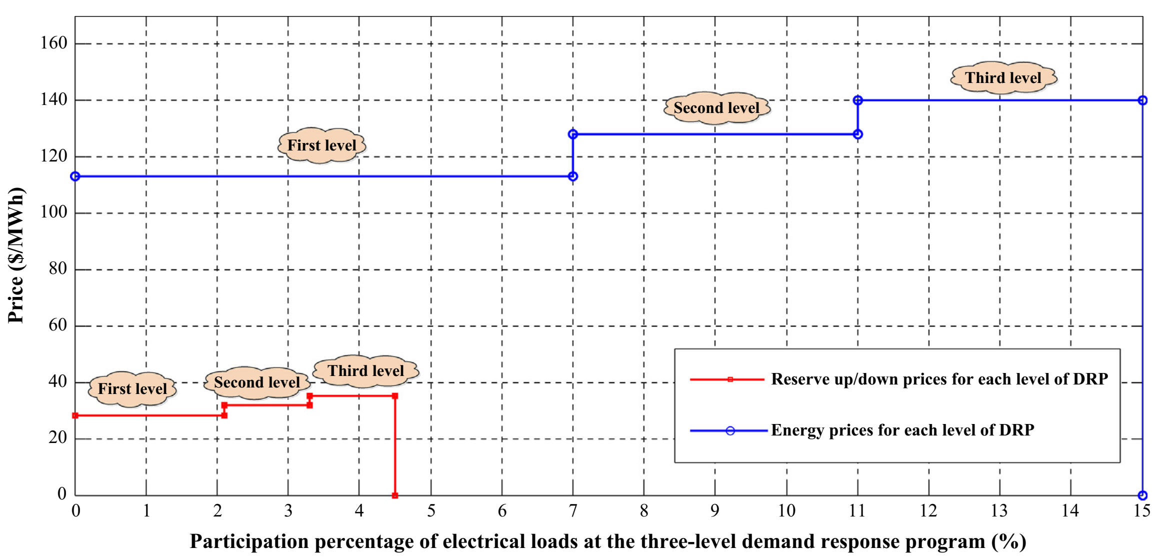

Fig. 4. The values pertaining to energy/reserve prices and allowable curtailed load of the three-level DRP.

The proposed method has been evaluated in three different cases described as follows:

5.1. Case 1. Deterministic state

In this case, the determined values are taken into account as input data. The hourly profit of VPP is shown in Fig. 6. According to the results, the VPP's profit is low in the beginning and end periods of the entire simulation horizon, due to lack of solar energy and also the wind power is at its lowest level. However, in periods 8:00–12:00 and 16:00–19:00, due to increase of the renewable power generation, the VPP's profit is at its highest levels. During periods 12:00–16:00, the VPP's profit is in lower levels if compared with other middle hours because of reducing energy market price and VPP's retail rate. In order to analyze the thermal part of the proposed model, the thermal output power of CHP systems and thermal load demand are concurrently illustrated in Fig. 7. As the efficiencies of CHPs in zones 1 and 4 are at a high level, these units are fully committed at all hours but the CHP unit in zone 1 is not able to meet the entire thermal load power, so boiler and thermal storage must be committed to feed the remained part of thermal load, (also in zone 2). For zone 3, because of economic benefits in electrical part, the thermal output power of CHP system exceeds from thermal demand; the surplus heat can be used for recharging thermal storages.

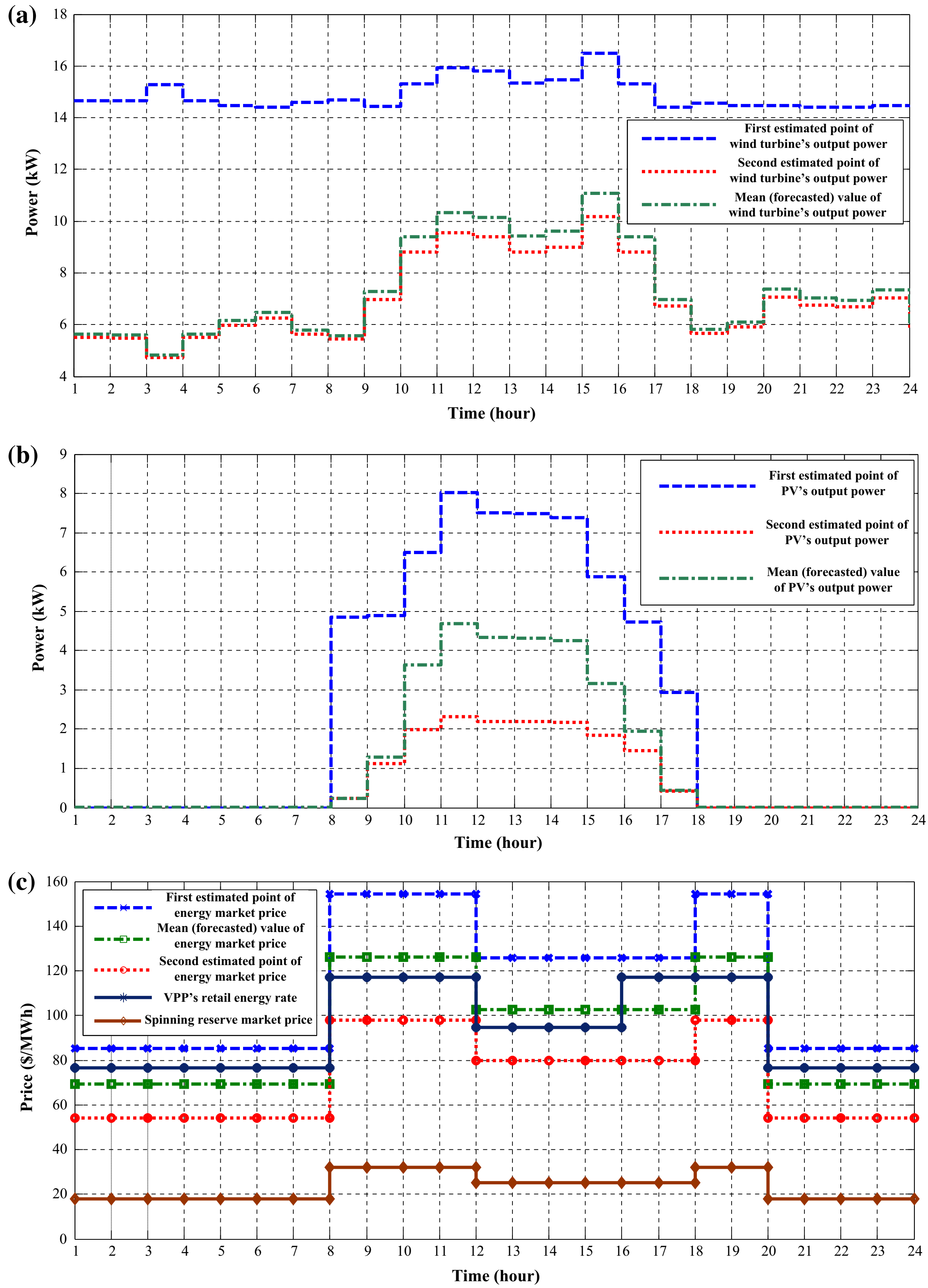

Fig. 5. Hourly forecasted, first estimated point and second estimated point for (a) output power of wind turbines, (b) output power of PVs, (c) energy market price in addition to contracted prices between VPP and end-consumers as well as spinning reserve market price and (d) VPP's electrical load power.

5.2. Case 2. Probabilistic state

In this case, the proposed model is simulated in which, scenarios are generated based on the presented approach in Section 3 for each uncertain parameter. The expected value of VPP's hourly profit and the scheduled exchanged power between VPP and energy/spinning reserve market are shown in Figs. 8 and 9, respectively. According to these results, during hours 1:00–6:00 and

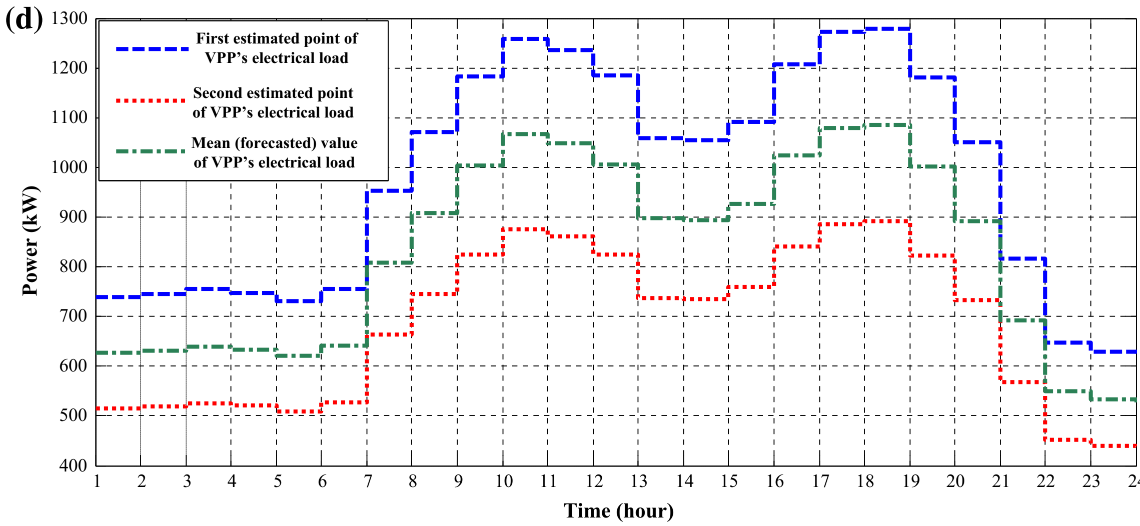

Fig. 5 (*continued*)

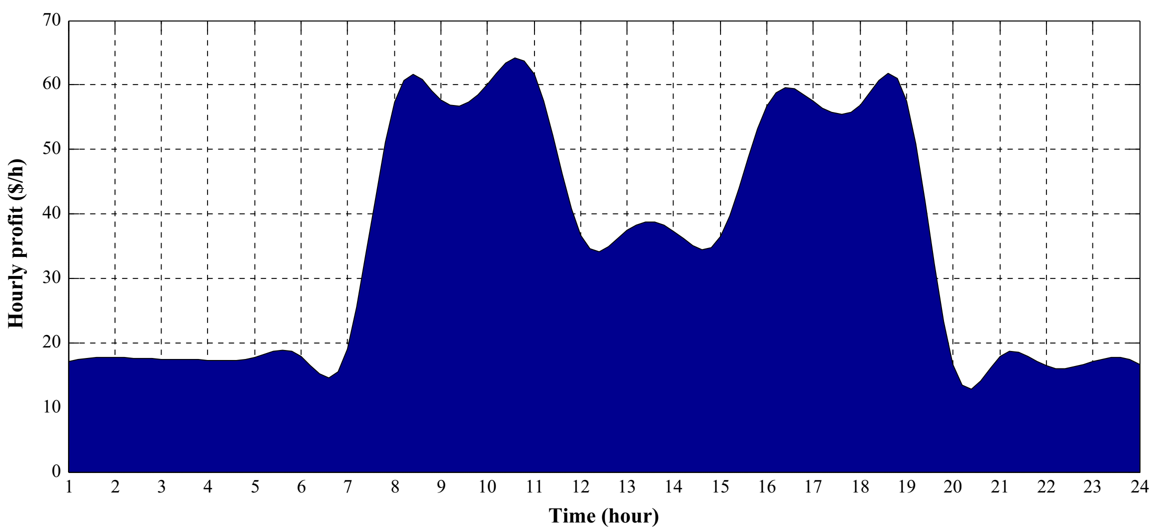

Fig. 6. Hourly profit of VPP for case 1.

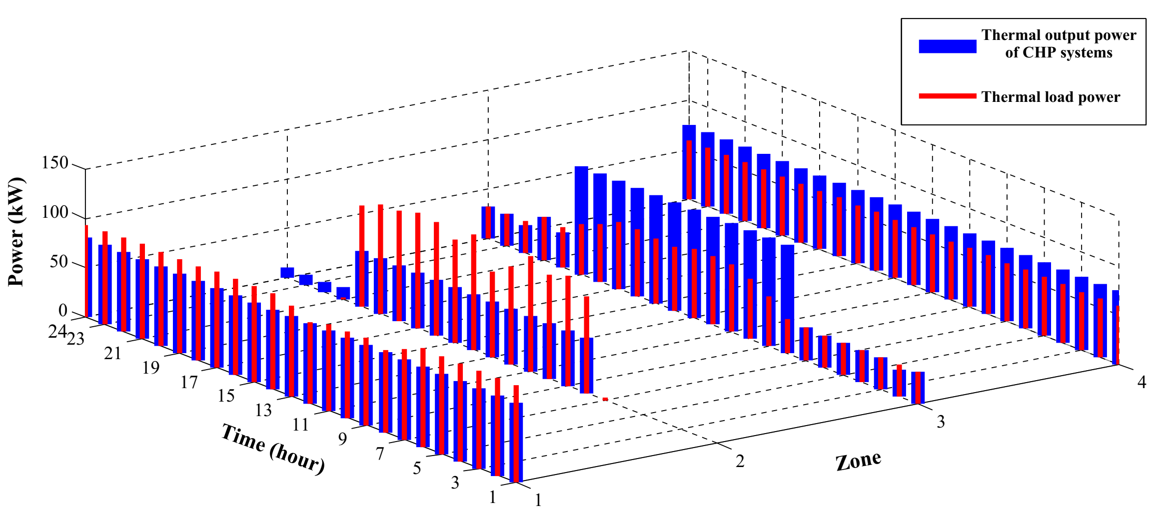

Fig. 7. Thermal output power of CHP systems and thermal load power in each zone and hour for case 1.

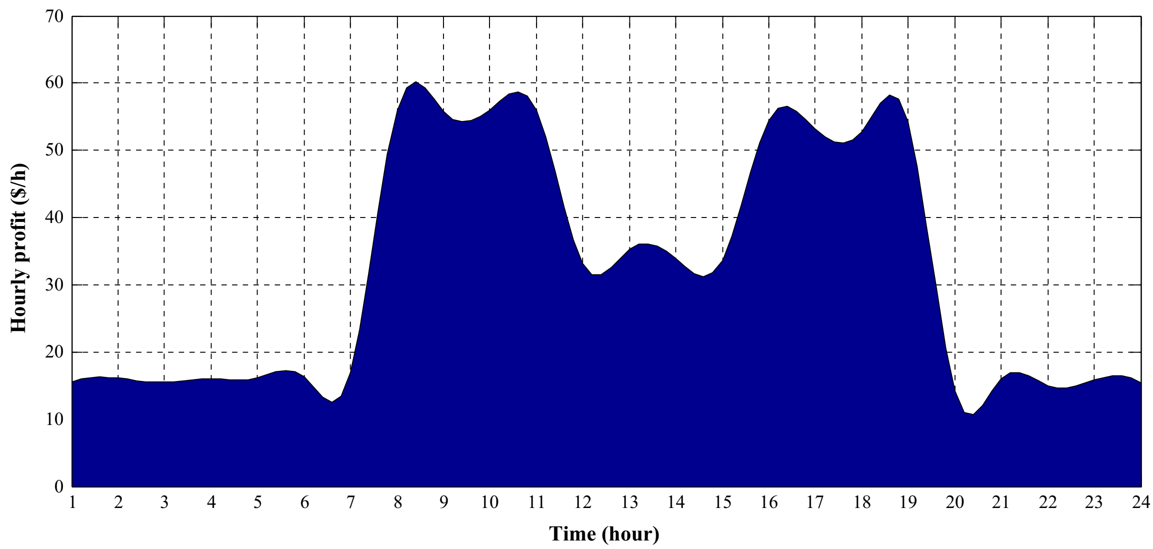

Fig. 8. The expected value of VPP's hourly profit for case 2.

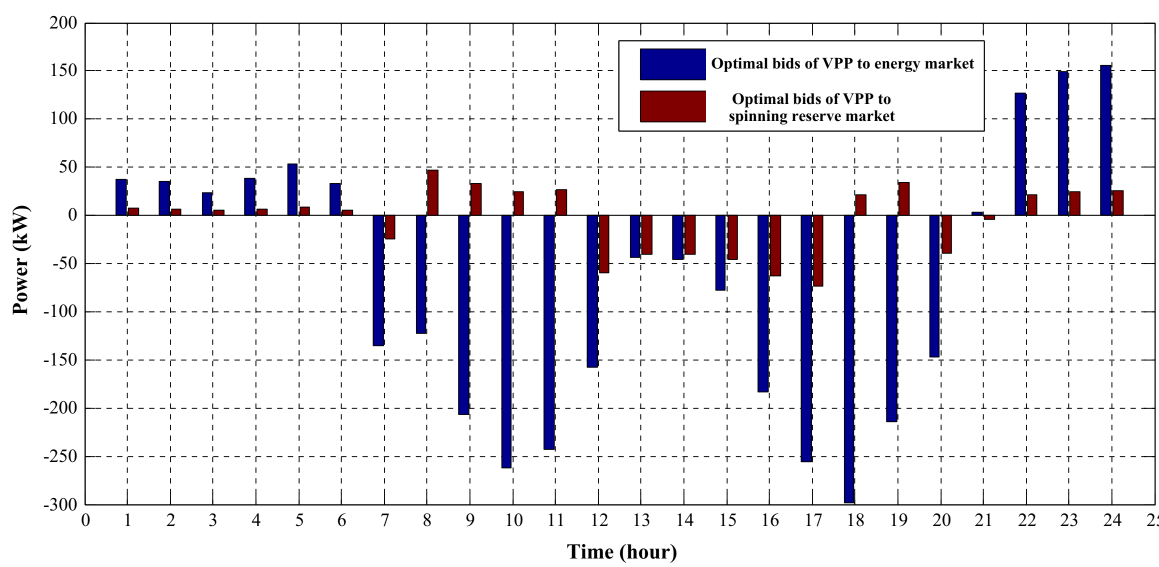

Fig. 9. Optimal bids of VPP to energy and spinning reserve markets for case 2.

21:00–24:00, VPP acts similar to a real power plant and sells specific amounts of energy to the energy market, while, its hourly profit is at the lowest levels, because, the level of solar energy equals zero (night hours) and the energy and VPP's retail prices are at the lowest levels. For the other hours (7:00–20:00), VPP is purchasing from energy market and its hourly profits are at high levels, because, the local productions are not able to meet the local demand, while, the retail prices goes up in the periods, if compared with the other periods. In periods (1:00–6:00), (8:00–11:00), (18:00–19:00) and (22:00–24:00), VPP's reserve providing resources not only are able to compensate VPP's energy shortage but also sell specific amounts of reserve to spinning reserve market. The state of charge in electrical storages is given in Fig. 10 which shows that at the most expensive hours of electricity (8:00–11:00 and 18:00–19:00), electrical storages are in discharging mode. On the other hand, when the electricity prices are low (in periods 1:00–7:00 and 20:00–24:00), electrical storages are in charging mode.

5.3. Case 3. Special state

In this case, a special state is investigated assuming that maximum power flow through upstream line of zone 2 is restricted to 120 kW to take network limitations into account. In fact, this case is just considered for performance assessment of the proposed model and how VPP manages its resources in the presence of network constraints. This case is run for two conditions, with/without presence of the proposed DRP. The VPP's hourly profits, curtailed power of the DRP and the energy not-served are shown in Figs. 11–13, respectively, which demonstrate that in the presence of DRP, the amounts of VPP's hourly profit and energy not-served are considerably improved if compared with the ones in the case without DRP. For instance, in period 18:00 at which a sharp drop is occurred in the VPP's profit, the considerable amount of curtailed load power from executing DRP is replaced with the energy not-served; so, the cost due to an incentive-based payment is substituted with VOLL that consequently imposes much more cost to VPP.

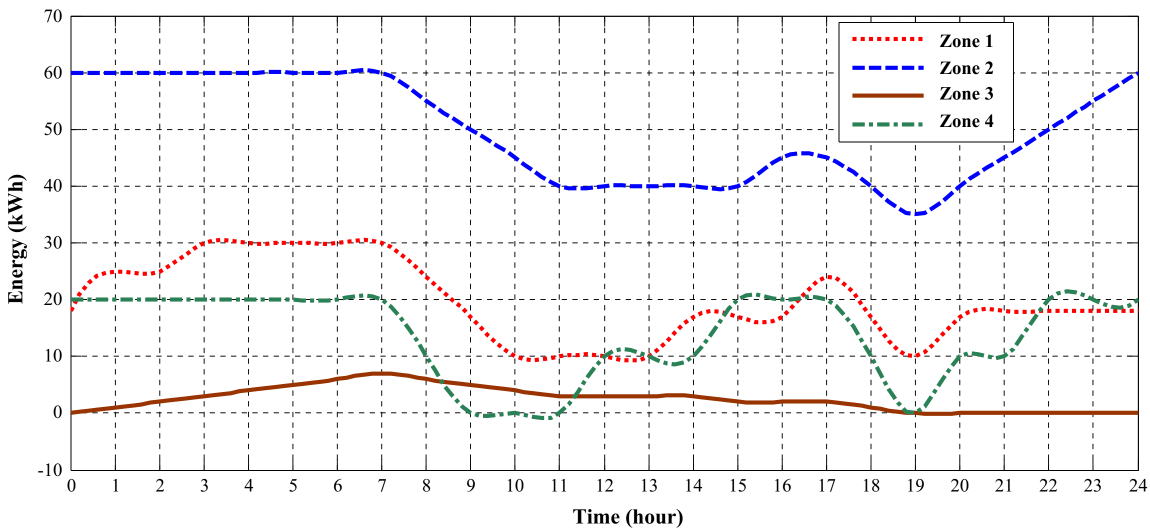

Fig. 10. State of charge in electrical storages in each zone and each hour for case 2.

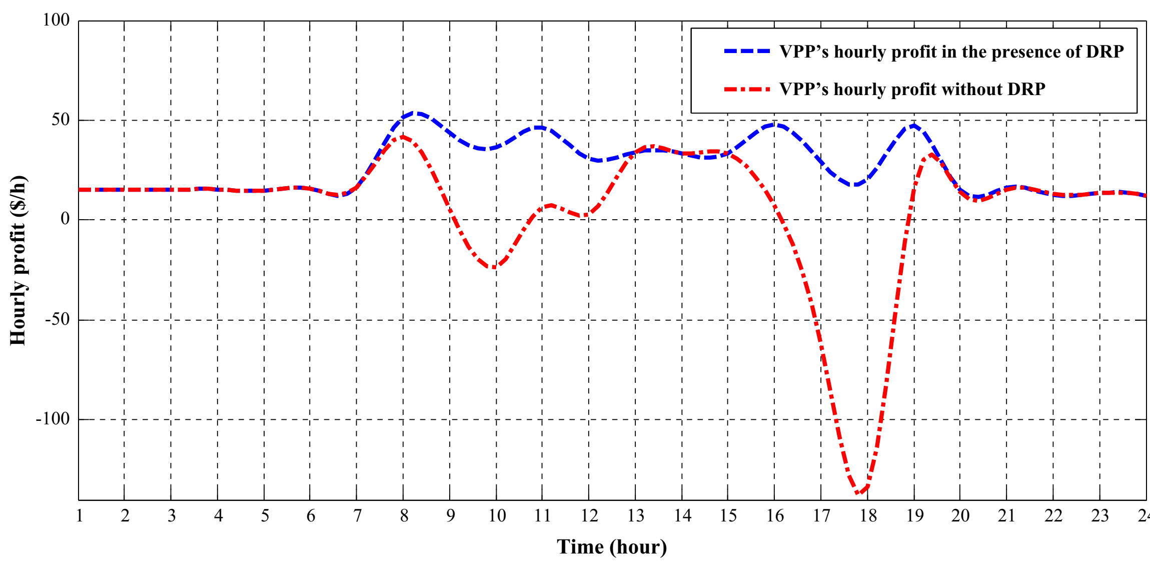

Fig. 11. The expected value of VPP's hourly profit for case 3.

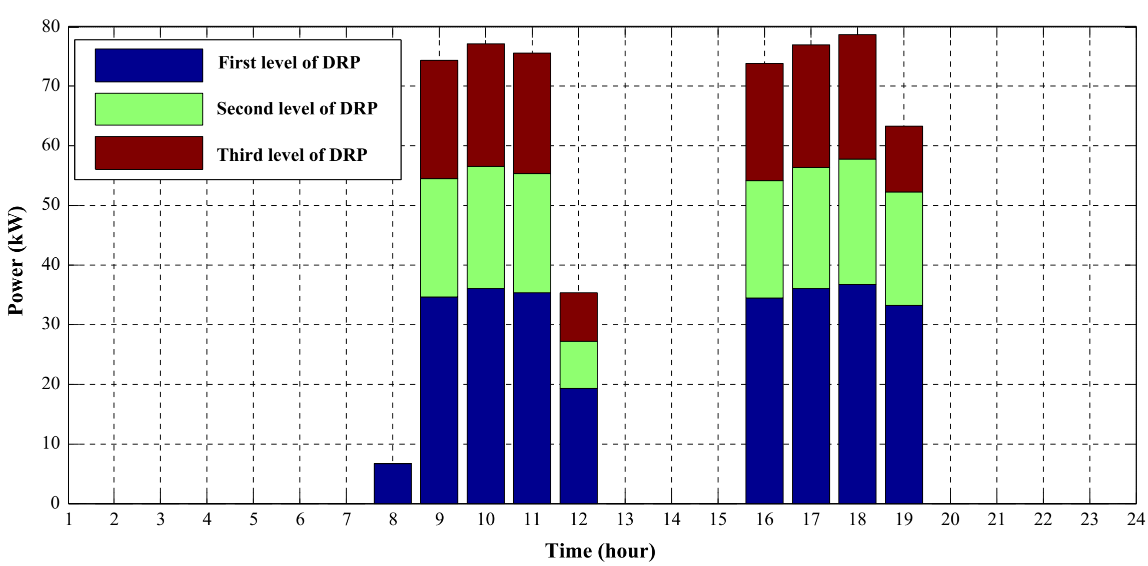

Fig. 12. The scheduled summation of curtailed power at each level of DRP for all zones in case3.

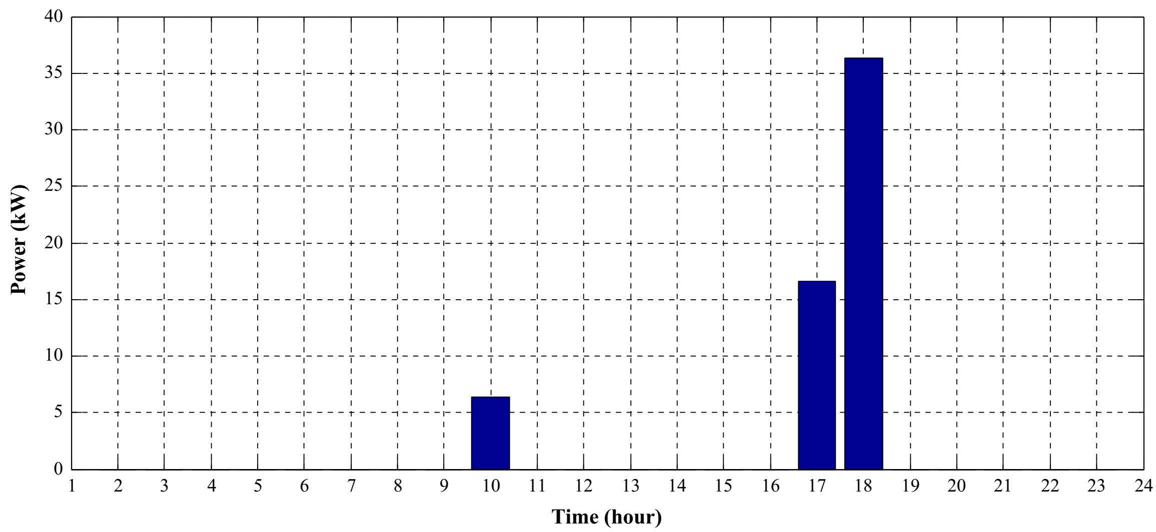

Fig. 13. The scheduled summation of energy not-served for all zones in case 3.

Table 2
The VPP's daily profit (value of objective function) at each case ($).

Case 1	Case 2	Case 3	
		With DRP	Without DRP
822.39	763.44	632.09	139.11

In order to compare these three simulated cases, the obtained results for VPP's daily profit at each case are reported in Table 2 which shows that the expected value of VPP's daily profit in case 2 is more than the ones obtained in case 3. A comparison between the results in cases 1 and 2 demonstrates that the VPP's profit extremely depends on the network situations.

6. Conclusion

In this paper, a probabilistic model is proposed for optimal electrical/thermal scheduling of a virtual power plant to incorporate in both energy and spinning reserve markets. To this end, the PEM is applied for modeling of existing uncertainties in operation of a generic VPP. Moreover, simultaneous energy and reserve scheduling method considering DRPs has been presented. The results evidenced that the VPP's reserve providing resources are not only able to compensate the plausible shortage of VPP's committed energy to the energy market due to the existing uncertainties, but also can bid the specific amounts of reserve to the spinning reserve market in some periods. Also, the results showed that coordination performance of storages and the proposed demand response resources could increase VPP's profit and reduce its dependency on the upstream network.

References

[1] Schulz C, Roder G, Kurrat M. Virtual power plants with combined heat and power micro-units. In: International conference on future power systems. IEEE; 2005. p. 16–8.
[2] Schulz C. Business models for distribution power generation with combined heat and power micro-unit. In: 3rd International conference on the European electricity market. IEEE; 2006. p. 24–6.
[3] Wille-Haussmann B, Erge T, Wittwer C. Decentralised optimization of cogeneration in virtual power plants. Solar Energy 2010;84(4):604–11.
[4] Dupont B, Dietrich K, De Jonghe C, Ramos A, Belmans R. Impact of residential demand response on power system operation: a Belgian case study. Appl Energy 2014;122:1–10.
[5] Alipour M, Mohammadi-Ivatloo B, Zare K. Stochastic risk-constrained short-term scheduling of industrial cogeneration systems in the presence of demand response programs. Appl Energy 2014;136:393–404.
[6] Gerami Moghaddam I, Nick M, Fallahi F, Sanei M, Mortazavi S. Risk-averse profit-based optimal operation strategy of a combined wind farm-cascade hydro system in an electricity market. Renew Energy 2013;55:252–9.
[7] Sousa T, Morais H, Vale Z, Castro R. A multi-objective optimization of the active and reactive resource scheduling at a distribution level in a smart grid context. Energy 2015;85:236–50.
[8] Pandzic H, Kuzle I, Capuder T. Virtual power plant mid-term dispatch optimization. Appl Energy 2013;101:134–41.
[9] Pandzic H, Morales JM, Conejo AJ, Kuzle I. Offering model for a virtual power plant based on stochastic programming. Appl Energy 2013;105:282–92.
[10] Mashhour E, Moghaddas-Tafreshi SM. Bidding strategy of virtual power plant for participating in energy and spinning reserve markets – part I: problem formulation. IEEE Trans Power Syst 2011;26(2):949–56.
[11] Mashhour E, Moghaddas-Tafreshi SM. Mathematical modeling of electrochemical storage for incorporation in methods to optimize the operational planning of an interconnected micro grid. J Zhejiang Univ Sci 2010;11(4):737–50.
[12] Mashhour E, Moghaddas-Tafreshi SM. Bidding strategy of virtual power plant for participating in energy and spinning reserve markets: part II: numerical analysis. IEEE Trans Power Syst 2011;26(2):957–64.
[13] Faria P, Soares J, Vale Z, Morais H, Sousa T. Modified particle swarm optimization applied to integrated demand response and DG resources scheduling. IEEE Trans Smart Grid 2013;4(1):606–16.
[14] Liu G, Tomsovic K. A full demand response model in co-optimized energy and reserve market. Electric Power Syst Res 2014;111:62–70.
[15] Sousa T, Morais H, Soares J, Vale Z. Day-ahead resource scheduling in smart grids considering Vehicle-to-Grid and network constraints. Appl Energy 2012;96:183–93.
[16] Wang D, Parkinson S, Miao M, Jia H, Crawford C, Djilali N. Hierarchical market integration of responsive loads as spinning reserve. Appl Energy 2013;104:229–38.
[17] Tascikaraoglu A, Erdinc O, Uzunoglu M, Karakas A. An adaptive load dispatching and forecasting strategy for a virtual power plant including renewable energy conversion units. Appl Energy 2014;119:445–53.
[18] Moghimi Ghadikolaei H, Tajik E, Aghaei J, Charwand M. Integrated day-ahead and hour-ahead operation model of discos in retail electricity markets considering DGs and CO_2 emission penalty cost. Appl Energy 2012;95:174–85.
[19] Giuntoli M, Poli D. Optimized thermal and electrical scheduling of a large scale virtual power plant in the presence of energy storages. IEEE Trans Smart Grid 2013;4(2):942–55.
[20] Shi L, Luo Y, Tu GY. Bidding strategy of microgrid with consideration of uncertainty for participating in power market. Electrical Power Energy Syst 2014;59:1–13.
[21] Mashhour E, Moghaddas-Tafreshi SM. A review on operation of micro grids and virtual power plants in the power markets. In: 2nd International conference on adaptive science & technology; 2009. p. 273–7.
[22] Pudjianto D, Ramsay C, Strbac G, Durstewitz M. The virtual power plant: enabling integration of distributed generation and demand. FENIX Bulletin 2008;2, February 2008.
[23] Stadler M, Groissbock M, Cardoso G, Marnay C. Optimizing distributed energy resources and building retrofits with the strategic DER-CA Model. Appl Energy 2014;132:557–67.

[24] Obara S, Kawai M, Kawae O, Morizane Y. Operational planning of an independent microgrid containing tidal power generators, SOFCs, and photovoltaics. Appl Energy 2013;102:1343–57.

[25] Jie Z, Peng W, Jie H. Control strategy of microgrid inverter operation in grid-connected and grid-disconnected modes. In: 2011 International conference on electrical information and control engineering (ICEICE); 2011. p. 1257–60.

[26] Basu AK, Bhattacharya A, Chowdhury S, Chowdhury SP. Planned scheduling for economic power sharing in a CHP-based micro-grid. IEEE Trans Power Syst 2012;27:30–8.

[27] Pudjianto D, Ramsay C, Strbac G. Virtual power plant and system integration of distributed energy resources. Renew Power Gener, IET 2007;1(1):10–6.

[28] Setiawan EA. Concept and controllability of virtual power plant, Ph.D. dissertation. Kassel Univ. (Kassel, Germany); 2007.

[29] Wood AJ, Wollenberg BF. Power generation, operation and control. 2nd ed. New York: Wiley; 1996.

[30] Bouffard F, Galiana FD, Conejo AJ. Market-clearing with stochastic security—part I: formulation. IEEE Trans Power Syst 2005;20:1818–26.

[31] Bouffard F, Galiana FD. Stochastic security for operations planning with significant wind power generation. IEEE Trans Power Syst 2008;23:306–16.

[32] Zakariazadeh A, Jadid S, Siano P. Stochastic operational scheduling of smart distribution system considering wind generation and demand response programs. Int J Electr Power Energy Syst 2014;63:218–25.

[33] Soroudi A. Taxonomy of uncertainty modeling techniques in renewable energy system studies. Green Energy Tech 2014:1–17 [The first chapter of large scale renewable power generation].

[34] Cervone A, Carbone G, Santini E, Teodori S. Optimization of the battery size for PV systems under regulatory rules using a Markov-Chains approach. Renew Energy 2016;85:657–65.

[35] Babiarz B, Blokus-Roszkowsk A. Probabilistic model of district heating operation process in changeable external conditions. Energy Build 2015;103:159–65.

[36] Zhang Y, Wang J, Wang X. Review on probabilistic forecasting of wind power generation. Renew Sustain Energy Rev 2014;32:255–70.

[37] Musolino V, Pievatolo A, Tironi E. A statistical approach to electrical storage sizing with application to the recovery of braking energy. Energy 2011;36:6697–704.

[38] Tajeddini M, Rahimi-Kian A, Soroudi A. Risk averse optimal operation of a virtual power plant using two stage stochastic programming. Energy 2014;73:958–67.

[39] Niknam T, Golestaneh F, Malekpour A. Probabilistic energy and operation management of a microgrid containing wind/ photovoltaic/fuel cell generation and energy storage devices based on point estimate method and self-adaptive gravitational search algorithm. Energy 2012;43:427–37.

[40] Li P, Zhou Z, Shi R. Probabilistic optimal operation management of microgrid using point estimate method and improved bat algorithm. In: 2014 PES general meeting conference and exposition. IEEE; 2014. p. 1-5.

[41] Peik-Herfeh M, Seifi H, Sheikh-El-Eslami MK. Decision making of a virtual power plant under uncertainties for bidding in a day-ahead market using point estimate method. Electr Power Energy Syst 2013;44:88–98.

[42] Zakariazadeh A, Jadid S, Siano P. Stochastic multi-objective operational planning of smart distribution systems considering demand response programs. Electric Power Syst Res 2014;111:156–68.

[43] EURELECTRIC. Active distribution system management: a key tool for the smooth integration of distributed generation. EURELECTRIC paper; 2013 <http://www.eurelectric.org/media/74346/asmfinalgenerisrecomm130204de-flr-2013-030-0116-01-e.pdf>.

[44] Magness B, Seely CV. Value of lost load literature review and macroeconomic analysis prepared for Ercot by London Economics International LLC. public utility commission of texas, project no. 40000; 2013.

[45] Lee J, Kim H. LP-based mathematical model for optimal microgrid operation considering heat trade with district heat system. Int J Energy, Inf Commun 2013;4(4):13–22.

[46] Atwa YM, El-Saadany EF, Salama MMA, Seethapathy R. Optimal renewable resources mix for distribution system energy loss minimization. IEEE Trans Power Syst 2010;25:360–70.

[47] Atwa YM, El-Saadany EF. Probabilistic approach for optimal allocation of wind-based distributed generation in distribution systems. Renew Power Gen IET 2011;5(1):79–88.

[48] Wang MQ, Gooi HB. Spinning reserve estimation in microgrids. IEEE Trans Power Syst 2011;26(3):1164–74.

[49] Marwali M KC, Ma H, Shahidehpour SM, Abdul-Rahman KH. Short term generation scheduling in photovoltaic-utility grid with battery storage. IEEE Trans Power Syst 1998;13(3):1057–62.

[50] Lu B, Shahidehpour M. Short-term scheduling of battery in a grid-connected PV/battery system. IEEE Trans Power Syst 2005;20(2):1053–61.

[51] Available online <http://www.ontarioenergyboard.ca/oeb/Consumers/Natural%20Gas/Natural%20Gas%20Rates>.

[52] Available online <http://www.nrcan.gc.ca/energy/natural-gas/5641>.

[53] Available online <http://weather.uwaterloo.ca/data.html>.

[54] Available online <http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Electricity+Prices>.