Optimal day-ahead scheduling of integrated urban energy systems

Jin, X., Mu, Y., Jia, H., Wu, J., Xu, X., & Yu, X. (2016). Optimal day-ahead scheduling of integrated urban energy systems. Applied Energy, 180, 1-13. DOI: 10.1016/j.apenergy.2016.07.071

Published in:
Applied Energy

Document Version:
Peer reviewed version

Optimal Day-Ahead Scheduling of Integrated Urban Energy Systems

Xiaolong Jin[a], Yunfei Mu[a*], Hongjie Jia[a], Jianzhong Wu[b], Xiandong Xu[c], Xiaodan Yu[a]

[a]Key Laboratory of Smart Grid of Ministry of Education, Tianjin University, Tianjin 30072, China

[b]Institute of Energy, School of Engineering, Cardiff University, Cardiff CF24 3AA, UK

[c]School of Electronics, Electrical Engineering and Computer Science, Queen's University Belfast, Belfast BT9 5 AH, UK

Email address: xljin@tju.edu.cn, yunfeimu@tju.edu.cn, hjjia@tju.edu.cn, wuj5@cardiff.ac.uk, x.xu@qub.ac.uk, yuxd@tju.edu.cn

*Corresponding author: Yunfei Mu: Tel.: +86-158-2250-9583; E-mail address: yunfeimu@tju.edu.cn

Abstract

An optimal day-ahead scheduling method (ODSM) for the integrated urban energy system (IUES) is introduced, which considers the reconfigurable capability of an electric distribution network. The hourly topology of a distribution network, a natural gas network, the energy centers including the combined heat and power (CHP) units, different energy conversion devices and demand responsive loads (DRLs), are optimized to minimize the day-ahead operation cost of the IUES. The hourly reconfigurable capability of the electric distribution network utilizing remotely controlled switches (RCSs) is explored and discussed. The operational constraints of the unbalanced three-phase electric distribution network, the natural gas network, and the energy centers are considered. The interactions among the above systems are described by an energy hub model. A hybrid optimization method based on genetic algorithm (GA) and a nonlinear interior point method (IPM) is utilized to solve the ODSM model. Numerical studies demonstrate that the proposed ODSM is able to provide the IUES with an effective and economical day-ahead scheduling scheme and reduce the operational cost of the IUES.

Keywords: Integrated urban energy system (IUES), energy center, combined heat and power (CHP) unit, reconfiguration, energy hub, day-ahead scheduling.

NOMENCLATURE

Abbreviations

ODSM	Optimal day-ahead scheduling method.
IUES	Integrated urban energy system.
CHP	Combined heat and power.
RCS	Remotely controlled switches.
DRL	Demand responsive load.
CAC	Central air-conditioning.

Indices

t	Index of time intervals.
i, j, $N_{e\text{-}bus}$	Indices and total number of electric buses.
m, k, $N_{g\text{-}bus}$	Indices and total number of natural gas nodes.
N_{br}	Total number of electric feeders.
$N_{pipeline}$	Total number of natural gas pipelines.
N_{EH}	Total number of energy hubs.
$N_{EH\text{-I}}$, $N_{EH\text{-}\Pi}$	Total number of type-I and type-Π energy hubs.
δ	Index of DRLs.
r	Index of RCSs.
ε	Index of energy centers in IUES.

Parameters and constants

C^e, C^g	Day-ahead wholesale electricity price and natural gas price.
C^{DRL}, C^{SW}	Day-ahead contract price of DRLs participation and cost of each switching action for RCSs.
P_e^l	Other electric loads not supplied by the energy centers.
L_e, L_h	Electric power and heat power output of the energy center.
Y, θ	Magnitude and phase angle of electric feeder’s admittance.
$P_{\min}^{grid}, P_{\max}^{grid}$	Maximum and minimum limits of the day-ahead electricity purchase.
$P_{\min}^{gas}, P_{\max}^{gas}$	Maximum and minimum limits of the day-ahead natural gas purchase.
$P_{e,\min}^{EH}, P_{e,\max}^{EH}$	Maximum and minimum limits of electric power exchange of the energy center.
$P_{g,\min}^{EH}, P_{g,\max}^{EH}$	Maximum and minimum limits of natural gas power exchange of the energy center.
$P_{\max}^{\mathrm{DRL}}$	Maximum power reduction by DRLs.
$V_{\min}$, $V_{\max}$	Maximum and minimum limits of the magnitude of bus voltage.
$i_{\max}^{f_e}$	Upper current limit of electric feeder.
p_{min}, p_{max}	Maximum and minimum limits of gas node pressure.
N_{loop}	Number of main loops in the electric distribution network.
k_{kn}	Parameter that depends on gas pipeline parameters, gas properties and gas temperature.
$\eta_{ge}^{CHP}, \eta_{gh}^{CHP}$	Conversion efficiency of gas into electricity and heat through CHP unit.
η^{AC}	Thermal energy conversion rate of the CAC.
η^{GB}	Efficiency of the gas-boiler.
$P_{\varepsilon,\max}^{\mathrm{CHP}}, P_{\varepsilon,\min}^{\mathrm{CHP}}$	Upper and lower limits of the power output of the CHP unit.
$P_{\varepsilon,\max}^{\mathrm{AC}}, P_{\varepsilon,\min}^{\mathrm{AC}}$	Maximum and minimum capacity of the CAC.

Variables

P^{grid}	Day-ahead electric power purchases.
P^{gas}	Day-ahead natural gas purchases.
P^{DRL}	Day-ahead power reduction by DRLs.
RCS	Vector of remotely controlled switch status.
N_{RCS}^{SW}	Switching actions for RCS.
P^{f_e}	Active electric power flow of electric feeder.
V, S	Bus voltage and apparent power flow of electric feeder.
p, F^{f_g}	Gas node pressure and gas pipeline flow.
P_e^{EH}, P_g^{EH}	Electric power and natural gas power exchange of the energy center.
v_e, v_g	Electric and natural gas partition coefficients.
P^{PV}	Output of the photovoltaic panel.
P^{WT}	Output of the wind turbine.

1. Introduction

The increasing level of environmental pollution and depletion of fossil fuels are the two main factors that restrict the development of future low-carbon cities [1]. In order to tackle these problems, more and more attention has been paid on the integrated urban energy system (IUES) with couplings and interactions among various energy systems (e.g. electric power systems, natural gas supply systems, and heat systems) at the urban or community level [2] [3]. The IUES is able to coordinate the above energy systems to provide new solutions for more secure, sustainable and economical energy production, distribution and consumption in the future low-carbon cites [4].

The active elements (e.g. the electric distribution network with hourly reconfigurable topology enabled by remotely controlled switches (RCSs) and the energy center including combined heat and power (CHP) units, different energy conversion devices and demand responsive load (DRL)) endow the IUES with a more flexible operation capability, which can realize a comprehensive utilization of multiple energy resources. However, with an increasing penetration of renewable energy resources and a large-scale adoption of electric vehicles (EVs) at the demand side [5]-[8], the efficiency and reliability of both natural gas and electric distribution networks in the IUES are affected significantly. Thus, the optimization, coordination and management of these active elements in various energy systems are of significant importance for the integration of renewable energy and reducing the cost of energy utilization for the IUES.

The energy resource scheduling plays an increasingly important role for the daily operation of energy systems, which mainly focuses on unit commitment and economic dispatch. The optimal scheduling approaches for various energy systems have been intensively studied, including power systems [9]-[12], natural gas supply systems [13]-[15], and integrated energy systems [16]-[25].

- Power systems

Optimal scheduling approaches were developed for stochastic power systems [9], distribution networks [10] and Microgrids [11] to seek the optimum scheduling solutions. A day-ahead stochastic scheduling approach based on a chance-constrained stochastic programming was proposed in [9]. An optimal scheduling and control model for a Microgrid was proposed in [11] taking several uncertainties into consideration. It is worth noting that an optimal scheduling framework was proposed in [10] which used the flexible topology of a distribution network as a control variable to increase the amount of imported electric power with low electricity prices. More economic saving was realized because the topology reconfiguration increased the electric power supply capability [12].

- Natural gas supply systems

An optimal scheduling model for a natural gas transmission network was developed in [13] to solve the problem of transmitting natural gas at a minimum cost through a pipeline network under the constraints of nonlinear flow-pressure relations, material balance equations and pressure bounds. A dynamic programming-based tree decomposition algorithm was utilized in [14] to minimize the fuel cost for natural gas transmission networks. A new geometric programming approach for optimizing the operation in natural gas system was developed in [15].

- Integrated energy systems

The interactions between different energy systems at different scales were analyzed, including the impact from pipeline faults of the natural gas system on the power system security [16] and the unit commitment [17], *etc*. In this context, hourly optimal scheduling of integrated energy systems (interdependent natural gas and electric power systems) with high penetration of wind energy [18] and flexible hourly demand response [19] was proposed to determine the optimum day-ahead scheduling solutions. Dynamic modeling and interaction of hybrid natural gas and electricity supply systems in a Microgrid were studied in [20]. Operational scheduling of the Great Britain integrated gas and electricity networks considering the uncertainties in wind power forecast was developed to reduce the operation cost [21]. The optimal scheduling of IUES at the urban or community level was developed based on an energy hub model [22]-[25]. An energy hub based optimization model of residential IUES was presented in [22] to optimally control the residential energy loads, storage system and production components considering the customer preferences and the comfort level. A general optimization framework was presented for urban multiple energy carrier systems in [23]. A hierarchical energy management system was designed for a community level Microgrid and IUES based on the energy hub model in [24][25].

The existing research works have made good contributions to the scheduling of different energy systems, especially power systems and natural gas systems, which are mature for engineering applications. As to the IUES, the current research on optimal scheduling mainly concentrates on the scheduling of energy generation and energy demand. The flexible reconfigurable topology of the electric distribution network of the IUES was always neglected, which is conservative to some extent for the operation cost reduction of the IUES. Actually, the topology of an electric distribution network has close relationship with the scheduling scheme of the IUES [26]. Furthermore, the electric distribution network of the IUES is generally characterized as an unbalanced three-phase system. However, previous studies usually assumed that the IUES is balanced and the constraints from the unbalanced three-phase electric distribution network were not considered in the optimal scheduling solutions.

To solve the above problems, an optimal day-ahead scheduling method (ODSM) for an IUES considering the reconfigurable capability of an electric distribution network was developed. The hourly reconfigurable capability of the electric distribution network utilizing RCSs was explored and discussed. The interactions between the electric distribution network and a natural gas network of the IUES were represented by an energy hub model. The constraints of the unbalanced three-phase electric distribution network, the natural gas network, and the energy centers were considered in the ODSM. A hybrid optimization method based on genetic algorithm (GA) and a nonlinear interior point method (IPM) was utilized to solve the ODSM model. The ODSM allows the operators of the IUES to coordinate the interrelated power, gas, and heating systems, taking three-phase electric distribution network characteristics into account. Numerical studies shown that different energy systems were coordinated effectively and the operation cost of IUES was reduced.

2. Model of the integrated urban energy system (IUES)

An IUES is illustrated in Fig. 1, which involves three energy systems, i.e. an electric distribution system, a natural gas system and an energy center. The IUES purchases energy (electricity and natural gas) from different energy utilities and distributes them via the electric distribution network, the natural gas network and the energy center to satisfy the energy demand. At the energy demand side, the IUES signs bilateral contracts with DRLs for their participation in the provision of ancillary services for the IUES. The coupling relationships between the electric distribution network and the natural gas network are represented by the energy centers.

Fig. 1. Description of the IUES.

In this paper, an energy hub model is utilized to describe the energy center, which includes the CHP unit, the power transformers, the central air-conditionings (CACs) and the gas-boilers. The input energy consists of electricity and gas, the output energy consists of electricity and thermal energy. The energy exchanges are executed through three different types of common coupling points (PCC), i.e. the electric PCC, the natural gas PCC and the heat PCC, of the IUES.

2.1. Natural gas network model

The general equation for calculating gas flow F_{kn} is shown as Eqs. (1)~(2) [27]:

$$F_{kn} = k_{kn} s_{kn} \sqrt{s_{kn} (p_k^2 - p_n^2)} \tag{1}$$

$$s_{kn} = \begin{cases} +1 \text{ if } & p_k - p_n \geq 0 \\ -1 \text{ if } & p_k - p_n < 0 \end{cases} \tag{2}$$

2.2. Energy center model

The energy center includes three operating modes, the electric load following mode, the thermal load following mode, and the hybrid thermal-electric load following mode [28]. In this paper, the energy conversion processes of the energy center under the hybrid thermal-electric load following mode are characterized in the energy hub model incorporating interactions among different energy systems and component constraints, as shown in Fig. 2.

Fig. 2. Structure of the energy hub model.

Two types of energy hub structure are considered in this paper as shown in Fig. 2. The first type is composed of a power transformer, an aggregated CHP units group and an aggregated CACs group (which are utilized to provide adequate capacity for energy supply of electric/thermal loads and hereafter referred as CHP unit and CAC) . The input energy consists of electricity and natural gas. The output energy consists of electric and thermal loads. The coupling relationship between the input and output energy is expressed by Eq. (3). The partition coefficient ν_e is used, $0 \leqslant \nu_e \leqslant 1$. $\nu_e P_e$ represents the electric power supply for electric loads, and $(1-\nu_e)\,P_e$ represents the electric power supply for CAC.

$$\underbrace{\begin{bmatrix} L_e^{\varepsilon} \\ L_h^{\varepsilon} \end{bmatrix}}_{L} = \underbrace{\begin{bmatrix} \nu_e & \eta_{ge}^{CHP} \\ (1-\nu_e)\eta^{AC} & \eta_{gh}^{CHP} \end{bmatrix}}_{C} \underbrace{\begin{bmatrix} P_{e,\varepsilon}^{EH} \\ P_{g,\varepsilon}^{EH} \end{bmatrix}}_{P} \tag{3}$$

The second type of energy hub is composed of a power transformer, an aggregated CHP units group and an aggregated gas-boilers group (which are utilized to provide adequate capacity for energy supply of electric/thermal loads and hereafter referred as CHP unit and gas-boiler). The coupling relationship of input and output is the same as that of the first type, while the energy conversion loop is different. The coupling relationship of input and output energy is expressed by Eq. (4).

$$\underbrace{\begin{bmatrix} L_e^{\varepsilon} \\ L_h^{\varepsilon} \end{bmatrix}}_{L} = \underbrace{\begin{bmatrix} 1 & \nu_g\eta_{ge}^{CHP} \\ 0 & \nu_g\eta_{gh}^{CHP} + (1-\nu_g)\eta^{GB} \end{bmatrix}}_{C} \underbrace{\begin{bmatrix} P_{e,\varepsilon}^{EH} \\ P_{g,\varepsilon}^{EH} \end{bmatrix}}_{P} \tag{4}$$

where $(1-\nu_g)P_g$ represents the natural gas supply for gas-boiler, and $\nu_g P_g$ represents the natural gas supply for CHP unit.

3. Formulation of the optimal day-ahead scheduling method (ODSM)

In this section, the ODSM for the IUES is given in details. The proposed ODSM schedules the active elements of the IUES over a 24-h time-period with an hourly time step. Network reconfiguration is one of the control methods for electric distribution networks that change the open/close status of switchgear to change the operational topology of a network. Network Reconfiguration is used for various purposes, including loss minimization, load balancing, service restoration and reliability improvement [26]. In this paper, the hourly reconfigurable capability of the electric distribution network utilizing RCSs was considered in the ODSM to reduce the operation cost of IUES.

3.1. Framework of the ODSM

The framework of the ODSM is depicted in Fig. 3. The inputs of the ODSM are energy prices, distributed energy resources forecasting results, electric/thermal/natural gas loads forecasting results and the DRLs participation conditions. The outputs of the ODSM are the scheduling scheme of the optimized variables in the next 24 hours. The ODSM solver was implemented based on an Open Source Distribution System Simulator (OpenDSS) and MATLAB. The OpenDSS was utilized for solving the three-phase power flow [29]. The natural gas flow calculation, the energy center energy flow calculation and the optimization problem for optimal day-ahead scheduling based on a hybrid optimization algorithm (integrated GA with IPM) were implemented in MATLAB. The data exchange with MATLAB was implemented by driving the Component Object Model (COM, OpenDSSEngine.DLL) interface that is available in the OpenDSS package.

Fig. 3. The framework of the ODSM.

3.2. Objective Function

The objective function depicted in Eq. (5) is to minimize the total operation cost for day-ahead scheduling, which consists of four cost terms: 1) the cost of purchasing electric power ($C_t^e P_t^{grid}$); 2) the cost of purchasing natural gas power ($C_t^g P_t^{gas}$); 3) the cost of IUES's contracting with DRLs ($C_t^{\mathrm{DRL}} P_{t,\delta}^{\mathrm{DRL}}$); 4) the switching cost of RCSs ($C^{\mathrm{SW}} N_{RCS_r}^{\mathrm{SW}}$).

$$\min f(\boldsymbol{x},\boldsymbol{u}) = \min \left\{ \left(C_t^e P_t^{grid} + C_t^g P_t^{gas} + \sum_{\delta \in DRL} C_t^{\mathrm{DRL}} P_{t,\delta}^{\mathrm{DRL}} \right) + \sum_r C^{\mathrm{SW}} N_{RCS_r}^{\mathrm{SW}} \right\} \tag{5}$$

where $\boldsymbol{x}$ and $\boldsymbol{u}$ are state and control variables of the IUES, which consists of both discrete and continuous control variables as Eqs. (6) - (13).

$$\boldsymbol{x} = \left[\boldsymbol{F}_e, \boldsymbol{F}_g, \boldsymbol{F}_{EH} \right] \tag{6}$$

$$\boldsymbol{F}_e = [\boldsymbol{V}; \boldsymbol{S}] = \left[|V_1|, |V_2|, \ldots, |V_{N_{e-bus}}|; |S_1|, |S_2|, \ldots, |S_{N_{br}}| \right] \tag{7}$$

$$\boldsymbol{F}_g = [\boldsymbol{p}; \boldsymbol{F}_n] = \left[|p_1|, |p_2|, \ldots, |p_{N_{g-bus}}|; |F_{n,1}|, |F_{n,2}|, \ldots, |F_{n,N_{pipeline}}| \right] \tag{8}$$

$$\boldsymbol{F}_{EH} = \left[|P_{e,1}^{EH}|, |P_{e,2}^{EH}|, \ldots, |P_{e,N_{EH}}^{EH}|; |P_{g,1}^{EH}|, |P_{g,2}^{EH}|, \ldots, |P_{g,N_{EH}}^{EH}| \right] \tag{9}$$

$$\boldsymbol{u}=\left[P_t^{grid},P_t^{gas},P_{t,\delta}^{\mathrm{DRL}},\boldsymbol{RCS},\boldsymbol{v_e},\boldsymbol{v_g}\right] \tag{10}$$

$$\boldsymbol{RCS}=\left[RCS_1,RCS_2,\ldots,RCS_{N_{br}}\right] \tag{11}$$

$$\begin{cases}\boldsymbol{v_e}=\left[v_{e,1},v_{e,2},\ldots,v_{e,N_{EH-1}}\right]\\ \boldsymbol{v_g}=\left[v_{g,1},v_{g,2},\ldots,v_{g,N_{EH-\Pi}}\right]\end{cases} \tag{12}$$

$$N_{RCS_r}^{\mathrm{SW}}=\sum_t \mathrm{abs}\left(RCS_{r,t}-RCS_{r,t-1}\right) \tag{13}$$

where $\boldsymbol{F}_e$, $\boldsymbol{F}_g$ and $\boldsymbol{F}_{EH}$ are state variables of the IUES, which represent the state of electric distribution network, the natural gas network and the energy center respectively; $RCS_{N_{br}}$ is the RCS statues, with "1" denotes that the RCS is closed and "0" the RCS is open.

3.3. Constraints

3.3.1. Three-phase electric network constraints

$$\begin{aligned}&P_t^{grid}+\sum_{p\in PV}P_{t,p}^{PV}+\sum_{w\in WT}P_{t,w}^{WT}+\sum_{\delta\in RL}P_{t,\delta}^{\mathrm{DRL}}-\sum_{\varepsilon\in EH}P_{e,t,\varepsilon}^{EH}\\&-\sum_{l\in L}P_{e,t}^{l}-\sum_{\substack{f_e\in N_{br}\\ j\in N_{e\text{-}bus}}}P_{t,ij}^{f_e}\left(V_i,V_j,Y_{ij},\theta_{ij}\right)=0\end{aligned} \tag{14}$$

$$P_{t,\min}^{grid}\le P_t^{grid}\le P_{t,\max}^{grid} \tag{15}$$

$$\begin{cases}V_{\min}\le V_i^a\le V_{\max}\\ V_{\min}\le V_i^b\le V_{\max}\\ V_{\min}\le V_i^c\le V_{\max}\end{cases} \tag{16}$$

$$0\le P_{t,\delta}^{\mathrm{DRL}}\le P_{t,\delta,\max}^{\mathrm{DRL}} \tag{17}$$

$$0\le i_{t,ij}^{f_e}\le i_{ij,\max}^{f_e} \tag{18}$$

$$N_{loop}=N_{br}-N_{e\text{-}bus}+1 \tag{19}$$

Eq. (17) is the contracts constraint for DRL. Eq. (19) is established to guarantee that the electric distribution network has a radial structure.

3.3.2. Natural gas network constraints

$$P_t^{gas}-\sum_{\varepsilon\in EH}P_{g,t,\varepsilon}^{EH}-\sum_{\substack{f_g\in N_{g\text{-}bus}\\ n\in N_{pipeline}}}F_{t,kn}^{f_g}\left(p_k,p_n\right)=0 \tag{20}$$

$$P_{t,\min}^{gas}\le P_t^{gas}\le P_{t,\max}^{gas} \tag{21}$$

$$p_{\min}\le p_n\le p_{\max} \tag{22}$$

$$k_{cp}^{\min}\le k_{cp}\le k_{cp}^{\max} \tag{23}$$

3.3.3. Energy center constraints

$$\boldsymbol{L}^{EH} - \boldsymbol{C}^{EH}\boldsymbol{P}^{EH} = \boldsymbol{0} \tag{24}$$

where $\boldsymbol{P}^{EH}$ is energy center energy power input vector; $\boldsymbol{L}^{EH}$ is energy center energy power output vector; $\boldsymbol{C}^{EH}$ is energy conversion matrix. The concrete energy center equality constraints are illustrated in Eq. (3) and Eq. (4).

Considering component capacities (illustrated in Eq. (25)) of the energy centers, the constraints of the exchange power between the energy centers and energy networks $P^{EH}_{e,t,\varepsilon}$ and $P^{EH}_{e,t,\varepsilon}$ are defined as Eq. (26).

$$\begin{cases} P^{\mathrm{CHP}}_{\varepsilon,\min} \le P^{\mathrm{CHP}}_{\varepsilon} \le P^{\mathrm{CHP}}_{\varepsilon,\max} \\ P^{\mathrm{AC}}_{\varepsilon,\min} \le P^{\mathrm{AC}}_{\varepsilon} \le P^{\mathrm{AC}}_{\varepsilon,\max} \end{cases} \tag{25}$$

$$\begin{cases} P^{EH}_{e,t,\varepsilon,\min} \le P^{EH}_{e,t,\varepsilon} \le P^{EH}_{e,t,\varepsilon,\max} \\ P^{EH}_{g,t,\varepsilon,\min} \le P^{EH}_{g,t,\varepsilon} \le P^{EH}_{g,t,\varepsilon,\max} \end{cases} \tag{26}$$

For the two types of energy centers, different upper and lower boundaries are illustrated in Eq. (27) and Eq. (28), respectively.

$$(\text{Type---Ⅰ})\begin{cases} (\text{Electricity})\begin{cases} P^{EH}_{e,t,\varepsilon,\min} = L^{\varepsilon}_{e,t} - P^{\mathrm{CHP}}_{\varepsilon,\max} \\ P^{EH}_{e,t,\varepsilon,\max} = L^{\varepsilon}_{e,t} + P^{\mathrm{AC}}_{\varepsilon,\max} / \eta^{\mathrm{AC}} \end{cases} \\ (\text{Gas})\begin{cases} P^{EH}_{g,t,\varepsilon,\min} = 0 \\ P^{EH}_{g,t,\varepsilon,\max} = P^{\mathrm{CHP}}_{\varepsilon,\max} / \eta^{\mathrm{CHP}}_{ge} \end{cases} \end{cases} \tag{27}$$

$$(\text{Type---Ⅱ})\begin{cases} (\text{Electricity})\begin{cases} P^{EH}_{e,t,\varepsilon,\min} = L^{\varepsilon}_{e,t} - P^{\mathrm{CHP}}_{\varepsilon,\max} \\ P^{EH}_{e,t,\varepsilon,\max} = L^{\varepsilon}_{e,t} \end{cases} \\ (\text{Gas})\begin{cases} P^{EH}_{g,t,\varepsilon,\min} = L^{\varepsilon}_{h,t} / \eta^{\mathrm{GB}} \\ P^{EH}_{g,t,\varepsilon,\max} = P^{\mathrm{CHP}}_{\varepsilon,\max} / \eta^{\mathrm{CHP}}_{ge} + (L^{\varepsilon}_{h,t} - P^{\mathrm{CHP}}_{\varepsilon,\max} * \dfrac{\eta^{\mathrm{CHP}}_{gh}}{\eta^{\mathrm{CHP}}_{ge}}) / \eta^{\mathrm{GB}} \end{cases} \end{cases} \tag{28}$$

3.3.4. Solution

A hybrid optimization method, integrating GA with a nonlinear IPM, was employed to solve the above mixed-integer and nonlinear constraint ODSM problem [30]. The flow chart of the hybrid optimization method is shown in Fig.4.

Fig. 4. Flowchart of solving the ODSM based on the hybrid method.

The optimization problem is decomposed into two sub-problems. The first one is the continuous optimization sub-problem and is solved by the IPM, where the discrete control variables (***RCS***) are kept constant. The second one is the discrete optimization sub-problem and is solved by GA, where the continuous control variables ($P_t^{grid}, P_t^{gas}, P_{t,\delta}^{\mathrm{DRL}}, \boldsymbol{v_e}, \boldsymbol{v_g}$) are kept constant. The steps of solving ODSM based on the hybrid method are given as follows:

Step 1) Initialize the IUES, including energy center initialization, electric distribution network initialization and natural gas network initialization, based on the system structure and the input data;

Step 2) Separate the discrete control variables and continuous control variables; Generate the initial population of GA based on the input data and set iteration count k=1 for GA;

Step 3) Solving the continuous optimization sub-problem using the IPM with the discrete control variables (***RCS***) constant; Check the constraints and ensure all initial individuals satisfy the operating constraints; An individual is a solution for the ODSM encoded as a string, called chromosome in GA and every chromosome defines a unique scheduling solution of the IUES.

Step 4) Assess an individual based on the fitness calculation: If the iterations satisfy the stopping criteria, then go to **Step 6)**; Otherwise, set k=k+1 and go to **Step 5)**;

Step 5) Produce the offspring generation by solving the discrete optimization sub-problem using GA keeping the obtained continuous control variables ($P_t^{grid}, P_t^{gas}, P_{t,\delta}^{\mathrm{DRL}}, \boldsymbol{v_e}, \boldsymbol{v_g}$) in the continuous optimization sub-problem constant; Check the radiation of the electric distribution network and ensure all individuals satisfy the operating constraints and go to **Step 3)**;

Step 6) Obtain the optimal day-ahead scheduling results for the IUES and the corresponding set-points of control variables for all participants.

The algorithm is stopped if one of the following stopping criteria is satisfied:

1) The number of iterations exceeds its limit (maximum number of iterations is set to be 150);

2) The optimal individual keeps unchanged within 10 iterations.

4. Case studies

4.1. Case Study

An IUES test case in Fig. 5 was utilized to verify the effectiveness of the developed ODSM. The day-ahead scaled wholesale market prices of electricity and forecasted load on January 16, 2015 at NYISOs NPX were utilized to assess the proposed scheduling method [31]. The natural gas price was 42.5\$/MWh[1] taken from PG&E [32]. The energy prices are shown in Fig. 6 and the forecasted day-ahead electric load is shown in Fig. 7 [10].

[1] In order to study the natural gas power and electric power in a unified scale, the unit of natural gas price is converted from \$/therm to \$/MWh (1therm=29.32kWh).

Fig. 5. Scheme of the IUES case.

Fig. 6. Day-ahead market energy price.

Fig. 7. Forecasted day-ahead electric load.

The IUES investigated in this paper consists of three parts:

Part 1) (Electric distribution network): An typical IEEE 33-bus 12.66 kV radial distribution system (including 5 tie-lines and 32 sectionalizing-lines, equipped with RCSs on each feeder) was used, and the bus voltage is subject to the constraint of $0.95 \le V_i^{a,b,c} \le 1.05$ [33]. Three wind turbines (forecasted hourly power generation is shown in Fig. 8) were included in the network at nodes 14, 16 (A-phase grid-connected), and 31 (B-phase grid-connected). Also, three photovoltaic panels (forecasted hourly power generation is shown in Fig. 9) were connected to the electric power network at nodes 19, 27 (A-phase grid-connected), and 32 (C-phase grid-connected). Five controllable loads at nodes 8, 14, 24, 30, and 32 were considered as DRLs. The controllable loads can be decreased up to 20% as the contracts constraints for DRLs. The price for 1 MW decrease by DRLs was $90. Also, the cost for each switching action was $1 [10].

Fig. 8. Forecasted hourly power generation by WTs.

Fig. 9. Forecasted hourly solar radiation.

Part 2) (Natural gas network): A modified 7-node natural gas network is used here [25], which was initially designed for line-pack studies. And the natural gas network data is shown in Tab. A1. The upper and lower limits of the natural gas pipeline pressure are π_{min} =0.2 (p.u.) and π_{max} =1.3 (p.u.) respectively. The natural gas node GB1 is the gas resource node with a constant gas pressure 400kPa.

Part 3) (Energy centers): Four energy centers were plugged to the electric buses 8, 13, 16, 33 in the electric network and the natural gas nodes GB3, GB4, GB6, GB7 in the natural gas network. Energy center 1 and energy center 4 are set to be the type I of energy hub (depicted in Fig. 2(a)) and energy center 2 and energy center 3 are set to be the type II of energy hub (depicted in Fig. 2(b)). The energy center component capacities are given in Tab. A2. The electric/thermal loads of the four energy centers in a whole day are shown in Fig. 10.

Fig. 10. The electric/thermal loads of energy centers in a whole day.

4.2. Simulation results

Two comparative cases are presented to illustrate the effectiveness of the proposed ODSM.

Case 1): Optimal day-ahead scheduling without electric distribution network reconfiguration, i.e., seeking the optimal day-ahead scheduling solutions through controlling the electricity purchases, natural gas purchases and DRL participations, without changing the topology of the electric distribution network.

Case 2): Optimal day-ahead scheduling with reconfigurable topology of the electric distribution network, i.e., optimally scheduling all the active elements of the IUES including the hourly electric distribution network reconfiguration capability, the electricity purchases, the natural gas purchases and the DRL participations, seeking to minimize the day-ahead total operation cost.

The optimal day-ahead scheduling scheme of the power purchases for Case 1 and Case 2 are shown in Fig. 11. For the time periods including 1 to 6, 12 to 16 and 23 to 24, as the electricity purchase price is lower than that of other periods, the IUES tends to purchase more electric power and less natural gas power in both Case 1 and Case 2. For these time periods including 7 to 9 and 17 to 22, as the electricity purchase price is higher than that of other hours, the IUES tends to purchase more natural gas power and less electric power in both Case 1 and Case 2.

Fig. 11. Power purchase from energy utilities.

Compared with Case 1, the advantages of Case 2 including electric distribution network reconfiguration lie in two aspects:

1) The voltage profile for the worst bus has been improved in the whole day by adjusting the statuses of RCSs in Case 2 as shown in Fig. 12. This reason is that electric distribution network reconfiguration can transfer loads from heavily loaded feeders to lightly loaded ones contributing voltage profile improvement. Actually, the low voltage is an important factor causing decrease of power supply capability.

Fig. 12. Worst bus voltage magnitudes.

2) For the time periods including 1 to 6, 12 to 16 and 23 to 24, by adjusting the statuses of RCSs in Case 2, the reconfiguration of the electric distribution network topology enables IUES to purchase more electric power at lower electric prices and contributes to more economic savings benefitted from the electric power supply capability enhancement and optimized electric power flows through network reconfiguration. The power supply capability enhancement is due to the voltage profile improvement and optimized electric power flows through network reconfiguration, e.g. the violated bus voltage constraints are removed in the load peak hours (between 8 and 21), as shown in Fig. 12.

The electric power purchase and the natural gas power purchase in Case 1 and Case 2 are shown in Fig. 13 and Fig. 14 respectively. The imported electric power has increased and consequently the imported natural gas power has decreased by adjusting the statuses of RCSs in Case 2. This is because in order to minimize the operation cost, the IUES tends to purchase more electricity and minimize the natural gas power purchase with the energy price conditions depicted in Fig 6.

Fig. 13. Electric power purchase.

Fig. 14. Natural gas power purchase.

The optimal day-ahead schedules of the four energy centers are shown in Fig. 15. It can be seen that all the energy centers consume electric power (the positive value of electric power represents power consumption, and the negative value of electric power represents power generation) and natural gas power to satisfy the electric/thermal loads within the power regulation constraints (depicted by the black dotted lines in Fig. 15).

Fig. 15. The optimal day-ahead schedule of energy centers.

1) Energy center 1

For the time periods including 1 to 6, 12 to 16 and 23 to 24, as the electricity purchase price is lower than that of other time periods, the energy center 1 tends to consume more electric power (close to the upper electric power regulation boundary) and less natural gas power (close to the lower natural gas power regulation boundary) in both Case 1 and Case 2. In Case 1, due to the bus voltage constraint, the required electric power cannot be imported from the substation and the required electric power cannot be consumed by the energy center. Compared with Case 1, the electric power supply capability is improved and the violated bus voltage constraint is also removed in Case 2 through changing the network topology, which has resulted in more electric power consumption.

For the time periods 7 to 9 and 17 to 22, as the electricity purchase price is higher than that of other time periods, the energy center 1 tends to consume more natural gas power and less electric power in both Case 1 and Case 2. It is worth noting that energy center 1 tends to consume more natural gas power to generate electric power and inject the extra electric power back into the electric network in the time period 7 to 9, as shown in Fig. 15(a). There are two main reasons for this phenomenon. Firstly, the electricity purchase price is higher in the time period 7 to 9, and the energy center 1 tends to consume less electric power for cost saving. Secondly, the energy center 1 has more thermal load and relatively less electric load (high heat to power ratio of energy center loads [34]) in time period 7 to 9 (depicted in Fig. 10 (a)), which matches the relative high heat to power ratio of the CHP unit [35] (set to be 1.43) closely. Therefore, most of the natural gas is utilized by the CHP unit in the time period 7 to 9 for cost saving and the extra electric power generated by the CHP unit is injected back into electric network to reduce the operation cost.

2) Energy center 2

Energy center 2 tends to consume more electric power and less natural gas power in time periods 1 to 9, 15 to 17 and 20 to 24 in both Case 1 and Case 2, as shown in Fig. 15(b). The reason is that the primary energy efficiency of CAC for generating heat [36] is higher than that of the CHP unit for generating electricity and heat [37]. Therefore, almost all the thermal loads are satisfied by CAC and most of the electric loads are supplied by the electric distribution network, in despite of the high electricity purchase prices in the time periods including 7 to 9 and 20 to 22. In Case 1, due to the bus voltage constraint, the required electric power cannot be consumed by energy center 2, which results in more natural gas power consumption in the time periods 10 to 14 and 19 to 22. Compared with Case 1, by adjusting the statuses of RCSs in Case 2, the electric power supply capability is improved and the violated bus voltage constraint are removed through reconfiguring the network topology, which has resulted in more electric power consumption and almost no natural gas power consumption. As Fig. 15(b) shows, energy center 2 consumes natural gas power only in hour 18 in Case 2, which is due to the highest electricity price at hour 18.

Comparing the power schedule results of energy center 2 with energy center 1, different components characteristics (different primary energy efficiency of the energy center components) and different energy center load conditions (heat to power ratio of energy center loads) can lead to different power schedule results. And the optimal schedule results of energy center 2 are mainly determined by the energy market price and the electric power supply capability of the electric distribution network.

3) Energy center 3

The schedule of energy center 3 is similar to that of energy center 2 due to the same energy center components characteristics and similar load condition.

4) Energy center 4

The schedule of energy center 4 is similar to that of energy center 1 due to the same energy center components characteristics. It is worth noting that, different from energy center 1, energy center 4 tends to consume more natural gas power in Case 1 while less natural gas power in Case 2 in time periods 17 to 21. The reason is that the energy center 4 has more electric loads and less thermal loads than that of energy center 1 in time period 17 to 21 (low heat to power ratio of energy center loads). Therefore, the load condition fails to match the heat to power ratio of the CHP unit and the extra heat generated by the CHP unit must be shed (the extra heat power cannot be injected back to the utility like the electric power), which has poor economic efficiency. Consequently, more electric power should be consumed to satisfy the energy loads and reduce the operation cost, in despite of the high electricity purchase price in the time periods 17 to 21. However, the bus voltage violation occurs in Case 1 in time periods 17 to 21, leading to no more electric power could be consumed and more natural gas power must be consumed to cover the energy center loads. The electric bus voltage magnitude in hour 19 for

Case 1 and Case 2 are shown in Fig. 16. Compared with Case 1, the violated bus voltage constraint is removed through reconfiguring the network topology in Case 2, which enables the energy center 4 consume more electric power and less natural gas power to reduce the operation cost.

Fig. 16. Electric bus voltage magnitude in hour 19.

It was found that the optimal schedule results of energy centers change with the energy market prices, energy center loads and energy center components characteristics.

Fig. 17 shows the electric power reduction by DRLs in the optimal day-ahead scheduling. The total electric power reduction by DRLs follows the day-ahead scaled wholesale market prices (more power reductions in time periods 7 to 10 and 17 to 20, while less power reductions in other time periods) in both cases and subject to the DRLs contract constraints at the same time. Compared with Case 1, the scheduling process in Case 2 has less power reductions by DRLs at the most time periods in a whole day, which contributes to higher comfort level of demand side.

Fig. 17. The optimal day-ahead schedule of DRLs.

The natural gas pipeline node pressures of the 7-node natural gas network in the whole schedule day are shown in Fig. 18. The simulation results show that natural gas pipeline pressure can satisfy the pressure boundaries in both cases, which guarantees the reliable operation of the natural gas network.

Fig. 18. Node pressure of the natural gas network.

Tab. 1 demonstrates the optimal hourly operation cost of the IUES in both cases. It is found that the operation cost reductions at all hours in the whole day were achieved through the hourly electric distribution network reconfiguration.

Tab. 1. Optimal day-ahead operation cost comparison.

5. Conclusion

An ODSM for the IUES considering the reconfigurable capability of electric distribution networks was developed. The main contributions of this paper are summarized as follows:

1) An ODSM was developed to provide the IUES with economical day-ahead scheduling schemes and reduce the operation cost of the IUES;

2) The constraints of the electric distribution network, the natural gas network and the coupled constraints between the two energy systems are considered in ODSM to coordinate thermal, gas, and electric energy systems in the IUES day-ahead scheduling;

3) The flexible electric distribution network topologies are considered in the ODSM making a good use of the active network elements (e.g. the electric distribution network with the hourly reconfigurable topology) of the IUES.

Compared with optimal scheduling excluding RCSs, considering RCSs in scheduling of the IUES has benefits in electric power supply capacity improvement (enables the IUES to purchase more electric power from the wholesale market at lower electricity prices), better power quality (the worst bus voltage magnitude has improved through electric distribution network reconfiguration) and higher comfort level of energy demand side (lower dispatch of DRLs). Meanwhile, implementation of hourly flexible topologies has an improvement in economic efficiency of the IUES. Numerical studies show that the proposed ODSM made a good use of the active elements of the IUES, which coordinated different energy systems and guaranteed the economic operation of the IUES.

Acknowledgements

This work was financially supported by the National High-tech R&D Program of China (863 Program with No. 2015AA050403), the UK-China NSFC/EPSRC EV project (Grant No. 51361130152 & EP/L001039/1), the project National Natural Science Foundation of China (Grant No. 51307115, 51377117, and 51277128), Research on Key Technologies of State Grid Corporation of Multi-energy Interconnection and Management for Smart City.

Appendix A.

Tab. A1. Natural gas network data.

Tab. A2. Energy center component capacities.

Reference

[1] Dong R, Yu Y, Zhang Z. Simultaneous optimization of integrated heat, mass and pressure exchange network using exergoeconomic method. Appl Energy 2014; 136:1098–1109.

[2] Keirstead J, Jennings M, Sivakumar A. A review of urban energy system models: Approaches, challenges and opportunities. Renew Sust Energ Rev 2012; 16(6):3847-3866.

[3] Zhang X, Karady G G, Piratla K R, et al. Network capacity assessment of combined heat and power-based distributed generation in urban energy infrastructures. IEEE Trans Smart Grid 2013; 4(4):2131-2138.

[4] Mendes G, Ioakimidis C, Ferrão P. On the planning and analysis of integrated community energy systems: A review and survey of available tools. Renew Sust Energ Rev 2011; 15(9):4836-4854.

[5] Qadrdan M, Chaudry M, Wu J, Jenkins N, Ekanayake J. Impact of a large penetration of wind generation on the GB gas network. Energy Policy 2010; 38(10):5684–5695.

[6] Mu Y, Wu J, Ekanayake J, et al. Primary frequency response from electric vehicles in the Great Britain power system. IEEE Trans Smart Grid 2013; 4(2):1142-1150.

[7] Mu Y, Wu J, Jenkins N, et al. A spatial–temporal model for grid impact analysis of plug-in electric vehicles. Appl Energy 2014; 114:456-465.

[8] Meng J, Mu Y, Jia H, et al. Dynamic frequency response from electric vehicles considering travelling behavior in the Great Britain power system. Appl Energy 2016; 162:966-979.

[9] Wu H, Shahidehpour M, Li Z, et al. Chance-constrained day-ahead scheduling in stochastic power system operation. IEEE Trans Power Syst 2014; 29(4):1583-1591.

[10] Golshannavaz S, Afsharnia S, Aminifar F. Smart distribution grid: optimal day-ahead scheduling with reconfigurable topology. IEEE Trans Smart Grid 2014; 5(5):2402-2411.

[11] Farzan F, Jafari M A, Masiello R, et al. Toward optimal day-ahead scheduling and operation control of microgrids under uncertainty. IEEE Trans Smart Grid 2015; 6(2):499-507.

[12] Luo F, Wang C, Xiao J, et al. Rapid evaluation method for power supply capability of urban distribution system based on *N*-1 contingency analysis of main-transformers. Int J Elect Power Energy Syst 2010; 32(10):1063–1068.

[13] De Wolf D, Smeers Y. The gas transmission problem solved by an extension of the simplex algorithm. Manage Sci 2000;46(11):1454–65.

[14] Borraz-Sánchez C, Haugland D. A tree decomposition algorithm for minimizing fuel cost in gas transmission networks. In: Kacem I, editor. Proceedings of the 39th international conference on computers & industrial engineering (CIE 2009). IEEE; 2009. p. 244–9. ISBN: 978-1-4244-4136-5.

[15] Misra S, Fisher M W, Backhaus S, et al. Optimal compression in natural gas networks: a geometric programming approach. IEEE Trans Contr Networ Syst 2015; 2(1):47-56.

[16] Shahidehpour M, Fu Y, Wiedman T. Impact of natural gas infrastructure on electric power systems. Proceedings of the IEEE 2005; 93(5):1042-1056.

[17] Kalantari A, Restrepo J F, Galiana F D. Security-constrained unit commitment with uncertain wind generation: The loadability set approach. IEEE Trans Power Syst 2013; 28(2):1787-1796.

[18] Alabdulwahab A, Abusorrah A, Zhang X, et al. Coordination of interdependent natural gas and electricity infrastructures for firming the variability of wind energy in stochastic day-ahead scheduling. IEEE Trans Sustain Energy 2015; 6(2):606-615.

[19] Zhang X, Shahidehpour M, Alabdulwahab A, et al. Hourly electricity demand response in the stochastic day-ahead scheduling of coordinated electricity and natural gas networks. IEEE Trans Power Syst in-press.

[20] Xu X, Jia H, Chiang H D, et al. Dynamic modeling and interaction of hybrid natural gas and electricity supply system in microgrid. IEEE Trans Power Syst 2015; 30(3):1212-1221.

[21] Qadrdan M, Wu J, Jenkins N, et al. Operating strategies for a GB integrated gas and electricity network considering the uncertainty in wind power forecasts. IEEE Trans Sustain Energy 2014; 5(1):128-138.

[22] Bozchalui M C, Hashmi S A, Hassen H, et al. Optimal operation of residential energy hubs in smart grids. IEEE Trans Smart Grid 2012; 3(4):1755-1766.

[23] Ramírez-Elizondo L M, Paap G C B. Scheduling and control framework for distribution-level systems containing multiple energy carrier systems: theoretical approach and illustrative example. Int J Elect Power Energy Syst 2015; 66:194-215.

[24] Xu X, Jia H, Wang D, et al. Hierarchical energy management system for multi-source multi-product microgrids. Renew Energy 2015; 78: 621-630.

[25] Xu X, Jin X, Jia H, et al. Hierarchical management for integrated community energy systems. Appl Energy 2015; 160: 231-243.

[26] Capitanescu F, Ochoa L F, Margossian H, et al. Assessing the potential of network reconfiguration to improve distributed generation hosting capacity in active distribution systems. IEEE Trans Power Syst 2015; 30(1):346-356.

[27] Martinez-Mares A, Fuerte-Esquivel C R. A unified gas and power flow analysis in natural gas and electricity coupled networks. IEEE Trans Power Syst 2012; 27(4):2156-2166.

[28] Mago P J, Chamra L M, Ramsay J. Micro-combined cooling, heating and power systems hybrid electric-thermal load following operation. Appl Therm Eng 2010; 30:800-806.

[29] Dugan R C. Reference Guide: The open distribution system simulator (OpenDSS). Electric Power Research Institute, Inc, 2012.

[30] Mahmoudabadi A, Rashidinejad M. An application of hybrid heuristic method to solve concurrent transmission network expansion and reactive power planning. Int J Electr Power Energy Syst 2013; 45(1):71-77.

[31] (2015, Jan.) New York Independent System Operator [Online]. Available:http://www.nyiso.com.

[32] Pacific Gas&Electrc. Tariffs. A-10 TOU, 200-500kW, http://www.pge.com/tariffs/electric.shtml.

[33] Baran M E, Wu F. Network reconfiguration in distribution systems for loss reduction and load balancing. IEEE Trans Power Del 1989; (2):1401-1407.

[34] Huang Y, McIlveen-Wright D R, Rezvani S, et al. Comparative techno-economic analysis of biomass fuelled combined heat and power for commercial buildings. Appl Energy 2013; 112: 518-525.

[35] Hawkes A D, Leach M A. On policy instruments for support of micro combined heat and power. Energy Policy 2008; 36(8): 2973-2982.

[36] Adnot J, RIVIERE P, MARCHIO D, et al. Energy efficiency and certification of central air conditioners (EECCAC). Study for the DG transportation-energy (DGTREN) of the Commission of the EU-final report 2003.

[37] Kaikko J, Backman J. Technical and economic performance analysis for a microturbine in combined heat and power generation. Energy 2007; 32(4): 378-387.