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Hierarchical management for integrated community energy systems

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Abstract

Due to the presence of combined heat and power plants (CHP) and thermostatically controlled loads, heat, natural gas and electric power systems are tightly coupled in community areas. However, the coordination among these systems has not been well considered, especially with the integration of renewable energy. This paper aims to develop a hierarchical approach for an integrated community energy system (ICES). The proposed hierarchical framework is presented as day-ahead scheduling and two-layer intra-hour adjustment systems. Two objectives, namely operating cost and tie-line power smoothing, are integrated into the framework. In the intra-hour scheduling, a master-client structure is designed. The CHP and thermostatically controlled loads are coordinated by a method with two different time scales in order to execute the schedule and handle uncertainties from the load demand and the renewable generation. To obtain the optimal set-points for the CHP, an integrated optimal power flow method (IOPF) is developed, which also incorporates three-phase electric power flow and natural gas flow constraints. Furthermore, based on a time priority list method, a three-phase demand response approach is proposed to dispatch HVACs at different phases and locations. Numerical studies confirm that the ICES can be economically operated, and the tie-line power between the ICES and external energy network can be effectively smoothed.

Keywords: Hierarchical management, integrated community energy system (ICES), two-layered scheduling, integrated optimal power flow (IOPF), three-phase demand response

1. Introduction

A tendency as the result of global urbanization is that cities are gaining greater control over their development, economically, politically, and technologically, which enables new levels of intelligence [1]. To seize the opportunities and to build sustainable prosperities, integrated community energy systems (ICES) [2] are attracting more and more attentions in recent years, where heat, gas and electrical energy are becoming tightly coupled. It has been shown that the coordination of various energy conversion processes can play a key role in increasing the intermittent energy penetration level, and economic operation, etc. [3-4]. However, to achieve these targets is still quite challenging. This is mainly due to the uncertainty of renewable energy and complex interactions among different energy systems. Therefore, coordination and management of various energy systems are of significant importance for the integration of renewable energy and developing better energy management system for the ICES.

Since multiple energy services are required in a community, the integration of various energy systems has been intensively researched, including combined heat and power plants (CHP) [5], microgrids [6], smart energy systems [7], etc. In [8], a general model was presented for a community-based microgrid, integrating renewable generations and CHP plants. A combined analysis was proposed for heat and electricity flow dispatch in a small scale energy system with CHP units [9]. Based on the energy hub (EHub) [10] that was first developed for interrelated energy system description, an integrated optimal energy flow was proposed for multi-carrier energy network optimization in an island [11]. Furthermore, multiple objective were incorporated into the community energy system optimization due to various requirements [12]. In addition to the energy supply system, it was shown that utilities and system operators could integrate loads into both decentralized and centralized energy management systems [13-14] and demand response (DR) could be used to reduce the energy consumption and green-house gas emissions. In [15], a two-stage DR scheduling was proposed to integrate renewable energy into power systems. Furthermore, the energy market was integrated into the day-ahead and hourly scheduling system to exchange the DR with variable renewable generation [16].

To implement an integrated management of different resources, distributed generations and the DR should be coordinated in the energy management system [17]. It has been shown that the operating cost can be significantly reduced by integrating CHP with the DR in real time control [18]. However, different response characteristics of the CHP and the DR are not well considered in previous studies. Moreover, community energy systems are generally accessed to the low voltage distribution network, which is usually a unbalanced three-phase system [19]. However, previous studies usually assume that the community system is balanced. Few discussions have been given to how to manage the loads and generations in three phases.

The hierarchical framework offers a measure to handle various objectives and manage the whole system [20]. In [21], a two-level hierarchical framework was presented to handle the uncertainty and to realize an economic generation schedule of microgrids by coordinating battery energy storage systems and distributed generations (DGs). A hierarchical energy management system was proposed in [22] for a multi-source multi-product microgrid with thermal and electrical power storage systems. A multi-agent based hierarchical energy management strategy was implemented by the combination of the autonomous control of distributed energy resources at the local level with the coordinated energy control at the central level of the microgrid [23]. The DR was integrated into the microgrid management system by hierarchical agents [24]. Inspired by the hierarchical framework, this paper aims to develop a novel coordination and management system for the ICES. Firstly, combined with traditional day-ahead scheduling system, a master-client structure is integrated into the hourly adjustment system. The CHP and the DR are dispatched in two time scales in order to handle the long term and short-term forecast errors. Then an integrated optimal power flow (IOPF) algorithm is developed for multiple energy system dispatch considering three-phase electric power flow and gas flow constraints. Two objectives, operating cost and tie-line power smoothing, are integrated into the hierarchical framework for day-ahead scheduling and intra-hour adjustments. Furthermore, a traditional time priority list method is extended to a three phase DR approach in order to utilize the loads in different phases and locations. Numerical tests are performed on a community energy system obtained from a modified IEEE-37 node system. Experimental results demonstrate that the proposed hierarchical framework is effective in interrelated energy system management. The methods and algorithms developed in this paper make it possible to utilize loads and DGs in three-phase electric power systems.

The rest of this paper is organized as follows: Section 2 presents an overview of the community energy system and the proposed hierarchical energy management system. Section 3 presents a detailed description of the hierarchical framework integrating optimal energy flow and three-phase DR methodology. Section 4 discusses the results for energy cost reduction, three-phase scheduling, and tie-line power smoothing. Finally, conclusions and recommendations are given in Section 5.

2. Problem description

2.1. Community configuration and energy service provider

Community energy systems can have diverse topologies. In this paper, the community model consists of energy service providers and customers. As shown in Fig. 1, buildings and residential houses are featured as customers. In buildings, the energy service provider obtains electricity and gas from utilities and supplies both electricity and heat to customers. In residential houses, the electricity is supplied to satisfy both heat and electricity demands of customers with thermostatically controlled loads such as heat pumps, air-conditioners, and heating, ventilating, and air conditioning (HVAC) units.

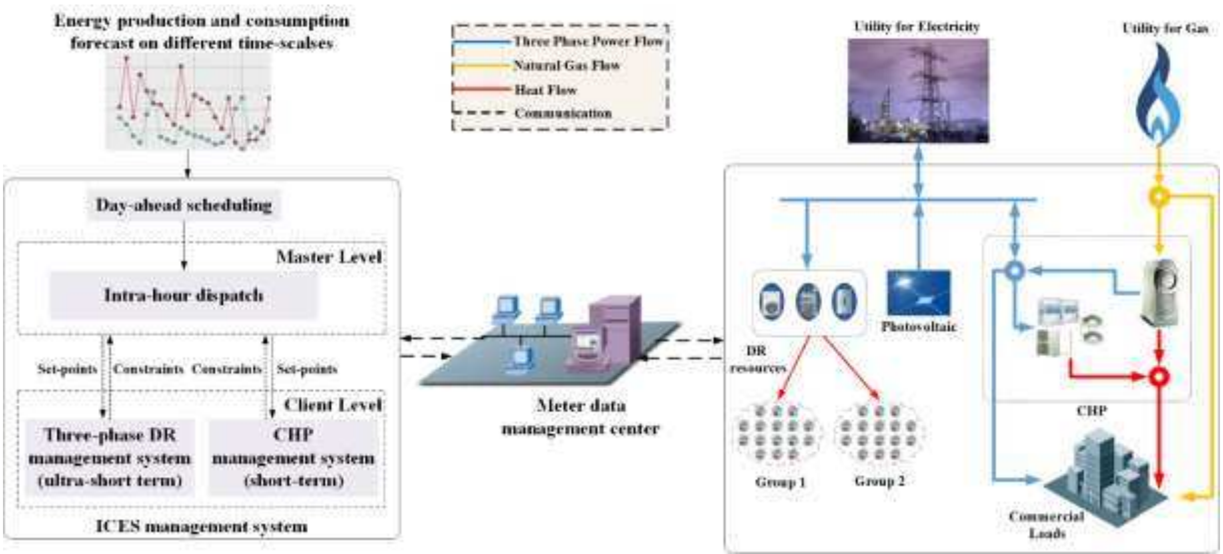

Fig. 1 Framework of the ICES management system

The energy service providers own DGs including the CHP and photovoltaic (PV) panels. In real applications, there may be several possible energy service providers. Three of them are listed as follows: (1) Customer owned community energy system. This type of customers own both loads and DGs. The energy supplier only buys energy from utilities without charging the energy users. Also, there is no charge for the DR. The objective can be set to be operating cost minimization; (2) Local energy service retailers owned by third parties. They buy energy from utility and sell energy to customers. The objective is to maximize their profits; and (3) Energy service provided by utilities. This type of energy providers supply energy directly to customers. The objective is to minimize the loss or some other utility requirements.

2.2. Integrated optimal power flow (IOPF)

As illustrated in Fig. 1, a hierarchical framework is designed to satisfy various requirements of the energy service provider. With load and renewable generation forecast results, day-ahead scheduling results are obtained by calling the IOPF program. The intra-hour scheduling system is further decomposed into a two-layer structure to balance time-varying energy demand and supply forecast errors in two time scales while meet the requirement of interrelated constraints between multiple energy systems. At the master level, the IOPF is called to generate set-points for CHP systems and DR to track load and generation forecast mismatch in both short term and ultra-short term. At the client level, CHP power exchange boundary and the three-phase DR operating constraints are calculated and sent to the master.

3. Hierarchical management for the integrated community energy systems

3.1. Integrated optimal power flow (IOPF)

To optimize the interrelated thermal, gas, and electric power systems, an IOPF program is developed for the ICES. As previously mentioned, economic interests are considered as objectives of energy service providers. In addition, the impacts of renewable integration on the external power grid are also taken into account. For type (1) and (2) energy service providers, they can negotiate with utilities to obtain subsidies by reducing tie-line power fluctuation. For type (3), smoothing tie-line power is one of the utility requirements. Therefore, different objectives are considered for the two-layered optimization problem to ensure the economic operation and mitigate adverse impacts of renewable energy sources fluctuations on the power quality of the external power grid. The clients in this study consist of CHP systems and DR resources. Considering the diversity of the response time and the capacity of different system components, different scheduling intervals are set for the CHP systems and the DR resources respectively in day-ahead scheduling level. Since the CHP systems are not suitable for frequent adjustment, while DR resources have small regulation range, therefore the CHP systems are used to match the difference between the load and generation forecast results within a short control interval, and the DR resources are used to balance the mismatch between the load and generation forecast results in a ultra-short control interval for guaranting the customer comfort level.

3.1.1. Objectives

1) IOPF for day-ahead scheduling

To minimize the operating cost, the IOPF program is called to generate set-points for clients. The control objective is set as follow

$$\min\left[\mathrm{P}_{\mathrm{e,tl}}(\mathrm{k})\frac{\mu_{\mathrm{e,buy}}(\mathrm{k})+\mu_{\mathrm{e,sell}}(\mathrm{k})}{2}+\mathrm{P}_{\mathrm{e,tl}}(\mathrm{k})\frac{\left|\mu_{\mathrm{e,buy}}(\mathrm{k})-\mu_{\mathrm{e,sell}}(\mathrm{k})\right|}{2}+\mu_{\mathrm{g}}(\mathrm{k})\mathrm{P}_{\mathrm{g,tl}}(\mathrm{k})\right] \tag{1}$$

where $\mathrm{P}_{\mathrm{g,tl}}(\mathrm{k})$ is the gas tie-line power, $\mathrm{P}_{\mathrm{e,tl}}(\mathrm{k})$ is the real electric tie-line power, $\mu_{\mathrm{e,buy}}(\mathrm{k})$ and $\mu_{\mathrm{e,sell}}(\mathrm{k})$ represent the electricity prices to purchase and sell respectively at the kth hour, $\mu_{\mathrm{g}}(\mathrm{k})$ represents the gas price at the kth hour. It should be noted that in this paper, DR is only used for short-period mismatch correction and the cost for DR is not considered and can be a future work.

2) IOPF for intra-hour dispatch

The ICES is connected to the external power grid and gas network, as shown in Fig. 1. In the master level, the IOPF program is called to follow the electric and gas tie-line power set-points. The objective can be formulated as

$$\min\left\{\omega_e\left[P_{e,tl}(k)-P_{e,tl}^{set}(k)\right]^2+\omega_g\left[P_{g,tl}(k)-P_{g,tl}^{set}(k)\right]^2\right\} \quad (2)$$

where $P_{e,tl}^{set}(k)$ and $P_{g,tl}^{set}(k)$ are set-points of the electric and gas tie-line power at the kth hour. ω_e and ω_g are weighting factors for electric/gas tie-line power tracking, and when ω_g=0, the IOPF program is called to follow only the electric tie-line power set-points.

3.1.2. Constraints

1) Energy network constraints

The energy network constraints include three phase electric power flow Eq. (3) [25], and gas flow Eq. (4) [26] and feasibility domain for control variables Eq. (5)-(7).

$$\mathbf{f_e}(\mathbf{P},\mathbf{Q},\mathbf{V},\boldsymbol{\theta})=0 \quad (3)$$

$$\mathbf{f_g}(\mathbf{M},\mathbf{p},\mathbf{k_{cp}})=0 \quad (4)$$

$$\begin{cases} V_{min}\le V_i^a\le V_{max} \\ V_{min}\le V_i^b\le V_{max} \\ V_{min}\le V_i^c\le V_{max} \end{cases} \quad (5)$$

$$p_{min}\le p_j\le p_{max} \quad (6)$$

$$k_{cp,j_c}^{min}\le k_{cp,j_c}\le k_{cp,j_c}^{max} \quad (7)$$

where **P**, **Q** represent power at the electric node; **V**, $\boldsymbol{\theta}$ represent electric node voltage; V_i^a, V_i^b, V_i^c represent three-phase voltage at bus i; V_{min} and V_{max} represent lower and upper bounds of bus voltage; **M** represents gas flow; **p** is the gas node pressure; $\mathbf{k_{cp}}$ is the compressor ratios; p_{min} and p_{max} represent the lower and upper bounds of gas pressure; k_{cp,j_c}^{min} and k_{cp,j_c}^{max} are the lower and upper bounds of the ratio of compressor j_c.

2) CHP constraints

The clients in this study include the CHP systems and DR resources. To minimize the customer discomfort, CHP system is used first to balance the mismatch between the day-ahead scheduling and the load forecast results in a short control interval. The feasibility domain of the exchange power between the CHP and energy networks $P_{e,chp}$ and $P_{g,chp}$ (electricity and gas) can be defined as follow:

$$\begin{cases} P_{e,chp}^{min} \le P_{e,chp} \le P_{e,chp}^{max} \\ P_{g,chp}^{min} \le P_{g,chp} \le P_{g,chp}^{max} \end{cases} \tag{8}$$

where $P_{e,chp}^{min}, P_{e,chp}^{max}, P_{g,chp}^{min}, P_{g,chp}^{max}$ can be obtained from Eq. (11) and Eq. (12).

3.1.3. Energy hub model

The CHP systems include three operating modes, following the electric load mode, following the thermal load mode, and following hybrid thermal-electric load mode [27]. In this paper, the EHub model is utilized to describe the CHP system under following hybrid thermal-electric load mode incorporating different energy system interactions and component constraints.

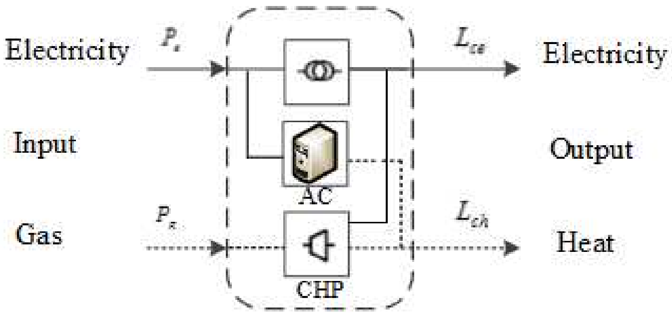

Fig. 2 EHub model topology

The EHub model in this paper is shown in Fig. 2, which is composed of the power transformer, microturbine and air-conditioning. The input energy consists of electricity and gas, the output energy consists of electricity and thermal energy. The energy conversion process can be described as

$$\underbrace{\begin{bmatrix} L_{ce} \\ L_{ch} \end{bmatrix}}_{L} = \underbrace{\begin{bmatrix} \upsilon_e & \eta_{ge}^{CHP} \\ (1-\upsilon_e) * \eta^{AC} & \eta_{gh}^{CHP} \end{bmatrix}}_{C(\upsilon_e)} \underbrace{\begin{bmatrix} P_e \\ P_g \end{bmatrix}}_{P} \tag{9}$$

where η_{ge}^{CHP} and η_{gh}^{CHP} are the conversion efficiency of gas into electricity and thermal energy through the CHP respectively; η^{AC} is heat/cold energy conversion rate of the air-conditioner; P_e and P_g are the power exchanges between EHub and the electricity/gas network; L_{ce} and L_{ch}

are the electric and thermal loads provided by EHub. The partition coefficient is used in this paper, $0 \le \upsilon_e \le 1$, and $\upsilon_e P_e$ represents the electric power that supplies the electric loads and $(1-\upsilon_e) P_e$ represents the supply of electric power to the air-conditioner.

In the CHP systems, the power generation should be equal to the electric load while the thermal generation can be more than the thermal load by shedding the extra thermal energy. This gives the equality and inequality constraints for the EHub output power L_{ce}, L_{ch} and the required power L_e, L_h, as illustrated in Eq. (10).

$$\begin{cases} L_e = L_{ce} \\ L_h \le L_{ch} \end{cases} \tag{10}$$

Considering component capacities, the boundaries for the power exchanges between the CHP systems and the ICES illustrated in Eq. (9) can be expressed as

$$(\text{Electricity})\begin{cases} P_{e,chp}^{min} = L_e - P_{mt}^{max} \\ P_{e,chp}^{max} = L_e + P_{ac}^{max} / \eta_{ac} \end{cases} \tag{11}$$

$$(\text{Gas})\begin{cases} P_{g,chp}^{min} = 0 \\ P_{g,chp}^{max} = P_{mt}^{max} / \eta_{ge}^{chp} \end{cases} \tag{12}$$

3.1.4. Solving algorithm

From the electric power flow model, the gas flow model, and the EHub model, it is known that there are complex nonlinear relationships between variables in the ICES. Solving the models as a whole requires high memory requirement and may suffer from the slow convergence problem. It is difficult to solve the optimization problem using analytical methods. Thus, a heuristic algorithm, namely particle swarm optimization (PSO) method [28], is used. Denote a particle position $x_i = [x_{id}, x_{id}, ..., x_{id}]$ and its corresponding flight velocity $\upsilon_i = [\upsilon_{id}, \upsilon_{id}, ..., \upsilon_{id}]$ in a d-dimensional search space.

$$v_{id}^{t+1} = \omega^t v_{id}^t + c_1 * r_1 * (pbset_{id} - x_{id}^t) + c_1 * r_2 * (gbset_d - x_{id}^t) \tag{13}$$

$$x_{id}^{t+1} = x_{id}^t + v_{id}^{t+1}, i = 1, 2, ..., n, d = 1, 2, ..., m \tag{14}$$

where n is the number of particles in a group; m is the number members in a particle; t is the particle generation; ω^t is the inertia weight factor; c_1 and c_2 are acceleration constants; r_1 and r_2 are uniformly distributed random numbers in [0,1]; υ_i^t is velocity of particle i at iteration t, $V_d^{min} \le v_{id}^t \le V_d^{max}$; x_i^t is current position of particle i at iteration t, $X_d^{min} \le x_{id}^t \le X_d^{max}$; $pbest_{id}$ represents the recorded individual best position of particle i; $gbest_d$ represents the recorded global best position.

In this paper, an IOPF method is proposed based on the PSO algorithm as illustrated in Fig. 3, and the algorithm and procedures are summarized as follows:

Step 1) (EHub initialization): Compute EHub control variables P_e, P_g, and ε_e according to the thermal and electric loads in the EHub.

Step 2) (Electric power and gas network initialization): Calculate the three-phase power flow and gas flow separately, and obtain lower and upper bound information for the hybrid gas and electricity network.

Step 3) (PSO initialization): Set the time counter $t_0 = 0$. Initialize randomly the individuals of the population based on the limit of the EHub (10)-(12). The initial individuals must be feasible candidate solutions that satisfy the operating constraints.

Step 4) (Time update): Update the time counter t = t + 1.

Step 5) (Hybrid gas and electric power flow computation): Solve gas and electric power flow, and obtain ICES tie-line power and gas consumptions.

Step 6) (Fitness calculation): Calculate the fitness of each individual in the population.

Step 7): Update individual best position and global best position.

Step 8): Update the velocity and position while satisfying constraints (3)-(8) and (10)-(12).

Step 9) (Stop criteria): If the number of iterations reaches the maximum t_{max}, then go to Step 10). Otherwise, go to Step 5).

Step 10): The individual that generates the latest global best position is the optimal solution with the minimum operating cost.

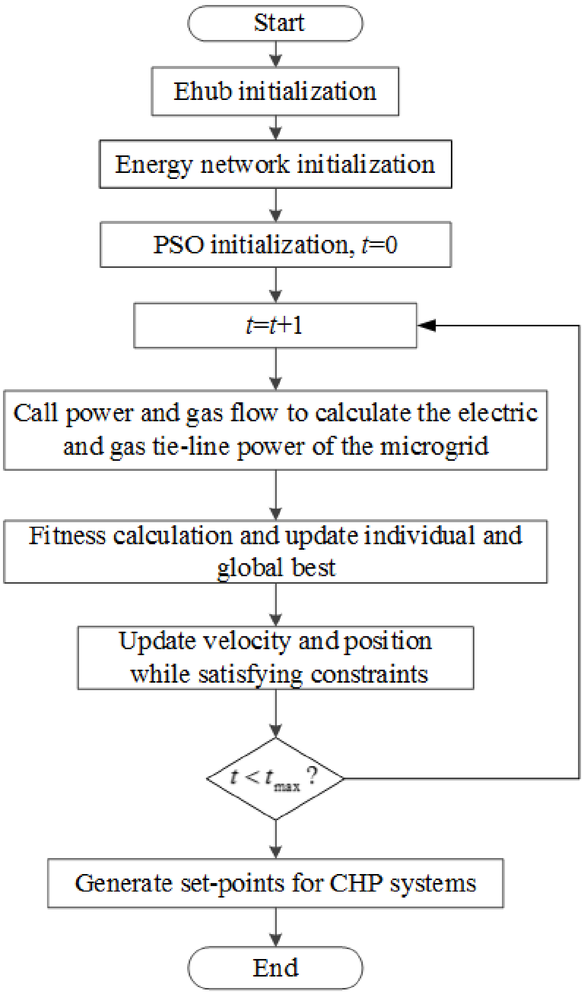

Fig. 3 Flowchart of the IOPF for the ICES.

3.2. Three-phase demand response dispatch

Various DR resources can be flexible to provide the needed fast-response services for scheduling of the ICES. Considering the three-phase unbalanced load and single-phase DGs in an ICES, a three-phase DR dispatch method is used in this paper to utilize the DR resources in different phases and at different locations. The existence of line-pack allows natural gas network to ehandle short-term gas load fluctuations. Thus, DRs are only used to smooth the electric tie-line power variations. Considering that DR resources are often distributed in different phases and locations, a three-phase DR dispatch algorithm is developed. Three-phase electric power systems are considered in this study with the emphasis on single-phase DGs coupled with unbalanced load.

3.2.1. Time series model for thermostatically controlled loads

In this paper, heating, ventilating, and air conditioning (HVAC) is studied as thermostatically controlled loads and a simplified space heating model [29] is used to describe its behaviours.[1] Aggregated HVAC loads are utilized as DR resource units in the three-phase dispatch process. When the HVAC is turned on or switched off, the room temperature T_{room}^{t} at time t can be described by

$$\begin{cases} T_{room}^{t+1} = T_{o}^{t+1} + QR - (T_{o}^{t+1} + QR - T_{room}^{t})e^{-\Delta t/RC} & \text{the HVAC is ON} \\ T_{room}^{t+1} = T_{o}^{t+1} - (T_{o}^{t+1} - T_{room}^{t})e^{-\Delta t/RC} & \text{the HVAC is OFF} \end{cases} \tag{15}$$

where T_{room}^{t} represents the room temperature at time t (^{o}C); C represents the equivalent heat capacity ($J/^{o}C$); R represents the equivalent thermal resistance ($^{o}C/W$); Q represents the equivalent heat rate (W); Δt represents the time step (1 minute); and T_0 represents the ambient temperature (^{o}C).

The DR units in each phase are prioritized in order based on their room temperatures to generate temperature priority lists (shown in Fig. 4). The upward and down regulations of the DRs can be expressed based on the ON/OFF status of HVAC temperature priority lists as described in Eq. (16) and Eq. (17).

$$\begin{cases} P_{DR,a,i}^{up} = \sum_{j=1}^{m_a} P_{rated,j}^{i} \\ P_{DR,b,i}^{up} = \sum_{j=1}^{m_b} P_{rated,j}^{i} \\ P_{DR,c,i}^{up} = \sum_{j=1}^{m_c} P_{rated,j}^{i} \end{cases} \tag{16}$$

[1] For practical application, more complex model and normalization method can be used for the time priority list method.

$$\begin{cases} P_{DR,a,i}^{down} = \sum_{j=m_a+1}^{N_{DR,a}} P_{rated,i}^{j} \\ P_{DR,b,i}^{down} = \sum_{j=m_b+1}^{N_{DR,b}} P_{rated,i}^{j} \\ P_{DR,c,i}^{down} = \sum_{j=m_c+1}^{N_{DR,c}} P_{rated,i}^{j} \end{cases} \tag{17}$$

where m is the number of DR units that are "OFF"; $P_{DR,a,i}^{up}, P_{DR,b,i}^{up}, P_{DR,c,i}^{up}$ and $P_{DR,a,i}^{down}, P_{DR,b,i}^{down}, P_{DR,c,i}^{down}$ are the upward and down regulations for group i; $P_{rated,i}$ is the average rated power of HVACs in group i; $m_{a,i}$, $m_{b,i}$, $m_{c,i}$ are the numbers of HVACs in group i that are "OFF" for the three phases; $N_{DR,a,i}$, $N_{DR,b,i}$, $N_{DR,c,i}$ are the numbers of controllable HVACs in group i for the three phases.

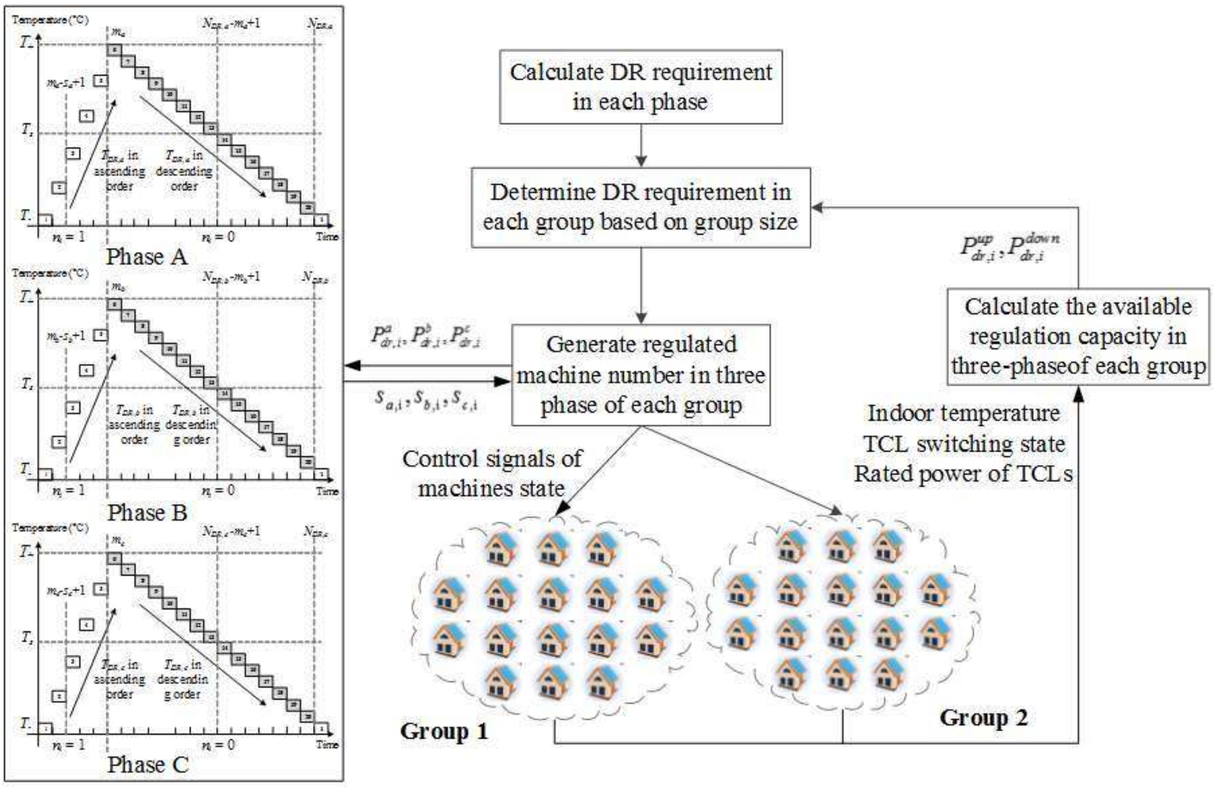

Fig. 4 Flowchart of the three-phase DR.

3.2.2. Objectives

Due to the compressibility of natural gas, the gas demand fluctuation can be compensated by the line-pack in the gas network. Therefore, the control objective in the ultra-short period is to smooth the tie-line power for the electric power networks as follows

$$\begin{cases} P_{DR,a} = \sum_{i=1}^{N_{CHP}} \Delta L_{E,a,i} - \sum_{i=1}^{N_{PV,a}} \Delta P_{PV,a,i} \\ P_{DR,b} = \sum_{i=1}^{N_{CHP}} \Delta L_{E,b,i} - \sum_{i=1}^{N_{PV,b}} \Delta P_{PV,b,i} \\ P_{DR,c} = \sum_{i=1}^{N_{CHP}} \Delta L_{E,c,i} - \sum_{i=1}^{N_{PV,c}} \Delta P_{PV,c,i} \end{cases} \tag{18}$$

where N_{CHP} is the number of CHP systems; $N_{PV,a}$, $N_{PV,b}$, $N_{PV,c}$ are the numbers of photovoltaics (PVs) plugged in three-phase; $\Delta L_{E,a,i}$, $\Delta L_{E,b,i}$, $\Delta L_{E,c,i}$ are the short-term three-phase electrical load forecasting errors of CHP system i; $\Delta P_{PV,a,i}$, $\Delta P_{PV,b,i}$, $\Delta P_{PV,c,i}$ are the short-term forecasting errors of the ith PV three-phase output.

3.2.3. Algorithm implementation

A group-based DR approach is proposed to alleviate the communication burden caused by the unified scheduling for huge volumes of DR resources. This also covers the utilization of the DR resources in different phases and at different locations. DR units are split into groups based on their distributed locations, and three phase dispatch is implemented based on the DR requirement in three-phase for each group respectively. At the client level, the available regulation capacity of each group in three phases is calculated based on the ON/OFF status of HVACs for the master level. In the master level, DR requirements (Eq. (18)) in each group are calculated based on the group size as shown in Eq. (19).

$$\begin{cases} P_{DR,a,i} = \dfrac{P_{DR,a} C_{DR,a,i}}{\sum_{i=1}^{N_g} C_{DR,a,i}} \\ P_{DR,b,i} = \dfrac{P_{DR,b} C_{DR,b,i}}{\sum_{i=1}^{N_g} C_{DR,b,i}} \\ P_{DR,c,i} = \dfrac{P_{DR,c} C_{DR,c,i}}{\sum_{i=1}^{N_g} C_{DR,a,i}} \end{cases} \tag{19}$$

where N_g is the number of DR groups; $C_{DR,a,i}$, $C_{DR,b,i}$, $C_{DR,c,i}$ are the capacities of controllable HVACs in group i for three phases; $C_{DR,a,i} = \sum_{j=1}^{N_{DR,a,i}} P_{rated,i}$, $C_{DR,b,i} = \sum_{j=1}^{N_{DR,b,i}} P_{rated,i}$, $C_{DR,c,i} = \sum_{j=1}^{N_{DR,c,i}} P_{rated,i}$; $P_{rated,i}$ is the average rated power of HVAC units in group i.

The feasibility domain is defined by the DR regulation limits

$$\begin{cases} P_{DR,a,i}^{lower} \le P_{DR,a,i} \le P_{DR,a,i}^{upper} \\ P_{DR,b,i}^{lower} \le P_{DR,b,i} \le P_{DR,b,i}^{upper} \\ P_{DR,c,i}^{lower} \le P_{DR,c,i} \le P_{DR,c,i}^{upper} \end{cases} \tag{20}$$

where $P_{DR,a,i}$, $P_{DR,b,i}$, $P_{DR,c,i}$ are the DR power at each phase in group i.

The adjusted power in each group, $P_{DR,a,i}$, $P_{DR,b,i}$, $P_{DR,c,i}$ are converted to the number of HVAC units required to be regulated $s_{a,i}$, $s_{b,i}$, $s_{c,i}$ as illustrated by

$$\begin{cases} s_{a,i} = \left| P_{DR,a,i} \,/\, P_{rated,i} \right| \\ s_{b,i} = \left| P_{DR,b,i} \,/\, P_{rated,i} \right| \\ s_{c,i} = \left| P_{DR,c,i} \,/\, P_{rated,i} \right| \end{cases} \tag{21}$$

3.3. Implementation of the hierarchical management algorithm

As discussed in Section 2, the hierarchical energy system consists of day-ahead scheduling and intra-hour adjustment. In the day-ahead scheduling, initial set-points are generated for energy hub outputs. A master-client structure is embedded in the intra-hour adjustment system to manage the CHP and the DR in two different time scales. In order to handle the system unbalance and single phase DG variation, the loads in three phases are managed synthetically. The proposed algorithm is introduced as follows (see Fig. 5):

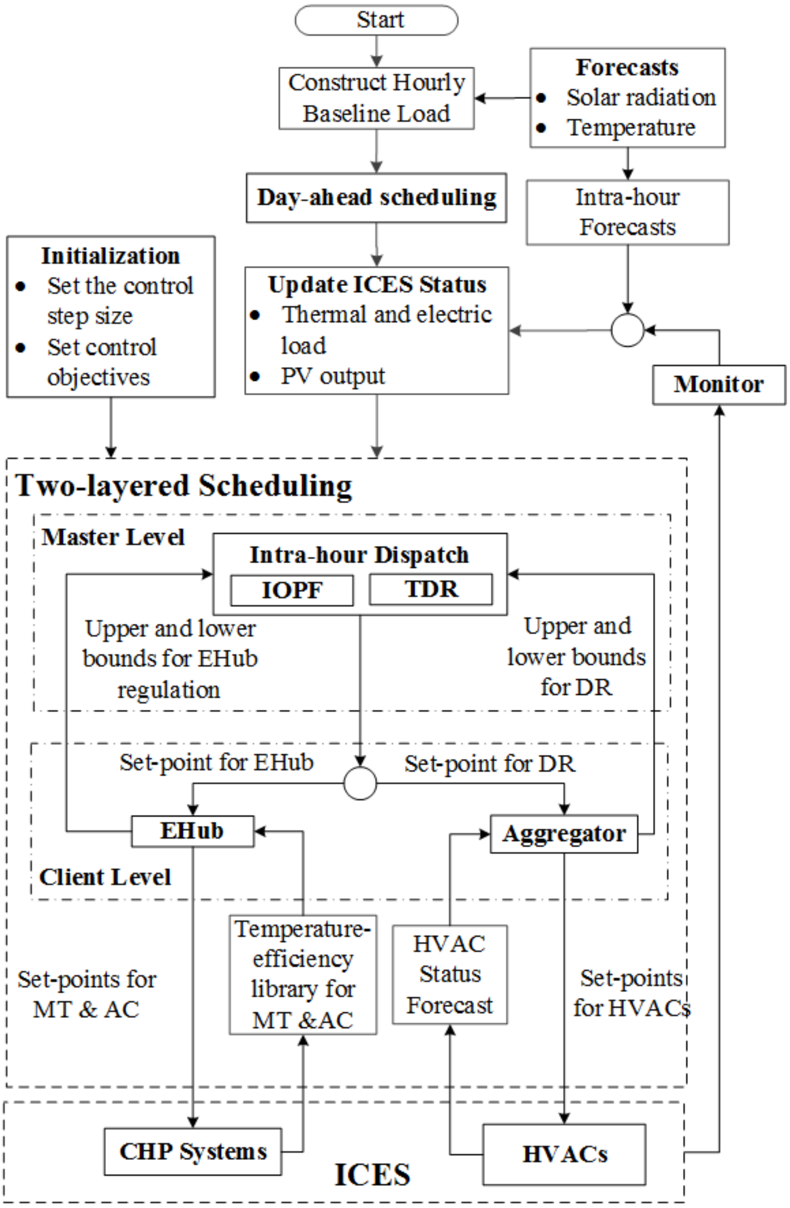

Fig. 5 Flowchart of the hierarchical management for the ICES.

Step 1) (ICES initialization): Set the control objectives and scheduling periods for CHP systems and DR resources according to the actual operation status of the ICES and the client demand. As mentioned earlier, the control objective is set to minimize the operation cost for day-ahead scheduling (shown in Eq. (1)); the control objective is to follow the electric and gas tie-line power set-points for short term intra-day scheduling (shown in Eq. (2)); while for ultra-short term intra-day scheduling (shown in Eq. (18)), the control objective is to smooth the tie-line power for the electricity networks.

Step 2) (Day-ahead scheduling): Given the load and generation forecasting results (hourly forecasting), day-ahead scheduling results (24 hour power and gas dispatch signal for the clients) are obtained by the IOPF program.

Step 3) (Update ICES status): Update ICES status (DG output/ short term and ultra-short term load forecast results) based on load and generation short term forecast results (intra-hour forecast) and measured data.

Step 4) (Intra-day scheduling, including dispatch of CHP systems and three-phase DR resources): A two-layered scheduling method is proposed to balance time-varying energy demand and supply while to meet the requirement of interrelated constraints between multiple energy systems.

At the master level, the main dispatch tasks are:

- For CHP systems, the IOPF is called to generate set-points for CHP systems to follow the electric and gas tie-line power based on the day-ahead electric and gas tie-line power scheduling results and DGs short term forecast results;
- For the DR resources, generate power regulation command for each phase (described in Eq. (18)) based on the three-phase electrical load and DGs ultra-short term forecast results; Then, determine DR requirements in each group based on group size (described in Eq. (19)) and the regulation limits (described in Eq. (19)) could be taken into account in the regulation.

At the client level, the main dispatch tasks are:

- For CHP systems, on one hand, generate set-points for components of CHP systems based on the EHub model; One the other hand, calculate the feasibility domain of the power exchange between the CHP and energy networks $P_{e,chp}$ and $P_{g,chp}$ (electricity and gas) based on the Eq. (11) and (12) and upload the upper and lower bounds for CHP systems to the master level;
- For DR resources, on one hand, calculate the feasibility domain of the DR regulation

based on Eq. (16) and (17) and upload the upward and down regulations to the master level; On the other hand, the regulated power in each group, $P_{DR,a,i}$, $P_{DR,b,i}$, $P_{DR,c,i}$ are converted to the number of HVAC units required to be regulated[2] $s_{a,i}$, $s_{b,i}$, $s_{c,i}$ as illustrated in Eq. (21).

In this paper, the electrical system is an unbalanced three-phase power system. The software of Open Distribution System Simulator (OpenDSS) [30] is used to solve the electric power flow. The proposed algorithm has been implemented based on the OpenDSS simulation engine that calculates three-phase electric power flow and Microsoft Visual C++ that performs the gas flow, EHub, PSO, and three-phase DR algorithm.

4. Case studies

The test system in Fig. 6 is used to investigate the proposed hierarchical management system. Based on the solar forecast results as shown in Fig. 7, the output of the PV panels and the CHP component efficiency can be obtained. To highlight the effectiveness of the proposed method, only load variations connected to the CHP systems 1 and 2 are considered in this paper. The ICES investigated in this paper includes the following main components:

- IEEE 37-bus radial distribution feeder [31], and the bus voltage is subject to the constraint $0.9 \leq V \leq 1.1$;
- A 4-node natural gas network, and the gas network data is shown in Table 1. The gas network used in this paper was initially designed for line-pack studies. Thus, wider pipelines are utilized in the network[3]. The upper and lower limits of the compression ratio are $k_{cp}^{min}=1.2$ and $k_{cp}^{min}=1.8$ respectively; the upper and lower limits of natural gas pipeline pressure are $p^{min}=0.2$ and $p^{max}=1.3$, respectively.

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[2] The regulation method of controllable loads (take HVAC as example) is based on the commonly used assumption in inconsistent literatures, etc. the system state at next time step could be predicted accurately based on the system state in the current time step, and the prediction technique for HVAC would be further studied in the future research.

[3] In order to ensure the gas network pressure level above a certain range, gas companies requires customer who use gas-fired generators to have gas storage devices. However, due to the security requirements, customers usually don’t have enough room for gas storage. An alternative way is to install wider pipelines with line-pack as storage.

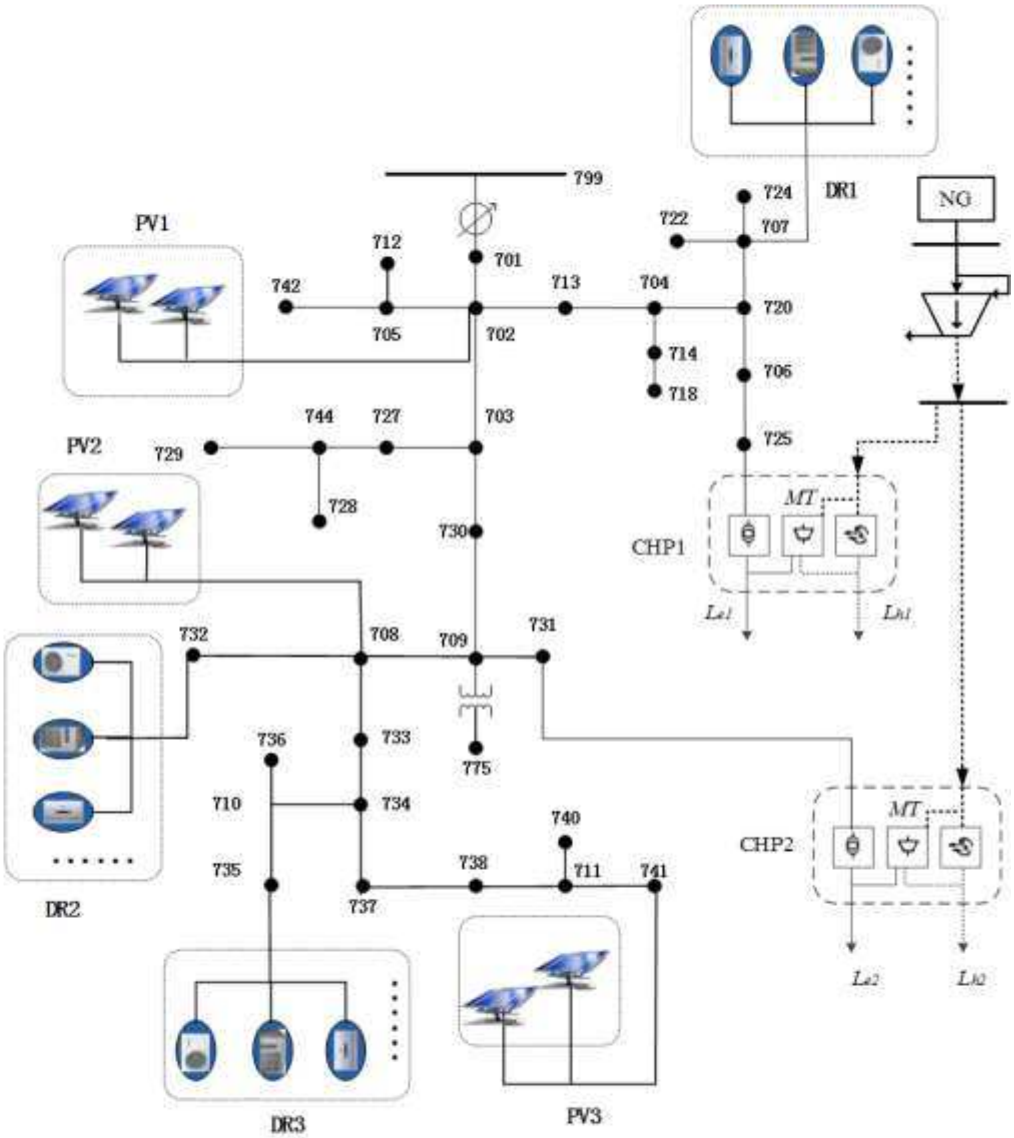

Fig. 6 Scheme diagram of the ICES case.

Table 1.
Natural gas network parameters

Pipe number	Start node	End node	Pipeline Diameter(mm)	Pipeline Length(m)
1	1	2	900	500
2	2	3	900	500
3	2	4	900	500

- Three PV panels are connected to the electric power network via bus 702, 708, and 741. The rated power of the three PV panels are 1000kW, 60kW (A-phase) and 2000kW. The actual and forecasted radiation levels are shown in Fig. 7;

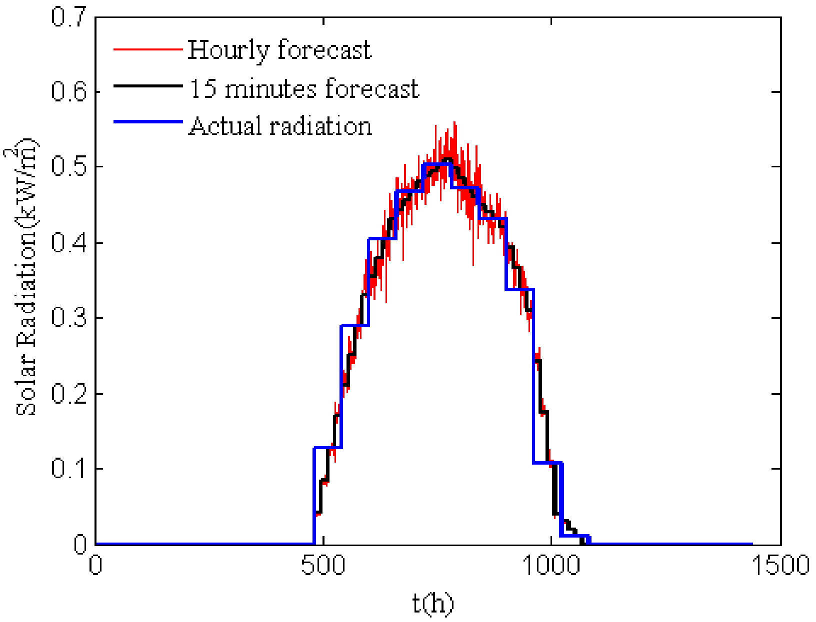

Fig. 7 Solar radiation data.

- Two EHubs, consisting of transformers, microturbines, and air-conditioners, are connected to bus 725, 731 in the electric power network and node 003, 004 in the gas network. The EHub data is presented in Table 2;

Table 2.
EHub Component Capacity

	EHub number	Value (kW)	EHub number	Value (kW)
MT	1	300	2	300
AC	1	100	2	100

- Three groups of HVAC units at bus 707, 732, and 735 are used for demand response. Considering that not all customers would like to participate in the DR program, only a certain number of HVAC units are incorporated in the DR, as shown in Table. 3. The rated power of HVACs is 1 kW with a dead band of 4 °C. Customer thermostat settings, T_{set}, are set to be 23 °C. The mean values of C, R, and Q are set to 3599.3 J/°C, 0.1208

°C/W, and 400 W respectively. The parameters C, R, and Q are randomized to create load diversity.

Table 3.
HVAC number in each phase of the three groups.

Group number	Bus number	Phase A	Phase B	Phase C
1	707	210	210	210
2	732	270	270	270
3	735	150	150	150

The electricity and gas from distribution networks are included in the overall simulation. The energy price used in this paper is taken from PG&E [32]. By providing renewable generation smoothing, the local energy supplier can obtain some profits from the utility. In this paper, this profit is not considered in the economic interests of the local energy supplier. Since the DR is only used for small adjustment, a fixed subsidy can be used that will not affect the operating cost optimization. More complex market model and pricing mechanism will be investigated in future work.

5. Results and discussion

5.1. Day-ahead scheduling

The 24 hour profile of the load is presented in Fig. 8 with hourly forecast and short term (15 minutes) forecast results, together with realistic load data. The CHP power input boundaries are calculated using the EHub model.

At the master level in the hierarchical scheme, the feasibility domain of the power exchange between the CHP and the energy networks $P_{e,chp}$ and $P_{g,chp}$ (electricity and gas) are calculated, and a 24 hour power and gas dispatch signals are generated for the clients in order to minimize the operating cost by utilizing the IOPF tool. The energy price and the operating cost are shown in Fig. 9. The 24 hour power and gas dispatch results to minimize the operating cost are shown as the red solid line and the 24 hour power and gas dispatch results to minimize the electrical power loss are shown by the blue dotted lines in Fig. 10. The comparison of the two dispatch results suggests that the operation cost of the ICES can be reduced significantly through the optimal dispatch. The 24 hour day-ahead scheduling EHub (EHub1 and EHub2) electric/gas regulation signals and the feasibility domain of the exchange power between the CHP and energy networks are depicted in Fig. 11.

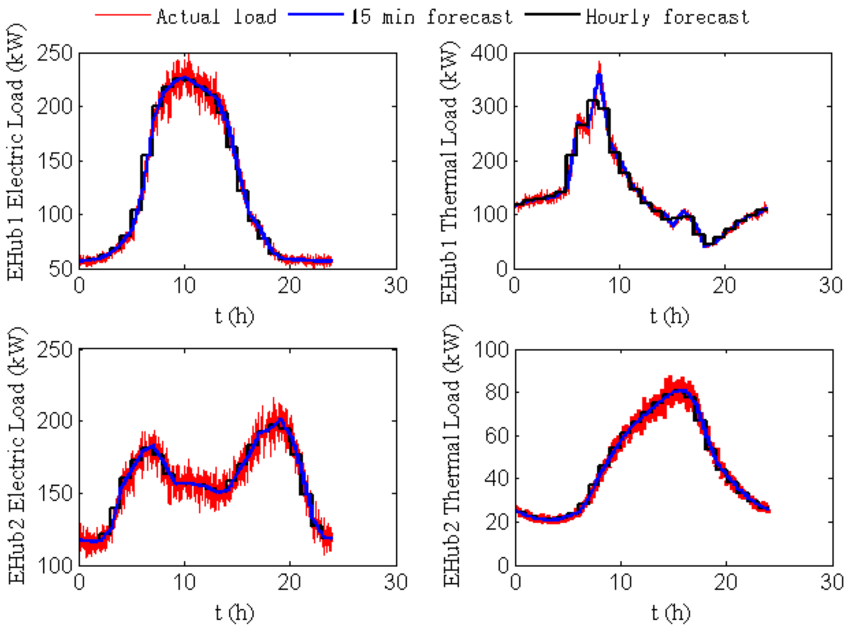

Fig. 8 CHP system loads.

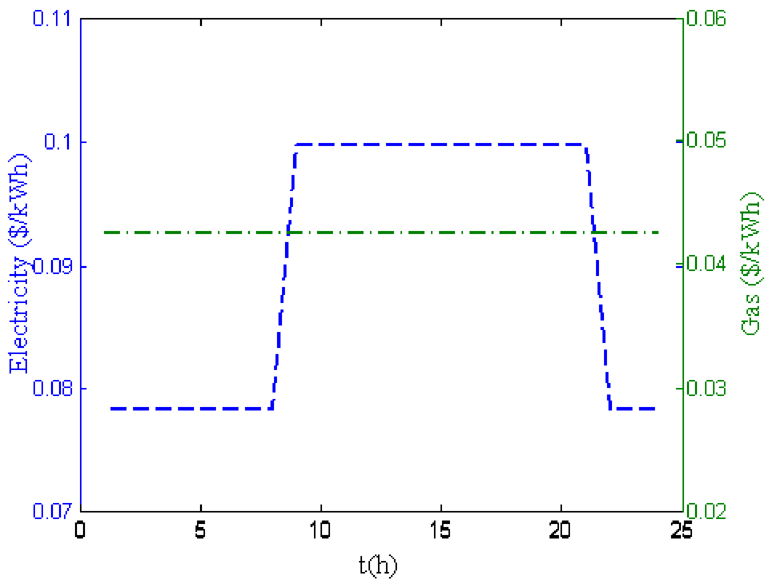

Fig. 9 Energy price.

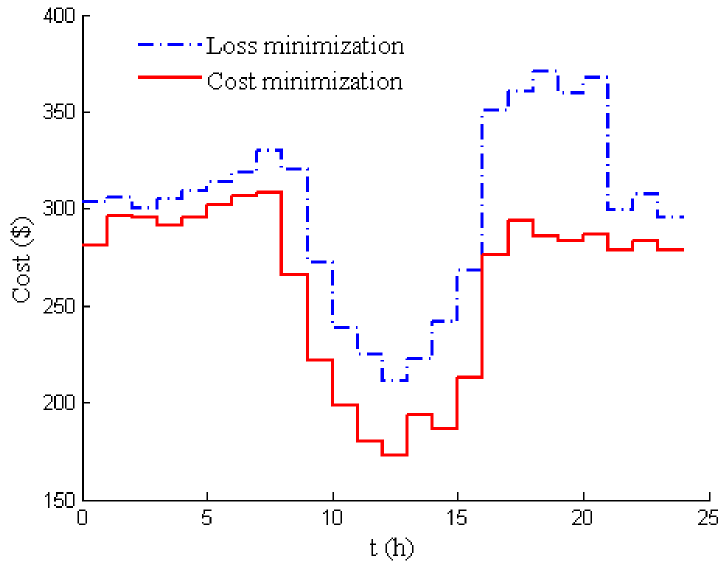

Fig. 10 ICES operating cost comparison under different objectives.

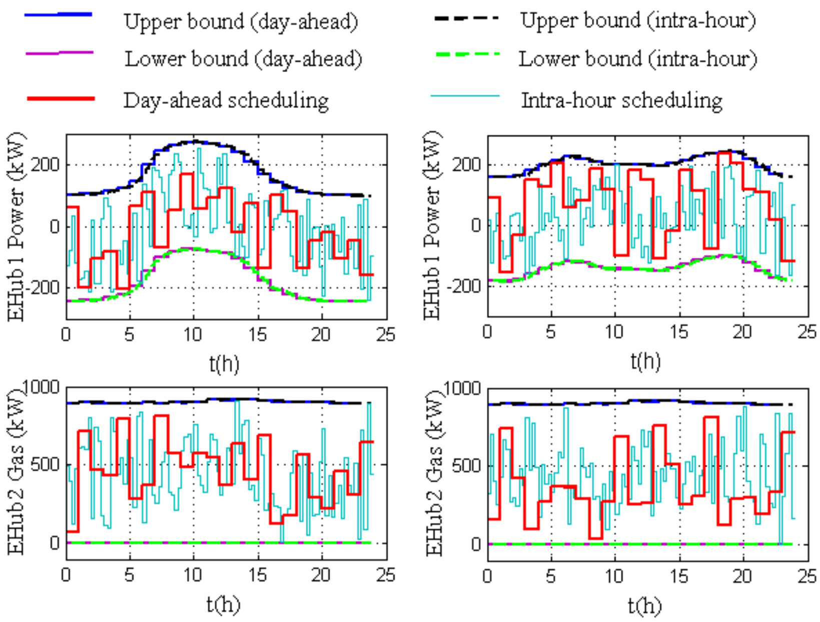

Fig. 11 Set-points and bounds for CHP systems.

5.2. Intra-hour scheduling

5.2.1. CHP regulation test

Considering that microturbines and air-conditioners are not suitable for frequent adjustment, the control period for the CHP is set to be 15 minutes. Based on the set-point obtained from the master level and the short-term load forecast signals as depicted by the black and blue line in Fig. 8, the CHP input is adjusted within the limits. Since the gas pipeline network can mitigate the flow fluctuations to some extent due to the gas storage characteristic of the pipeline network, the IOPF program is called to track the electric tie-line power mainly in intra-hour scheduling. Therefore, a relatively large value for ω_e in Eq. (2) is taken, and gas tie-line power tracking is considered under the natural gas pipeline network constraints.

At the client level, the upper and lower power regulation boundaries for EHub1 and EHub2 (represented by the black and green dotted lines in Fig. 11) are calculated, based on the load and DGs short term forecast results. The boundaries for the CHP systems to the master level are also calculated for short term dispatch. At the master level, the exchange power between the CHP and electric power/gas networks are regulated to track the electric and gas tie-line power set-points obtained in day-ahead scheduling for smoothing the tie-power fluctuations caused by the day-ahead forecast errors. The electric/gas regulation signals of EHub1 and EHub2 are described by the cyan solid lines in Fig. 11, which suggests that the CHP can effectively respond to the intra-hour scheduling commands and the regulation power of EHub1 and EHub2 are within the feasibility domain to guarantee the customer comfort level.

Two scenarios have been developed to verify the effectiveness of the proposed hierarchical scheduling method for smoothing the electric/gas tie-line power fluctuations as follows:

Scenario I: Intra-hour scheduling of the ICES based on the day-ahead scheduling results. The day-ahead scheduling discussed in section 5.1 is shown by the red solid line in Fig. 12, and the intra-hour scheduling results without short term dispatch of the CHP systems are shown by the yellow solid line in Fig. 12. When there is electric power /gas energy shortage caused by day-ahead forecasting errors in the ICES, all the energy shortage would be supplied by electrical power (electric loads are supplied by the electric power network and the thermal loads are supplied by the ACs in CHP systems) without the short term dispatch of CHP systems, and the electric/gas tie-line power fluctuations will mainly be reflected in the electric tie-line power fluctuations, which is shown by the yellow solid line in Fig. 12.

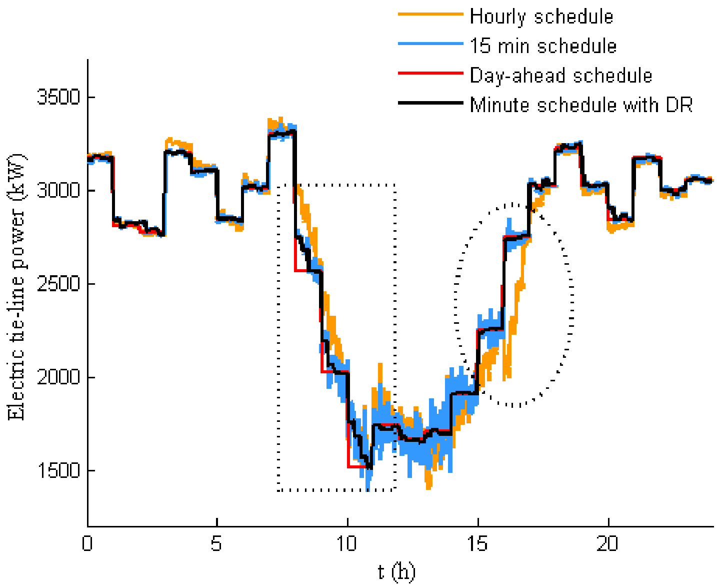

Fig. 12 ICES electric tie-line power.

Scenario II: Further conduction of 15 minute ahead scheduling based on the scheduling results taken from Scenario I. The exchange power between the CHP and electric/gas networks is regulated to track the electric and gas tie-line power set-points obtained from the day-ahead scheduling for smoothing the tie-line power fluctuations. The scheduling results in Scenario II are shown by the blue solid line in Fig. 12.

The comparison of scheduling results in Scenario I and Scenario II (shown in Fig. 12.) suggests that the electric tie-line power fluctuations of the ICES can be reduced to some extend using the short term dispatch of CHP systems. It is worth noting that electric tie-line power fluctuations still exist after the short term dispatch of the CHP systems due to the 15 minutes scheduling period for the CHP system. With the 15 minute scheduling results, the natural gas network pressure is shown in Fig. 13. It can be seen that the obtained gas network pressure are under the permissible range considering gas flow constraints. As previously mentioned, the operator tends to use more gas when the gas price is low. If gas flow constraints are not considered, the scheduling objective cannot be achieved. Moreover, the large amount of gas consumption will affect the gas pressure level of other loads.

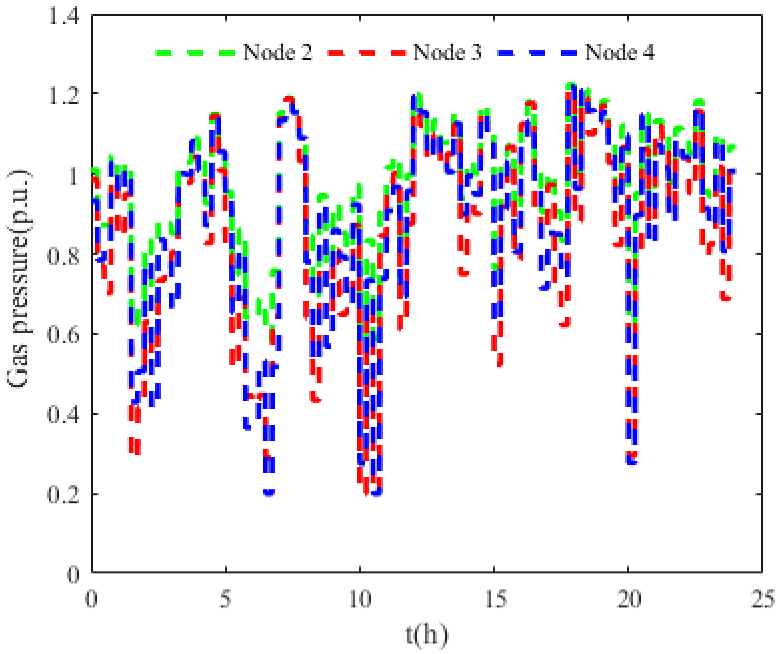

Fig. 13 Natural gas network pressure.

5.2.2. Three-phase DR scheduling test

As previously mentioned, the DR resources are used to balance the load and DG forecasting mismatch in an ultra-short control period to guarantee the customer comfort level. As another type of clients, HVAC groups are used to compensate the ultra-short term (1 minute) forecasting mismatch. The initial room temperature and ON/OFF status are set by randomizing each HVAC for 24 hours.

Scenario III is developed to verify the effectiveness of the proposed three-phase DR dispatch method. The dispatch based on the scheduling results from Scenario II is conducted to further smooth the electric tie-line power fluctuations. The specific scheduling procedure is introduced as follows:

At the master level, the power regulation commands are generated for DR in each phase (described in Eq. (18)) based on the three-phase electrical load and DG ultra-short term forecast results. Then, the DR requirement in each group is determined based on the group size (described in Eq. (19)). The DR required power and HVACs temperature of Phase A in the three groups after DR dispatching are shown in Fig. 14.

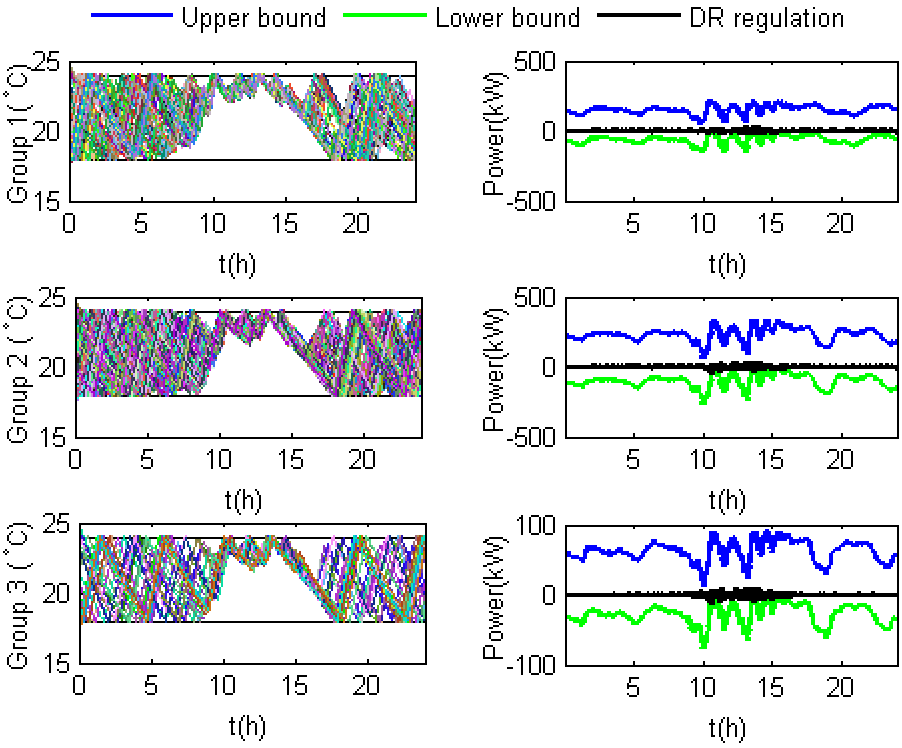

Fig. 14 DR of Phase A in the three groups.

At the client level, the feasibility domain of the DR regulation is calculated first based on the ON/OFF status of HVACs in each group, and the boundaries for the DR regulation are generated by the client as illustrated in the green and blue area of Fig. 14. The boundaries are uploaded to the master for the short period dispatch.

The simulation results reveal that the DR signals (the black line in Fig. 14) are dispatched to the three groups within the limits. All the HVACs are operated in the dead band. It is worth noting that PV outputs increase in 10-15 hours leading to the increase of the electric tie-line power fluctuations, and the DR required power increases accordingly while the boundaries for the DR regulation are narrowed in the three groups. The relative voltage at each node of the HVACs is shown in Fig. 15.

A comparison of the scheduling results in Scenario III (black solid line in Fig. 12), Scenario I (yellow solid line in Fig. 12) and Scenario II (blue solid line in Fig. 12) suggests that the tie-power fluctuations are well smoothed by the DR. A small number of fluctuations shown in the red lines are due to the DR dispatch signals reaching the boundaries of the HVACs. In addition to the tie-line power, the operating cost in the three scenarios are shown in Fig. 16. It can be seen that although there are some mismatch between the set points and the real operating points due to forecast errors, the operating cost is close to the day-ahead schedule. In the meanwhile, the tie-line power fluctuation is significantly reduced as depicted in Fig. 12. Because the DR is not charged in this paper, the intra-hour dispatch with and without DR has almost the same operating cost unless the DR reach its boundaries (see the dashed green line and black line). By providing controllable tie-line response, the energy service provider can earn some profits from utilities and pay customers some money for the DR. Considering the positive effect of the DR on smoothing the tie-line power flow, it is possible for energy service providers to negotiate with both utilities and customers to obtain more profits and reducing operating costs.

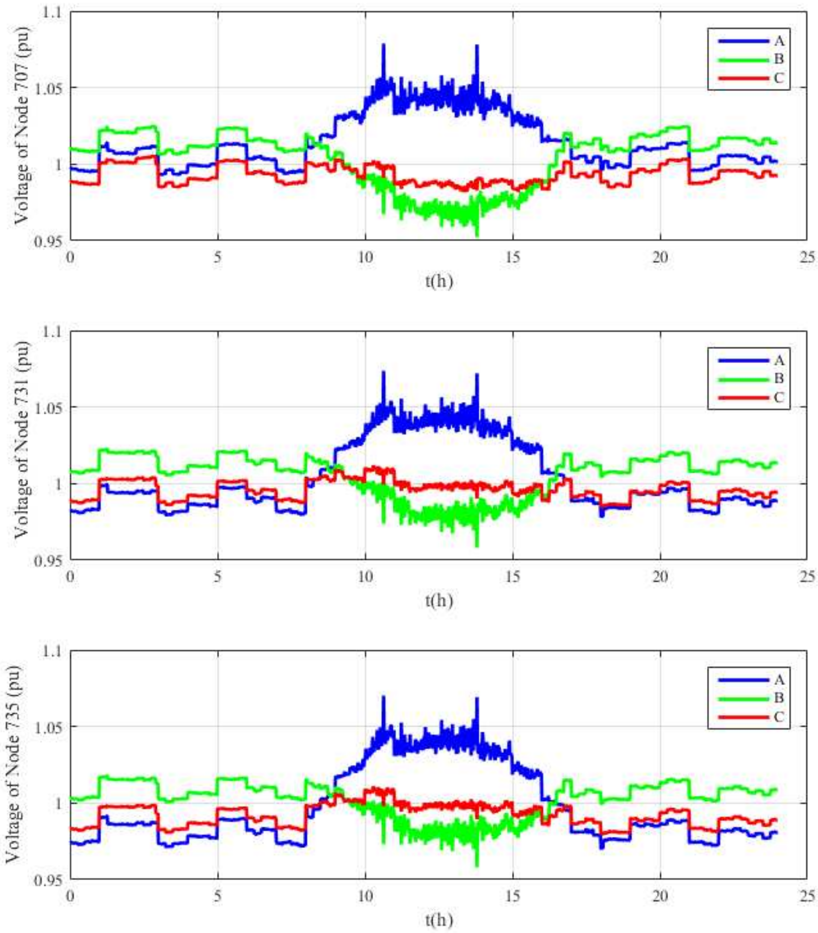

Fig. 15 Three-phase voltage of the aggregated loads.

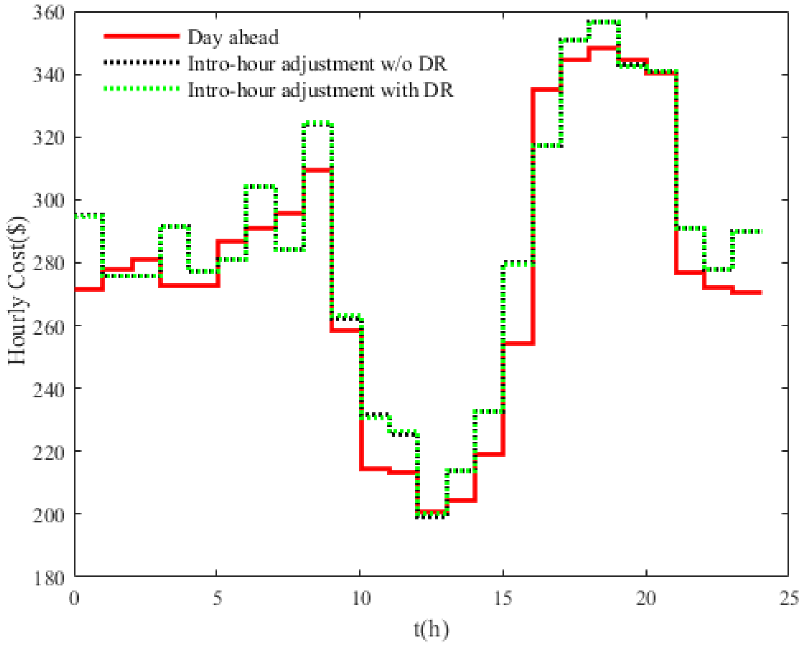

Fig. 16 Operating cost comparison between the three scenarios.

6. Conclusion

This paper designed a hierarchical management system for a community area by scheduling the CHP and demand response. It allows the operators to coordinate the interrelated power, gas and heat systems, taking three-phase electric power system characteristics into account. With the integrated optimal power flow method, optimal operating plan can be generated for CHP in the day-ahead scheduling. For intra-hour scheduling, a two-layered approach is designed to follow the day-ahead operating plan, taking into account the uncertainties associated with renewable generations and loads. To incorporate various device characteristics, CHPs and demand response are coordinated at two different time scales. At the master level, CHP systems are dispatched to follow the electric and gas tie-line power set-points within a short-term. A three-phase demand response method is further presented to smooth the electric tie-line power fluctuations by managing loads and DGs from various locations and at different phases within an ultra-short term. At the client level, the operating boundaries for the CHP and the DR are generated and transmitted to the upper layer. The set-points from the upper level are then converted to control signals for each unit.

The developed methodology is applied to a simulated community energy system obtained from a modified IEEE 37-node system. Numerical results have shown that the proposed scheduling method can effectively reduce the operating cost while smooth the tie-power power fluctuations. It is also shown that the amount of data traffic will be significantly reduced as only the operating boundary information is transmitted. The proposed method can also be used to meet other requirements for the integrated community energy system, such as minimizing the energy loss and emissions.

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