

Optimal Expansion Planning Model for Integrated Energy System Considering Integrated Demand Response and Bidirectional Energy Exchange

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Abstract—The challenges of energy shortage and environmental protection motivate people to take various measures to use energy wisely, and integrated energy systems are such a measure to tackle this challenge. In this paper, an optimal expansion planning model for an integrated energy system consisting of power grid, gas network and multiple energy hubs is proposed, where the planning objective is to minimize operational fuel cost and capital investment cost covering carbon capture equipment and energy hubs among others. To demonstrate the advantage of the proposed planning model, six case studies are investigated, and 13.47% annual cost savings can be achieved compared with the baseline planning scenario, which does not consider bidirectional energy exchange and integrated demand response program.

Index Terms—Bidirectional energy exchange, energy hubs, integrated energy system, integrated demand response.

I. INTRODUCTION

DUE to concerns on energy shortage and environmental protection, the concept of integrated energy system (IES) is proposed to improve efficiency of energy usage [1]–[3]. By integrating energy converting facilities and energy storage, IES can convert, store, and distribute multiple types of energy resources.

Optimal planning of regional IESs has been an important research focus. In [4], a multi-objective optimization method is used to optimize installed capacity of an IES. Reference [5] presents an optimal IES planning model considering reliability constraints, and selection of facilities and their capacities are optimized, simultaneously. Reference [6] proposes IESs for buildings, where power and heating loads are considered in the model. In [7], a modular regional-user level IES planning model considering a two-layer bus structure and modular

simulation is presented. Focusing on the IES configuration planning, [8] presented an energy hub (EH) optimal planning model using branch energy flow and graph theory, and the obtained model is also simplified as a mixed-integer linear programming (MILP) problem using the big M method for ease of computing. In [9], an IES is divided into several simple EHs to simplify the model, and a change-of-variables is performed in the modeling process to transform the model into a MILP. In [10], a directed acyclic graph is adopted to build a MILP optimal planning model of IES, where the topological layers of directed acyclic graphs can conveniently describe RES facilities in the model. In [11], the concept of energy buses is proposed to formulate the IES planning model as a MILP. The above studies mainly focus on a single regional IES. When multiple regional IESs are considered, impact of the electric power network and gas network should be considered.

The IES optimal planning considering energy network is studied in [12]–[17]. An optimal planning model of an IES consisting of an electric network and a gas network is presented in [12], where transmission loss and transmission infrastructure investment are considered in the planning. Reference [13] proposes an IES expansion planning model under an active distribution network and corresponding management technologies. In [14], optimal long-term planning of an IES, including electricity transmission networks, power and heat resources, is studied. In [15], expansion of the electric power and gas networks, and optimal configuration of multiple EHs are considered in IES planning. Reference [16] proposes an optimal planning model considering multiple region IES interconnection, transmission line expansion, and reliability constraints, but configuration of IESs is not discussed. Note increasing utilization of electric vehicles, an IES optimal expansion planning model is presented in [17] to optimally configure the EHs within the integrated transportation network, gas network, and active distribution network. In the IES planning, multiple EHs are proposed in these coupled networks, and the main objective is optimal EH configuration planning. However, CO₂ reduction and recycling technologies, such as carbon capture system (CCS) and combined operation of power-to-gas (P2G) and CCS, are not considered in the above studies. Moreover, energy exchange between EHs and the energy network is regarded as a unidirectional exchange in the above studies, while impact of bidirectional energy

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exchange on IES planning and EHs' structure configuration is not discussed.

In literature, there are many discussions on bidirectional electric power exchange between EHs and other energy networks. For instance, a Peer-to-Peer Electricity Market is proposed in [18] to realize bidirectional electricity exchange between different EHs. Reference [19] proposed a smart energy hub, and bidirectional electricity exchange between the energy hub and power grid is considered to reduce operation costs. However, only bidirectional electricity exchange is considered in the above studies, while bidirectional gas exchange is not considered. In [20], bidirectional gas exchange is considered to improve utilization efficiency of wind power and promote CO₂ capture; however, energy network constraint is not considered in the study.

Impact of Demand response (DR) on the planning of power systems also catches significant attention. In [19], an analytical framework for adopting DR in long-term resource planning is proposed, and ten recommendations are identified for incorporating DR into energy resource planning. DR also has a positive impact on IES planning, and several DR programs are adopted in the IES optimal planning studies. For example, in [22], integrated demand response (IDR) is considered in an IES planning model for dealing with uncertainties of RESs and loads. However, impact of DR on the EH structure configuration is not discussed in the above studies. DR's impact on carbon emission and CO₂ recycling is also not considered.

Based on the above literature review, it is noted that carbon capture/conversion facilities and bidirectional energy exchange between the EHs and multi-energy networks are not included in the IES modeling, and the IDR is not considered in EHs' structure configuration planning.

Targeting the above problems, an optimal IES expansion planning model is proposed in the paper. In the proposed planning model, the structure configuration of multiple EHs and CCS configuration in the energy network are considered, and combined operation of carbon capture and conversion facilities, along with bidirectional energy exchange, are also included in the IES modeling. Moreover, an IDR program is adopted in the EH structure configuration, and its impact on optimal expansion planning is studied. In brief, the key contributions are highlighted below:

1) An optimal IES expansion planning model is proposed, which includes multiple EH structure configuration planning under constraints of multiple energy networks, gas-fired units (GFUs), and coal-fired units (CFUs). Moreover, bidirectional energy exchange between the EHs and multi-energy networks is considered in IES optimal expansion planning, and its impact on IES operation is discussed. The concept of energy buses is introduced in the EH modeling for formulating the proposed planning model as a MILP.

2) In structure configuration planning of multiple EHs, impact of the IDR programs is considered. IDR's impact on the reduction of CO₂ emission, as well as the combined operation of P2G and CCS in EHs, is also analyzed.

The rest of this paper is presented as follows. System framework of the IES is described in Section II. Section III

proposes modeling of EHs. Section IV presents the optimal expansion planning model of the IES. Section V is on case studies, which is followed by conclusions in Section VI.

II. SYSTEM DESCRIPTION

A. System Description of the IES

Figure 1 illustrates the system sketch of an IES. The main part of the IES is a multi-energy network composed of the electric power network and the gas network coupled by GFUs and EHs.

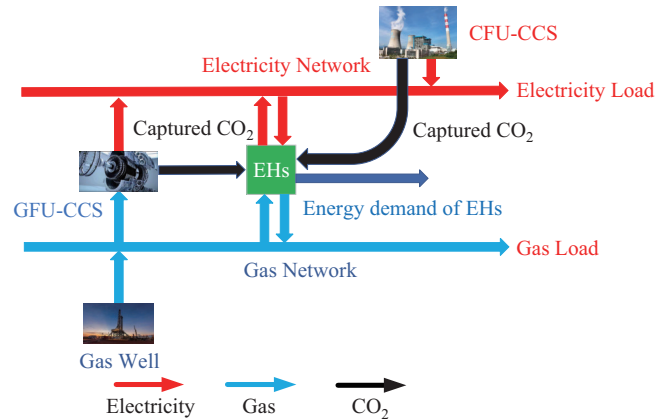


Fig. 1. The framework of an IES.

As shown in the system sketch, two functions can be implemented by EHs in the IES: one is bidirectional energy exchange between the multi-energy network and EHs, and the other is coordinated energy supply and the management of IDR on the user side. To simplify analysis, such as internal energy transactions within the IES, the presented IES is assumed to be owned by a single utility company, similar to many existing studies [23]–[26].

B. EH Framework

Figure 2 shows the framework of a typical EH. It consists of RESs, energy conversion facilities, and energy storage facilities. Within the EH, the RESs refer to wind turbines (WTs) and PVs; energy conversion facilities include CHPs, gas boilers (GB), P2G, hydrogen-fired units (HFUs), electric heaters and electric chillers; energy storage facilities contain batteries, gas storage, H₂ storage, CO₂ storage, heat storage and cooling storage.

Electrical demand of end users is met by RESs, electric network and GFUs; gas demand can be supplied by gas network and combined operation of P2G and CCS [23]; heating demand is provided by gas boilers, gas-fired power units, P2G and electric heaters; cooling demand is provided by absorption chillers and electric chillers; H₂ demand is supplied by P2G. Furthermore, part of the captured CO₂ from CFUs, GFUs and GB, which are not able to be utilized by P2G, need to be transported and buried deeply. This is what is shown as 'Transmission and Burying' in Fig. 2.

Excess power of WTs from an EH can be supplied to the electric network and other EHs after meeting the power

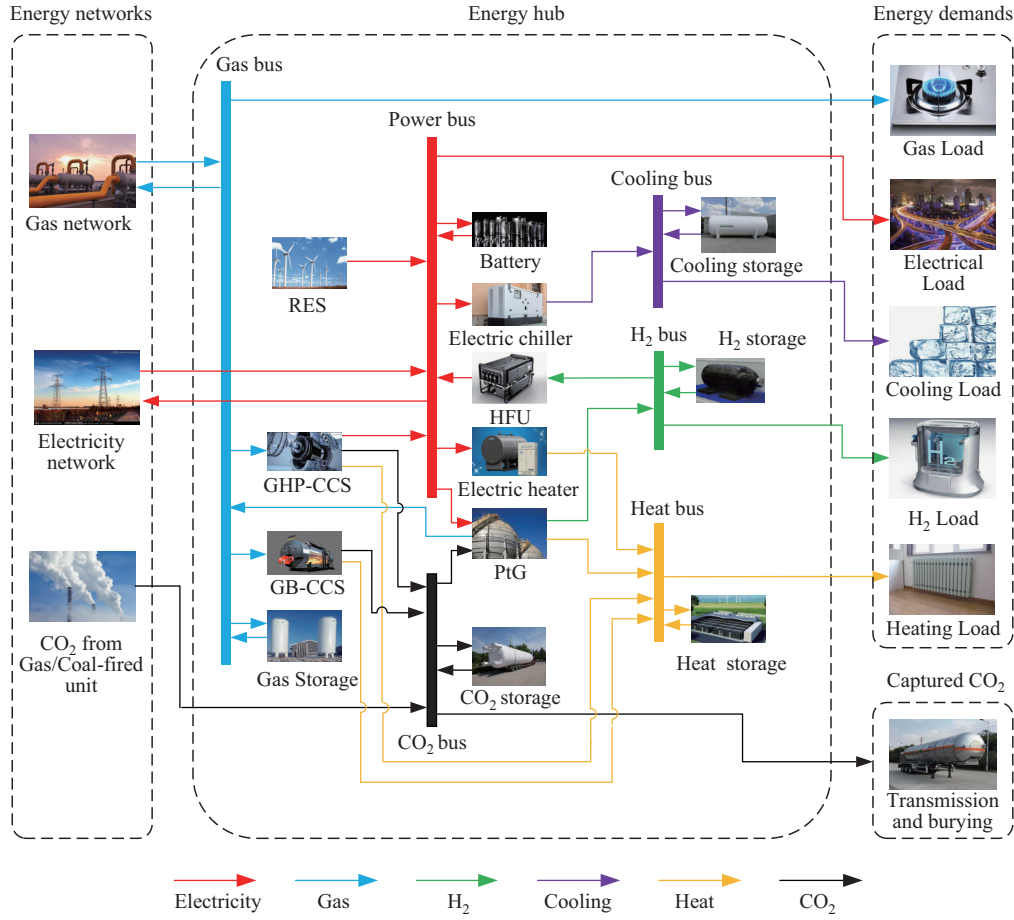


Fig. 2. The framework of a typical EH.

demand of the electrical load and other energy conversion facilities within the EH, or being transformed to CH_4 by P2G and supplied to the gas network and other EHs. Therefore, the EHs can be coupled to both the gas network and electric power network, and the gas network and electric power network can exchange energy with each other.

III. EH MODELING

A. Energy Buses

The concept of energy buses is used to model the EH configuration planning, where an energy bus is defined as a virtual device that can collect and allocate energy. As shown in Fig. 2, energy buses are assumed in the EHs. Energy from an energy network and output of facilities in an EH (i.e., RESs, CHPs, batteries, and so on) are collected by energy buses, which are further allocated to corresponding facilities and loads.

EH configuration planning can be described by a binary matrix as shown in (1), where m is the number of the EHs in the IES, and n refers to the number of alternative facilities. If facility j is chosen in EH i , then element $x_{ij} = 1$; otherwise, element $x_{ij} = 0$.

$$X = \begin{bmatrix} x_{11} & \cdots & x_{1n} \\ \vdots & \ddots & \vdots \\ x_{m1} & \cdots & x_{mn} \end{bmatrix} \quad (1)$$

Energy input/output in EHs can be described by matrices $P_t^{k,\text{in}}$ and $P_t^{k,\text{out}}$, where element $P_{ij,t}^{k,\text{in}}$ from matrix $P_t^{k,\text{in}}$ refers to energy input of the facility j in EH i , element $P_{ij,t}^{k,\text{out}}$ in the matrix $P_t^{k,\text{out}}$ is energy generated by the facility j of EH i , and superscripts k and t denote energy type and time period, respectively. If facility j is not in EH i , or facility j does not have type k energy as its input or output, then corresponding elements $P_{ij,t}^{k,\text{in}}$ and $P_{ij,t}^{k,\text{out}}$ are equal to zero. Notations e, h, g, c and H_2 denote electricity, heat, natural gas, cooling, and hydrogen, respectively. Symbols CO_2^1 , CO_2^2 , and CO_2^3 denote the amount of CO_2 not captured, captured and buried deeply, and captured but supplied to P2G for CH_4 generation, respectively.

$$P_t^{k,\text{in}} = \begin{bmatrix} P_{11,t}^{k,\text{in}} & \cdots & P_{1n,t}^{k,\text{in}} \\ \vdots & \ddots & \vdots \\ P_{m1,t}^{k,\text{in}} & \cdots & P_{mn,t}^{k,\text{in}} \end{bmatrix} \quad (2)$$

$$P_t^{k,\text{out}} = \begin{bmatrix} P_{11,t}^{k,\text{out}} & \cdots & P_{1n,t}^{k,\text{out}} \\ \vdots & \ddots & \vdots \\ P_{m1,t}^{k,\text{out}} & \cdots & P_{mn,t}^{k,\text{out}} \end{bmatrix} \quad (3)$$

Energy balance in the EHs is shown as (4). The left-hand side of (4) is composed of two parts, one is end user load L_{it}^k , and the other is inputs of energy type k to all facilities $\sum_{j=1}^n P_{ij,t}^{k,\text{in}}$. The right-hand side of (4) also includes

two items, the first item $P_{it}^{k, \text{EH}}$ means energy exchange between the EHs and energy networks, and the second item $\sum_{j=1}^n P_{ij,t}^{k, \text{out}}$ represents outputs of energy type k from all facilities. Note when $P_{it}^{k, \text{EH}}$ is non-negative, energy flow is from energy networks to EHs; otherwise, energy flow is from EHs to energy networks. $P_{it}^{k, \text{EH}}$ is equal to zero when $k \in \{h, c, H_2\}$, because the energy network consists of the electric network and natural gas network.

$$L_{it}^k + \sum_{j=1}^n P_{ij,t}^{k, \text{in}} = P_{it}^{k, \text{EH}} + \sum_{j=1}^n P_{ij,t}^{k, \text{out}} \quad \forall i, t \forall k \in \{e, g, h, c, H_2\} \quad (4)$$

The balance of CO₂ is shown as (5)–(7), where notations $C_{it}^{\text{EH}, \text{in}}$ and $C_{it}^{\text{EH}, \text{out}}$ are captured CO₂ input and captured CO₂ output of the EH i at time t , and $C_{it}^{\text{SEH}, \text{out-c}}$ denotes untreated CO₂.

$$\sum_{j=1}^n P_{ij,t}^{\text{CO}_2^3, \text{in}} = C_{it}^{\text{EH}, \text{in}} + \sum_{j=1}^n P_{ij,t}^{\text{CO}_2^3, \text{out}}, \quad \forall i, t \quad (5)$$

$$\sum_{j=1}^n P_{ij,t}^{\text{CO}_2^2, \text{in}} = C_{it}^{\text{EH}, \text{out}}, \quad \forall i, t \quad (6)$$

$$\sum_{j=1}^n P_{ij,t}^{\text{CO}_2^1, \text{out}} = C_{it}^{\text{EH}, \text{out-c}}, \quad \forall i, t \quad (7)$$

B. System Facilities Modeling

1) Energy conversion facilities

For CHP-CCS, heating output and power output are determined by gas input.

$$P_{ij,t}^{\text{h}, \text{out}} = P_{ij,t}^{\text{g}, \text{in}} \eta_j^{\text{gh}} P_{ij,t}^{\text{e}, \text{out}} = P_{ij,t}^{\text{g}, \text{in}} \eta_j^{\text{ge}} \quad (8)$$

where η_j is conversion efficiency of facility j .

Total CO₂ emission of the CHP-CCS is determined by output as shown in (10):

$$P_{ij,t}^{\text{CO}_2^1, \text{out}} + P_{ij,t}^{\text{CO}_2^2, \text{out}} + P_{ij,t}^{\text{CO}_2^3, \text{out}} = P_{ij,t}^{\text{e}, \text{out}} \chi_j \quad (9)$$

where χ_j is carbon emission intensity of facility j .

Power consumption of a CCS equipped on the CHPs in EHs consists of fixed power consumption and operation power consumption [27]. Therefore, the relationship between power input and captured CO₂ is shown as (10), where $P_{ij,t}^{\text{e}, \text{in}}$ is the total power input to CCS, P_j^{CCS} is fixed power consumption part, x_{ij} is a binary variable with value 1 indicating facility j installed in the EH i and 0 otherwise.

$$P_{ij,t}^{\text{CO}_2^2, \text{out}} + P_{ij,t}^{\text{CO}_2^3, \text{out}} = \left(P_{ij,t}^{\text{e}, \text{in}} - x_{ij} P_j^{\text{CCS}} \right) \gamma \quad (10)$$

where γ is the CO₂ treating efficiency in Kg/kW.

For GB-CCS, heating output is determined by gas input.

$$P_{ij,t}^{\text{h}, \text{out}} = P_{ij,t}^{\text{g}, \text{in}} \eta_j^{\text{gh}} \quad (11)$$

Similar to the CHP, total CO₂ emission of the GB is determined by output as shown in (12), and input-output relationship of CCS satisfies (10).

$$P_{ij,t}^{\text{CO}_2^1, \text{out}} + P_{ij,t}^{\text{CO}_2^2, \text{out}} + P_{ij,t}^{\text{CO}_2^3, \text{out}} = P_{ij,t}^{\text{h}, \text{out}} \chi_j \quad (12)$$

For CHP and GB without CCS, input (or output) constraints are the same as (8) and (11).

CO₂ emissions of the CHP and GB are determined by their power output and heating output, respectively:

$$P_{ij,t}^{\text{CO}_2^1, \text{out}} = P_{ij,t}^{\text{e}, \text{out}} \chi_j, \quad P_{ij,t}^{\text{CO}_2^1, \text{out}} = P_{ij,t}^{\text{h}, \text{out}} \chi_j \quad (13)$$

Input-output relations of the P2G facilities satisfy the following equations [1]:

$$P_{ij,t}^{\text{H}_2, \text{out}} = P_{ij,t}^{\text{e}, \text{in}} \eta_j^{\text{H}_2\text{-e}} \quad (14)$$

$$P_{ij,t}^{\text{g}, \text{out}} = P_{ij,t}^{\text{CO}_2^3, \text{in}} \eta_j^{\text{CO}_2\text{-g}} \quad (15)$$

$$P_{ij,t}^{\text{g}, \text{out}} = P_{ij,t}^{\text{H}_2, \text{in}} \eta_j^{\text{H}_2\text{-g}} \quad (16)$$

$$P_{ij,t}^{\text{h}, \text{out}} = P_{ij,t}^{\text{CO}_2^3, \text{in}} \varphi \quad (17)$$

where φ is the exothermic coefficient of methanation.

For other facilities which have no CO₂ input or CO₂ output, corresponding constraints are shown as (18), where $k1$ and $k2$ is energy type of input and output:

$$P_{ij,t}^{k2, \text{out}} = P_{ij,t}^{k1, \text{in}} \eta_j^{k1k2} \quad (18)$$

Moreover, for all the above-mentioned energy conversion facilities, their inputs (or outputs) are subject to the following minimum and maximum boundaries:

$$x_{ij} P_{j, \text{min}}^{k1, \text{in}} \leq P_{ij,t}^{k1, \text{in}} \leq x_{ij} P_{j, \text{max}}^{k1, \text{in}} \quad (19)$$

2) Energy storage facilities

For storage facilities, the input-output relationship is shown as (20)

$$E_{ij,t} - E_{ij,t-1} = \frac{\left[P_{ij,t}^{k, \text{in}} \eta_j^{\text{in}} - P_{ij,t}^{k, \text{out}} \frac{1}{\eta_j^{\text{out}}} \right]}{W_j} \Delta t \quad (20)$$

where $E_{ij,t}$ is the state-of-charge (SOC) of the storage j in EH i at time t , and W_j is the corresponding capacity of storage j .

Input and output constraints of storage facilities are shown as (21)–(22), and capacity constraint is shown as (23):

$$v_{ij}^{\text{in}}(t) P_{j, \text{min}}^{k, \text{in}} \leq P_{ij,t}^{k, \text{in}} \leq v_{ij}^{\text{in}}(t) P_{j, \text{max}}^{k, \text{in}} \quad (21)$$

$$v_{ij}^{\text{out}}(t) P_{j, \text{min}}^{k, \text{out}} \leq P_{ij,t}^{k, \text{out}} \leq v_{ij}^{\text{out}}(t) P_{j, \text{max}}^{k, \text{out}} \quad (22)$$

$$x_{ij} E_{j, \text{min}} \leq E_{ij,t} \leq x_{ij} E_{j, \text{max}} \quad (23)$$

where binary variables $v_{ij}^{\text{in}}(t)$ and $v_{ij}^{\text{out}}(t)$ are used to describe SOC of storage facilities. Notation $v_{ij}^{\text{in}}(t)$ is equal to 1 when storage facility j is being charged; and 0 otherwise. Storage units should not be charged and discharged at the same time to improve efficiency, thus $v_{ij}^{\text{in}}(t)$ and $v_{ij}^{\text{out}}(t)$ satisfy the following constraints:

$$v_{ij,t}^{\text{in}} + v_{ij,t}^{\text{out}} \leq x_{ij} \quad (24)$$

Equation (25) is proposed to ensure continuity of storage facilities.

$$E_{ij,0} = E_{ij,T} \quad (25)$$

3) Renewable energy sources

Power output of RES must satisfy the following constraint:

$$x_{ij} P_{j, \text{min}}^{\text{e}, \text{out}} \leq P_{ij,t}^{\text{e}, \text{out}} \leq x_{ij} P_{j, \text{max}}^{\text{e}, \text{out}} \quad (26)$$

C. IDR Program

A priced-based IDR model [27]–[29] is adopted in the proposed EHs. The modeling process is shown as follows.

In price-based IDR modeling, energy demand is sensitive to energy price. Generally, the concept of elasticity is used to describe the mentioned sensitivity, and elasticity is defined as the specific value of energy demand change rate and price change rate as shown in (27):

$$\begin{cases} \zeta_{i,tt}^k = \frac{\partial L_{it}^k}{\partial \rho_{it}^k} / \frac{\partial \rho_{it}^k}{\partial \rho_{it}^k} = \frac{\partial L_{it}^k}{\partial \rho_{it}^k} \frac{\rho_{it}^k}{L_{it}^k}, & \forall k \in \Omega^K \\ \zeta_{i,t\tau}^k = \frac{\partial L_{it}^k}{\partial \rho_{i\tau}^k} / \frac{\partial \rho_{i\tau}^k}{\partial \rho_{i\tau}^k} = \frac{\partial L_{it}^k}{\partial \rho_{i\tau}^k} \frac{\rho_{i\tau}^k}{L_{it}^k}, & \forall k \in \Omega^K, t \neq \tau \end{cases} \quad (27)$$

where $\zeta_{i,tt}^k$ is self-elasticity which describes sensitivity of customers' energy demand at time t with respect to energy price in the current period; $\zeta_{i,t\tau}^k$ is cross-elasticity representing sensitivity of customers' energy demands at time t with respect to the energy price in time periods other than t . Value of self-elasticity $\zeta_{i,tt}^k$ is always negative, and value of cross-elasticity $\zeta_{i,t\tau}^k$ is always non-negative. Notation $L_{it}^{\text{ini},k}$ is the initial energy demand of energy type k at time t , and L_{it}^k is the corresponding modified energy demand after IDR. Similarly, $\rho_{it}^{\text{ini},k}$ is the initial energy price while ρ_{it}^k represents the modified energy price. Notation Ω^K is the set of energy types.

Value of the customers' net benefit is shown as (28):

$$F(L_{it}^k) = \Psi(L_{it}^k) - \rho_{it}^k L_{it}^k \quad (28)$$

where $F(L_{it}^k)$ is customers' net benefit, $\Psi(L_{it}^k)$ is the benefit from energy consumption after the DR, and it is calculated by (29):

$$\begin{aligned} \Psi(L_{it}^k) &= \Psi(L_{it}^{\text{ini},k}) \\ &+ \rho_{it}^{\text{ini},k} (L_{it}^k - L_{it}^{\text{ini},k}) \left(1 + \frac{L_{it}^k - L_{it}^{\text{ini},k}}{2\zeta_{i,tt}^k L_{it}^{\text{ini},k}} \right) \end{aligned} \quad (29)$$

In (30), $\rho_{it}^k L_{it}^k$ is energy purchasing cost. Customers' net benefit can be maximum when the differential coefficient $\partial F(L_{it}^k) / \partial L_{it}^k$ is equal to zero. By calculating this differential coefficient, end users' energy demand with self-elasticity at the current period can be modeled as follows.

$$L_{it}^k = L_{it}^{\text{ini},k} \left(1 + \zeta_{i,tt}^k \frac{\rho_{it}^k - \rho_{it}^{\text{ini},k}}{\rho_{it}^{\text{ini},k}} \right) \quad (30)$$

Similarly, end users' energy demand with cross-elasticity at other time periods satisfies the following

$$L_{it}^k = L_{it}^{\text{ini},k} \left(1 + \sum_{\tau \in \Omega^T \& \tau \neq t} \zeta_{i,t\tau}^k \frac{\rho_{i\tau}^k - \rho_{i\tau}^{\text{ini},k}}{\rho_{i\tau}^{\text{ini},k}} \right) \quad (31)$$

Combining (30) and (31), modified energy demand after IDR can be represented by (32):

$$\begin{aligned} L_{it}^k &= \\ &L_{it}^{\text{ini},k} \left(1 + \zeta_{i,tt}^k \frac{\rho_{it}^k - \rho_{it}^{\text{ini},k}}{\rho_{it}^{\text{ini},k}} + \sum_{\tau \in \Omega^T \& \tau \neq t} \zeta_{i,t\tau}^k \frac{\rho_{i\tau}^k - \rho_{i\tau}^{\text{ini},k}}{\rho_{i\tau}^{\text{ini},k}} \right) \end{aligned} \quad (32)$$

Note in this paper, load demand for heating, cooling, and H_2 are assumed to be inelastic in the EHs. Therefore, the IDR consists of electricity DR and gas DR.

Moreover, energy price changes and IDR participation coefficients should be limited:

$$\begin{cases} \kappa_{\min} \rho_{it}^{\text{ini},k} \leq \rho_{it}^k \leq \kappa_{\max} \rho_{it}^{\text{ini},k} \\ \alpha_{\min} L_{it}^{\text{ini},k} \leq L_{it}^k \leq \alpha_{\max} L_{it}^{\text{ini},k} \end{cases} \quad (33)$$

where $\kappa_{\min}$ and $\kappa_{\max}$ are adjustment coefficients for energy price, and $\alpha_{\min}$ and $\alpha_{\max}$ are the IDR participation coefficients of EHs' load.

In order to ensure customers' comfort, initial energy demand should be equal to modified energy demand:

$$\sum_t L_{it}^k = \sum_t L_{it}^{\text{ini},k} \quad (34)$$

IV. PROPOSED OPTIMAL EXPANSION PLANNING MODEL

A. Objective Function

Cost minimization objective includes five parts:

$$F = \min (F_{\text{EH}} + F_{\text{CCS}} + F_{\text{op}} + F_{\text{CO}_2}^{\text{tax}} + F_{\text{CO}_2}^{\text{cap}}) \quad (35)$$

where F_{EH} is equivalent annual cost of the EH investment, and it can be found from (36); F_{CCS} refers to investment cost of the CCS equipped on the coal/gas-fired power unit in multi-energy network, see (37); F_{op} denotes annual fossil fuel cost including coal cost of CFUs and production cost of gas wells, see (38).

Carbon cost includes carbon tax cost and carbon capturing (i.e., transportation and bury) cost. Notation $F_{\text{CO}_2}^{\text{tax}}$ represents the carbon tax cost of CFUs, GFUs and EHs as shown in (39), and $F_{\text{CO}_2}^{\text{cap}}$ denotes carbon capturing cost and is calculated by (40).

Notations Ω^{CU} , Ω^{GU} , Ω^{GW} and Ω^{CCS} are the sets of CFUs, GFUs, gas wells and CCS facilities in the multi-energy network, respectively. C_j and L_j are investment cost and lifetime of facility j in EHs, respectively. C_s and L_s are investment cost and lifetime of CCS facility s , respectively. ρ_ω and ρ_u are generation costs of gas well ω and CFU u , respectively. $\lambda(z)$ is scenario probability. c_{de} and c_{car} are CO_2 transmission and burying price and carbon tax price, respectively. R , r and D are residual rate, discount rate, and the total number of days in one year, respectively. P_{ut}^k and P_{vt}^k are output of CGU u and GFU v ($k \in \{e, \text{CO}_2^1, \text{CO}_2^2, \text{CO}_2^3\}$), respectively. Output of gas well ω is denoted by $Q_{\omega t}$.

$$F_{\text{EH}} = \sum_{i=1}^m \sum_{j=1}^n \left[x_{ij} C_j (1-R) \frac{r(1+r)^{L_j}}{(1+r)^{L_j} - 1} \right] \quad (36)$$

$$F_{\text{CCS}} = \sum_{s \in \Omega^{\text{CCS}}} \left[x_s C_s (1-R) \frac{r(1+r)^{L_s}}{(1+r)^{L_s} - 1} \right] \quad (37)$$

$$F_{\text{op}} = D \sum_{z=1}^{N_s} \lambda(z) \left\{ \sum_{u \in \Omega^{\text{CU}}} \rho_u G(P_{ut}^e) + \sum_{\omega \in \Omega^{\text{GW}}} \rho_\omega Q_{\omega t} \right\} \quad (38)$$

$$F_{\text{CO}_2}^{\text{tax}} = D c_{\text{car}} \sum_{z=1}^{N_s} \lambda(z) \left\{ \sum_{t=1}^T \sum_{i=1}^M C_{it}^{\text{EH,out-c}} \right\}$$

$$+ \sum_{t=1}^T \left(\sum_{u \in \Omega^{CU}} P_{ut}^{CO_2^1, out} + \sum_{v \in \Omega^{GU}} P_{vt}^{CO_2^1, out} \right) \Bigg\} \quad (39)$$

$$F_{CO_2}^{cap} = D_{cde} \sum_{z=1}^{N_s} \lambda(z) \left\{ \sum_{t=1}^T \left(\sum_{u \in \Omega^{CU}} P_{ut}^{CO_2^2, out} + \sum_{v \in \Omega^{GU}} P_{vt}^{CO_2^2, out} \right) + \sum_{t=1}^T \sum_{i=1}^M C_{it}^{EH, out} \right\} \quad (40)$$

$G(P_{ut}^e)$ in (38) is coal consumption of CFU u , which is calculated by:

$$G(P_{ut}^e) = a(P_{ut}^e)^2 + b(P_{ut}^e) + c \quad (41)$$

B. Power System Constraints

Line resistance of the power transmission network is much smaller than line reactance, thus DC power flow method can be used to calculate power flow. Each transmission line's real power flow is calculated by (42), where PL_{lt} is real power on line l at time t ; x_l is corresponding line impedance; θ_{l1} and θ_{l2} are the voltage angle at the two ends of transmission line l , respectively; and Ω^{TL} denotes the set of transmission lines.

$$PL_{lt} = (\theta_{l1} - \theta_{l2})/x_l, \forall l \in \Omega^{TL} \quad (42)$$

Constraints of real power flow are shown as (43). Note the reference bus's voltage angle is equal to zero.

$$\begin{cases} PL_{l, \min} \leq PL_{lt} \leq PL_{l, \max}, \forall l \in \Omega^{TL} \\ \theta_{b, \min} \leq \theta_{bt} \leq \theta_{b, \max} \\ \theta_{ref} = 0 \end{cases} \quad (43)$$

Power balance constraints of each power bus are shown as (44), where Ω^{EH} is the set of EHs, P_{st} is input power of CCS s , $Y_{b(\cdot)}$ is incidence matrices for bus b , and EL_{bt} is power load.

$$\begin{aligned} \sum_{l \in \Omega^{TL}} Y_{bl} PL_{lt} &= \sum_{u \in \Omega^{CU}} Y_{bu} P_{ut}^e + \sum_{v \in \Omega^{GU}} Y_{bv} P_{vt}^e \\ &+ \sum_{i \in \Omega^{EH}} Y_{bi} P_{it}^{e, EH} - \sum_{s \in \Omega^S} Y_{bs} P_{st} - EL_{bt} \end{aligned} \quad (44)$$

Output constraints and ramp rates constraints of CFUs and GFUs are shown as (46), where $RD_{(\cdot)}$ and $RU_{(\cdot)}$ denote ramp up and ramp down rates, respectively:

$$\begin{cases} P_{u, \min} \leq P_{ut}^e \leq P_{u, \max} \\ RD_u \leq P_{ut}^e - P_{u, t-1}^e \leq RU_u \\ P_{v, \min} \leq P_{vt}^e \leq P_{v, \max} \\ RD_v \leq P_{vt}^e - P_{v, t-1}^e \leq RU_v \end{cases} \quad (45)$$

CO_2 outputs of the CFUs and GFUs are determined by their power output as shown in (46), where Y_{ui} and Y_{vi} are incidence matrices:

$$\begin{cases} P_{ut}^{CO_2^1} + P_{ut}^{CO_2^2} + P_{ut}^{CO_2^3} = P_{ut}^e \chi_u \\ P_{vt}^{CO_2^1} + P_{vt}^{CO_2^2} + P_{vt}^{CO_2^3} = P_{vt}^e \chi_v \\ P_{ut}^{CO_2^3} = \sum_{i \in \Omega^{EH}} (Y_{ui} C_{it}^{EH, in}) \\ P_{vt}^{CO_2^3} = \sum_{i \in \Omega^{EH}} (Y_{vi} C_{it}^{EH, in}) \end{cases} \quad (46)$$

For CCS equipped on the CFUs and GFUs in the multi-energy network, the relationship between the power input of CCS and amount of captured CO_2 is similar to GFU-CCS as shown in (47):

$$\begin{cases} P_{ut}^{CO_2^2} + P_{ut}^{CO_2^3} = \sum_{s \in \Omega^{CCS}} Y_{us} [(P_{st} - x_s \times P_s^{CCS}) \gamma] \\ P_{vt}^{CO_2^2} + P_{vt}^{CO_2^3} = \sum_{s \in \Omega^{CCS}} Y_{vs} [(P_{st} - x_s \times P_s^{CCS}) \gamma] \end{cases} \quad (47)$$

where x_s is the decision variable to determine whether the CCS is equipped or not, P_s^{CCS} is the fixed power consumption part of CCS s .

Power input of CCS is within its lower and upper bounds:

$$x_s P_{s, \min} \leq P_{st} \leq x_s P_{s, \max} \quad (48)$$

C. Natural Gas System Constraints

Generally, a gas network is composed of compressors, pipelines and gas wells. For pipelines without compressors, gas flows from high-pressure nodes to low-pressure nodes, and the relationship between the gas flow and node pressures can be calculated by (49), where Pr_{p1} and Pr_{p2} are node pressures at the two ends of gas pipeline p , C_p is the gas flow coefficient of gas pipeline p .

$$Q_{pt} = \text{sgn}(Pr_{p1} - Pr_{p2}) C_p \sqrt{|Pr_{p1}^2 - Pr_{p2}^2|}, p \in \Omega^{PP} \quad (49)$$

For pipelines equipped with compressors, gas flow is constrained by (50):

$$\delta_{\min} Pr_{p1} \leq Pr_{p2} \leq \delta_{\max} Pr_{p1}, p \in \Omega^{PC} \quad (50)$$

where Ω^{PP} and Ω^{PC} are the set of gas pipelines and passive pipelines, respectively.

Balance constraints of each node are shown as (51):

$$\begin{aligned} \sum_{p \in \Omega^{GP}} Y_{np} Q_{pt} &= \sum_{\omega \in \Omega^{GW}} Y_{n\omega} Q_{\omega t} - \sum_{v \in \Omega^{GU}} Y_{nv} Q_{vt} \\ &+ \sum_{i \in \Omega^{EH}} Y_{ni} P_{it}^{g, EH} - GL_{nt} \end{aligned} \quad (51)$$

where $Y_{n(\cdot)}$ is incidence matrices for node n , Q_{pt} represents flow rate of gas pipeline p at t , and Q_{vt} denotes gas consumption of GFU v at time t . Gas consumption of the GFUs is calculated by (52), where HHV is the higher heating value:

$$Q_{vt} = \frac{G(P_{vt})}{HHV}, v \in \Omega^{GU} \quad (52)$$

Gas well outputs and nodal pressures are constrained by (54), where Ω^G is the set of gas network nodes:

$$\begin{cases} Q_{\omega, \min} \leq Q_{\omega t} \leq Q_{\omega, \max}, \forall \omega \in \Omega^{GW} \\ Pr_{n, \min} \leq Pr_{nt} \leq Pr_{n, \max}, \forall n \in \Omega^G \end{cases} \quad (53)$$

D. Linearization of Equations and Model Solving

The nonlinear constraint in (50) can be rewritten as (54) by replacing Pr_{p1}^2 and Pr_{p2}^2 by Pr_{sp1} and Pr_{sp2} , then only the nonlinear term $Q_{pt}|Q_{pt}|$ needs to be linearized by the piecewise linearization technique [27], [30], [31].

$$Q_{pt}|Q_{pt}| = C_p^2 (Pr_{sp1} - Pr_{sp2}), p \in \Omega^{PP} \quad (54)$$

After linearization of (54), the resulting MILP can be solved by efficient optimization tools, such as the YALMP and CPLEX tools adopted in this paper.

V. CASE STUDIES

To validate the obtained model in the previous section, two cases studies are conducted, one is for a 6-bus electric power system coupled with a 7-node gas system (see Fig. 3), and the other one is a modified IEEE 39-bus electric power system coupled with a Belgian 20-node gas system.

A. An Integrated 6-bus Power System and 7-node Natural Gas System

Figure 3 shows the 6-bus power system includes three CFUs G1, G2, and G4, a GFU G3, seven transmission lines, and three electrical loads EL1-EL3, while the 7-node gas system consists of six pipelines, one compressor, gas wells GW1 and GW2, and gas loads GL1 and GL2. Two unplanned EHs are denoted by EH1 and EH2. Parameters of the 6-bus power system and the 7-node gas system are taken from [23].

Load demand data of EHs and three typical scenarios of WT power outputs are referred to [10], [11], [17], and [27].

Candidate facility parameters of efficiency, investment and lifetime refer to [20] and [32], and capacities of candidate components are shown in Table I. These facilities include CHP, auxiliary boilers (ABs), P2Gs, Hydrogen fuel cells (HFCs), compression electric refrigerator groups (CERGs), electric boilers (EBs), electric heat pumps (EHPs), water absorption refrigerator groups (WARGs), gas storage (GS), H₂ storage, CO₂ storage, batteries, heat storage (HSs), cooling storage (CSs) and WTs. Carbon tax for net emissions is \$45/ton, and CO₂ transmission and burying price is \$5/ton [33] and [34]. The minimum and maximum price adjustment coefficients are given by $\kappa_{\min} = 0.5$ and $\kappa_{\max} = 2$, respectively. Moreover, participation coefficients of IDR are chosen as $\alpha_{\min} = 0.8$ and $\alpha_{\max} = 1.2$.

Although [27] has proposed models with IDR, it focuses primarily on the impact of IDR on operation of given EHs, while this paper focuses on impact of IDR on the design of EHs; therefore, our results are not comparable to [27]. In order to show effectiveness of the expansion planning model, this paper compares six different cases.

Case 1: Optimal expansion planning without considering bidirectional energy exchange and IDR program. In this baseline case, energy networks can supply power and gas to EHs,

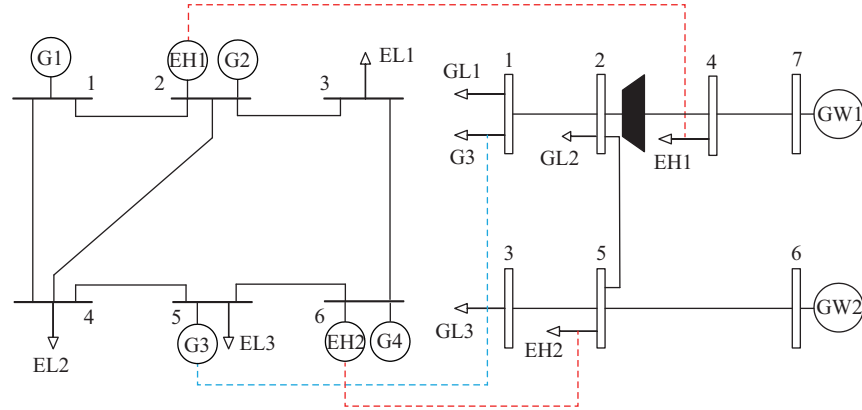


Fig. 3. 6-bus power system and 7-node natural gas system.

TABLE I
CAPACITIES OF CANDIDATE COMPONENTS

Name	Type 1	Type 2	Type 3
CHP-CCS	Electrical: 50 MW Heat: 75 MW	Electrical: 100 MW Heat: 150 MW	Electrical: 150 MW Heat: 225 MW
CHP	Electrical: 50 MW Heat: 75 MW	Electrical: 100 MW Heat: 150 MW	Electrical: 150 MW Heat: 225 MW
AB-CCS	255 MW	450 MW	675 MW
AB	255 MW	450 MW	675 MW
PtG	Hydrogen: 250 MW Gas: 200 MW	Hydrogen: 500 MW Gas: 400 MW	Hydrogen: 750 MW Gas: 600 MW
HFC	35 MW	70 MW	105 MW
EHP	200 MW	400 MW	600 MW
EB	250 MW	500 MW	750 MW
CERG	200 MW	400 MW	600 MW
WERG	200 MW	400 MW	600 MW
GS	100 MW/200 MWh	200 MW/400 MWh	300 MW/600 MWh
H ₂ Storage	500 MW/1000 MWh	1000 kW/2000 MWh	1500 kW/3000 MWh
CO ₂ Storage	100 t /200 t	200 t/400 t	300 t/600 t
Battery	50 MW/200kMh	100 MW/400 MWh	150 MW/600 MWh
HS	100 MW/200 MWh	200 MW/400 MWh	300 MW/600 MWh
CS	100 MW/200 MWh	200 MW/400 MWh	300 MW/600 MWh
WT	200 MW	200 MW	200 MW

while the EHs cannot supply energy to these energy networks.

Case 2: Case 1 plus bidirectional energy exchange between EHs and power grid.

Case 3: Case 1 plus bidirectional energy exchange between EHs and gas network.

Case 4: Case 1 plus both the bidirectional energy exchanges between the EHs and power grid and between the EHs and gas network.

Case 5: Case 1 plus IDR program.

Case 6: Case 4 plus IDR program, i.e., the optimal case proposed in this paper.

1) Optimization Results and Analysis

Table II gives the EH investment decisions corresponding to the six cases, while Table III shows the corresponding

investment decisions of CCS. In Table III, the number “1” means a CCS is configured on the corresponding GFU/CFU in IES; for example, if a CCS is installed in G1 in Fig. 3 in Case 1, then the corresponding factor in Table III is equal to “1”. Comparison results for various planning costs are shown in Figs. 4–5.

TABLE II
DIFFERENT EH INVESTMENT DECISIONS CORRESPONDING TO
DIFFERENT CASE

Case	EH 1	EH 2
Case 1	CHP-CCS 1,3	
	EHP 2	EHP 1-2
	CERG 1	CERG 2
	P2G 1	P2G 1
	HS 2-3	HS 1-3
	CS 2	CS 2-3
	GS 1	H ₂ storage 1
	H ₂ storage 1	WT 1-3
	WT 1-2	
Case 2	CHP-CCS 3	
	EHP 2	EHP 1-2
	CERG 1	CERG 1
	P2G 1	P2G 1
	HS 2-3	HS 1-3
	CS 2	CS 2
	GS 1-2	GS 2
	H ₂ storage 1	H ₂ storage 1
	WT 1-3	WT 1-3
Case 3	CHP-CCS 1,3	
	EHP 2	EHP 1-2
	CERG 1	CERG 1
	P2G 1	P2G 1
	HS 2-3	HS 1-3
	CS 2	CS 1-2
	H ₂ storage 1	H ₂ storage 1
	WT 1-2	WT 1-3
Case 4	CHP-CCS 3	
	EHP 2	EHP 1-2
	CERG 1	CERG 1
	P2G 1	P2G 1
	HS 2-3	HS 1-3
	CS 2	CS 2
	H ₂ storage 1	H ₂ storage 1
	WT 1-3	WT 1-3
Case 5	CHP-CCS 1,3	
	EHP 2	EHP 1-2
	CERG 1	CERG 2
	P2G 1	P2G 1
	HS 2-3	HS 1-3
	CS 2	CS 2-3
	H ₂ storage 1	H ₂ storage 1
	WT 1-2	WT 1-3
Case 6	CHP-CCS 2	
	EHP 2	EHP 3
	CERG 1	CERG 1
	P2G 1	P2G 1
	HS 1-3	HS 1-3
	CS 2	CS 2
	H ₂ storage 1	H ₂ storage 1
	WT 1-3	WT 1-3

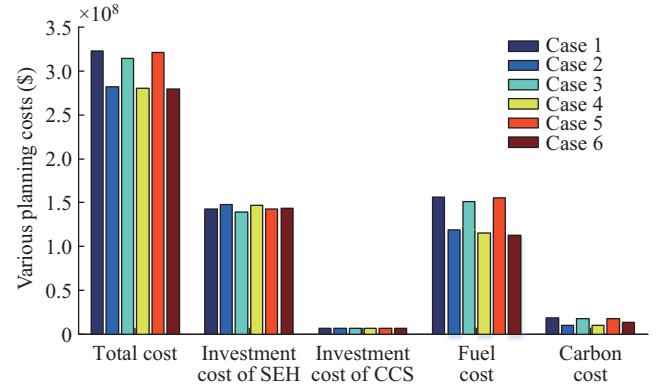


Fig. 4. Comparison results for various planning costs.

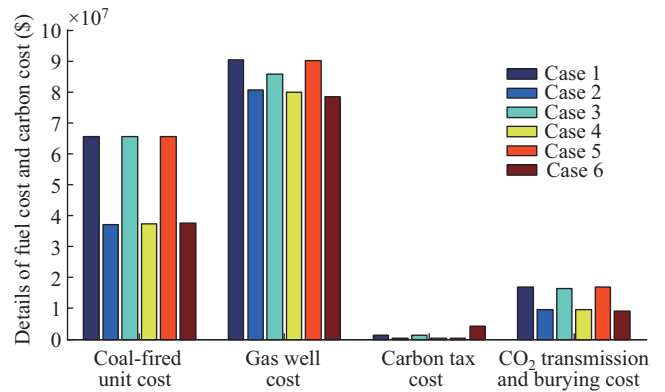


Fig. 5. Details for fuel cost and carbon cost.

Case 2 shows the advantage of including bidirectional energy exchange between EHs and the power grid. Compared with Case 1, total planning cost of Case 2 decreases by 12.63% (see Fig. 4). Investment cost of EHs has a slight increase, i.e., 3.90%, while the CCS's investment cost remains the same as Case 1. Fossil fuel and carbon costs are reduced by 24.51% and 44.78%, respectively. The reason for the above difference is shown as follows. In Case 2, surplus wind power from each EH can be supplied to other nodes or EHs by the power grid, thus installed capacity of WTs are not limited by load of EHs, and accordingly, more WTs are chosen in Case 2 (see Table II). Due to increase of WTs' output, installed capacity of CHP and the output of fuel-fired units can be reduced; therefore, only CHP-CCS of type 3 is chosen in Case 2 (see Table II), and both carbon and fossil fuel costs decrease.

The advantage of bidirectional energy exchange between EHs and gas network is demonstrated by comparing Case 3 and Case 1. When bidirectional energy exchange between EHs and the gas network is considered in Case 3, more surplus power of WTs can be transformed to CH₄ and supplied to the

gas network rather than being stored in storage facilities, thus there is no GS chosen in EH1, and installed capacity of CS in EH2 is smaller than Case 1 (see Table II). Accordingly, 2.35% of the EH investment cost is reduced compared with Case 1. Moreover, gas wells' output can be reduced by transforming WTs' surplus power to CH₄ and supplying the CH₄ to the gas network, and accordingly, gas well cost in Case 3 decreases by 5.25% compared with Case 1. In terms of carbon cost, Case 3 has a slight decrease (1.75%), because more captured CO₂ is consumed to synthesize CH₄, which reduces transmission and burying cost of CO₂. To summarize, total planning cost of Case 3 is 2.60% less than Case 1.

When both the power grid and gas network can exchange energy with EHs, the surplus power of WTs in Case 4 has been better utilized than in Cases 2–3, which reduces EHs' dependence on energy storage and improves efficient use of wind power. Therefore, the EH1 in Case 4 has no GS and all types of WTs are selected. Moreover, the EH2 in Case 4 has a smaller installed capacity of CS compared with Cases 1–3 (see Table II). In terms of operating costs, due to improvement of surplus wind power's utilization efficiency, fuel cost of Case 4 is less than Cases 1–3 (see Fig. 4).

Comparison between Case 1 and Case 5 shows the impact of IDR program. When IDR is considered, electrical load distribution and gas load distribution of EHs are optimized to meet output fluctuation of WTs, which brings two advantages: one is improvement of wind power's utilization efficiency, the other is more power can be used to treat CO₂ emissions at periods when WTs' output is low, thus less storage is chosen (see Table II), and gas well and carbon costs of Case 5 are decreased compared with Case 1, which are about 0.44% and 4.14% less, respectively. Accordingly, total planning cost decreases by 0.41% compared with Case 1.

Case 6 shows the advantage of considering, simultaneously, IDR and bidirectional energy exchange between EHs and energy networks. Compared with Cases 1–5, the EH1 in Case 6 has minimum CHP installed capacity (see Table II), and fuel cost of Case 6 is minimum in all six cases (see Fig. 4), which indicates that fossil fuel dependence of IES in Case 6 is lowest. In terms of carbon costs, Case 6 is higher than Cases 2 and 4, since the CHP installed capacity in Case 6 is less than those in Cases 2 and 4, and CCSs equipped on the CHP, CFU and GFU have not enough power to capture CO₂ at high load periods. Nonetheless, total planning cost of Case 6 is still minimum in the six cases (see Fig. 4).

Moreover, the CCS is equipped on G1, G2, G3 and G4 in all cases (see Table III), because their total power output in all scenarios is much more than of CHP in EHs, carbon tax

cost for releasing all CO₂ into the atmosphere is much higher than CCS installation and carbon capture costs.

In conclusion, inclusion of IDR and bidirectional energy flow between EHs and energy networks has the following advantages:

- 1) Compared with the base case, consideration of bidirectional electricity flow can improve penetration level and energy utilization efficiency of wind power, and reduce dependence on fossil fuel and carbon cost (including carbon tax and transmission and burying cost).
- 2) By considering bidirectional gas flow between the EHs and gas network, energy utilization efficiency of WTs is further improved, which reduces the investment cost of storage, and captures and utilizes more CO₂.
- 3) Consideration of IDR optimizes electrical load distribution and gas load distribution of EHs, which further reduces investment cost of storage, and enables more CO₂ capture.

B. 39-bus Power System and 20-node Natural Gas System

A modified IEEE 39-bus power system integrated with a 20-node natural gas system is studied, where parameters of the modified IEEE 39-bus power system and the 20-node gas system are taken from [23]. EHs' load demand data and WTs' output data refer to [14], [23], and other parameters are the same as cases in Section IV-A. Case 1 and Case 6 in the previous case study are considered here.

Tables IV and V show the investment decisions of the planned EHs and CCSs in each case. Comparison results for planning costs are given in Figs. 6–7.

In Case 6, the WTs' configuration is not limited by the EHs'

TABLE IV
DIFFERENT EH INVESTMENT DECISIONS CORRESPONDING TO
DIFFERENT CASE

EH	Case 1	Case 6
EH1	CHP 1	CHP-CCS 2
	CHP-CCS 1-2	EHP 1-2
	EHP 3	CERG 1
	CERG 1	P2G 1
	P2G 1	HS 1-3
	HS 1-3	CS 2
	CS 2	GS 1-3
	GS 1-3	H2 storage 1
	H2 storage 1	WT 1-3
	WT 1-2	
EH2	CHP 1	CHP-CCS 2-3
	CHP-CCS 1	EHP 2
	EHP 1-2	CERG 1
	CERG 1	P2G 1
	P2G 1	Battery 3
	HS 1-3	HS 1-3
	CS 1-2	CS 2
	GS 3	GS 1-3
	H2 storage 1	H2 storage 1
	WT 1,3	WT 1-3
EH3	CHP-CCS 1,3	CHP-CCS 2-3
	EHP 2	EHP 2
	CERG 1	CERG 1
	P2G 1	P2G 1
	HS 1-3	HS 1-3
	CS 1	CS 1-2
	GS 1-3	GS 1-3
	H2 storage 1	H2 storage 1
	WT 1-2	WT 1-3

TABLE III
DIFFERENT CCS INVESTMENT DECISIONS CORRESPONDING TO
DIFFERENT CASE

Case	EH 1	EH 2
Case 1	1	1
Case 2	1	1
Case 3	1	1
Case 4	1	1
Case 5	1	1
Case 6	1	1

TABLE V
DIFFERENT CCS INVESTMENT DECISIONS CORRESPONDING TO
DIFFERENT CASE

Generator	Case 1	Case 6
G1	1	1
G2	1	1
G3	1	1
G4	1	1
G5	1	1
G6	1	1
G7	1	1
G8	1	1
G9	1	1
G10	1	1

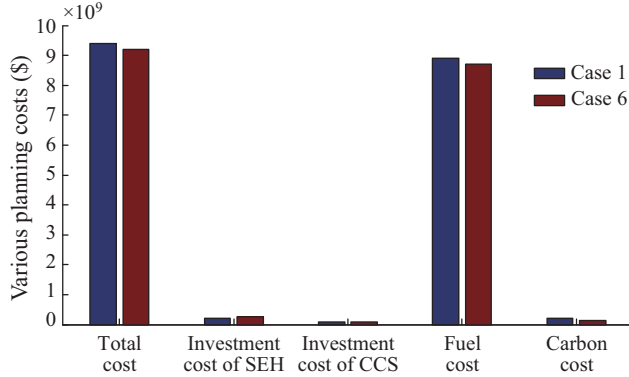


Fig. 6. Comparison results for various planning costs.

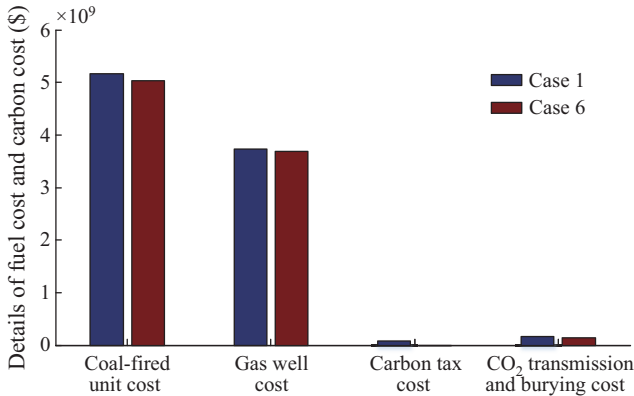


Fig. 7. Details for fuel cost and carbon cost.

load demand due to bidirectional energy exchange between EHs and energy networks, thus all types of WTs are selected in the three EHs (see Table IV). Due to increase of WTs' installed capacity, more surplus wind power, and hence more gas transformed by surplus wind power, can be supplied to the power grid and gas network, which reduces CFU cost and gas well cost (see Fig. 7). In terms of carbon cost, the IDR contributes to optimized power and gas load distribution of EHs. Therefore, more power can be used to capture CO₂, and accordingly, carbon cost in Case 6 decreases by 36.16% compared with Case 1 (see Fig. 6).

VI. CONCLUSION

An IES optimal expansion planning model for configuration of multiple EHs and CCS under various constraints of energy

networks is presented in this paper. Bidirectional energy exchange between EHs and multiple energy networks is modeled along with IDR programs in the planning model to improve utilization efficiency of renewable energy and reduce carbon emission. Compared with the case which does not consider bidirectional energy exchange and IDR, total annual cost of the case considering the above factors decreases by 13.47%, and total carbon cost of the IES decreases by 25.84%.

Moreover, the whole IES is assumed to be owned by one utility company in this study, thus the trading fee for bidirectional energy exchange between EHs and multiple energy networks is not considered, and neither peer-to-peer transactions nor charged trading between different stakeholders is considered. These places will be considered in future work to cater to the case of multiple stakeholders.

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