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Article

An Inexact Mix-Integer Two-Stage Linear Programming Model for Supporting the Management of a Low-Carbon Energy System in China

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Abstract: In view of the great contribution of coal-fired units to CO_2 emissions, the coupled coal and power system with consideration of CO_2 mitigation is a typical sub-system of the highly emitting Chinese energy system for low-carbon studies. In this study, an inexact mix-integer two-stage programming (IMITSP) model for the management of low-carbon energy systems was developed based on the integration of multiple inexact programming techniques. Uncertainties and complexities related to the carbon mitigation issues in the coupled coal and power system can be effectively reflected and dealt with in this model. An optimal CO_2 mitigation strategy associated with stochastic power-generation demand under specific CO_2 mitigation targets could be obtained. Dynamic analysis of capacity expansion, facility improvement, coal selection, as well as coal blending within a multi-period and multi-option context could be facilitated. The developed IMITSP model was applied to a semi-hypothetical case of long-term coupled management of coal and power within a low-carbon energy system in north China. The generated decision alternatives could help decision makers identify desired strategies related to coal production and allocation, CO_2 emission mitigation, as well as facility capacity upgrade and expansion

under various social-economic, ecological, environmental and system-reliability constraints. It could also provide interval solutions with a minimized system cost, a maximized system reliability and a maximized power-generation demand security. Moreover, the developed model could provide an in-depth insight into various CO_2 mitigation technologies and the associated environmental and economic implications under a given reduction target. Tradeoffs among system costs, energy security and CO_2 emission reduction could be analyzed.

Keywords: carbon dioxide reduction; coupled coal and power systems; low-carbon energy system; policy analysis; uncertainty

1. Introduction

Greenhouse gas (GHG) emissions are a key factor leading to climate change. The reduction of GHG emissions is of significance within a low-carbon energy system. Globally, as the most important component of GHG, the majority of CO_2 comes from combustion of various energy resources [1]. For example, since more than 50 GW of new coal-fired power plants have been constructed in China annually after 2005 and coal is estimated to supply over 60% of primary energy in the country through 2020, China has ranked as the world's top CO_2 emitter [2,3]. Considering the synergy of power generation, coal consumption and CO_2 emission, coupled management of coal and power with CO_2 emissions mitigation in an economical and environment-friendly manner desperately desired in China. It is also an important and typical low-carbon energy system of the highly emitting Chinese energy system for studies. Moreover, planning of coupled coal and power systems with CO_2 emission mitigation management incorporates multiple sectors and processes, such as policy intervention, CO_2 reduction targets, energy activities, as well as the associated environment effects [4–9]. However, a great number of system parameters (such as coal properties, power-generation demand, and facility capacity, as well as their interactions) may appear uncertain and be presented in interval, possibilistic and probabilistic formats. These uncertainties may not only be complicated by the interactions of multiple sectors and processes, but also could be affected by associated economic and environmental implications, leading to a variety of complexities in relevant decision-making processes [10–19]. Consequently, effective systems analysis methods are desired for supporting the planning of coupled coal and power systems with CO_2 emissions mitigation management under uncertainty.

In the past, a great number of system analysis techniques were proposed for energy management [20–39]. Many of them focused on China's energy management systems under multiple scales, particularly those highly reliant on coal for power generation. For instance, Zhang and Kumar evaluated renewable energy based rural electrification program in western China [40]. Zhao and Ortolano analyzed the effect of China's national energy conservation policies implemented at state-owned electric power generation plants [41]. Wang studied developing patterns of coal and electricity industries in China and concluded that policy intervention for deliberate low coal prices would cause losses to both coal and electricity industries [34]. Du *et al.* assessed the impact of a set of regulatory policies on China's electricity generation industry using the plant-level national survey data

collected in 1995 and 2004 [42]. Steenhof and Fulton developed a framework to explore the factors affecting electricity generation in China and predicted the sector's future development [43]. Jin *et al.* recommended a number of strategies for sustainable development of energy management systems in the western region of China [44]. Dianshu *et al.* investigated environmental-friendly patterns of household electricity consumption in Liaoning, China [45]. Meanwhile, within the global domain, many studies have examined the contributions of different mitigation technologies to CO_2 reduction [46–54]. For instance, Edwards *et al.* developed multiple models to analyze contributions of air pollutants emissions from residential fuel/stoves in China to global CO_2 emissions [55]. Liu *et al.* used an energy technology model (*i.e.*, MESSAGE-China) to analyze the effects of major updated power generation technologies and explore their contributions to GHG mitigation in China [1]. Li and Colombier studied building energy efficiency regarding the promotion of low-carbon construction technologies in China [56]. Liu and Gallagher adopted an engineering-economic model to estimate the cost of onshore CO_2 pipeline transportation in China, which could be used for a broad range of potential carbon capture and storage (CCS) projects in this country [57]. Although the previous studies could be effective in addressing either power/energy management or GHG mitigation problems, most of them could barely reflect linkages that exist among activities of management efforts, coal production, power generation and CO_2 emission reduction, as well as their socio-economic and environmental implications in a multi-sector, multi-option and multi-period context. Moreover, these studies could scarcely deal with uncertainties and dynamic complexities associated with spatial and/or temporal variations of system factors and parameters.

At the same time, a large number of inexact programming methods were successfully used for managing municipal solid waste, water resources, air quality as well as energy resource allocation problems [10,12,18,19,33,58–79]. However, few studies focused on uncertainties existed in low-carbon energy system management [11,21]. In this research, an inexact mix-integer two-stage linear programming (IMITSP) model is developed for planning of the coupled coal and power systems with CO_2 reduction management. Based on integration of interval linear programming (ILP), two-stage stochastic programming (TSP) and mixed integer linear programming (MILP), IMITSP is an efficient extension approach which could not only tackle uncertainties with interval values and probability distributions existed in the system, but also formulate in-depth analysis of long-term stochastic planning problems in which an examination of policy scenarios is desired. Applying the IMITSP method to the coupled coal and power management with CO_2 reduction system planning will take a primary advantage in flexibly formulating modeling framework, enhances the robustness of the optimization process, and generates desired decision alternatives by delimiting an uncertain decision space through dimensional enlargement of the original stochastic constraints. Moreover, IMITSP could also reflect and deal with CO_2 emission mitigation and other energy-related problems during the planning of coal and power management systems with CO_2 emission reduction.

Therefore, the objective of this study is to propose an inexact mix-integer two-stage linear programming (IMITSP) model for planning coupled coal and power systems with CO_2 reduction management through the integration of ILP, TSP and MILP approaches into a general modeling framework. Multiple forms of uncertainties in terms of probability density functions (PDFs) and discrete interval values could be effectively addressed. Meanwhile, quantitative analysis of various CO_2 mitigation target scenarios before realizations of the random power-generation demands could

also be facilitated, generating desired strategies for coal allocation and CO_2 mitigation in a coupled coal and power management system. Then, it is applied to a semi-hypothetical case of long-term coupled coal and power systems with CO_2 reduction management planning in China for demonstrating applicability of the developed model. In detail, this study will: (a) develop an inexact model to tackle multiple forms of uncertainties and their interactions in the coupled coal and power systems with CO_2 reduction management, (b) facilitate dynamic analysis of facilities improvement and expansion, as well as coal blending within a multi-period and multi-option context, (c) generate a number of decision alternatives under various system conditions, helping decision makers identify desired strategies for CO_2 mitigation, coal production and allocation, as well as facility capacity improvement and expansion under various social-economic, ecological, environmental and system-reliability constraints with a minimized system cost, a maximized system reliability and a maximized power-generation demand security, and (d) analyze various CO_2 mitigation target scenarios associated with different levels of power-generation demand conditions before realization of stochastic processes.

2. Modeling Formulation

A coupled coal and power management system based on a large-scale coupled coal and power energy network has complex interactions with CO_2 emission reduction (Figure 1). In this system, a large number of sectors and processes would be considered by decision makers, such as power demand, coal production, transportation, coal blending, inventory problem, CO_2 emission control and so on. Uncertainties may exist in these sectors, processes, as well as various related system factors. According to the coal pricing mechanism in China, a unified amount of coal-flow from each coal mine to each power plant needs to be determined beforehand through a long-term contract [77]. If the demand of coal is not beyond the prefixed amount, it will lead to a regular system cost. Otherwise, it will result in an excess cost to the system, in which coal would have higher purchase and transportation costs. Also, for the CO_2 mitigation consideration, as the CO_2 emission permits and corresponding CO_2 emissions trading schemes are technically feasible measures to control the emitted CO_2 to an allowable level, they are incorporated in the system. However, the potential power-generation demands which would change with the weather changes, population explosion and economic growth, can be usually expressed as random variables. Since contracts for the allowable amounts of coal-flow and allocation strategies of CO_2 emission permits to power plant are made up before the realizations of the random power demand, excess coal-flows and CO_2 reduction measures are needed in the system [80]. In this research, another two CO_2 mitigating technologies (e.g., carbon capture and storage (CCS) and chemical absorption) are also supposed to be incorporated to reduce the excess CO_2 emission beyond the emission permits. Moreover, based on the prediction of power-generation demand, capacity expansion schemes of power plants with multiple options would be formulated during the planning periods. Meanwhile, in order to avoid risks of coal and power shortages, a certain amount of coal need to be reserved as coal inventory in the power plants. The coal inventory is subject to dynamic changes of system conditions, which is also interrelated with competitions of multiple coal-supply options with diverse economic costs and resources availabilities. Multiple coal sources incorporated for maintaining sustainable coal supply to circumvent unreliability of single-source coal supply and guarantee continuous demands for electricity generation and coal inventory can be highly

guaranteed. The coal blending facilities are also employed to balance variations of coal properties from different sources [4,33]. To solve the above stochastic planning problem, the two-stage stochastic programming (TSP) technique is suitable to be adopted in this research, which is suitable to provide analysis of CO_2 mitigation targets scenarios. Also, since most coefficients and parameters of cost and benefit coefficients are inexact and can be expressed as interval numbers, interval linear programming (ILP) is considered as a useful tool to deal with these uncertainties [61]. Mixed integer linear programming (MILP), which could effectively facilitate capacity expansion plans, is integrated into the proposed planning framework [62,64]. The objective of the model is to minimize the net system cost associated with optimal coal-flow allocations and CO_2 mitigation schemes. The total coal-flow is a sum of prefixed allowable amount of coal within the contract and the random exceeded coal-flow; while the total CO_2 emissions is a sum of the allowable emission permits and extra CO_2 emission treated by other mitigating technologies. In detail, the objective function and constraints can be formulated as follows:

$$\begin{aligned} Minmize\ f^{\pm} = & \sum_{i=1}^{I}\sum_{j=1}^{J}\sum_{k=1}^{K} X_{ijk}^{\pm} * (CF_{ik}^{\pm} + TF_{ijk}^{\pm}) * \Delta L_{\mathrm{k}} \\ & + \sum_{i=1}^{I}\sum_{j=1}^{J}\sum_{k=1}^{K}\sum_{h=1}^{H} t_{jkh} Y_{ijkh}^{\pm} * (CCF_{ik}^{\pm} + CTF_{ijk}^{\pm}) * \Delta L_{\mathrm{k}} \\ & + \sum_{j=1}^{J}\sum_{k=1}^{K} OPP_{jk}^{\pm} * (M_j + \sum_{k=1}^{k'}\sum_{w=1}^{W} \Delta M_{jkw}\gamma_{jkw}^{\pm}) * h_j^{\pm} * \Delta L_k \\ & + \sum_{j=1}^{J}\sum_{l=1}^{L}\sum_{k=1}^{K}\sum_{h=1}^{H} OMP_{jlk}^{\pm} * t_{jkh} D_{jlkh}^{\pm} * \Delta L_k \\ & + \sum_{j=1}^{J}\sum_{k=1}^{K}\sum_{w=1}^{W} PMC_{jk}^{\pm} * \Delta M_{jkw}\gamma_{jkw}^{\pm} + \sum_{j=1}^{J}\sum_{l=1}^{L}\sum_{k=1}^{K}\sum_{n=1}^{N} PCC_{jlk}^{\pm} * \Delta C_{jlkn} Z_{jlkn}^{\pm} \end{aligned} \tag{1a}$$

subject to:

$$\sum_{i=1}^{I}(X_{ijk}^{\pm} + Y_{ijkh}^{\pm})(1-\theta) \geq (TD_{jkh}^{\pm}/30) * (q_{jk}^{\pm}/10^6),\ \forall j,k,h \tag{1b}$$

$$(M_j + \sum_{k=1}^{k'}\sum_{w=1}^{W} \Delta M_{jkw}\gamma_{jkw}^{\pm}) * h_j^{\pm} \geq TD_{jkh}^{\pm}/30,\ \forall j,k,h \tag{1c}$$

$$\sum_{k=1}^{K}\sum_{w=1}^{W} \gamma_{jkw}^{\pm} = 1,\ \forall j \tag{1d}$$

(power generation capacity constraints)

$$CIM_{jk}^{\pm} \geq CIM_{jk\min}^{\pm} \tag{1e}$$

$$k = 1\ \ CIM_{jk-1}^{\pm} = CIM_j^{\pm},\ \forall j \tag{1f}$$

$$CIM_{jk}^{\pm} = CIM_{jk-1}^{\pm} + [\sum_{i=1}^{I}(X_{ijk}^{\pm} + Y_{ijkh}^{\pm})(1-\theta) - (TD_{jkh}^{\pm}/30) * (q_{jk}^{\pm}/10^6)] * \Delta L_k,\ \forall j,k,h \tag{1g}$$

(coal inventory constraints)

$$\sum_{j=1}^{J}(X_{ijk}^{\pm} + Y_{ijkh}^{\pm})(1-\theta) \leq R_{ik}^{\pm}/30,\ \forall j,k,h \tag{1h}$$

(transportation supply constraints)

$$(TD_{jkh}^{\pm}/30)*\rho_{jk}-\sum_{l=1}^{L}\sum_{h=1}^{H}\eta_l D_{jlkh}^{\pm}\le TE_{jkh}^{\pm},\ \forall j,k,h \tag{1i}$$

$$\sum_{j=1}^{J}TE_{jkh}^{\pm}\le(1-\sigma)*TP_k^{\pm},\ \forall k,h \tag{1j}$$

(CO_2 emission limit constraints)

$$D_{jlkh}^{\pm}\le C_{jl}+\sum_{k=1}^{k'}\sum_{n=1}^{N}\Delta C_{jlkn}Z_{jlkn},\ \forall j,l,k,h \tag{1k}$$

(CO_2 treated capacity constraints)

$$\sum_{j=1}^{J}\sum_{k=1}^{K}\sum_{w=1}^{W}PMC_{jk}^{\pm}*\Delta M_{jkw}\gamma_{jkw}^{\pm}+\sum_{j=1}^{J}\sum_{l=1}^{L}\sum_{k=1}^{K}\sum_{n=1}^{N}PCC_{jlk}^{\pm}*\Delta C_{jlkn}Z_{jlkn}^{\pm}\le MPC^{\pm},\ \forall h \tag{1l}$$

(capital budget constraints)

$$\sum_{i=1}^{I}\mu_i Q_i^{\pm}(X_{ijk}^{\pm}+Y_{ijkh}^{\pm})\ge Q_{j\min}^{\pm}\sum_{i=1}^{I}(X_{ijk}^{\pm}+Y_{ijkh}^{\pm}),\ \forall j,k,h \tag{1m}$$

(low heating value constraints for coal blending systems)

$$\sum_{i=1}^{I}\alpha_i V_i^{\pm}(X_{ijk}^{\pm}+Y_{ijkh}^{\pm})\ge V_{j\min}^{\pm}\sum_{i=1}^{I}(X_{ijk}^{\pm}+Y_{ijkh}^{\pm}),\ \forall j,k,h \tag{1n}$$

$$\sum_{i=1}^{I}\alpha_i V_i^{\pm}(X_{ijk}^{\pm}+Y_{ijkh}^{\pm})\le V_{j\max}^{\pm}\sum_{i=1}^{I}(X_{ijk}^{\pm}+Y_{ijkh}^{\pm}),\ \forall j,k,h \tag{1o}$$

(volatile matter content constraints for coal blending systems)

$$\sum_{i=1}^{I}\beta_i A_i^{\pm}(X_{ijk}^{\pm}+Y_{ijkh}^{\pm})\ge A_{j\min}^{\pm}\sum_{i=1}^{I}(X_{ijk}^{\pm}+Y_{ijkh}^{\pm}),\ \forall j,k,h \tag{1p}$$

$$\sum_{i=1}^{I}\beta_i A_i^{\pm}(X_{ijk}^{\pm}+Y_{ijkh}^{\pm})\le A_{j\max}^{\pm}\sum_{i=1}^{I}(X_{ijk}^{\pm}+Y_{ijkh}^{\pm}),\ \forall j,k,h \tag{1q}$$

(ash content constraints for coal blending systems)

$$\sum_{i=1}^{I}\varphi_i MC_i^{\pm}(X_{ijk}^{\pm}+Y_{ijkh}^{\pm})\le MC_{j\max}^{\pm}\sum_{i=1}^{I}(X_{ijk}^{\pm}+Y_{ijkh}^{\pm}),\ \forall j,k,h \tag{1r}$$

(moisture content constraints for coal blending systems)

$$\sum_{i=1}^{I}\delta_i S_i^{\pm}(X_{ijk}^{\pm}+Y_{ijkh}^{\pm})\le S_{j\max}^{\pm}\sum_{i=1}^{I}(X_{ijk}^{\pm}+Y_{ijkh}^{\pm}),\ \forall j,k,h \tag{1s}$$

(sulfur content constraints for coal blending systems)

$$\gamma_{jkw}^{\pm}=\{0,\ 1\},\ \forall j,k,w \tag{1t}$$

$$Z_{jlkn}^{\pm}=\{0,\ 1\},\ \forall j,l,k,n \tag{1u}$$

(binary constraints for generation capacity expansion and desulphurization facility installation)

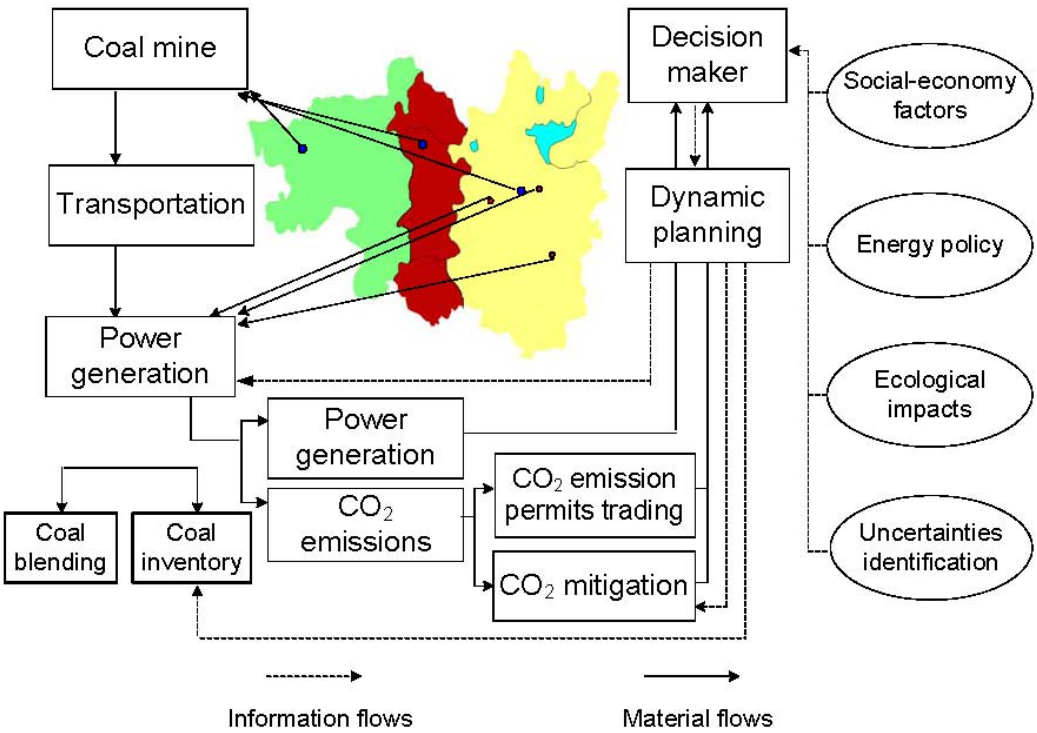
$$(TD_{jkh}^{\pm}/30)*\rho_{jk} \geq \sum_{l=1}^{L}\eta_l D_{jlkh}^{\pm} \geq 0,\ \forall j,k,h \tag{1v}$$

$$X_{ijk}^{\pm} \geq Y_{ijkh}^{\pm} \geq 0,\ \forall i,j,k,h \tag{1w}$$

$$D_{jlkh}^{\pm} \geq 0,\ \forall j,l,k,h \tag{1x}$$

(non-negativity and technical constraints)

Figure 1. The study system.



The notations in model (1) are attached in the appendix. An inexact mix-integer two-stage linear programming model (IMITSP) based on the ILP, TSP and MILP approaches for the coupled coal and power management system (CCPM) with CO_2 reduction is formulated in above model (1). Inexact uncertainties existed in the decision making process can be effectively addressed in this model. According to the interactive solution algorithm developed by Huang *et al.*, model (1) can be divided into two deterministic sub-models, corresponding to the lower and upper bounds of the objective-function value [18,63,65]. The coefficients (both in the objective function and constraints) in terms of intervals can be considered and reflected in the two sub-models regarding the lower and upper bounds of the intervals. Solutions are generated through this two-step method, representing the most optimistic and pessimistic solution sets. A series of decision alternatives can be obtained within the continuous solution intervals (instead of discrete solutions) for the lower and upper bounds of the objective function values in response to the variations of modeling parameters within their corresponding intervals. A sub-model corresponding to f^- (when the objective function is to be minimized) is firstly formulated, and then the relevant sub-model corresponding to f^+ can be formulated based on solutions of the first sub-model. The two sub-models are presented as follows:

(a) sub-model 1,

$$
\begin{aligned}
Minmize\ f^{-} = & \sum_{i=1}^{I}\sum_{j=1}^{J}\sum_{k=1}^{K} X_{ijk}^{-} * (CF_{ik}^{-} + TF_{ijk}^{-}) * \Delta L_{\mathrm{k}} \\
& + \sum_{i=1}^{I}\sum_{j=1}^{J}\sum_{k=1}^{K}\sum_{h=1}^{H} t_{jkh} Y_{ijkh}^{-} * (CCF_{ik}^{-} + CTF_{ijk}^{-}) * \Delta L_{\mathrm{k}} \\
& + \sum_{j=1}^{J}\sum_{k=1}^{K} OPP_{jk}^{-} * (M_j + \sum\nolimits_{k=1}^{k'}\sum\nolimits_{w=1}^{W} \Delta M_{jkw}\gamma_{jkw}^{-}) * h_j^{-} * \Delta L_k \\
& + \sum_{j=1}^{J}\sum_{l=1}^{L}\sum_{k=1}^{K}\sum_{h=1}^{H} OMP_{jlk}^{-} * t_{jkh} D_{jlkh}^{-} * \Delta L_k \\
& + \sum_{j=1}^{J}\sum_{k=1}^{K}\sum_{w=1}^{W} PMC_{jk}^{-} * \Delta M_{jkw}\gamma_{jkw}^{-} + \sum_{j=1}^{J}\sum_{l=1}^{L}\sum_{k=1}^{K}\sum_{n=1}^{N} PCC_{jlk}^{-} * \Delta C_{jlkn} Z_{jlkn}^{-}
\end{aligned}
\tag{2a}
$$

$$\sum_{i=1}^{I}(X_{ijk}^{-} + Y_{ijkh}^{-})(1-\theta) \geq (TD_{jkh}^{-}/30) * (q_{jk}^{-}/10^{6}),\ \forall j,k,h \tag{2b}$$

$$(M_j + \sum\nolimits_{k=1}^{k'}\sum\nolimits_{w=1}^{W} \Delta M_{jkw}\gamma_{jkw}^{-}) * h_j^{-} \geq TD_{jkh}^{-}/30,\ \forall j,k,h \tag{2c}$$

$$\sum_{k=1}^{K}\sum_{w=1}^{W} \gamma_{jkw}^{-} = 1,\ \forall j \tag{2d}$$

$$
\begin{aligned}
& \sum\nolimits_{i=1}^{I}(X_{ijk}^{-} + Y_{ijkh}^{-})(1-\theta) * \Delta L_k \\
& \geq CIM_{jk\min}^{-} + (TD_{jkh}^{-}/30) * (q_{jk}^{-}/10^{6}) * \Delta L_k - CIM_{jk-1}^{+},\ \forall j,k,h
\end{aligned}
\tag{2e}
$$

$$k = 1\ \ CIM_{jk-1}^{+} = CIM_j^{+},\ \forall j \tag{2f}$$

$$\sum_{j=1}^{J}(X_{ijk}^{-} + Y_{ijkh}^{-}) \leq R_{ik}^{+}/30,\ \forall j,k,h \tag{2g}$$

$$\sum_{l=1}^{L}\sum_{h=1}^{H} \eta_l D_{jlkh}^{-} \geq (TD_{jkh}^{-}/30) * \rho_{jk} - TE_{jkh}^{+},\ \forall j,k,h \tag{2h}$$

$$\sum_{j=1}^{J} TE_{jkh}^{+} \leq (1-\sigma) * TP_k^{+},\ \forall k,h \tag{2i}$$

$$D_{jlkh}^{-} \leq C_{jl} + \sum\nolimits_{k=1}^{k'}\sum\nolimits_{n=1}^{N} \Delta C_{jlkn} Z_{jlkn}^{-},\ \forall j,l,k,h \tag{2j}$$

$$\sum_{j=1}^{J}\sum_{k=1}^{K}\sum_{w=1}^{W} PMC_{jk}^{-} * \Delta M_{jkw}\gamma_{jkw}^{-} + \sum_{j=1}^{J}\sum_{l=1}^{L}\sum_{k=1}^{K}\sum_{n=1}^{N} PCC_{jlk}^{-} * \Delta C_{jlkn} Z_{jlkn}^{-} \leq MPC^{+},\ \forall h \tag{2k}$$

$$\sum_{i=1}^{I}\left|Q_{ij\min}\right|^{+} Sign\left(Q_{ij\min}^{+}\right)(X_{ijk}^{-} + Y_{ijkh}^{-}) \geq 0,\ \forall j,k,h \tag{2l}$$

$$Q_{ij\min}^{\pm} = \mu_i Q_i^{\pm} - Q_{j\min}^{\pm},\ \forall i,j,k \tag{2m}$$

$$\sum_{i=1}^{I}\left|V_{ij\min}\right|^{+} Sign\left(V_{ij\min}^{+}\right)(X_{ijk}^{-} + Y_{ijkh}^{-}) \geq 0,\ \forall j,k,h \tag{2n}$$

$$V_{ij\min}^{\pm} = \alpha_i V_i^{\pm} - V_{j\min}^{\pm},\ \forall i, j, k \tag{2o}$$

$$\sum_{i=1}^{I} \left| V_{ij\max} \right|^{+} Sign\left(V_{ij\max}^{+} \right) (X_{ijk}^{-} + Y_{ijkh}^{-}) \le 0,\ \forall j, k, h \tag{2p}$$

$$V_{ij\max}^{\pm} = \alpha_i V_i^{\pm} - V_{j\max}^{\pm},\ \forall i, j, k \tag{2q}$$

$$\sum_{i=1}^{I} \left| A_{ij\min} \right|^{+} Sign\left(A_{ij\min}^{+} \right) (X_{ijk}^{-} + Y_{ijkh}^{-}) \ge 0,\ \forall j, k, h \tag{2r}$$

$$A_{ij\min}^{\pm} = \beta_i A_i^{\pm} - A_{j\min}^{\pm},\ \forall i, j, k \tag{2s}$$

$$\sum_{i=1}^{I} \left| A_{ij\max} \right|^{+} Sign\left(A_{j\max}^{+} \right) (X_{ijk}^{-} + Y_{ijkh}^{-}) \le 0,\ \forall j, k, h \tag{2t}$$

$$A_{ij\max}^{\pm} = \beta_i A_i^{\pm} - A_{j\max}^{\pm},\ \forall i, j, k \tag{2u}$$

$$\sum_{i=1}^{I} \left| MC_{ij\max} \right|^{+} Sign\left(MC_{ij\max}^{+} \right) (X_{ijk}^{-} + Y_{ijkh}^{-}) \le 0,\ \forall j, k, h \tag{2v}$$

$$MC_{ij\max}^{\pm} = \varphi_i MC_i^{\pm} - MC_{j\max}^{\pm},\ \forall i, j, k \tag{2w}$$

$$\sum_{i=1}^{I} \left| S_{ij\max} \right|^{+} Sign\left(S_{ij\max}^{+} \right) (X_{ijk}^{-} + Y_{ijkh}^{-}) \le 0,\ \forall j, k, h \tag{2x}$$

$$S_{ij\max}^{\pm} = \delta_i S_i^{\pm} - S_{j\max}^{\pm},\ \forall i, j, k \tag{2y}$$

$$\gamma_{jkw}^{-} = \{0,\ 1\},\ \forall j, k, w \tag{2z}$$

$$Z_{jlkn}^{-} = \{0,\ 1\},\ \forall j, l, k, n \tag{2aa}$$

$$(TD_{jkh}^{-} / 30) * \rho_{jk} \ge \sum_{l=1}^{L} \eta_l D_{jlkh}^{-} \ge 0,\ \forall j, k, h \tag{2ab}$$

$$X_{ijk}^{-} \ge Y_{ijkh}^{-} \ge 0,\ \forall i, j, k, h \tag{2ac}$$

$$D_{jlkh}^{-} \ge 0,\ \forall i, j, k, h \tag{2ad}$$

Through sub-model (2), solutions of f_{opt}^{-}, $(Y_{ijkh}^{-})_{opt}$, $(D_{jlkh}^{-})_{opt}$, $(\gamma_{jkw}^{-})_{opt}$ and $(Z_{jlkn}^{-})_{opt}$, can be obtained. The optimum allocation of coal flow corresponding to the lower bound of objective (f_{opt}^{-}) is: $(AC_{ijkh}^{-})_{opt} = X_{ijk}^{-} + (Y_{ijkh}^{-})_{opt}$. While the total emitted CO_2 is: $(TC_{jkh}^{-})_{opt} = TE_{jkh}^{-} + \sum_{l=1}^{L} (D_{jlkh}^{-})_{opt}$. Thus, the sub-model corresponding to f^{+} can be formulated as follows (assuming that $f^{+} > 0$):

(b) sub-model 2,

$$\begin{aligned} Minmize\ f^{+} = & \sum_{i=1}^{I} \sum_{j=1}^{J} \sum_{k=1}^{K} X_{ijk}^{+} * (CF_{ik}^{+} + TF_{ijk}^{+}) * \Delta L_{\mathrm{k}} \\ & + \sum_{i=1}^{I} \sum_{j=1}^{J} \sum_{k=1}^{K} \sum_{h=1}^{H} t_{jkh} Y_{ijkh}^{+} * (CCF_{ik}^{+} + CTF_{ijk}^{+}) * \Delta L_{\mathrm{k}} \\ & + \sum_{j=1}^{J} \sum_{k=1}^{K} OPP_{jk}^{+} * (M_j + \sum_{k=1}^{k'} \sum_{w=1}^{W} \Delta M_{jkw} \gamma_{jkw}^{+}) * h_j^{+} * \Delta L_k \end{aligned} \tag{3a}$$

$$+\sum_{j=1}^{J}\sum_{l=1}^{L}\sum_{k=1}^{K}\sum_{h=1}^{H} OMP_{jlk}^{+} * t_{jkh} D_{jlkh}^{+} * \Delta L_k$$

$$+\sum_{j=1}^{J}\sum_{k=1}^{K}\sum_{w=1}^{W} PMC_{jk}^{+} * \Delta M_{jkw}\gamma_{jkw}^{+} + \sum_{j=1}^{J}\sum_{l=1}^{L}\sum_{k=1}^{K}\sum_{n=1}^{N} PCC_{jlk}^{+} * \Delta C_{jlkn} Z_{jlkn}^{+}$$

$$\sum_{i=1}^{I}(X_{ijk}^{+} + Y_{ijkh}^{+})(1-\theta) \geq (TD_{jkh}^{+}/30) * (q_{jk}^{+}/10^6),\ \forall j,k,h \tag{3b}$$

$$(M_j + \sum\nolimits_{k=1}^{k'}\sum\nolimits_{w=1}^{W} \Delta M_{jkw}\gamma_{jkw}^{+}) * h_j^{+} \geq TD_{jkh}^{+}/30,\ \forall j,k,h \tag{3c}$$

$$\sum_{k=1}^{K}\sum_{w=1}^{W} \gamma_{jkw}^{-} = 1,\ \forall j \tag{3d}$$

$$\begin{aligned} &\sum\nolimits_{i=1}^{I}(X_{ijk}^{+} + Y_{ijkh}^{+})(1-\theta) * \Delta L_k \\ &\geq CIM_{jk\min}^{+} + (TD_{jkh}^{+}/30) * (q_{jk}^{+}/10^6) * \Delta L_k - CIM_{jk-1}^{-},\ \forall j,k,h \end{aligned} \tag{3e}$$

$$k = 1 \quad CIM_{jk-1}^{-} = CIM_j^{-},\ \forall j \tag{3f}$$

$$\sum_{j=1}^{J}(X_{ijk}^{+} + Y_{ijkh}^{+}) \leq R_{ik}^{\pm}/30,\ \forall j,k,h \tag{3g}$$

$$\sum_{l=1}^{L}\sum_{h=1}^{H} \eta_l D_{jlkh}^{+} \geq (TD_{jkh}^{+}/30) * \rho_{jk} - TE_{jkh}^{-},\ \forall j,k,h \tag{3h}$$

$$\sum_{j=1}^{J} TE_{jkh}^{-} \leq (1-\sigma) * TP_k^{-},\ \forall k,h \tag{3i}$$

$$D_{jlkh}^{-} \leq C_{jl} + \sum\nolimits_{k=1}^{k'}\sum\nolimits_{n=1}^{N} \Delta C_{jlkn} Z_{jlkn}^{-},\ \forall j,l,k,h \tag{3j}$$

$$\sum_{j=1}^{J}\sum_{k=1}^{K}\sum_{w=1}^{W} PMC_{jk}^{+} * \Delta M_{jkw}\gamma_{jkw}^{+} + \sum_{j=1}^{J}\sum_{l=1}^{L}\sum_{k=1}^{K}\sum_{n=1}^{N} PCC_{jlk}^{+} * \Delta C_{jlkn} Z_{jlkn}^{+} \leq MPC^{-},\ \forall h \tag{3k}$$

$$\sum_{i=1}^{I}\left|Q_{ij\min}\right|^{-} Sign\left(Q_{ij\min}^{-}\right)(X_{ijk}^{+} + Y_{ijkh}^{+}) \geq 0,\ \forall j,k,h \tag{3l}$$

$$Q_{ij\min}^{\pm} = \mu_i Q_i^{\pm} - Q_{j\min}^{\pm},\ \forall i,j,k \tag{3m}$$

$$\sum_{i=1}^{I}\left|V_{ij\min}\right|^{-} Sign\left(V_{ij\min}^{-}\right)(X_{ijk}^{+} + Y_{ijkh}^{+}) \geq 0,\ \forall j,k,h \tag{3n}$$

$$V_{ij\min}^{\pm} = \alpha_i V_i^{\pm} - V_{j\min}^{\pm},\ \forall i,j,k \tag{3o}$$

$$\sum_{i=1}^{I}\left|V_{ij\max}\right|^{-} Sign\left(V_{ij\max}^{-}\right)(X_{ijk}^{+} + Y_{ijkh}^{+}) \leq 0,\ \forall j,k,h \tag{3p}$$

$$V_{ij\max}^{\pm} = \alpha_i V_i^{\pm} - V_{j\max}^{\pm},\ \forall i,j,k \tag{3q}$$

$$\sum_{i=1}^{I}\left|A_{ij\min}\right|^{-} Sign\left(A_{ij\min}^{-}\right)(X_{ijk}^{+} + Y_{ijkh}^{+}) \geq 0,\ \forall j,k,h \tag{3r}$$

$$A_{ij\min}^{\pm} = \beta_i A_i^{\pm} - A_{j\min}^{\pm},\ \forall i, j, k \tag{3s}$$

$$\sum_{i=1}^{I} \left| A_{ij\max} \right|^{-} Sign\left(A_{j\max}^{-} \right)(X_{ijk}^{+} + Y_{ijkh}^{+}) \le 0,\ \forall j, k, h \tag{3t}$$

$$A_{ij\max}^{\pm} = \beta_i A_i^{\pm} - A_{j\max}^{\pm},\ \forall i, j, k \tag{3u}$$

$$\sum_{i=1}^{I} \left| MC_{ij\max} \right|^{-} Sign\left(MC_{ij\max}^{-} \right)(X_{ijk}^{+} + Y_{ijkh}^{+}) \le 0,\ \forall j, k, h \tag{3v}$$

$$MC_{ij\max}^{\pm} = \varphi_i MC_i^{\pm} - MC_{j\max}^{\pm},\ \forall i, j, k \tag{3w}$$

$$\sum_{i=1}^{I} \left| S_{ij\max} \right|^{-} Sign\left(S_{ij\max}^{-} \right)(X_{ijk}^{+} + Y_{ijkh}^{+}) \le 0,\ \forall j, k, h \tag{3x}$$

$$S_{ij\max}^{\pm} = \delta_i S_i^{\pm} - S_{j\max}^{\pm},\ \forall i, j, k \tag{3y}$$

$$\gamma_{jkw}^{+} = \{0,\ 1\},\ \forall j, k, w \tag{3z}$$

$$Z_{jlkn}^{+} = \{0,\ 1\},\ \forall j, l, k, n \tag{3aa}$$

$$X_{ijk}^{+} \ge Y_{ijkh}^{+} \ge 0,\ \forall i, j, k, h \tag{3ab}$$

$$(TD_{jkh}^{+} / 30) * \rho_{jk} \ge \sum_{l=1}^{L} \eta_l D_{jlkh}^{+} \ge 0,\ \forall j, k, h \tag{3ac}$$

$$Y_{ijkh}^{+} \ge (Y_{ijkh}^{-})_{opt} \ge 0,\ \forall i, j, k, h \tag{3ad}$$

$$D_{jlkh}^{+} \ge (D_{jlkh}^{-})_{opt} \ge 0,\ \forall i, j, k, h \tag{3ae}$$

$$1 \ge \gamma_{jkw}^{+} \ge (\gamma_{jkw}^{-})_{opt} \ge 0,\ \forall j, k, w \tag{3af}$$

$$1 \ge Z_{jlkn}^{+} \ge (Z_{jlkn}^{-})_{opt} \ge 0,\ \forall j, l, k, n \tag{3ag}$$

$$f^{+} \ge f_{opt}^{-} \tag{3ah}$$

Hence, solutions of f_{opt}^{+}, $(Y_{ijkh}^{+})_{opt}$, $(D_{jlkh}^{+})_{opt}$, $(\gamma_{jkw}^{+})_{opt}$ and $(Z_{jlkn}^{+})_{opt}$ can be obtained through solving the sub-model (3).

The optimum allocation of coal flow to each power plant corresponding to the upper bound of objective (f_{opt}^{+}) is:

$$(AC_{ijkh}^{+})_{opt} = X_{ijk}^{+} + (Y_{ijkh}^{+})_{opt}$$

and the total emitted CO_2 is:

$$(TC_{jkh}^{+})_{opt} = TE_{jkh}^{+} + \sum\nolimits_{l=1}^{L} (D_{jlkh}^{+})_{opt}$$

Thus, we can have the final solution of $f_{opt}^{\pm} = \left[f_{opt}^{-},\ f_{opt}^{+} \right]$, $(Y_{ijkh}^{\pm})_{opt} = \left[(Y_{ijkh}^{-})_{opt},\ (Y_{ijkh}^{+})_{opt} \right]$, $(D_{jlkh}^{\pm})_{opt} = \left[(D_{jlkh}^{-})_{opt},\ (D_{jlkh}^{+})_{opt} \right]$, $(\gamma_{jkw}^{\pm})_{opt} = \left[(\gamma_{jkw}^{-})_{opt},\ (\gamma_{jkw}^{+})_{opt} \right]$, $(Z_{jlkn}^{\pm})_{opt} = \left[(Z_{jlkn}^{-})_{opt},\ (Z_{jlkn}^{+})_{opt} \right]$ $(AC_{ijkh}^{\pm})_{opt} = \left[(AC_{ijkh}^{-})_{opt},\ (AC_{ijkh}^{+})_{opt} \right]$ and $(TC_{jkh}^{\pm})_{opt} = \left[(TC_{jkh}^{-})_{opt},\ (TC_{jkh}^{+})_{opt} \right]$.

3. Case Study

A semi-hypothetical case is advanced to demonstrate the applicability of the developed IMITSP model for CCPM system with CO_2 mitigation issues. In this study, three typical large power plants and three coal mines in a long-distance network are considered. In addition to the CO_2 emission permit and CO_2 emissions trading schemes, another two CO_2 mitigation technologies, carbon capture and storage (CCS) and chemical absorption, are also incorporated to reduce the excess CO_2 emissions. To examine the impacts of CO_2 emission reduction on the CCPM systems, two scenarios with different limits of CO_2 emission permits are formulated. One reference scenario is developed as scenario 1, in which the system programming is conducted in the absence of any CO_2 emission control target; while, scenario 2 are designed to help identify the optimal mitigation strategies with a certain emission reduction on the CCPM systems and, in which 50% CO_2 emission reduction is assumed to achieve during the whole planning periods.

The planning horizon is 15 years (from 2011 to 2025), which is divided into three 5-year periods. Table 1 shows the power-generation demands under varied probabilities of occurrence for the three power plants. Table 2 contains the coal property parameters of each coal mine and the performance requirements of the power plant. Table 3 displays some basic parameters of the power plants, such as coal consumption rate, initial power generation capacity and coal inventory, operation and maintenance cost, capital cost of power-generation capacity expansion and decarburization facility improvement, power-generation capacity expansion and CO_2 capture facility improvement options, amount of CO_2 emission loading per power generation, total CO_2 emission permits for the system, maximum allowable investment, and so on. Several assumptions are applicable in this research, including (a) the capacity expansion and decarburization facility improvement of each power plant are respectively limited to only one time within the planning horizon, (b) the loss ratio of coal during transportation is supposed to be zero, (c) a fixed reduced efficiency of CO_2 mitigation measure are adopted over the planning horizon, which is supposed to be 1 and [0.8, 0.9] for CCS and chemical absorption, (d) coal properties are stable during the entire planning horizon, and (e) CO_2 emission permit market is existed within the system, hence the emission permits could be exchanged and reallocated to meet limited total CO_2 emission permits.

Table 1. Power-generation demands under different probability levels (10^8 kWh/month).

Power Plant	Level	Probability	Period		
			$k = 1$	$k = 2$	$k = 3$
$j = 1$	$h = 1$ (Low level)	0.2	[3.1, 3.3]	[5.1, 5.5]	[6.9, 7.0]
	$h = 2$ (Medium level)	0.6	[3.4, 3.6]	[5.4, 5.5]	[7.15, 7.0]
	$h = 3$ (High level)	0.2	[3.8, 4.0]	[5.7, 5.8]	[7.4, 8.0]
$j = 2$	$h = 1$ (Low level)	0.2	[2.05, 2.21]	[3.4, 3.5]	[4.9, 5.0]
	$h = 2$ (Medium level)	0.6	[2.35, 2.51]	[3.7, 3.8]	[5.1, 5.2]
	$h = 3$ (High level)	0.2	[2.65, 2.8]	[4.0, 4.1]	[5.4, 5.5]
$j = 3$	$h = 1$ (Low level)	0.2	[9.1, 9.7]	[11.3, 11.6]	[14.3, 14.7]
	$h = 2$ (Medium level)	0.6	[9.9, 10.2]	[11.7, 11.8]	[15.0, 15.5]
	$h = 3$ (High level)	0.2	[10.4, 11.0]	[11.9, 12.0]	[15.9, 16.5]

Table 2. Coal properties of the mines and performance requirements of the power plant.

Mine	Coal property				
	Q **(MJ/kg)**	***V*** **(%)**	***A*** **(%)**	***MC*** **(%)**	***S*** **(%)**
$i = 1$	[25.12, 25.42]	[35.11, 35.62]	[18.02, 18.68]	[7.65, 8.31]	[0.85, 1.10]
$i = 2$	[23.91, 24.25]	[29.98, 31.49]	[7.77, 8.26]	[11.56, 12.04]	[0.40, 0.60]
$i = 3$	[24.49, 25.20]	[30.02, 31.53]	[19.68, 20.46]	[1.06, 1.58]	[0.70, 0.80]

Power Plant	Performance requirement						
	Q_{min} **(MJ/kg)**	V_{max} **(%)**	V_{min} **(%)**	A_{max} **(%)**	A_{min} **(%)**	MC_{max} **(%)**	S_{max} **(%)**
$j = 1$	[24.5, 25]	[37, 38]	[30, 32]	[17, 18]	[11, 12]	[10, 11]	[0.7, 0.90]
$j = 2$	[24.5, 25]	[37, 38]	[30, 32.5]	[19, 20]	[12, 13]	[9, 10]	[0.7, 0.95]
$j = 3$	[24.5, 25]	[35, 36]	[30, 33]	[17, 18]	[12, 13]	[9, 10]	[0.7, 0.95]

Table 3. Basic parameters of the system.

Parameters	Period		
	$j = 1$	$j = 2$	$j = 3$
Coal consumption rate for power generation (g/kWh)	[310, 320]	[325, 335]	[300, 310]
Initial power generation capacity (kW)	850,000	385,000	2,540,000
Initial CO_2 capture capacity (10^5 tonne/year)	[93, 108]	[96, 111]	[99, 114]
Initial coal inventory (tonne)	[32030, 39168]	[20054, 34823]	[110000, 125000]
Operation and maintenance cost of power plant (RMB/kWh)			
$k = 1$	[0.19, 0.22]	[0.23, 0.26]	[0.15, 0.18]
$k = 2$	[0.34, 0.40]	[0.41, 0.47]	[0.27, 0.32]
$k = 3$	[0.51, 0.59]	[0.62, 0.70]	[0.41, 0.49]
Operating hours (h/day)	[16, 18]	[16, 18]	[18, 20]
Operation and maintenance cost of CO_2 mitigation measure (RMB/tonne)			
Carbon capture and storage			
$k = 1$	[14, 16]	[15, 17]	[13, 15]
$k = 2$	[19, 21]	[20, 22]	[18, 20]
$k = 3$	[24, 26]	[25, 27]	[23, 25]
Chemical absorption			
$k = 1$	[29, 31]	[30, 32]	[28, 30]
$k = 2$	[34, 36]	[35, 36]	[33, 35]
$k = 3$	[39, 41]	[39, 41]	[38, 40]
Amount of CO_2 emission loading per power generation (10^{-4} tonne/kWh)	9.3	9.0	9.5
Maximum allowable investment of the whole planning horizon (10^9 RMB)			[12, 15]
The total CO_2 emissions permits for the system (tonne/year)			
$k = 1$			6,600,000
$k = 2$			6,655,000
$k = 3$			6,711,000
Capital cost of CO_2 capture facility installation/expansion (RMB/tonne)			
$k = 1$	[1290, 1303]	[1240, 1253]	[1180, 1195]
$k = 2$	[1239, 1245]	[1200, 1207]	[1137, 1144]
$k = 3$	[1168, 1180]	[1133, 1140]	[1092, 1100]

Table 3. *Cont.*

Parameters	Period		
	$j = 1$	$j = 2$	$j = 3$
Capital cost of power-generation capacity expansion (kW/tonne)			
$k = 1$	[4964, 4972]	[4562, 4569]	[4785, 4792]
$k = 2$	[4172, 4179]	[4334, 4342]	[4245, 4253]
$k = 3$	[3833, 3840]	[3584, 3591]	[3303, 3311]
CO_2 capture facility improvement options (10^5 tonne/year)			
$n = 1$	13	20	23
$n = 2$	20	28	33
$n = 3$	26	35	38
Power-generation capacity expansion options (10^5 kW)			
$w = 1$	5	3	8.5
$w = 2$	8.5	6	10
$w = 3$	12	9	11.5

Figure 2. Optimum total coal flows to the power plants under scenarios 1 and 2.

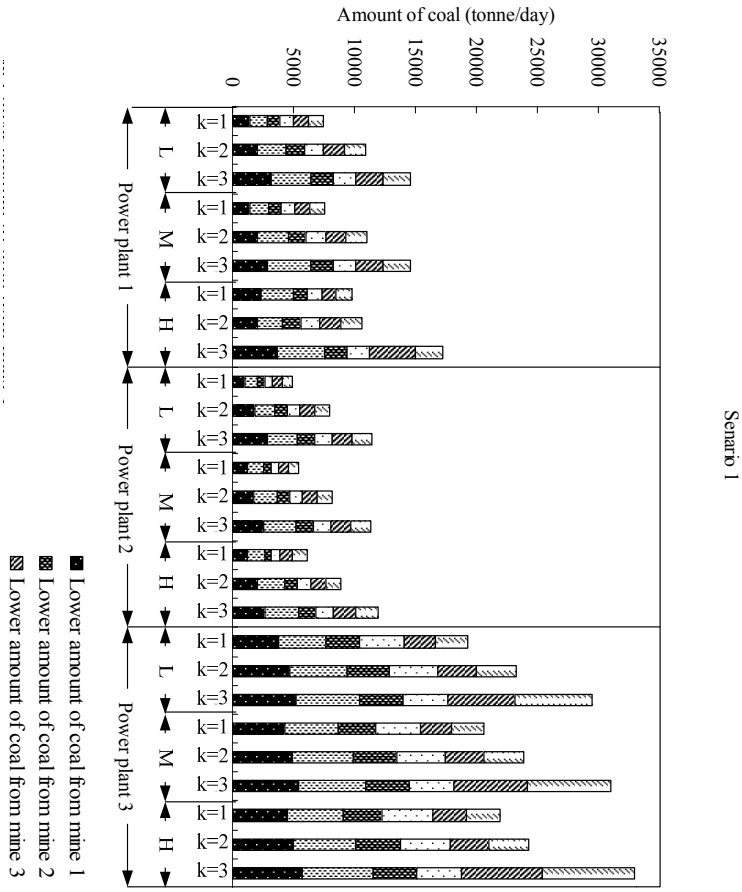


Figure 2. *Cont.*

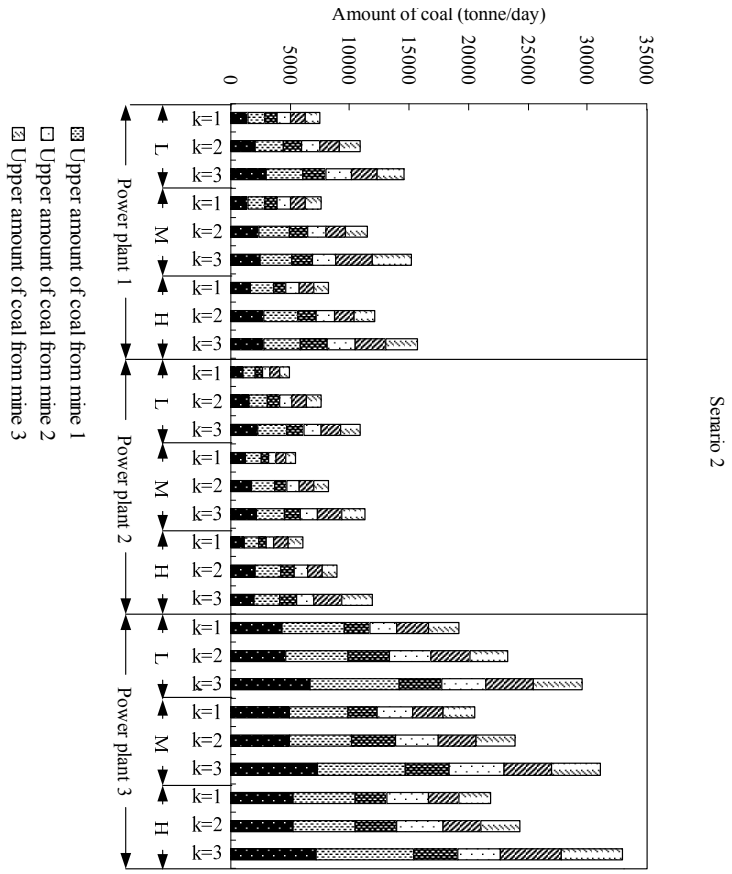


Figure 3. Optimized excess coal flows to the power plants under scenarios 1 and 2.

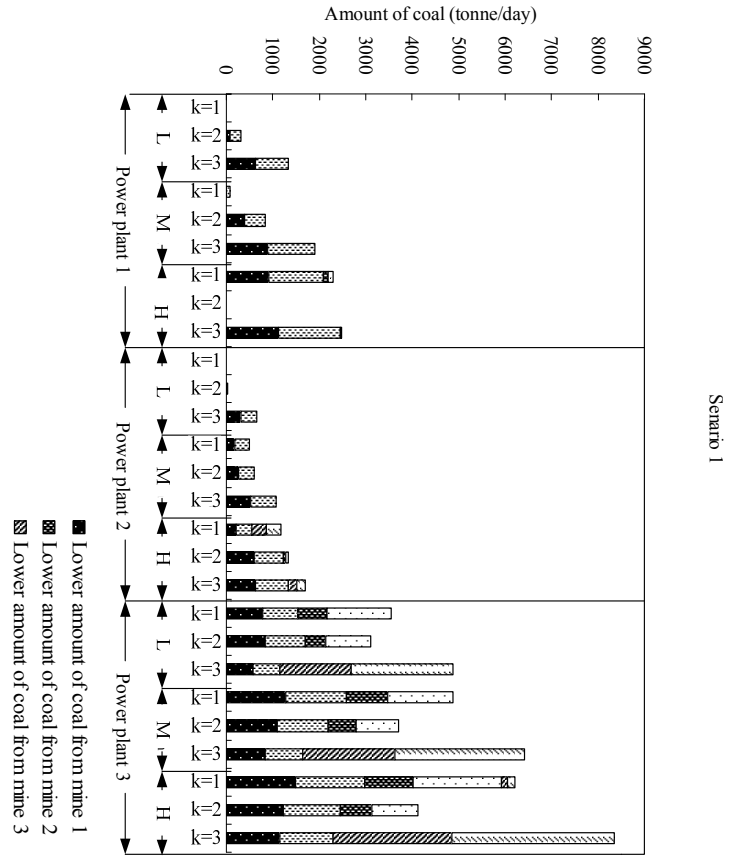
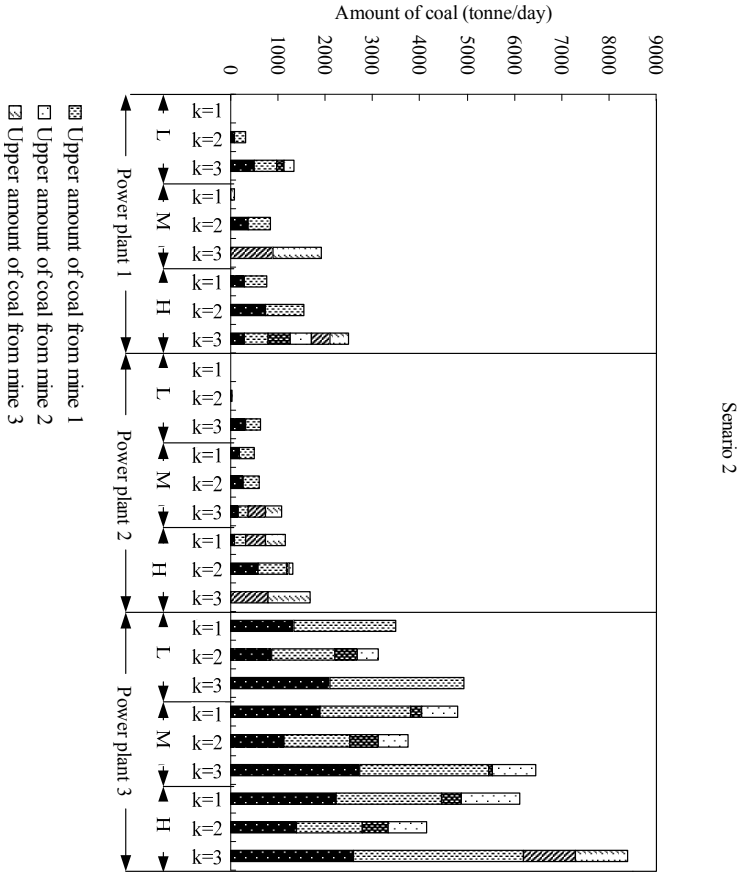


Figure 3. *Cont.*



Figures 2 and 3 display the solutions for excess and total amounts of coal-flow allocated to power plants over entire planning horizon under scenarios 1 and 2. When the predefined coal flow could not satisfy the requirements of varied power-generation demand, excess amounts of coal would exist, implying deficiency of the predefined coal flows in meeting the requirements of power-generation demand. The result analysis of the coal allocation pattern for power plant 1 is presented in detail, while results for power plants 2 and 3 could be similarly interpreted as shown in Figures 2 and 3.

Under scenario 1, the optimized coal flows from three coal mines would change greatly with power generation demand increased. Specifically, when the demand level of power-generation is low, the optimized total coal flows (including prefixed and excess flows) allocated from mine 1 to power plant 1 would rise from [1400, 1470], [2070, 2343.3] to [2991.7, 3296.7] tonnes/day in three periods; while the excess coal flows would appear as 0, [70, 243.3] and [630, 696.7] tonnes/day over three periods, respectively. For the optimized total coal flows allocated from mine 2, it become to [1050, 1100], [1500, 1560] and [1800, 1890] tonnes/day for the three periods, which would be less than the optimized coal flows from coal mine 1. The corresponding excess coal flows all would be zero. Comparatively, the total coal flows allocated from mine 3 would increase from [1200, 1260], [1700, 1750] to [2200, 2280] tonnes/day for periods 1–3, but no excess coal-flow would exist from mine 3. Under the condition of medium power-generation demand, the excess coal flows would also raise over the planning horizon. The optimized total coal flows allocated from mine 1 would increase from [1400, 1542.9], [2380, 2556.7] to [2808.3, 3616.7] tonnes/day in three periods; while the excess coal flows would be [0, 72.9] [380, 456.7] and [888.3, 1016.7] tonnes/day over three periods, respectively. For the optimized total coal flows allocated from mine 2, it would stay as [1050, 1100], [1500, 1560] and [1800, 1890] tonnes/day for the three periods, and no excess coal-flow would exist. Similarly, the total coal flows allocated from mine 3 would be [1200, 1260], [1700, 1750] and [2200, 2280] tonnes/day for periods 1–3; also, there is no excess coal flow. If the power-generation demand grows to the high level, the optimized coal reallocation schemes would adjust corresponding. The optimized total coal flows allocated from mine 1 to power plant 1 would be [2309.7, 2641.4], [2000, 2100] and [2631.1, 2921.1] tonnes/day in three periods; while the excess coal flows would be [909.7, 1171.4], 0 and [1131.1, 1321.1] tonnes/day over three periods, respectively. For the optimized total coal flows allocated from mine 2, it would become to [1154.8, 1204.8], [1500, 1560] and [1815.6, 1905.6] tonnes/day for the three periods. And the excess coal flow would change to 104.8, 0 and 15.6 tonnes/day over the three periods. The total coal flows allocated from mine 3 would be [1200, 1260], [1700, 1750] and [2200, 2280] tonnes/day for periods 1–3; but the corresponding excess coal flow would be zero. These results imply the allocation schemes of coal flows for power plant 1 in three periods would vary dramatically with varied power generation demands under scenario 1.

Similarly, under scenario 2, a certain variation could be observed for the optimal coal-flows under three power generation demand levels, compared with the results of scenario 1. when the power-generation demand is low, the optimized total coal flows allocated from mine 1 to power plant 1 would be [1400, 1470], [2070, 2343.3] and [2991.7, 3091.7] tonnes/day in three periods; while the excess coal flows would be 0, [70, 243.3] and 491.7 tonnes/day over three periods, respectively. For the optimized total coal flows allocated from mine 2, it would remain the same with scenario 1 in periods 1 and 2, but rise to [1938.3, 2095] tonnes/day in period 3. The corresponding excess coal-flow in periods 1 and 2 would be zero, but in period 3 would exist as [138.3, 205] tonnes/day from mine 2.

The total coal flows allocated from mine 3 would stay the same values for periods 1–3 with scenario 1; the corresponding excess coal flow would be zero. Under medium power-generation demand condition, the excess coal flows would increase over the planning periods. The optimized total coal flows allocated from mine 1 show the similar growing trend with coal flows from mine 1 under low power generation level during the planning period, which would be [1400, 1470], [2380, 2556.7] and [2500, 2600] tonnes/day in three periods; while the excess coal flows would be 0, [380, 456.7] and 0 tonnes/day over three periods, respectively. For the optimized total coal flows allocated from mine 2, it would stay the same value with scenario 1 for the three periods, and no excess coal-flow would exist. However, the total coal flows allocated from mine 3 would become [1200, 1332.9], [1700, 1750] and [3088.3, 3296.67] tonnes/day for periods 1–3; then, the excess coal flow would be [0, 72.9], 0 and [888.3, 1016.7] tonnes/day. When the power-generation demand grows to the high level, the optimized coal reallocation scheme would change corresponding. In scenario 2, the optimized total coal flows allocated from mine 1 to power plant 1 would increase against scenario 1, which would be [1689.9, 1929.4], [2724.7, 2916.9] and [2800, 3090] tonnes/day in three periods; while the excess coal flows would be [289.9, 459.7], [724.7, 816.9] and [300, 490] tonnes/day over three periods, respectively. For the optimized total coal flows allocated from mine 2, it would increase from [1050, 1100], [1500, 1560] to [2258.3, 2348.3] tonnes/day for the three periods, and the excess coal-flow would corresponding be 0, 0 and 458.2 tonnes/day for the three periods. With the excess coal flows would change to 0, 0 and 388.4 tonnes/day for the three periods, the total coal flows allocated from mine 3 would not vary greatly compared with scenario 1, which would be [1200, 1260], [1700, 1750] and [2588.4, 2668.4] tonnes/day for periods 1–3. These solutions show that the prefixed allowable coal flows would not be sufficient for meeting varied power generation demands under scenario 2.

Generally, the optimized total and excess coal flows would increase with the demand varying from low to high level, implying predefined deficiency of the predefined coal allocation strategy in satisfying the power-generation demand. In addition, since an increased strictness total allowable emission permit limit means a raised risk of violating the CO_2 mitigation constraints, coal-flow-allocation patterns are obtained with different CO_2 emission permit limits in scenarios 1 and 2. For example, if the power-generation demand grows to the high level, the optimized total coal flows from mine 1 to power plant 1 would increase from [2631.1, 2921.1] tonnes/day in scenario 1, to [2800, 3090] tonne/day in scenario 2 in period 3; while the optimized total coal flows allocated from mines 2 and 3 to power plant 1 would be [1815.6, 1905.6] and [2200, 2280] tonnes/day in scenario 1, then rise to [2258.3, 2348.3] and [2588.4, 2668.4] tonnes/day in scenario 2, respectively. Due to three types of coal which have different property parameters, production and transportation costs, would be mixed in the coal blending systems. In order to balance variations of coal from different mines, the amounts of coal allocated to power plants from different mines would be interrelated with each other. As Figures 2 and 3 presented, the coal allocation patterns for power plants 2 and 3 are similar with power plant 1 under these two scenarios in three periods except minor adjustments, which would both increase corresponding to the increasing power-generation demands. Meanwhile, the total coal flows for power plants 2 and 3 would also increase along with the increasing planning periods. In spite of these, with planning periods changing from 1 to 3, the excess amounts of coal to power plant 2 would grow at all three levels of power-generation demands under two scenarios; comparatively, the exceeding coal flows for power plant 3 would decrease firstly, then increase over the planning horizon under scenarios 1 and 2.

Figure 4 presents the optimal solutions for CO_2 emission treated by different measures for the three power plants under scenarios 1 and 2. As Figure 4 presented, the predefined CO_2 emission permits could not satisfy the varied emitted CO_2, while the excess amounts of CO_2 emission would exist and would be treated by CCS and chemical absorption facilities. For all power plants, the exceeding CO_2 emission would rise with the demand varying from low to high level, implying predefined emission permit's deficiency in meeting the requirements of CO_2 emission demand. The detailed analysis of excess CO_2 emission treated scheme for power plant 3 is displayed as an illustration example. For power plant 3, the amounts of excess CO_2 emission treated by CCS would be 26494.5, 35783.3 and [30857.8, 32300.0] tonnes/day in three periods under scenario 1, respectively, when the power-generation demand is at low level; the corresponding CO_2 emission permits would be [1252.19, 2322.19], 0 and [6317.17, 6927.17] tonnes/day. If the power-generation demand is at medium level, the amounts of excess CO_2 emission treated by CCS would change to [30857.8, 32300.0], [37050, 37366.7] and [38356.7. 34246.6] tonnes/day for the three periods; corresponding reallocated CO_2 emission permits would be [0, 492.2], 0 and [8378.8, 9143.8] tonnes/day. Under the condition of high power-generation demand, the excess CO_2 treated by CCS in power plant 1 would be [32876.7, 34246.6], 35616.44 and [38356.2, 39906.1] tonnes/day in scenario 1; the reallocated CO_2 emission permits would change to [56.6, 586.8], [0, 191.78] and [11154.1, 11993.8] tonnes/day, respectively. Meanwhile, no excess emission from power plant 3 would be treated chemical absorption facilities under scenario 1. However, in scenario 2, the optimal treated schemes of excess CO_2 emission would be greatly changed. With the low level of power-generation demand, the excess CO_2 treated by CCS facilities in three periods, would be 19775.6, 35616.4 and 38356.2 tonnes/day; the excess CO_2 emissions allocated to chemical absorption facilities would be [0, 2111.1], [0, 1241.0] and 0 tonnes/day; the corresponding reallocated emission permits would be 9041.1, [0, 166.9] and [6927.2, 8193.8] tonnes/day. When the power-generation demand is at medium level, the amounts of excess CO_2 treated by CCS facilities in three periods, would be 29358.9, 35616.4 and 38356.2 tonnes/day; the excess CO_2 emissions allocated to chemical absorption facilities would be [0, 1555.6], 0 and [0, 1704.5] tonnes/day; the corresponding reallocated emission permits would be [1541.1, 1991.1], [1433.6, 1750.2] and [9143.8, 9193.2] tonnes/day. Under the condition of high power-generation demand, the exceeding CO_2 emission allocated to CCS facilities in three periods, would be 32,876.7, 35,616.4 and [38,356.2, 39,906.1] tonnes/day; the excess CO_2 emissions treated by chemical absorption facilities would be [0, 2174.0], 0 and 3500.9 tonnes/day; the corresponding reallocated emission permits would be [0, 56.6], [2066.9, 2383.6] and 9193.15 tonnes/day. The solutions for power plants 1 and 2 could be similarly interpreted as presented in Figure 4. The results indicate that, for the three power plant, no excess emission would be allocated to chemical absorption facilities under scenario 1; when 50% CO_2 emission reduction is supposed to be achieved in scenario 2, there are more excess CO_2 emission treated by CCS, while less CO_2 treated by chemical absorption facilities, due to the operation and maintenance costs of CCS is much lower than the chemical absorption measures.

Figure 4. Optimal solutions for CO_2 emission treated by CCS and chemical absorption measures for the three power plants under scenarios 1 and 2.

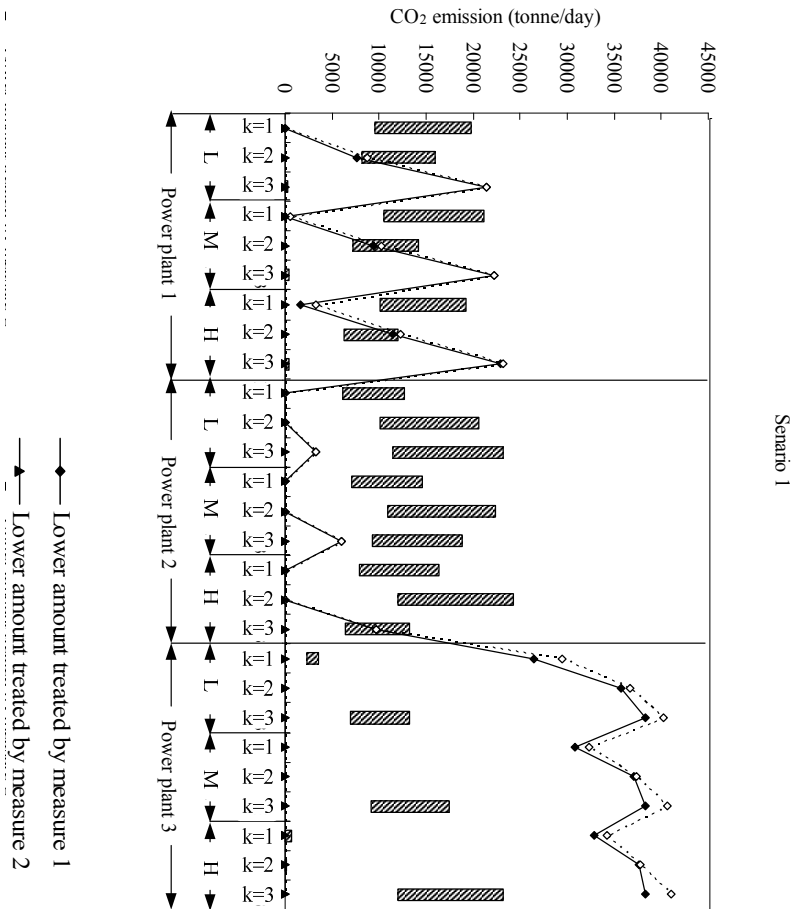
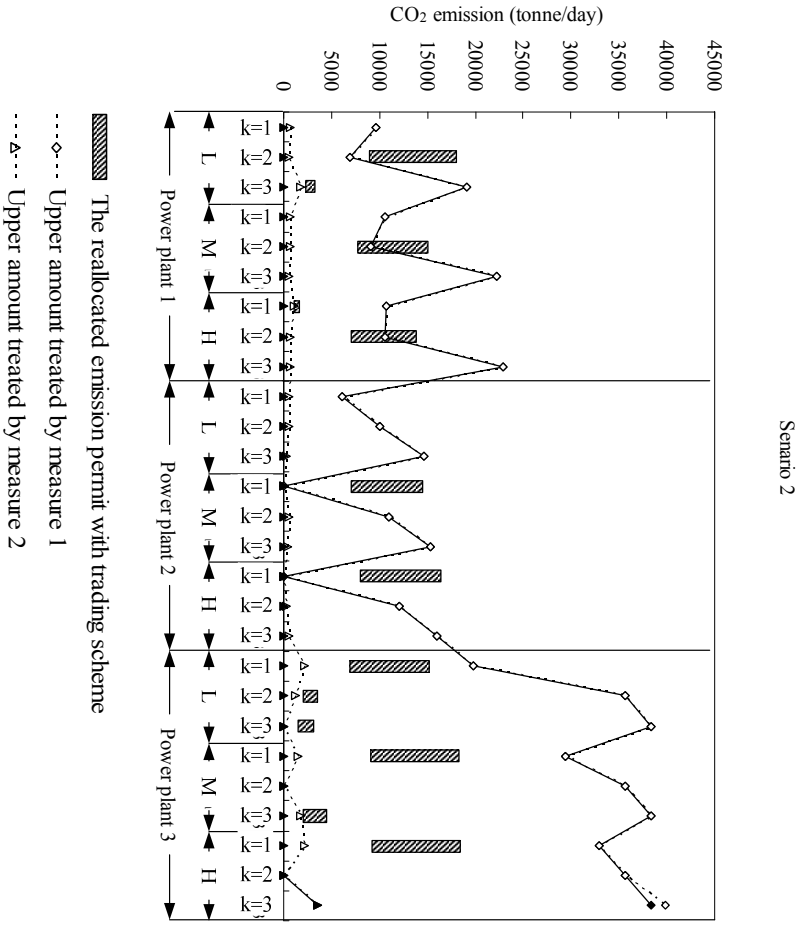


Figure 4. *Cont.*



The results show that solutions for binary variables of power generation capacity expansion and CCS facilities improvement would be quite different for each power plant. In terms of multiple expansion options, the capacity of power plant 1 would be expanded at the start of period 2 with the incremental capacity option 2 of 8.5 × 10^5 kW (*i.e.*, $(\gamma_{123}^{\pm})_{opt}$ = [1, 1]); power plant 2 would expand the power generation capacity at the beginning of period 1 with 9 × 10^5 kW (*i.e.*, $(\gamma_{213}^{\pm})_{opt}$ = [1, 1]); while, the power generation capacity of power plant 3 would increase by 8.5 × 10^5 kW (*i.e.*, $(\gamma_{331}^{\pm})_{opt}$ = [1, 1]) before period 3 under scenarios 1 and 2, respectively. The optimal schemes for power-generation capacity expansion would not vary under different scenarios. Meanwhile, according to the obtained optimal solutions from the IMITS-CCPM model, there would be no CCS facility improvement for the three power plants over the whole planning horizon within this system, meaning the initial capacity of carbon mitigation measures would be adequate under these two CO_2 reduction targets. Although maybe no major variations would be observed for optimized coal flows allocated from the three mines under two scenarios, the total system costs would obviously change, reflecting interrelationship among economic costs, CO_2 mitigation targets and energy supply reliability. The resulting system costs $f_{opt}^{\pm}$ through IMITS-CCPM are RMB [2.47, 3.07] × 10^{11} under scenario 1 and [2.48, 3.09] × 10^{11} under scenario 2, respectively. As the actual values of the variables and/or parameters vary within their boundaries, the expected system costs would change correspondingly between f_{opt}^{-} and f_{opt}^{+} with different reliability levels. The results of the model are also indicated that, with an increased strictness of CO_2 emission permits, the system costs would increase to achieve a more optimistic result. This is because more CO_2 emission would be treated by CCS and chemical absorption facilities resulting in higher operating and treating costs, due to the limitation of CO_2 emission permits.

Through the proposed modeling approach, various forms of uncertainties in terms of intervals and probability are successfully incorporated within the IMITS-CCPM framework. A number of solutions for decision variables are intervals, while some remain as deterministic values. For example, in scenario 1, the excess coal flows from mine 1 to power plant 1 in three periods would be 0, [70, 243.3] and [630, 696.7] tonnes/day under low power-generation demand level, respectively; as well, the exceeding amounts of coal allocated from mine 2 to power plant 1 in three periods would be 104.8, 0, and 15.6 tonnes/day under high power-generation level in scenario 1, respectively. Most of the solutions are presented as intervals, facilitating the reflection of uncertainties during the decision-making process. Other solutions remain as deterministic values, which may not respond sensitively to the input uncertainties, implying they would reach the maximum allowable levels or show the unfavorable situation due to its high costs in this system-cost minimization planning. Based on the interval solutions, multiple decision alternatives can be generated. Therefore, uncertain information can be effectively used by decision makers to adjust decision strategies and analyze tradeoffs between economic cost and system reliability. When a conservative policy is adopted, a scheme corresponding to the upper bound of the objective value would be appropriate; however, when an optimistic strategy is adopted, a scheme corresponding to the lower objective value would be suitable.

Overall, the solutions indicate that the developed IMITS-CCPM model can not only effectively examine the planning problem where an analysis of policy scenarios is desired before realization of random variables with known probability distributions, but can also formulate CO_2 mitigation strategies with limited emission permits. A variety of coal-allocated and carbon mitigation scenarios that are

associated with various socio-economic effects and environmental implications can be analyzed, while the prefixed allocation patterns of coal resources and CO_2 emission permits will be adjusted by the obtained results over the planning horizon. Meanwhile, a robust reflection of the system complexities and uncertainties also could be conducted, as well as dynamic analysis of power generation capacity expansion, CO_2 mitigation facility improvement, coal inventory planning, and coal blending could be facilitated in this model.

4. Conclusions

In this paper, an Inexact Mix-Integer Two-Stage Programming (IMITSP) model was proposed for supporting CO_2 mitigation-oriented coupled coal and power management system under uncertainty. Through integrating mixed-integer programming, interval linear programming and two-stage stochastic programming methods into a general optimization framework, system complexities originated from a number of sectors/processes could be successfully reflected. Dual uncertainties expressed as interval values, probability distribution and their combinations could be effectively dealt with in this proposed model. The developed IMITSP model can not only analyze various CO_2 mitigation scenarios associated with varied power-generation demand condition, but also generate optimal solutions based on an overall consideration of all complications and uncertainties within the system. Moreover, dynamic analysis of capacity expansion, facility improvement, coal inventory planning, as well as coal blending within a multi-period and multi-option context could be facilitated in this model. Interval solutions associated with varying power-generation demand condition under two limitation scenarios of CO_2 emission permit have been obtained.

The developed IMITSP model has been applied to a semi-hypothetical case for supporting long-term coupled coal and power management systems planning. The results of two scenario studies were presented and analyzed in order to examine the optimal coal-flow allocation patterns and CO_2 emission mitigation schemes for the coupled coal and power management system which was forced to comply with a given CO_2 emission permit limit. The generated decision alternatives would help decision makers identify desired CO_2 mitigation strategies, energy schemes for coal production and allocation, as well as facility capacity improvement and expansion under various social-economic, ecological, environmental and system-reliability constraints with a minimized system cost, a maximized system reliability and a maximized power-generation demand security. The developed models could provide considerable insights into various aspects of CO_2 mitigation issues under a given reduction target. Tradeoffs among system costs, energy security and CO_2 emission reduction could also be analyzed. This would be helpful to investigate interactive relationships among economic, ecological, environmental and energy security targets within the study system. The results of the model are also indicated that, with an increased strictness of CO_2 emission permits, the system costs would increase to achieve a more optimistic result. This is because more CO_2 emission would be treated by CCS and chemical absorption facilities resulting in higher operating and treating costs, due to the limitation of CO_2 emission permits.

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Appendix I. Notation

The following symbols are used in model (1) of this paper:

$X_{ijk}^{\pm}$ allowable amount of coal provided from the *i*th coal mine to the *j*th power plant within the contract in period *k* (tonne/day) (the first-stage decision variable);

$Y_{ijkh}^{\pm}$ excess amount of coal provided from the *i*th coal mine to the *j*th power plant when the power generation demand of the *j*th power plant in period *k* is at *h*th level (tonne/day) (the second-stage decision variable);

t_{jkh} probability of demand level *h* of power generation to *j*th power plant in period *k*;

$CF_{ik}^{\pm}$ average purchase cost of allowable amount of coal from the *i*th coal mine in period *k* (RMB/tonne);

$TF_{ijk}^{\pm}$ the average transportation cost of allowable amount of coal from the *i*th coal mine to the *j*th power plant in period *k* (RMB/tonne);

$CCF_{ik}^{\pm}$ the average purchase cost of excess amount of coal from the *i*th coal mine in period *k* (RMB/tonne);

$CTF_{ijk}^{\pm}$ average transportation cost of excess amount of coal from the *i*th coal mine to the *j*th power plant in period *k* (RMB/tonne);

$\triangle L_k$ the duration of period *k* (days);

$OPP_{jk}^{\pm}$ operation and maintenance cost of the *j*th power plant in period *k* (RMB/kWh);

M_j initial power generation capacity of the *j*th power plant at the beginning of the planning horizon (kW);

$\triangle M_{jkw}$ the *w*th option of generation capacity expansion for the *j*th power plant in period *k* (kW);

$\gamma_{jkw}^{\pm}$ is the binary variables of the *w*th generation capacity expansion option for the *j*th power plant in period *k*;

$h_j^{\pm}$ average operating hours of the *j*th power plant (hour/day);

$OMP_{jlk}^{\pm}$ operation and maintenance cost of the *l*th CO_2 mitigation measure in the *j*th power plant during period *k* (RMB/tonne);

$D_{jlkh}^{\pm}$ excess CO_2 emissions from the *j*th power plant treated by the *l*th measure in period *k* when the power generation demand at *h*th level (tonne/day);

$Z_{jlkn}^{\pm}$ binary variables of the *n*th capacity expansion option of the *l*th CO_2 mitigation measure in the *j*th power plant during period *k*;

$PMC_{jk}^{\pm}$ capital cost for power generation capacity expansion of the *j*th power plant in period *k* (RMB/kW);

$PCC_{jlk}^{\pm}$ capital cost for capacity expansion of the *l*th CO_2 mitigation measure in the *j*th power plant during period *k* (RMB/tonne);

$\triangle C_{jlkn}$ the *n*th capacity expansion option of the *l*th CO_2 mitigation measure in the *j*th power plant during period *k* (tonne);

θ the ratio of coal loss during transportation (%);

$TD_{jkh}^{\pm}$ random power generation demand with level *h* to *j*th power plant in period *k* (kWh/month);

$CIM_{jk}^{\pm}$ coal inventory of the *j*th power plant at the end of period *k* (tonne);

$CIM_{jk\min}^{\pm}$ the minimum required coal-inventory of the *j*th power plant in period *k* (tonne);

$CIM_{j}^{\pm}$ coal inventory of the *j*th power plant at the beginning of the planning horizon (tonne);

$q_{jk}^{\pm}$ coal consumption rate for power generation of the *j*th power plant in period *k* (g/kWh);

$R_{ik}^{\pm}$ transportation supply for distributing coal from the *i*th coal mine to power plants in period *k* (tonne/month);

η_l efficiency of *l*th CO_2 emissions mitigation measure;

σ reduced percentage of total CO_2 emission permit;

ρ_{jk} amount of CO_2 emission loading per power generation for *i*th power plant in period *k* (tonne/kWh);

$TP_{k}^{\pm}$ total CO_2 emissions permits for the system during period *k* (tonne/year);

$TE_{jkh}^{\pm}$ reallocated CO_2 emission permit to *j*th power plant with trading scheme in period *k* when the power generation demand is at *h*th level (tonne/day);

C_{jl} initial CO_2 mitigation capacity of the *l*th CO_2 mitigation measure in the *j*th power plant at the beginning of the planning horizon (tonne/day);

$MPC^{\pm}$ maximum allowable investment of the whole planning horizon (RMB);

μ_i weigh factor of coal low heating value from the *i*th coal mine for coal blending systems' combustion process;

$Q_{i}^{\pm}$ average low heating value of coal from the *i*th coal mine (MJ/kg);

$Q_{j\min}^{\pm}$ lower limit of coal low heating value for coal blending systems' combustion process of the *j*th power plant (MJ/kg);

α_i weigh factor of coal volatile matter content from the *i*th coal mine for coal blending systems' combustion process;

$V_{i}^{\pm}$ average volatile matter content of coal from the *i*th coal mine (%);

$V_{j\min}^{\pm}$ lower limit of coal volatile matter content for coal blending systems' combustion process of the *j*th power plant (%);

$V_{j\max}^{\pm}$ upper limit of coal volatile matter content for coal blending systems' combustion process of the *j*th power plant (%);

β_i weigh factor of coal ash content from the *i*th coal mine for coal blending systems' combustion process;

$A_{i}^{\pm}$ average ash content of coal from the *i*th coal mine (%);

$A_{j\min}^{\pm}$ lower limit of coal ash content for coal blending systems' combustion process of the *j*th power plant (%);

$A_{j\max}^{\pm}$ upper limit of coal ash content for coal blending systems' combustion process of the *j*th power plant (%);

φ_i weigh factor of coal moisture content from the *i*th coal mine for coal blending systems' combustion process;

$MC_i^{\pm}$ average moisture content of coal from the *i*th coal mine (%);

$MC_{j\max}^{\pm}$ upper limit of coal moisture content for coal blending systems' combustion process of the *j*th power plant (%);

δ_i weight factor of coal sulfur content from the *i*th coal mine for coal blending systems' combustion process;

$S_i^{\pm}$ average sulfur content of coal from the *i*th coal mine (%);

$S_{j\max}^{\pm}$ upper limit of coal sulfur content for coal blending systems' combustion process of the *j*th power plant (%);

i index for coal mine;

j index for coal-fired power plant;

k index for time period;

l the index for CO_2 mitigation measure;

n the index for CO_2 mitigation capacity expansion option;

w the index for generation capacity expansion option.

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