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Day-Ahead Schedule and Equilibrium for the Coupled Electricity and Natural Gas Markets

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ABSTRACT With the increasing utilization of natural gas-fired power plants, efficiency and even reliability challenges on both industries arise from the growing reliance on natural gas as fuel in the electricity sector and the increasing demand fluctuation in the natural gas sector. Following a brief review of the discontinuities, improvements are discussed to coping with the desired timely and cost-effectively gas supply in the electricity day-ahead market scheduling. Inspired by its successful implantation in the electricity market, the locational marginal pricing mechanism is applied to the natural gas day-ahead market. Moreover, the bidding strategy for general gas demand utilities is provided while considering the potential applicability of demand response (DR) which is also practiced in the electricity market. The formulations are represented as bilevel problems of each corresponding market, of which upper level problems maximize the participants' profit, while the lower level problem renders the market clearing with schedules and locational marginal prices. Then, a coevolutionary algorithm is proposed to find the equilibrium of the two coupled markets with integrated participants. Results show that the proposed methodology with synchronized intraday time intervals and DR abilities could provide higher efficiency for the natural gas market, which will help the electricity market better coordinated to provide flatter price signals while scheduling more renewable energy sources.

INDEX TERMS Electricity market, natural gas market, locational marginal price, demand response, coevolutionary algorithm.

I. INTRODUCTION

The interdependence between the electricity and natural gas systems has been reinforced by the growing utilization of natural gas-fired power plants (NGFPPs). Compared with coal-fired power plants (CFPPs), NGFPPs have higher conversion rates and lower environmental impacts. And the fast ramp flexibility makes NGFPPs a nice complementary choice of the fast-growing renewable energy systems (RESs). Moreover, in the past decade, the competitiveness of NGFPPs is enhanced as the shale gas provides moderate gas prices. Along with the retirement of CFPPs, the global share of natural gas used for power generation has reached 40% and is expected to keep increasing in the following decade [1].

The growing interdependence brings unexpected risks in both electricity and gas sectors. Several regional power grid independent system operators (ISOs) in the U.S., e.g., ISO-NE and NYISO, have found themselves challenged to maintain system reliability due to the reduction of available capacity tied to limitations of gas supply or delivery [2]. The extreme intraday variability on the demand side caused by NGFPPs also creates new challenges to the natural gas sector [3]. The coordination of the two sectors gains more and more attention. Typical topics include the unit commitment of NGFPPs under given gas contracts with pipeline constraints, the coordinated operation of integrated electricity and natural gas networks, etc., of which various solutions can be found such as in [4]–[6] under current market mechanisms.

In the meantime, there is also a broader discussion about reformatting current market rules to compromise the disparities between current electricity and natural gas markets radically. For example, in the U.S., the pool-based market mechanism has been practiced successfully far and wide for the electricity market. Its solution renders the hourly schedule for electricity sold and brought along with locational marginal prices (LMPs) in an electric day [7]. The electric LMPs, i.e., ELMPs, provide participants in the electricity market accurate and transparent price signals along the transmission lines. And these time-varying ELMPs motivate electricity demand utilities (EDUs) to adjust their loads consciously. However, the current natural gas market is bundled with bilateral trades based on released capacities in a gas day [8]. And there are no incentives to encourage general gas demand utilities (GDUs) to regulate their hourly offtakes voluntarily. Plans for better coordinations also suffer from misaligned deadlines of the two market days and limited sharing with information. In 2012, the Federal Energy Regulatory Commission (FERC) had declared its strong concerns for further coordinating the two markets and has proposed a series of rule changes since then.

Considering the increasingly coupled relationship of the electricity and natural gas systems, research focusing on the modifications of the current market mechanisms expands latterly as well. In [9], one joint ISO for electricity and natural gas is proposed to increase the overall market efficiency and reduce the total operational cost by satisfying the gas demand of NGFPPs while shedding gas offtakes from other sectors. A similar structure of the joint ISO is also adopted in [10], and the proposed price-based approach provides necessary incentive to adjust NGFPPs' schedule. These examples reveal that the improvement on the gas price flexibility will be useful for the enhancement of market efficiency in both systems. Besides the proposal of one joint ISO, some other researches preserve the independence of ISOs in their respective markets. A mechanism that allows bi-directional energy trading is projected for independently cleared electricity and natural gas markets in [11]. A bidding strategy in [12] is proposed for integrated participants in both markets under synchronized market days, intraday hours, and market clearing mechanisms.

Bilevel problems are used to model the market clearing processes in general, of which participants maximize their profit with corresponding upper level (UL) problems, while the market social welfare is maximized by a lower level (LL) problem based on bids and offers in the UL problems. Being a nested optimization task, searching the equilibrium point in the bilevel problem is challenging [13]. And it is much harder when it involves integrated participants in both markets. The optimization models and the game theory-based models are among the most popular ones to solve a bilevel problem. A mathematical program with equilibrium constraints (MPEC) is applied to optimization models, of which the original bilevel problems can be reformulated into single level problems by using Karush-Kuhn-Tucker (KKT) conditions. However, in the process, altruistic estimations of competitors' strategies are taken for granted. In addition, the large number of Lagrange multipliers introduced will make the time and scale of the computation difficult to deal with [14]. On the contrary, in a game theory-based model, the Nash equilibrium (NE) can be reached where each participant optimizes its strategy by investigating competitors' interplay just like in the realistic markets. And the coevolutionary (CE) algorithm can find the best solutions to the advantages of parallel and global search and are proved to be useful in the large-scale cases [15].

With NGFPPs play as producers in the electricity market and consumers in the natural gas market simultaneously, the schedules and prices in one market will affect those in the other market. And it is referred to the coupled electricity and natural gas markets with integrated participants in this paper. The pool-based market mechanism is applied to both the electricity and natural gas markets here. Unlike the one joint ISO in [9] and [10], these two markets remain separate, with respective ISOs executing clearing processes independently, which are consistent with the current governance structure. Instead of the reformulation with KKT conditions in [11] and [12], the CE algorithm is adapted to acquire equilibrium of the coupled markets. To the best of the authors' knowledge, it is among the very first batch of studies to utilize such coupled markets under the NE. Moreover, the demand response (DR) abilities are modeled to investigate the significance of introducing these changes. The main contributions of this paper are identified as follows:

1) A brief review of the major concerns for the disparities in current electricity and natural gas day-ahead markets with corresponding suggestions.
2) Based on the suggestions, a pool-based natural gas day-ahead market with pipeline constraints is proposed including strategies for typical participants.
3) A specialized CE procedure is proposed to achieve the NE in both markets while these two markets are cleared separately but coupled by NGFPPs.

The rest of the paper is structured as follows. Section II summarizes the significant issues of disparities between current electricity and natural gas day-ahead markets. Section III proposes the derivation of the maximum social welfare optimization for the natural gas day-ahead market with steady-state flow conditions. The bidding strategies for GDUs with DR willingness and offering strategies for natural gas supply companies (NGSCOs) are also introduced in this section. Section IV follows with the clearing function of the electricity day-ahead market and strategies for power generation companies (GENCOs) and EDUs, respectively. Section V introduces the implementation of the CE approach. Numerical studies are presented in Section VI. Section VII provides some relevant conclusions and discussions of promising directions.

II. COORDINATION ISSUES FOR THE ELECTRICITY AND GAS DAY-AHEAD MARKETS

Being a reflection of needs in each market and various paths for how regulators have allowed each market to develop over time, the structures of electricity and natural gas markets and their differences vary significantly. Although the severity and details may be different across regions and countries, many common issues are shared in the coordination. In this section, the status quo is introduced by taking the markets in the U.S. as examples, considering that the U.S. is leading in the design and practice of both markets and has traceable reports released by regulation sectors. And the problems of the coordinated scheduling for the two day-ahead markets are concluded along with suggestions. If no special remarks are made, the markets mentioned below are all referred to day-ahead markets.

A. SCHEDULING INTERDEPENDENCE CHALLENGES

Consider a GENCO which submits its hourly bids for the next electric day to the electricity pool. When having NGFPPs, the GENCO participates in the natural gas market as well. Due to cost reasons, it typically uses interruptible capacity contracts with least expenses for its NGFPPs based on the total offtakes with constant prices through the next gas day [16]. With the misaligned deadlines, the GENCO also has to manage its gas procurement and scheduling that spans two gas days for each electric day. Then, the NGFPP is restricted to take gas based on 1/24 of its daily nomination for each hour if it is difficult to maintain pipeline operations, which brings costly imbalance fees in the electricity market. Besides, when GDUs with firm contracts call for more capacity, gas delivery of NGFPPs may be curtailed without notice. And the two markets barely share information with each other due to institutional reasons.

When the major consumers in the natural gas market were GDUs with predictable and stable offtakes, these problems did not cause frequent and significant impacts. However, as the NGFPPs gradually grow to be the largest consumer in the gas sector, the situation has changed. The NGFPP offtakes are highly volatile and may be burned over in only part of the time intervals, especially when there is a high penetration of intermittent RESs. With asymmetrical time intervals and little information exchanged with the two markets, such variation and unpredictability are incredibly challenging to the pipeline operators and will affect the offtakes needed in downstream pipelines. The growing reliance on gas as fuel has affected the reliability and efficiency in the power sector as well. It will even cause serious reliability problem of the power system when NGFPPs are forced to shut down due to lack of gas availability. However, GENCOs with NGFPPs are reluctant to change their contract type in the natural gas market due to the high costs as well as compounded uncertainties of their bids and offers in respective markets. There have been reports on cascading failures related to power outages and natural gas curtailment across multiple regions in the U.S..

B. CONVERGENCE OF MARKET NEEDS

Continuous development of regulations, e.g., aligning the deadlines for electric and gas days, sharing of requisite confidential information, increasing intraday gas nomination cycles, and introducing multi-party gas delivery contracts, are proposed by FERC Orders 787 and 809 since 2012 [17], [18]. With the improvement of computing resources, experience from the electricity market, and changes in the characteristics of gas demand, the interest in adopting a pool-based auction mechanism with pipeline constraints to the natural gas market, which can be traced back to a FERC report in 1987 [19], has once again attracted attention.

Participants and operators of both markets call for better-coordinated scheduling that is sufficient to provide gas timely and cost-effectively for the power sector. In particular, it may consider one or more of the following aspects:

1) A more integrated natural gas market mechanism which could improve the pricing and scheduling for both the commodity and delivery capacity of natural gas.
2) A more flexible natural gas demand rule, i.e., a demand bidding strategy which could encourage GDUs to nominate appropriate quantities under tight conditions.
3) A more frequent intraday cycle in the natural gas sector which could manage pipeline operations timely to comply with power grid ISO requests.

Conveniently, the significant experience gained from the successful implementation of physical control and market clearing in the power sector over the past two decades provides a conceptual basis on which to conduct the natural gas market as needed. Similar with ELMPs, the gas LMPs, i.e., GLMPs, derived from a pool-based natural gas market can provide price signals that reflect the varying delivery costs and physical ability of pipelines. The demand bids with DR ability give financial incentives to GDUs which will help to ease the peak gas offtakes and help NGFPPs to get enough fuel with less uncertainty. Moreover, ELMPs and GLMPs incorporate information that is critical for the coordinated schedule of the coupled markets. The alignment of deadlines for electric and gas days is considered as implemented in this paper.

III. FORMULATION OF THE NATURAL GAS MARKET

In the proposed pool-based natural gas market, NGSCOs and gas consumers, including GDUs and GENCOs with NGFPPs, submit offers/bids to an ISO of the natural gas market, i.e., the GISO, which determines schedules. The procedure is modeled as a bilevel problem, which includes an LL problem for the GISO to execute the market clearing with pipeline constraints, and UL problems for participants seeking optimal strategies.

A. LL PROBLEM FOR GISO

1) OBJECTIVE FUNCTION FOR NATURAL GAS MARKET CLEARING

The formulation of the natural gas market clearing by the GISO is to optimize the maximization of the social welfare. The social welfare is defined as the sum of the consumer and producer surplus, which is stated by:

$$\max \sum_t \left[\sum_{d\in\Psi_j} \alpha_{dt} q_{dt} + \sum_{g\in\Psi_{m\cap j}} \alpha_{gt} q_{gt} - \sum_{w\in\Psi_j} \alpha_{wt} q_{wt} - \sum_{k\in\Psi_m} \lambda_{mt}\omega_k P_{kt} \right] \Delta t^{\mathrm{GM}} \tag{1}$$

where

- t Index for time intervals.
- d Index for GDUs.
- g Index for NGFPPs.
- w Index for natural gas wells (GWs).

j Index for gas nodes.
m Index for electric nodes.
k Index for compressors in the gas network.
Ψ_j Set of components connected to gas node j.
$\Psi_{m\cap j}$ Set of components at electric node m and gas node j.
Ψ_m Set of components connected to electric node m.
α_{dt}/q_{dt} Bids of price/quantity by GDU d.
α_{gt}/q_{gt} Bids of price/quantity by NGFPP g.
α_{wt}/q_{wt} Offers of price/quantity by GW w.
λ_{mt} ELMP at electricity network node m.
ω_k Binary for compressor type, $\omega_k = 1$ when driven by electricity, and $\omega_k = 0$ when driven by natural gas.
P_{kt} Power consumed by compressor k.
Δt^{GM} Length of time intervals in the natural gas market.

The first two items in (1) are the profits obtained by trading gas to GDUs and NGFPPs, respectively. The third term states the expenses of purchasing gas from NGSCOs. The last item is the electricity expenses for electric-driven compressors.

The quantity bounds for demand and supply are fixed by:

$$q_d^{\min} \leq q_{dt} \leq q_d^{\max} \tag{2}$$
$$q_g^{\min} \leq q_{gt} \leq q_g^{\max} \tag{3}$$
$$q_w^{\min} \leq q_{wt} \leq q_w^{\max} \tag{4}$$

where

$q_d^{\min/\max}$ Lower/upper limits of GDU d.
$q_g^{\min/\max}$ Lower/upper limits of NGFPP g.
$q_w^{\min/\max}$ Lower/upper limits of GW w.

The limits of gas flow in (2)-(4) are saved in the gas pool, which participants do not need to submit every time. The physical constraints on the pipelines for (1) are given next.

2) NATURAL GAS NETWORK CONSTRAINTS

Natural gas is generally used as a just-in-time fuel delivered by the pipelines, especially considering the inconvenience of gas storages on the consumer side. Pipelines use compressors to boost gas flow from the injection point of consumers. A nonlinear steady-state approximation of the pipeline network is used to represent the balances and limits as follows:

$$\sum\nolimits_{i\in I(j)} q_{ijt} + q_{jt} = \sum\nolimits_{i\in O(j)} \left[q_{ijt} + (1-\omega_k)\, q_{kt}\right] : \lambda_{jt} \tag{5}$$
$$(p_{it})^2 - \left(R_{kt}p_{jt}\right)^2 = \beta_{ijt}q_{ijt}\left|q_{ijt}\right| \tag{6}$$
$$p_{jt} \geq p_j^{\min} \tag{7}$$
$$R_{kt}p_{it} \leq p_i^{\max} \tag{8}$$
$$P_{kt} = B_{kt}\left|q_{ijt}\right|\left[(R_{kt})^{C_{ij}} - 1\right] \leq P_k^{\max} \tag{9}$$
$$q_{kt} = a_k + b_kP_{kt} + c_kP_{kt}^2 \tag{10}$$
$$R_{kt} \geq 1 \tag{11}$$

where

i Index of gas nodes connected to node j.
$I(j)$ Set of head nodes for gas node j.
$O(j)$ Set of tail nodes for gas node j.
q_{ij} Gas flow in the pipeline (i, j).
q_{jt} Injected gas flow at node j, positive when the flow is incoming, negative when the flow is outgoing.
λ_{jt} GLMP at gas node j.
β_{ij} Resistance parameter of pipeline (i, j).
$p_{i/jt}$ Nodal pressure of gas node i or j.
R_{kt} Compression ratio of compressor k.
$a_k/b_k/c_k$ Parameters for compressor k.
B_{kt} Coefficient determined by compressor k.
C_{ij} Coefficient determined by gas through pipeline (i, j).
$p_j^{\min/\max}$ Lower/upper limits of the nodal pressure of j.

Equation (5) enforces the nodal flow balance for node j, of which the last term stands for the gas consumed by the gas-driven compressor k. The dual variables followed the colon state the GLMPs at corresponding gas nodes. A steady-state relationship between the gas flow and boundary pressures in pipeline (i, j) is described in (6). Constraints (7)-(8) represent the nodal pressure limits. The compressor conditions are constrained by (9)-(11). Note that the discussion of linepack which involves a transient model is not included here.

B. UL PROBLEMS FOR NATURAL GAS MARKET PARTICIPANTS

1) OBJECTIVE FUNCTION FOR GDU BIDS

The proposed market mechanism incorporates demand bids, thus, GDUs are equivalent to bids of price and corresponding quantity. The expected gas demand is divided into two groups, including the fixed base part and the price responsive part. The price-responsive part can be shifted to other time intervals, which is necessary to realize the DR. The ratio of price-responsive part in the expected offtakes is defined as gas DR factor γ_{dt} to represent the potential of DR ability [20]:

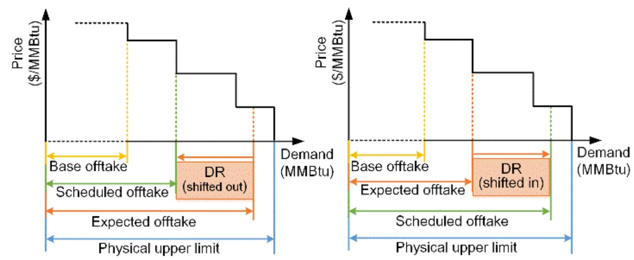
$$q_{dt}^{\mathrm{Exp}} = q_{dt}^{\mathrm{BD}} + q_{dt}^{\mathrm{PRD}} \tag{12}$$
$$\gamma_{dt} = q_{dt}^{\mathrm{PRD}} \Big/ \left(q_{dt}^{\mathrm{BD}} + q_{dt}^{\mathrm{PRD}}\right) \tag{13}$$

where

q_{dt}^{Exp} Expected gas offtakes before scheduling in GDU d.
q_{dt}^{PRD} Price-responsive part in GDU d.
q_{dt}^{BD} Base part in GDU d.

A higher γ_{dt} indicates a higher price elasticity. The demand bids with DR in a time interval is shown in Fig. 1, More specifically, q_{dt}^{PRD} is shifted out to other time intervals in Fig. 1(a), and is shifted in from other time intervals in Fig. 1(b).

The UL bidding strategy of GDU d is to minimize the total expenditure in the natural gas market, which is equivalent to the maximization of the negative cost to purchase the offtakes at the corresponding gas prices. The objective function can be



(a) (b)

FIGURE 1. Stepwise demand bids in the natural gas market.

stated as follows:

$$\max -\sum\nolimits_{t}\sum\nolimits_{d\in\Psi_j}\lambda_{jt}q_{dt} \tag{14}$$

$$\text{subject to } q_{dt}=q_{dt}^{\text{Exp}}-q_{dt}^{\text{DR}} \tag{15}$$

$$\begin{cases} q_{dt}^{\text{DR}}\leq\gamma_{dt}q_{dt}^{\text{Exp}} & \text{if } q_{dt}^{\text{DR}}\geq 0\\ q_{dt}^{\text{DR}}\geq q_{dt}^{\text{Exp}}-q_{d}^{\max} & \text{else}\end{cases} \tag{16}$$

$$\left|q_{dt}-q_{d(t-1)}\right|\leq\Delta q_d \tag{17}$$

$$\sum\nolimits_{t} q_{dt}^{\text{DR}}=0 \tag{18}$$

where

q_{dt}^{DR} The DR offtakes of GDU d, q_{dt}^{DR} is positive when the DR part is shifted out, and q_{dt}^{DR} is negative when shifted in.

Δq_d Upper limit of the ramp rate between consecutive hours for GDU d.

Equation (15) defines the actual offtakes of GDU d after schedule. The DR part is constrained by either the defined DR limit or the physical limit as indicated by (16). Limit on the ramp rate of the gas offtakes is given in (16). The total offtakes through the gas day are constrained by (18), meaning the offtakes will be only shifted but not curtailed.

2) OBJECTIVE FUNCTION FOR NGSCO OFFERS

The UL problem to identify the best offering strategy for NGSCO v can be stated by:

$$\max\sum\nolimits_{t}\sum\nolimits_{w\in\Psi_j^v}\left(\lambda_{jt}-\lambda_w\right)q_{vwt} \tag{19}$$

$$\text{subject to } \left|q_{wt}-q_{w(t-1)}\right|\leq\Delta q_w \tag{20}$$

where

Ψ_j^v Set of GWs belonging to NGSCO v at gas node j.

λ_w Marginal cost of GW w.

Δq_w Upper limit of the ramp rate between consecutive hours for GW w.

The UL problem (19) represents the profit maximization of the NGSCO v. Any NGSCO is allowed to own multiple GWs that located at different gas nodes at the same time. Constraint (20) acts as the ramp rate limits for GWs.

IV. FORMULATION OF THE ELECTRICITY MARKET

This section presents the derivation of maximizing the social welfare in an electricity pool by an electricity ISO (EISO). Then follow the optimal offering strategies of GENCOs and bidding strategies of EDUs.

A. LL PROBLEM FOR EISO

1) OBJECTIVE FUNCTION FOR ELECTRICITY MARKET CLEARING

The market clearing process by the EISO is to maximize the social welfare as well and is represented by:

$$\begin{aligned}\max\sum\nolimits_{t}\Big[&\sum\nolimits_{e\in\Psi_m}\beta_{et}P_{et}-\sum\nolimits_{(g\in\Psi_{j\cap m})b}\beta_{gbt}P_{gbt}\\ &-\sum\nolimits_{(c\in\Psi_m)b}\beta_{cbt}P_{cbt}-\sum\nolimits_{(h\in\Psi_m)b}\beta_{hbt}P_{hbt}\\ &-\sum\nolimits_{r\in\Psi_m}\beta_{rt}P_{rt}\Big]\Delta t^{\text{EM}}\end{aligned} \tag{21}$$

where

e	Index for EDUs.
c	Index for CFPPs.
h	Index for nuclear power plants (NPPs).
b	Index for power generation blocks.
r	Index for RESs.
β_{et}/P_{et}	Bids of price/quantity by EDU e.
β_{gbt}/P_{gbt}	Bids of price/quantity by block b in NGFPP g.
β_{cbt}/P_{cbt}	Bids of price/quantity by block b in CFPP c.
β_{hbt}/P_{gbt}	Bids of price/quantity by block b in NPP h.
β_{rt}/P_{rt}	Bids of price/quantity by RES r.
Δt^{EM}	Length of time intervals in the electricity market.

Equation (21) is the objective function of the LL problem in the electricity market. Note that the ancillary service offers and the start-up/shut-down costs are not included for simplicity.

The physical bounds for EDUs, NGFPPs, CFPPs, NPPs, and RESs are fixed by (22)-(26), respectively:

$$P_e^{\min}\leq P_{et}\leq P_e^{\max} \tag{22}$$

$$P_{gb}^{\min}\leq P_{gbt}\leq P_{gb}^{\max} \tag{23}$$

$$P_{cb}^{\min}\leq P_{cbt}\leq P_{cb}^{\max} \tag{24}$$

$$P_{hb}^{\min}\leq P_{hbt}\leq P_{hb}^{\max} \tag{25}$$

$$P_{rt}^{\min}\leq P_{rt}\leq P_{rt}^{\max} \tag{26}$$

where

$P_{et}^{\min/\max}$	Lower/upper power limits of EDU e.
$P_{gbt}^{\min/\max}$	Lower/upper power limits of block b in NGFPP g.
$P_{cbt}^{\min/\max}$	Lower/upper power limits of block b in CFPP c.
$P_{hbt}^{\min/\max}$	Lower/upper power limits of block b in NPP h.
$P_{rt}^{\min/\max}$	Lower/upper power limits of RES r.

2) ELECTRICITY NETWORK CONSTRAINTS

A direct current (DC) linear approximation for the electricity network is used to represent the power balance at each electric node as well as the transmission line capacity limits:

$$\sum_{(g\in\Psi_{j\cap m})b} P_{gbt} + \sum_{(c\in\Psi_m)b} P_{cbt} + \sum_{(h\in\Psi_m)b} P_{hbt} + \sum_{r\in\Psi_m} P_{rt} - \sum_{e\in\Psi_m} P_{et} - \sum_{k\in\Psi_m} \omega_k P_{kt} = \sum_{n\in N_m} B_{mn}\left(\delta_{mt}-\delta_{nt}\right) : \lambda_{mt} \tag{27}$$

$$-C_{mn} \le B_{mn}(\delta_{mt}-\delta_{nt}) \le C_{mn} \tag{28}$$

$$\delta_m^{\min} \le \delta_{mt} \le \delta_m^{\max} \tag{29}$$

$$\delta_{1t} = 0 \tag{30}$$

where

n	Index of electric nodes connected to node m.
B_{mn}	Susceptance of the transmission line between node m and node n.
C_{mn}	Capacity of the transmission line between node m and node n.
$\delta_m^{\min/\max}$	Upper/lower limits of voltage angle at node m.

Equation (27) enforces the power balance, of which the dual variables following the colon are the ELMPs at corresponding electric nodes. The last item in the second line of (27) is the power consumed by the electric-driven compressors in the gas network and is taken to be fulfilled entirely. The flow limits of transmission lines are enforced by (28). Constraint (29) fixes voltage angle limits for each node, of which the reference value is given by (30).

B. UL PROBLEMS FOR ELECTRICITY MARKET PARTICIPANTS

1) FORMULATION FOR EDU BIDS

The EDUs with DR ability are similar to the description in Fig. 1. The electricity DR factor γ_{et} for EDU e is expressed by:

$$P_{et}^{\text{Exp}} = P_{et}^{\text{BD}} + P_{et}^{\text{PRD}} \tag{31}$$

$$\gamma_{et} = P_{et}^{\text{PRD}} \Big/ \left(P_{et}^{\text{BD}} + P_{et}^{\text{PRD}}\right) \tag{32}$$

where

P_{et}^{Exp}	Expected load before scheduling in EDU e.
P_{et}^{PRD}	Price-responsive part in EDU e.
P_{et}^{BD}	Base part in EDU e.

The bidding strategy of EDU e is to maximize the negative total expenditure in the electricity market and can be stated by:

$$\max -\sum_t \sum_{e\in\Psi_m} \lambda_{mt} P_{et} \tag{33}$$

$$\text{subject to } P_{et} = P_{et}^{\text{Exp}} - P_{et}^{\text{DR}} \tag{34}$$

$$\begin{cases} P_{et}^{\text{DR}} \le \gamma_{et} P_{et}^{\text{Exp}} & \text{if } P_{et}^{\text{DR}} \ge 0 \\ P_{et}^{\text{DR}} \ge P_{et}^{\text{Exp}} - P_e^{\max} & \text{else} \end{cases} \tag{35}$$

$$\left|P_{et} - P_{e(t-1)}\right| \le \Delta P_e \tag{36}$$

$$\sum_t P_{et}^{\text{DR}} = 0 \tag{37}$$

where

P_{et}^{DR} The DR load of electricity demand e, P_{et}^{DR} is positive when the DR load is shifted out, and negative when shifted in.

ΔP_e Upper limit of the ramp rate between consecutive hours for EDU e.

Equation (34) defines the difference between the expected and scheduled load. Constraint (35) indicates that the DR load is constrained by either the DR limit or the physical limit. Limit on the ramp rate of EDU e is given in (36). Constraint (37) imposes the total loads through the electric day will be only shifted with no curtailment.

2) FORMULATION FOR GENCO OFFERS

The UL problem of GENCO u is to maximize the profit in the electricity market while minimizing the total fuel costs, including the expenditure in the natural gas market as well:

$$\max \sum_t \Bigg\{\Bigg[\sum_{(g\in\Psi_{j\cap m}^u)b} \lambda_{mt} P_{gbt} + \sum_{r\in\Psi_m^u} \lambda_{mt} P_{rt} + \sum_{(c\in\Psi_m^u)b} \left(\lambda_{mt} P_{cbt} - \lambda_c q_{cbt}\right) + \sum_{(h\in\Psi_m^u)b} \left(\lambda_{mt} P_{hbt} - \lambda_h q_{hbt}\right)\Bigg] \Delta t^{\text{EM}} - \sum_{g\in\Psi_{j\cap m}^u} \lambda_{jt} q_{gt} \Delta t^{\text{GM}}\Bigg\} \tag{38}$$

$$\text{subject to } q_{gt}\Delta t^{\text{GM}} = \sum_{b\in\Psi_g} \tau_{gb} P_{gbt} \Delta t^{\text{EM}} \tag{39}$$

$$q_{cbt} = \tau_{cb} P_{cbt} \tag{40}$$

$$q_{hbt} = \tau_{hb} P_{hbt} \tag{41}$$

$$\left|P_{gbt} - P_{gb(t-1)}\right| \le \Delta P_{gb} \tag{42}$$

$$\left|P_{cbt} - P_{cb(t-1)}\right| \le \Delta P_{cb} \tag{43}$$

$$\left|P_{hbt} - P_{hb(t-1)}\right| \le \Delta P_{hb} \tag{44}$$

where

$\Psi_{j\cap m}^u$	Set of NGFPPs belonging to GENCO u connected to gas node j and electric node m.
Ψ_m^u	Set of utilities belonging to GENCO u connected to electric node m.
$\tau_{gb/cb/hb}$	Heat rate of block $b$in NGFPP g/CFPP c/NPP h.
$\lambda_{c/h}$	Fuel cost of CFPP c or NPP h.
$\Delta P_{gb/cb/hb}$	Upper limit of the ramp rate between consecutive hours of block b in NGFPP g/CFPP c/NPP h.

It is assumed that the fuel costs for CFPPs and NPPs are known and constant during the electric day in (38). And GENCO u may own multiple power plants of different types in different locations at the same time. Constraints (39)-(41) represent the energy conversion efficiencies of blocks in NGFPPs, CFPPs, and NPPs, respectively. Constraints (42)-(44) impose the limits of the ramp rates in these blocks.

V. FINDING EQUILIBRIUM

Sections III and IV present the market clearing process and the bidding/offering strategies of participants in the natural gas market and electricity market, respectively. To reach the equilibrium of these two coupled markets, the proposed CE procedure is described in this section.

A. DESCRIPTION OF APPLYING THE CE ALGORITHM

According to the game theory, when the NE achieves, any participant cannot increase the profit by changing its strategy while the competitors' behaviors hold [21]. In a non-cooperative mode, a participant makes decision independently but is affected by competitors, assuming that all participants are rational and share specific knowledge of their competitors.

The CE algorithm, which is extended from classical evolutionary algorithms, simulates multiple populations coevolving towards a mutual benefit in an ecosystem. A participant is symbolized as a population of the CE framework, of which the decision variables of each participant represents the individuals of the corresponding population. The objective functions are utilized to assess the fitness values of individuals. In this way, a shared domain for all populations to interact with one another is provided by an LL problem, while an UL problem determines the fittest individual that brings the maximum profit for the population. Specifically, the mutual benefit of the natural gas market has been addressed by the social welfare in the LL problem (1). And the fitness value of each population, i.e., FV_d^{UL} of GDU d and FV_v^{UL} of NGSCO v, are described by UL problems of (14) and (19), respectively. Similarly, the social welfare in LL problem (21) addresses the mutual benefit of the electricity market, while the fitness values of EDU e and GENCO u, i.e., FV_u^{UL} and FV_e^{UL}, are described by UL problems (33) and (38), respectively.

Although not all participants are involved in both markets, any change in behavior is very likely to bring impacts to varying degrees due to the coupled relationship. Thus, to avoid sacrificing accuracy, both of the LL problems are conducted for any population $z \in \{d, v, l, u\}$ here.

B. PROCEDURES OF APPLYING THE CE ALGORITHM

Detailed CE procedures are described as follows, of which the proposed flowchart is depicted in Fig. 2:

Step 1. Require the number of populations $z \in Z$, and the individual $s_{zt} \in S_{zt}$ of each population z including the limits $s_{zt}^{\min}$, $s_{zt}^{\max}$ of each individual.
Step 2. Set the maximum generation number A with an initial number $a = 0$.
Step 3. **For** $t = 1 : T$ **do**
Step 4. Initialize s_{zat}, i.e., individuals of each population at generation a, by Latin hypercube sampling (LHS) within limits.

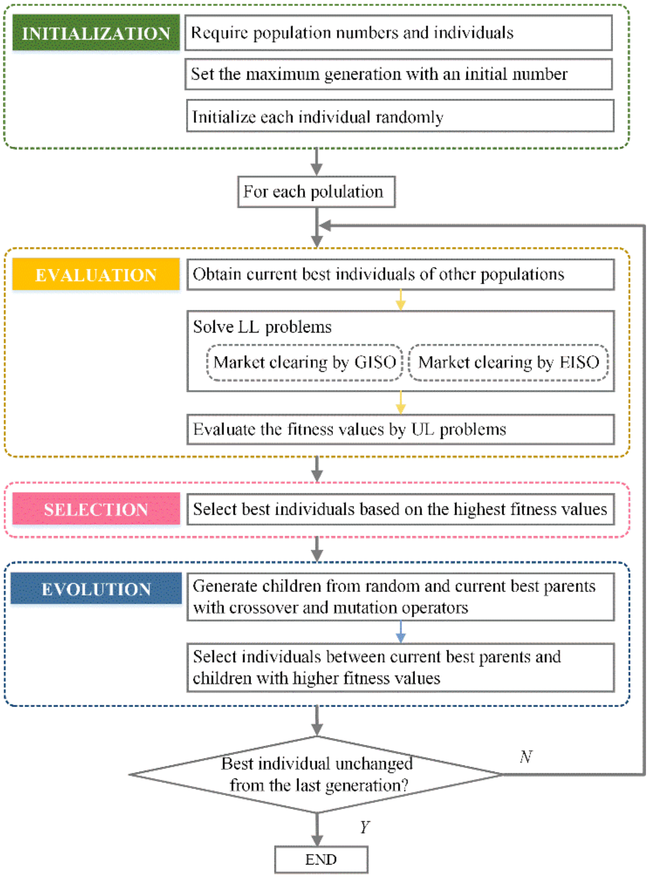


FIGURE 2. Flowchart of the CE algorithm at each time interval.

Step 5. **For** $a = 1 : A$ **do**
Step 6. **For** $z = 1 : Z$ **do**
Step 7. Obtain the current best individuals $s_{(-z)at}^{\mathrm{best}}$ of other populations, i.e., competitors; for $a = 0$, those values are the random samples obtained in Step 5.
Step 8. Solve the two LL problems based on s_{zat} and $s_{(-z)at}^{\mathrm{best}}$.
Step 9. Evaluate the corresponding fitness values by the UL problems, respectively.
Step 10. Sort and then select the best individuals s_{zat}^{best} in all populations based on their respective UL fitness values found in Step 8, which is determined by:

$$FV\left(s_{zat}^{\mathrm{best}}\right) \geq FV\left(s_{zat}\right) \tag{45}$$

Step 11. Generate the child of each individual s_{zat}^{best} from the current best parent and random parents by crossover and mutation operators.
Step 12. Select s_{zat}^{best} between the current best parent and the child with a higher fitness value using Step 10.
Step 13. Terminate if s_{zat}^{best} is unchanged from the $s_{z(a-1)t}^{\mathrm{best}}$ in the last generation; otherwise, count $a = a + 1$.
Step 14. **End For** (z)
Step 15. **End For** (a)
Step 16. **End For** (t)

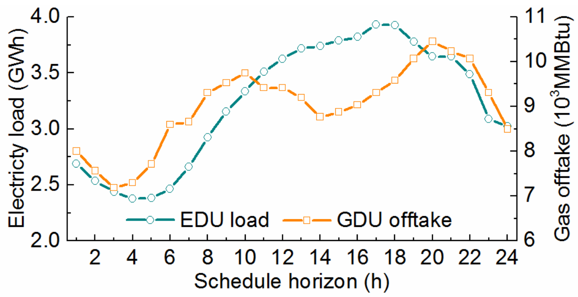


FIGURE 3. Hourly day-ahead prediction of the electric loads and the general natural gas offtakes before schedule.

TABLE 1. Properties of GENCOs in the electricity market.

Owner	No.	Node	Capacity (MW)	Marginal cost ($/MMbtu)
GENCO1	NGFPP1	m=18∩j=25	400	depends
	RES1	m=21	450	0
GENCO2	NGFPP2	m=13∩j=18	350	depends
	CFPP1	m=2	700	2.6
	RES2	m=23	350	0
GENCO3	NGFPP3	m=22∩j=8	400	depends
	CFPP2	m=7	600	2.6
	CFPP3	m=14	600	2.6
GENCO4	NPP	m=1	900	0.67
	RES3	m=16	200	0

TABLE 2. Properties of NGSCOs in the natural Gas market.

Owner	No.	Node	Min. output (MMbtu/h)	Max. output (MMbtu/h)	Marginal cost ($/MMbtu)
NGSCO1	GW1	j=1	600	5,000	3.0
NGSCO2	GW2	j=4	1,000	6,000	3.0
	GW3	j=15	600	4,000	3.5
NGSCO3	GW4	j=22	600	4,000	3.5

VI. CASE STUDY

A. PARAMETER DESCRIPTION

The numerical studies are tested for a coupled IEEE 24-bus electric network and 24-node natural gas network as shown in Fig. 7 in the Appendix. The properties of participants in the electricity market and the natural gas market are listed in Table 1 and Table 2, respectively. Note that the marginal costs of NGFPPs depend on the schedule in the natural gas market. The day-ahead prediction of EDU loads and GDU offtakes are depicted in Fig. 3. The parameters of generator blocks are provided Table 5. The distribution of EDU loads and GDU offtakes among the nodes are listed in Tables 6 and 7, respectively. The hourly day-ahead prediction of RESs can be found in Fig. 8. The parameters are considered to be known by all participants.

The model is implemented on a computer with 2.60 GHz processor and 32 GB RAM under the MATLAB environment interfacing with OPTI toolbox to solve the non-linearity. The CE procedure continues until the best individuals are no longer changed in generations, or the number of generations reaches 100. The probabilities of the crossover and mutation operators are set to 0.9 and 0.1, respectively.

B. REFERENCE CASES

The following three cases are considered, of which $\Delta t^{\mathrm{EM}} = 1$ h and $\gamma_{et} = 0.1$ are set for the electricity market:

1) *Case I:* the natural gas market is cleared with constant GLMPs based on the total offtakes throughout the gas day with no DR ability, i.e., $\Delta t^{\mathrm{GM}} = 24$ h and $\gamma_{dt} = 0$.
2) *Case II:* the natural gas market is cleared with hourly GLMPs with no DR ability, i.e., $\Delta t^{\mathrm{GM}} = 1$ h and $\gamma_{dt} = 0$.
3) *Case III:* the natural gas market is cleared with hourly GLMPs with DR ability, i.e., $\Delta t^{\mathrm{GM}} = 1$ h and $\gamma_{dt} = 0.1$.

The current electricity market which is cleared hour by hour while price-responsive DR ability remains the same in the three cases. As mentioned earlier, the gas price in the current reality is made up by a commodity price and a delivery price, which are scheduled in separate markets with various contract types. Being hard to be modeled accurate and straightforward, the gas price is introduced as known based on empirical data in most studies. Since comparisons are focused on the intraday variations and DR ability of the natural gas market when designing the reference cases, case I here is used as an optimistic view of the current natural gas market setup, which approximates the environment with little intraday nomination opportunities and no DR encouragement for GDUs.

C. SIMULATION RESULTS

The day-ahead evolution of GLMPs and scheduled natural gas offtakes in the natural gas market are depicted in Fig. 4. The gas node ($j = 8$) in which NGFPP3 integrates is chosen to be a representative node to compare GLMPs in different cases. The GLMPs in Fig. 4(a) in case II and case III change on an hourly basis through the scheduling day, which reflect the common intraday gas demand variations. Comparing with case II, the fluctuation of GLMPs in case III is flatter due to the availability of gas DR. This is because that the peak values of GLMPs are reduced with the help of the price-responsive gas demand, while the valley values of GLMPs increase due to the retrieval of the shifted gas offtakes at the corresponding time intervals. The gas schedules for NGFPPs and GDUs change as well. As illustrated in Fig. 4(b), the gas offtakes for NGFPPs are higher in cases II and III than in case I. The time-variant GLMPs enable more precise offers and schedules hour by hour, which encourage NGFPPs to consume more gas in general. Besides, the launching of gas DR ability in case III attracts more gas offtakes for NGFPPs than case II with lower GLMPs during certain hours. On the other hand, the GDU offtakes in case I and case II are coincident with the original demands but are shifted to a certain extent when the gas DR is permitted in case III, as shown in Fig. 4(c). Table 3 summarizes the total gas schedule in the scheduling day. It rises by 4.9% and 6.7% in case II and case III than case I, respectively, which implies that the overall efficiency of the natural gas network is improved by selling and delivering more gas by

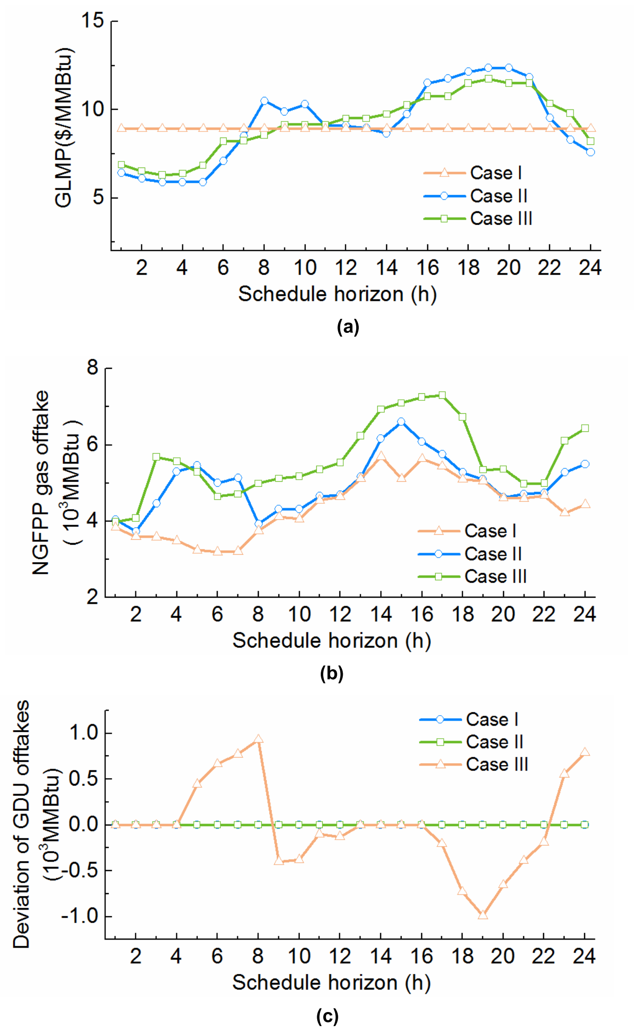


FIGURE 4. **Comparison of hourly schedule in the natural gas market. (a) GLMP at bus 8 in the natural gas network. (b) Scheduled natural gas offtakes for NGFPPs. (c) Deviation between expected and scheduled gas offtakes for GDUs**

TABLE 3. **Total scheduled natural gas offtakes under different cases.**

Gas demand type	Case I	Case II	Case III
NGFPPs (MMBtu)	104,917	120,641	126,407
GDUs (MMBtu)	215,809	215,809	215,809
Total (MMBtu)	320,726	336,450	342,216

applying the proposed mechanism with the same gas delivery capability.

The modifications in the natural gas market lead to changes in the schedules of the electricity market under the coupled relationship. The electricity node ($m = 22$) of which NGFPP3 is connected is chosen to be the representative node for ELMPs in Fig. 5(a). It can be seen that lower value and shorter duration of ELMP spikes are attained in cases II and III than in case I. The gas DR in case III also helps to lower the volatility of ELMPs than in case II. The GENCOs are able to submit their bids in the natural gas market while scheduling their outputs of NGFPPs in the electricity market more precisely and timely. The adjustments in the producer side reshape the EDU load profiles as indicated in Fig. 5(b). Different from the GDU offtake profiles, the hourly EDU load profiles with DR ability are closer to the expected one due to lower and flatter ELMPs.

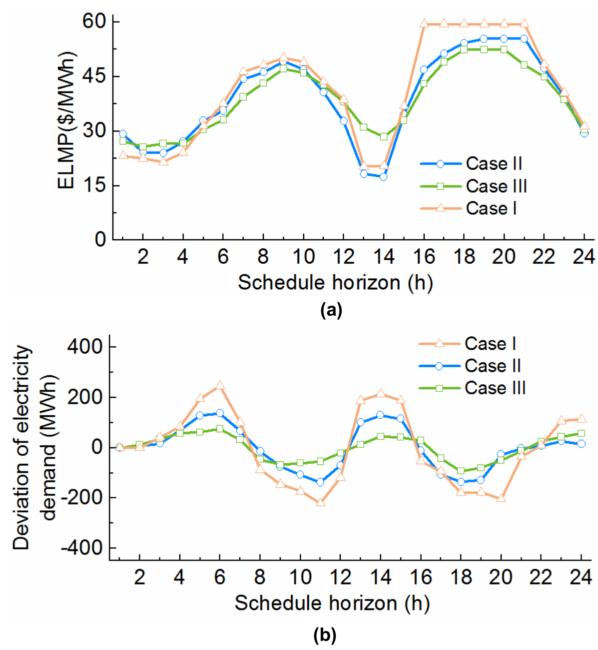


FIGURE 5. **Comparison of hourly schedule in the electricity market. (a) ELMP at bus 22 in the electricity network. (b) Deviation between expected and scheduled electricity load for EDUs.**

The power generation portfolios through the electric day are listed in Fig. 6. The implementation of the proposed market mechanism allows the NGFPPs to bid more gas as explained in Fig. 4(b). Thus, the scheduled electricity generated by the NGFPPs rise by 2,382 MWh and 3,256 MWh, in cases II and III, respectively. Another feature is the increase of scheduled RES outputs. The predicted total available output of RESs is 8,823 MWh, of which only 5,354 MWh is scheduled in case I. In case II and case III, the GENCOs can adjust offers to reduce the curtailment of available RES outputs by considering more flexible NGFPP outputs under the constraints. The scheduled dispatch of RESs rises to

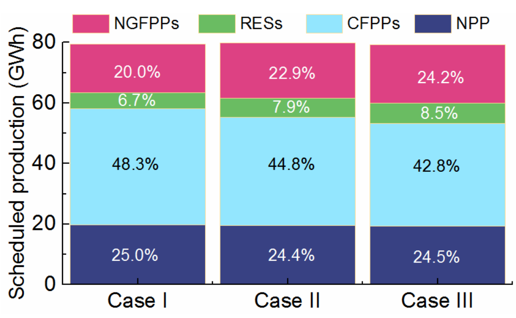


FIGURE 6. **Power generation portfolios in the scheduling day.**

6,291 MWh and 6,759 MWh in cases II and III, respectively. The electricity generated by CFPPs reduces 2,557 MWh and 4,450 MWh, respectively, which is affected by the increased schedule of NGFPPs and RESs. The NPP output remains about the same since it is scheduled mainly to cover the base demand part. The differences among the total output can be attributed to the accumulated consumption by the electric-powered compressors. The changes in the power generation portfolio show that the proposed mechanism can promote the scheduled consumption of RESs in the electricity market as well.

The computational time required for solving the problem of the three cases are shown in Table 4. Compared with case I, the computational time increase markedly in cases II and III. It is reasonable that the whole scheduling horizon for natural gas market clearing is divided from a single time interval into multiple time intervals. And the time consumed is dependent on the convergence conditions in the proposed CE procedure, which is coupled with the market clearing results in the electricity market at each time interval. A solution can be achieved within a reasonable time limit of day-ahead schedule under the steady-state natural gas network model.

TABLE 4. Computational time under different cases.

	Case I	Case II	Case III
Time (s)	172	5,764	6,217

VII. CONCLUSION AND FUTURE RESEARCH

The differences between the scheduling of current electricity and natural gas market reflect the disparities of regional needs, technical capabilities, and paths for how regulatory agencies, e.g., the FERC in the U.S., have allowed each market to evolve in their process of development. However, the significant intraday swings in demand for gas as fuel in the side of electricity generation is now creating increasing challenges to pipeline operators, and pose economy and even reliability risks for both natural gas and power systems. The increasing needs towards improving the coordination between the current electricity and natural gas markets have led to discussions and explorations. Along with continuous modifications to rules for existing pipeline services, successful experiences from the electricity market could be inspirational.

In this paper, the pool-based market mechanism, which has been widely practiced in the electricity market, is implemented in the natural gas market to enhance efficiency and provide enough transparency without confidential information shared between the two coupled markets. The proposed day-ahead scheduling with intraday variations for the natural gas market along with DR ability embedded in the gas demand sector can provide flexibility and efficiency for natural gas nominations and pipeline services to accommodate variations in intraday flow from the electric power sector. It also enables GENCOs with NGFPPs to couple their offers in the electricity market tightly with their bids in the natural gas market in a more accurate, economical and reliable way.

The investigation here is limited to formulations of simplified DC power flows and steady-state pipeline flows. More information, e.g., the effect of linepacks and the energy losses, can be revealed by extended network models in future works. When more detailed models and larger scale networks are simulated, the computational efficiency will become essential. Further improvements, such as various relaxation methods, should be incorporated by then. Other promising aspects serving as future research interests include detailed evaluation the DR ability of demands, participation of ancillary services in the electricity market clearing process, and designs of a real-time natural gas market under different pipeline flow models.

APPENDIX

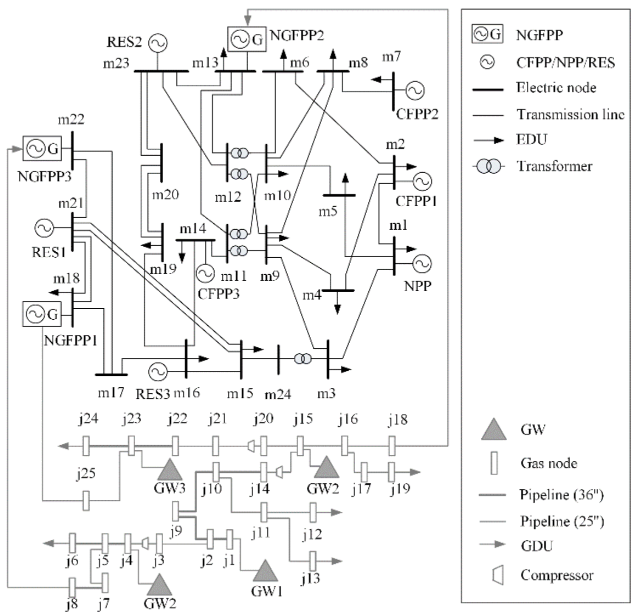


FIGURE 7. Modified IEEE 24-bus electric network coupled with a 24-node natural gas network, with network parameters in [22].

TABLE 5. Parameters of fuel-based generators.

No.		*b*=1	*b*=2	*b*=3	*b*=4
NGFPP1	Block limit	35%	25%	20%	20%
	Heat rate	6,500	6,600	6,700	6,750
NGFPP2	Block limit	35%	25%	20%	20%
	Heat rate	6,700	6,800	6,900	7,050
NGFPP3	Block limit	40%	20%	20%	20%
	Heat rate	6,600	6,700	6,800	6,900
CFPP1	Block limit	35%	25%	20%	20%
	Heat rate	8,200	8,450	8,600	8,750
CFPP2	Block limit	30%	25%	25%	20%
	Heat rate	9,500	9,750	10,000	10,500
CFPP3	Block limit	35%	25%	20%	20%
	Heat rate	9,250	9,400	9,550	9,700
NPP	Block limit	25%	35%	20%	20%
	Heat rate	10,000	10,250	10,500	10,950

Unit of heat rate: Btu/kWh

TABLE 6. Electricity load distribution factor.

Node no.	Factor (%)	Node no.	Factor (%)	Node no.	Factor (%)
m=1	3.8	m=7	4.4	m=15	11.1
m=2	3.4	m=8	6.0	m=16	3.5
m=3	6.3	m=9	6.1	m=18	11.7
m=4	2.6	m=10	6.8	m=19	6.4
m=5	2.5	m=13	9.3	m=20	4.5
m=6	4.8	m=14	6.8		

TABLE 7. GDU load distribution factor in the natural gas network.

Node no.	Factor (%)	Node no.	Factor (%)	Node no.	Factor (%)
j=6	20	j=13	20	j=24	30
j=12	10	j=19	20		

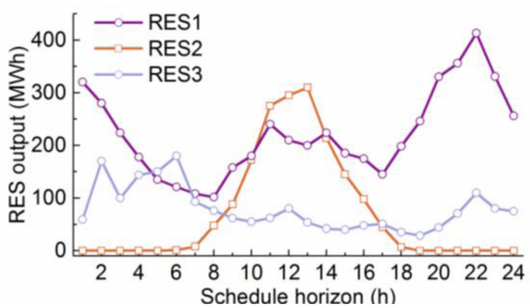


FIGURE 8. Hourly day-ahead RES output prediction.

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