

Article

Evaluate the Welfare and Allocation Effects of Pipeline Separation and Price Liberalization in China's Natural Gas Market

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Abstract

China considers the healthy and sustainable development of the natural gas market to be crucial for achieving carbon neutrality and has been actively reforming its natural gas market to optimize the energy and economic structure. While previous studies have discussed the effectiveness of policy measures, there is a lack of simulation research and quantitative analysis on the impact of reform measures in China. This study addresses this gap by constructing a numerical simulation model based on China's long-distance pipeline network and natural gas market, calibrated to 2019 as a pre-reform baseline and extended to the partially reformed market of 2024–2025. The model includes a base scenario to replicate real market conditions and two policy scenarios that incorporate market-oriented reform measures such as deregulation of prices, pipeline separation and interconnection. The effects of these measures on gas allocation and social welfare are examined. The results indicate that (1) pipeline separation and price deregulation increase social welfare, with welfare shifting from consumers to producers and distributors; (2) natural gas consumption and price changes exhibit pronounced regional heterogeneity, even though prices rise overall, reflecting the complexity of policy effects; (3) the reform follows a path of diminishing returns, and the current stage policy already captures about half of the welfare gain and most of the price adjustment, while shielding consumers from much of the surplus loss. Finally, we conclude with policy implications for China's natural gas market reform. As these reform measures are now being implemented, the quantified welfare and price effects also offer a timely, model-based reference for assessing China's ongoing gas-market marketization.



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1. Introduction

In late 2019, China made an important announcement of establishing a national pipeline company—China Oil & Gas Pipeline Network Corporation (PipeChina)—with the aim of transforming the monopolistic nature of the natural gas pipeline network. China's natural gas market has undergone numerous reforms over the past decade and is still in the process of market-oriented development. The construction of PipeChina and the

strengthening of market mechanisms are therefore key focuses in this ongoing endeavour. Such measures are of great importance in the context of carbon neutrality, as a well-regulated and efficient natural gas market is becoming increasingly important for China's energy and economic governance [1]. Since then, these reforms have been progressively implemented: PipeChina took over the trunk pipelines of the Big Three in 2020 and has been building a unified "national integrated pipeline network" with a third-party access platform, although interconnection and open access remain incomplete. Over the same period, domestic gas consumption rose from about 306 billion cubic meters (bcm) in 2019 to roughly 428 bcm in 2024, making China the world's largest natural gas importer [2]. Together with the 2030 carbon-peaking and 2060 carbon-neutrality targets, these developments have made an efficient, open and price-responsive gas market increasingly central to China's energy and economic policy. Natural gas, however, is best understood as a transition fuel rather than an end point. It can displace coal and back up variable wind and solar generation in the near term, but a fully decarbonized system will ultimately rely on renewables, hydrogen and carbon capture, and the longer-term role of gas remains debated [3]. China's strategy reflects this dual position: gas is used to reduce coal dependence while non-fossil energy is scaled up toward the 2030 peak and 2060 neutrality targets. An efficient gas market matters in this context because it lowers the cost of the transitional role of gas and limits the risk of locking in surplus fossil capacity.

Natural gas, as a non-renewable resource, is subject to constraints imposed by its reserve size and geographical distribution [4]. Since extraction inevitably depletes remaining reserves, the pursuit of short-term returns can diverge from long-term value maximization. As a result, resource owners tend to determine the production volume and price of natural gas based on market demand, which can easily lead to resource monopolies and monopolistic pricing in order to obtain higher economic benefits [5,6]. Another characteristic of the natural gas industry is its reliance on specialized pipeline systems for transportation, which, similar to electricity and road networks, exhibit natural monopolistic characteristics [7,8]. The monopolistic ownership of resources and the natural monopolistic nature of pipeline transport raise barriers to entry in the natural gas industry. Therefore, in the early stages of natural gas market development, it is common to see the dominance of well-established state-owned enterprises or government capital investment and operation, resulting in monopolistic or oligopolistic markets. This is the case in many regions, including European countries, the United States and China. As the natural gas market matures, price formation through free competition, interconnection between pipeline networks and third-party access are essential to promote competition and improve market efficiency [9–12]. The reform paths of the United States and the European Union illustrate this progression. In the United States, FERC Order 636 (1992) required interstate pipelines to unbundle transportation from gas sales and to provide open, non-discriminatory access, which fostered a competitive wholesale market and a secondary market for pipeline capacity [13]. In the European Union, the Third Energy Package (2009) mandated the unbundling of transmission networks from supply and guaranteed third-party access; subsequent assessments credit these rules with greater competition and stronger security of supply, though implementation has been uneven across member states [14]. China's creation of PipeChina and its move toward price linkage and zonal transmission tariffs follow a comparable logic, which makes the quantitative effects of these steps directly relevant to its own reform agenda.

The management system of pipeline networks has been a focus of reform in China over the past decade. In 2014, the National Energy Administration of China issued the 'Regulations on Fair and Open Supervision of Oil and Gas Pipeline Facilities (Trial)' to promote fair and open access to information on oil and gas pipelines. The regulations also proposed that pipeline operators should provide transportation services to private oil and

gas companies when excess gas transportation capacity is available. The ultimate goal of these measures is to achieve a nationwide interconnection of natural gas pipeline networks. Prior to 2019, the construction and operation of long-distance natural gas pipelines in China were monopolised by the Big Three oil and gas companies, China National Petroleum Corporation (CNPC), China Petroleum and Chemical Corporation (Sinopec), and China National Offshore Oil Corporation (CNOOC) [15]. These pipelines operated without interconnectivity, leading to pipeline gas congestion and insufficient utilization [11,12]. In December 2019, PipeChina was officially established to coordinate the national pipeline network system, with the goal of creating a unified network. The goal is to promote interconnectivity between pipelines, separate gas transportation from sales, and foster market competition.

The pricing mechanism is another important factor in developing the natural gas market. Before the 1980s, the Chinese government strictly regulated the petroleum and natural gas industry, and the government also guided the price of natural gas. After the price reform in 2011, the “net back value method” was adopted for pricing, which was linked to the prices of alternative energy sources, thus aligning with the international market. In 2013, the management of natural gas prices shifted from the ex-factory price to the regulated “provincial gate station price”, abbreviated as “provincial price” [16]. In 2015, the non-residential gas provincial prices were changed from “maximum provincial prices” to “benchmark provincial prices”, with both supply- and demand-side pricing based on the principle of no more than a 20% upward adjustment and no restriction on downward adjustments. In 2018, provincial prices for residential gas were streamlined to align with the pricing mechanism for non-residential gas. In addition, since 2016, a pilot program for gas provincial prices has been implemented in Fujian Province, where the provincial prices of natural gas supplied to Fujian Province through the West–East Gas Pipeline have been determined through negotiations between supply and demand parties. However, the pricing of natural gas in China’s national market is still restricted. Therefore, the market-oriented reform of natural gas pricing in China still needs to progress [17]. Since 2019, the pace of pricing reform has accelerated markedly. In June 2023, the National Development and Reform Commission (NDRC) issued the Guiding Opinions on Establishing and Improving the Upstream–Downstream Natural Gas Price Linkage Mechanism, enabling regulated end-user prices to track changes in city-gate procurement costs, and provinces such as Shanghai, Jiangsu, Hubei and Liaoning have since adopted local linkage rules [18]. In December 2023, the NDRC further replaced the province-by-province arrangement with a zonal cross-provincial pipeline transmission tariff covering four price zones (Northwest, Northeast, Central-East and Southwest) at 0.1262, 0.1828, 0.2783 and 0.3411 yuan per thousand cubic meters per kilometer, effective from January 2024 [19]. With more than half of city-gate volumes now priced through market negotiation, the “provincial gate–station price” regime analyzed in this paper increasingly represents the pre-reform benchmark against which the ongoing marketization can be assessed.

Many scholars have conducted theoretical and empirical research on the process of natural gas marketization in China. The Cournot competition model and game theory have been applied to study the competition and market equilibrium among oligopolistic players in the natural gas market [20,21]. Peng, Xiao [22] utilized the Cournot model to simulate the equilibrium price in China’s natural gas market, analyzed the interaction mechanism among the three main entities—natural gas producers, distributors, and consumers—in the market, and conducted an empirical study using Shanghai as an example. The study provided insights into the gas delivery volume and transaction prices in equilibrium states for various gas sources in Shanghai under scenarios involving multi-source competition and government price controls. Similar models include EUGAS [23], NATGAS [24], and global

natural gas trade models [25], which typically simulate the operation and game of the natural gas market with one or more producers, consumers, and pipeline operators as the main entities [26–28]. These models are usually theoretical, constructing objective functions and constraint conditions for each market player within the mixed complementarity problem (MCP) framework and deriving the equivalent Karush–Kuhn–Tucker (KKT) conditions. However, they provide little detail on the specific characteristics of actual markets. Moreover, existing studies typically evaluate reform outcomes in a binary before-versus-after manner, rather than as a staged trajectory that distinguishes the partially reformed present from the fully reformed frontier.

Against the background of the implementation of the natural gas market reform in China, this study constructs a model of China’s natural gas market. It takes full account of the current price fluctuation mechanism based on the “provincial gate station price” and the reality of integrated pipeline operation. Through comparative analysis, it examines the impacts of price deregulation and of pipeline separation and interconnection and provides policy insights for China’s natural gas market reform. Methodologically, the analysis is positioned within the officially endorsed “X + 1 + X” market architecture (multiple upstream suppliers, a unified midstream network, and competitive downstream sales) and quantifies the effects of its two core pillars, price deregulation and pipeline separation with interconnection, using 2019 as a pre-reform baseline. Rather than a single before-and-after comparison, we evaluate the reform as a staged trajectory: a pre-reform baseline (2019), a current-stage scenario (S1) representing the partially liberalized market of 2024–2025, and a full-reform scenario (S2), which allows us to quantify both the gains already realized and those still attainable.

The main objective of this study is to quantify how the two core pillars of China’s natural gas market reform, price deregulation and pipeline separation with interconnection, affect gas allocation, price levels and social welfare, and how these effects are distributed across market participants and regions. Three specific objectives follow from this aim: to build a network-based simulation model that reproduces the pre-reform market as a baseline; to measure the welfare, price and allocation effects of moving from that baseline to a partially reformed current-stage market and then to a fully reformed market; and to identify the distributional and regional consequences that bear on the design of reform policy.

The remainder of the paper is organized as follows. Section 2 describes the pipeline network and market model and defines the three reform scenarios. Section 3 reports the simulation results for gas allocation, prices and welfare. Section 4 discusses these findings in relation to prior research and international experience. Section 5 concludes and sets out the policy implications.

2. Materials and Methods

Due to the uneven distribution of natural gas reserves, long-distance pipelines have taken on the crucial role of facilitating the widespread allocation of natural gas. They are important physical foundations for the formation of a nationwide natural gas market. This article focuses on China’s natural gas market and constructs a numerical simulation model based on the long-distance pipeline network. Section 2.1 defines the boundaries of the pipeline network; Section 2.2 identifies the behavior of market participants and sets up three scenarios with different model settings.

2.1. Model Boundaries of the Long-Distance Pipeline Network and Market in China

China’s proven natural gas reserves reached 8.4 trillion cubic meters in 2020 [29]. However, these resources are predominantly concentrated in the central and western

regions of China, such as the Tarim oil and gas field in Xinjiang, the Southwest oil and gas field, and the Changqing oil and gas field. Meanwhile, the main consumption centers for natural gas are located in the economically developed eastern regions. This regional disparity in resource endowment necessitates the crucial role of long-distance natural gas transmission pipelines in achieving regional resource allocation. The Big Three have been mainly engaged in the construction and operation of long-distance gas transmission pipelines, which form the backbone of China's natural gas pipeline network.

This article considers the long-distance natural gas pipelines (with a designed gas transmission capacity of over 1 billion cubic meters per year) built by the Big Three as the physical boundary. This network covers a total of 24 provinces and municipalities in mainland China. Other regions not connected to this pipeline network system are not included in the model.

Key nodes in the pipeline network have been selected, some of which are natural gas sources and some of which are distribution cities, where natural gas flows out and is sold. Since natural gas pipelines may intersect in certain areas, the following rules are applied in selecting the nodes: (1) The gas source regions are designated as starting nodes. (2) For provinces crossed by long-distance pipelines, the capital city of the province is typically selected as the representative node. If the pipeline does not pass through the capital city, the first key station city in that province, as listed in Table 1 in Appendix A (compiled from publicly available pipeline layout data from the Big Three), is selected as the node. (3) In cases where multiple pipelines intersect within a province, the city where the intersection occurs is also selected as a representative node. Following these rules, 60 nodes are identified. Among them, 15 nodes represent the gas source regions, including domestic gas fields and imported gas sources, as listed in Table 2. The remaining 45 nodes represent the natural gas-consuming take-off cities, as listed in Table 3.

2.2. Model Setup with Three Scenarios

This study presents three scenarios: the first base scenario considers a simulation model based on the actual conditions of China's natural gas market and pipeline network (as of 2019); the new policy scenario includes deregulation of provincial prices and pipeline separation as reform measures in the model. Between these, an intermediate current-stage scenario (S1), detailed in Section 2.2.2, represents the partially liberalized prices and partially interconnected network of 2024–2025. The year 2019 is chosen as the most recent full year that predates the reform package (PipeChina's operational takeover and the 2023–2024 pricing reforms), providing a clean and internally consistent pre-reform benchmark. The comparison across the scenarios therefore isolates the effects of the reforms relative to this benchmark. Because the baseline is calibrated to a single pre-reform year, the reform scenarios are best read as comparative-statics experiments: they measure the welfare and allocation effects attributable to the reform measures under 2019 market conditions, rather than forecasts of realized outcomes in any particular later year. As the network topology and the structure of regional demand have remained broadly stable, the qualitative conclusions carry over to the current market, whereas the precise magnitudes would shift with updated demand, supply and cost data.

2.2.1. Base Scenario (S0)

Market participants: There are three major participants included in the model: producers, consumers, and distributors. In China, the Big Three are responsible for the extraction and sale of gas from their respective gas fields, as well as the import of natural gas. Since each gas field or import project is handled by a separate subsidiary, in this paper, we consider a gas source (gas field, import source) as a gas producer. Natural gas pipelines are

actually also operated by subsidiaries of the Big Three; these subsidiaries are regarded as the natural gas distributors. Each consuming take-off city connected to the long-distance pipeline is considered a consumer.

From a system-wide perspective, natural gas producers, consumers and distributors reach equilibrium through a competitive game to maximize the total social welfare of the natural gas market [30], as shown in Equation (1). From the perspective of individual interests, each participant has their own behavior rules and constraints, which will be introduced below:

$$\max F(q) = \sum_{d \in D} \int_0^{q_d} P_d(q_d) dq_d - \sum_{s \in S} \int_0^{q_s} P_s(q_s) dq_s - \sum_{i \in V} P^{ij} h_{ij} \quad (1)$$

where h_{ij} is the amount of natural gas consumed by the compressor station on pipeline ij , and P^{ij} is the average price of natural gas at consumption cities i and j .

(1) Producers

The producers' objective function is to maximize profit, with the constraints of capacity of gas supply sources, as follows:

$$\begin{aligned} & \max (p_{i-p}^o - c_i) * q_i^o \\ \text{s.t.} \quad & 0 < q_i^o < \bar{T}_i \quad i \in S \end{aligned} \quad (2)$$

where p_{i-p}^o is the price at which distributors purchase natural gas from the source owned by company o , c_i denotes the supply cost of gas source i , q_i^o is the amount of gas delivered from the gas source, and its maximum value, which is the gas supply capacity $\bar{T}_i$, is listed in Table 2.

The supply function of a gas producer is determined by the gas production costs and gas transmission volume at the gas fields of each oil and gas company, and the corresponding supply functions are assumed to be in the form of Equation (3).

$$P_i^o = a_i + b_i q_i^o \quad (3)$$

where P_i^o represents the gas supply price of producer o in region i , and q_i^o represents the supply quantity of producer o in region i . Due to the difficulty in obtaining historical gas supply and cost data for each gas field, it is not possible to derive the corresponding parameters through regression. Considering the stable production scale of each gas field in the short term, based on the Keynesian short-term supply curve theory, it can be assumed that the supply curve is horizontal, and the annual average production cost of the gas field is taken as the value of a_i .

Through publicly available data from the Big Three, a total of 11 gas fields and 4 imported gas sources were compiled. Therefore, this model includes a total of 15 natural gas producers, as listed in Table 2. The gas supply capacity data of each producer is difficult to obtain accurately, so we use the actual gas transmission volume from the 2019 company yearbooks published by the China National Petroleum Corporation (CNPC) and China Petroleum & Chemical Corporation (Sinopec) as a substitute. The production costs are also difficult to obtain from a unified channel. Xu [31] estimated the gas production costs of major gas fields and imported sources using publicly available data on gas ex-factory prices, purification fees, taxes, and other factors published by regulatory departments such as the National Development and Reform Commission. These estimates are used as a reference for setting the gas transmission costs of each source (c_i), listed in Table 2.

(2) Consumers

In the model, the take-off cities are considered the consumers. It is important to note that the consumer does not refer to the end-consuming resident or business, but rather the long-distance pipeline gas receivers at provincial and municipal sites. Therefore, the price involved in the model is not the end-consumer price, but the benchmark price corresponding to the regulated provincial gate station prices.

When the trunk pipeline passes through different provinces, the capital cities of each province are taken as the consumer nodes. If there are multiple representative city nodes within a province, each city is treated as a consumer entity, listed in Table 3. The consumer demand function is assumed to be linear in the form of Equation (4), and the determination of its parameters can be calculated based on historical consumption, prices, and demand price elasticity:

$$P_i = c_i + m_i q_i \quad (4)$$

where

$$e_i = \frac{dq}{dP} \times \frac{P_o}{q_o} = \frac{1}{m_i} \times \frac{P_o}{q_o}, m_i = \frac{P_o}{e_i * q_o}$$

where P_i represents the purchase price that consumer i is willing to pay for the quantity q_i of natural gas. Since the price elasticity of demand can be expressed as e_i , once the demand elasticity, current consumption quantity, and price are determined, the values of parameters c_i and m_i can be determined.

The consumption quantity of natural gas q_i is obtained from the National Bureau of Statistics of China. Due to data availability and the consideration of a consistent data scale for the model, annual data is used. When a province has only one representative city node, its consumption quantity is considered the consumption quantity of the entire province. When there are multiple representative city nodes within a province, the consumption quantity of the province is evenly distributed among them. As for the price data P_i , it is challenging to obtain the contract prices between natural gas companies and downstream distributors. Considering that each city is treated as a consumer unit in this model, the 2019 provincial prices published by the National Development and Reform Commission (NDRC) are used for the calculation. For multiple nodes within the same province, the same provincial gate station price is applied. The price elasticity of demand e_i is an important indicator for evaluating consumer behavior regarding natural gas consumption. Existing research results indicate that the short-term price elasticity of demand is around -0.5 , while the long-term elasticity is around -2 [32]. Since this study uses annual data, a long-term price elasticity of -2 is selected. Once the consumption quantity, price, and demand elasticity data are determined, the specific parameter values in the demand function Equation (4) can be calculated and are listed in Table 3.

The current natural gas price regulation in China is based on the benchmark of provincial (city) prices. The specific agreement prices are determined by both supply and demand parties, following the guidelines of a maximum increase of 20% and no limit on the decrease. Therefore, the price constraints are as follows:

$$0 < P_i < 1.2 \times P_i^* \quad i \in V \quad (5)$$

where P_i is the simulated provincial price for province (city) i , and P_i^* is the benchmark provincial price for province (city) i specified by the National Development and Reform Commission (NDRC).

(3) Pipeline gas distributors

The distributors are mainly subsidiaries of the Big Three, responsible for the operation of the pipelines, transportation of natural gas, and sales to consumers. Distributor's profit maximization depends on terminal demand price, production cost, transportation cost, etc. The transportation capacity constraints of the pipelines have a significant impact on the market allocation mechanism of natural gas, for which the data is sourced from the *Annual Report of China National Petroleum Corporation* and the *Annual Report of China Petroleum and Chemical Corporation*, which includes information on both existing and under-construction pipelines, listed in Table 4.

Flow conservation constraints: Conservation of flow refers to the fact that the in-flow of natural gas is the same as the outflow per unit of time at a node location of a pipeline. For long-distance natural gas pipelines, in order to realize long-distance natural gas transmission, it is necessary to establish pressure stations at key nodes to add pressure to make up for the loss of gas flow pressure due to long-distance transmission. The pressure stations need to consume natural gas resources to provide energy for their operation, so the resulting energy consumption needs to be considered. The amount of natural gas consumed by a pressure station on a long-distance pipeline is about 3% to 5% of the natural gas delivered [33], which is measured as 4% in this study:

$$\sum_{i \in In(j)} q_{ij}^o = \sum_{k \in Out(1)} (1 + 4\%) \times q_{jk}^o + q_j^o, \quad o \in O \quad j \in V, \quad o : A, B, C \quad (6)$$

where q_{ij}^o indicates flow volume between pipeline i - j , which is owned by operator o , and q_j^o refers to j 's gas consumption delivered by operator o . $In(j)$ denotes the set of starting nodes where traffic is directed to j , and $Out(j)$ denotes the set of end nodes flowing out of j . A , B , and C represent CNPC, Sinopec and CNOOC respectively.

Pipeline gas delivery capacity is calculated as follows:

$$0 < q_{i,j} < \overline{q}_{i,j} \quad i, j \in V \quad (7)$$

where $\overline{q}_{i,j}$ denotes the value of the gas delivery capacity of the pipeline between nodes i and j , listed in Table 4.

2.2.2. Current-Stage Scenario (S1): Partial Deregulation and Partial Interconnection

The current-stage scenario (S1) characterizes the partially reformed market of 2024–2025. Although the provincial gate-station benchmark price still follows the 2019 schedule, more than half of city-gate volumes are now sold at market-negotiated prices, while a regulated residual, mainly residential and public-service supply, remains under the benchmark with the +20% band. We represent this by retaining the +20% price-cap constraint Equation (5) only for nodes in provinces where regulated urban gas dominates demand, operationalized as provinces whose urban-gas supply exceeds the national-median share of provincial gas consumption, and removing it for the remaining, predominantly non-residential nodes. This produces a partial relaxation of the price constraint, intermediate between S0 (cap on all nodes) and S2 (no cap).

On the network side, S1 adopts the same interconnected topology as S2, so gas can move across the previously separated operator networks at the crossing nodes. Unlike the frictionless access assumed in S2, however, cross-operator transfers in S1 incur a regulated transmission charge reflecting the 2024 zonal pipeline-tariff reform: the cross-operator flows are charged a representative Central-East zonal tariff (0.2783 yuan per thousand cubic meters per kilometer; the four 2024 zonal rates range from 0.1262 to 0.3411), applied over their haul, and the welfare objective is entered as a cost. S1, therefore, represents third-party

access that exists but is priced, intermediate between the operator-segregated network of S0 and the fully open, frictionless access of S2.

Because S1 only partially relaxes the constraints of S0 while remaining more restricted than S2, the three scenarios form a nested sequence ($S0 \subseteq S1 \subseteq S2$). The comparison therefore traces a monotone reform path in aggregate social welfare, while permitting the non-monotone distributional and regional-price effects that are important for policy.

2.2.3. Full-Reform Scenario (S2): Complete Deregulation and Interconnection

In this new scenario, pipeline separation and elimination of price control are assumed to be implemented simultaneously, which would be taken into the model setup.

(1) Eliminating provincial gate station price control

In the base scenario stated in Section 2.2.1, the price formation adopts the current rules of provincial gate station price management. In 2016, the NDRC decided to carry out a pilot project of market-oriented reform of gas gate station prices in Fujian, where the price of natural gas is determined by negotiation between supply and demand. The new pricing mechanism will likely be implemented nationwide in the future. Therefore, we design a new policy scenario here, which removes the restriction of provincial price control nationwide and lets the supply and demand sides determine the price according to the market situation. In terms of model setting, that is, the price constraint Equation (5) is removed. This setting corresponds to the direction of the 2023 upstream–downstream price linkage mechanism and the 2024 zonal transmission-tariff reform, under which the Fujian pilot has effectively been generalized toward nationwide market-based pricing [18,19]; modeling the full removal of price control thus captures the end point toward which these reforms are moving.

(2) Pipeline separation and interconnection

To fully realize a nationwide free competitive pricing system, it is necessary first to realize the interconnection of pipeline networks. The current natural gas market competition mainly exists between pipeline network operators. The Big Three have monopolized the operation of their respective pipeline networks and corresponding natural gas resources, which makes it impossible for natural gas to be transported across the pipelines to which they belong and hinders the free allocation of natural gas. In Section 2.2.1, the flow conservation equation at the nodes needs to be established among the pipelines belonging to the same distributor, as shown in Equation (8):

$$\begin{cases} \sum q_{i,k}^A = \sum q_{k,j}^A + q_k^A \\ \sum q_{i,k}^B = \sum q_{k,j}^B + q_k^B \\ \sum q_{i,k}^C = \sum q_{k,j}^C + q_k^C \end{cases} \quad (8)$$

where $q_{i,k}^A$ denotes gas flowing into point k from point j of the pipeline belonging to distributor A ; $q_{k,j}^A$ denotes gas flowing out of point k ; and q_k^A denotes gas lost/consumed at node k . Since the pipelines under the jurisdiction of each distributor are not interoperable with each other, their flow conservation equations hold only at their respective pipeline nodes.

Based on the experience of the development of the natural gas industry in European countries, it is necessary to break the monopoly of the pipeline network, which often requires the government to introduce corresponding policies and regulations to facilitate its realization. At the end of 2019, PipeChina was established to coordinate pipeline operations and to be separated from the Big Three. Therefore, in the new policy scenario, different gas sources can freely use the pipelines for transportation in a place where there are crossings of pipelines belonging to different owners, such as natural gas belonging to Company A can

be transported using Company B's pipelines. The flow conservation constraint Equation (8) is changed to Equation (9):

$$\sum q_{i,k}^A + \sum q_{i,k}^B + \sum q_{i,k}^C = \sum q_{k,j}^A + \sum q_{k,j}^B + \sum q_{k,j}^C + q_k^A + q_k^B + q_k^C \quad (9)$$

where the natural gas from different distributors A , B , and C is interconnected at point k , so the flow conservation equation is unified.

Based on the geographical location of China's natural gas pipeline network, as indicated by the red circles in Figure 1, it can be seen that there are pipeline crossings of different companies, mainly in Jinan, Huangmei, Nanjing, and Zhongxian, so this new scenario mainly sets up the pipeline networks in these four places to be connected. In reality, the institutional basis for such interconnection now exists: since taking over the Big Three's trunk lines in 2020, PipeChina has dispatched the network on a unified basis and progressively interconnected previously isolated systems, which is a transition that is already underway [34].

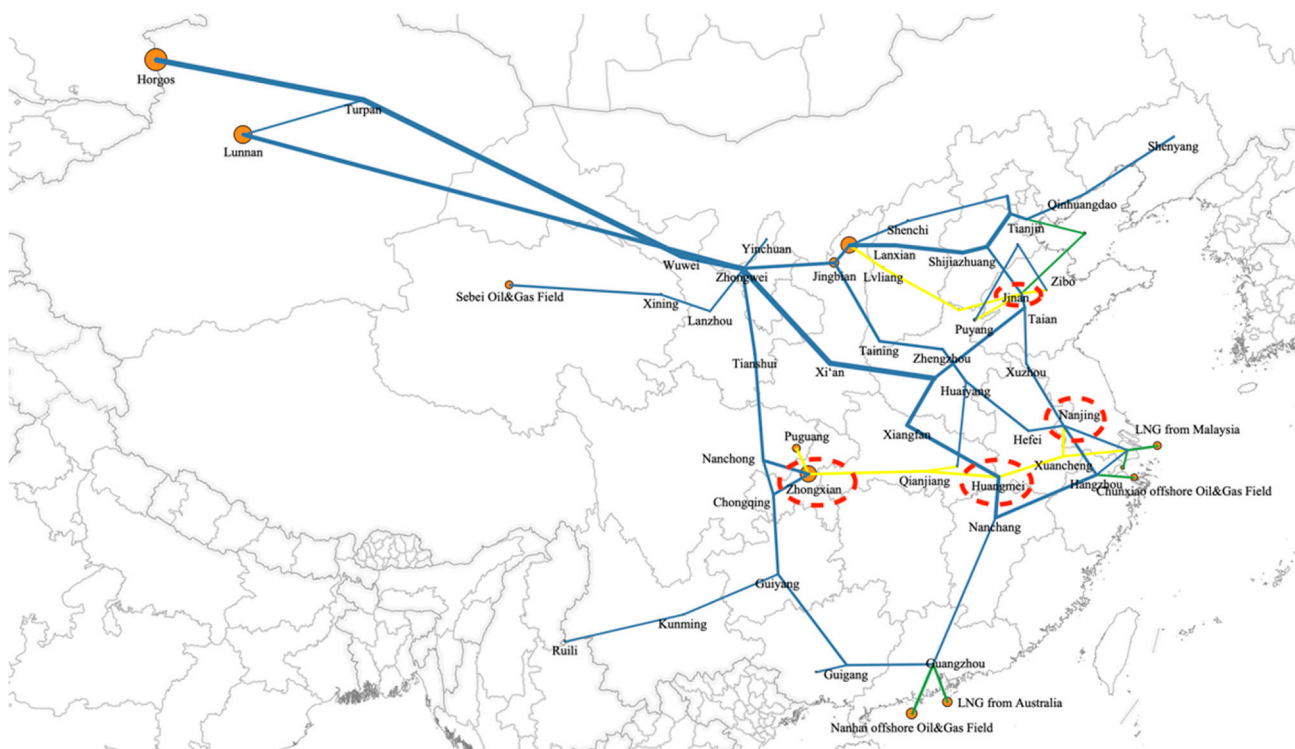


Figure 1. Distribution of natural gas pipeline trunk lines in China (Blue lines denote pipelines owned by CNPC, yellow lines denote pipelines owned by Sinopec, and green lines denote simplified maritime LNG import routes. The red circles mark the four trunk-line crossing points (Jinan, Huangmei, Nanjing and Zhongxian) at which interconnection between the separately built networks is introduced. Source: authors' own work).

2.3. Model Scope, Limitations, and Presentation of Results

Several features define the scope of the model and should be kept in mind when interpreting the results. The model is static and deterministic: it solves for a single annual equilibrium and does not represent seasonal demand swings, storage operation, short-term supply disruptions or price uncertainty. Gas demand is described by linear inverse-demand functions calibrated to observed prices and quantities, and the network is restricted to the long-distance trunk lines of the Big Three, so intra-provincial distribution and smaller pipelines are treated as exogenous. These simplifications keep the welfare accounting

tractable and transparent, at the cost of the finer temporal and local detail that a dynamic or stochastic model would capture.

The modelling approach is not specific to China. Any pipeline-networked gas market that is moving from vertically integrated, regulated operation toward unbundling and price liberalization can be represented by the same structure, given data on network topology, source capacities, regional demand and the prevailing price-control rules. The framework is therefore transferable to other economies undergoing comparable reforms, and the baseline, partial-reform and full-reform logic used here can be reused to benchmark how far a given market has progressed.

The results are reported in three complementary formats. Network maps show the spatial pattern of gas flows and the pipeline configuration under each scenario; bar and line figures report consumption, price and delivery changes across nodes and scenarios; and summary tables give the aggregate welfare, consumer surplus and price statistics. This combination is intended to convey both the system-wide outcomes and their regional distribution.

3. Results

Based on the model presented in Section 2, we can calculate the allocation of natural gas flow in the national pipeline network, the market supply and demand conditions, the equilibrium price that maximizes social welfare, and the social welfare status of each participating party. In Section 3.1, we obtain the allocation of natural gas in all segments of pipelines to maximize social welfare, and the results, compared with the actual data, verify the reliability of the simulation for China's gas market. In Section 3.2, we compare the changes when applying reform measures to the model.

3.1. Simulation Results in Base Scenario vs. Actual Data

3.1.1. Gas Flow Allocation and the Supply and Demand of Markets

Figure 2 shows the allocation of each pipeline network's gas flow to maximize social welfare. The blue lines are the CNPC pipelines, the yellow are the Sinopec pipelines, and the green are the CNOOC marine LNG routes. The thickness of the line represents the flow size, measured in billions of cubic meters per year, and the size of the yellow node indicates the amount of gas delivered from each source.

In the simulation model, we used data on gas consumption, production, imports, etc., in 2019 due to their accessibility and completeness. Figure 3 compares simulated gas consumption with actual consumption. The total consumption in the simulation results is 176.1 billion cubic meters in 2019, and the actual gas consumption in 2019 for regions included in the model is 248.7 billion cubic meters, with the simulation result accounting for 71% of the real consumption. This is because there are additional sources of natural gas, such as the supply from local decentralized sources, while the model statistics are mainly natural gas delivered by large pipeline networks, and the sources of gas are the main gas fields in the domestic continental region and import channels. Among them, the simulated value of natural gas consumption in Xinjiang differs greatly from the actual value because there are abundant gas-producing areas in the region with sufficient supply and low consumption costs. In contrast, the model, aiming to maximize the social welfare of the whole country, prioritizes the flow of natural gas that is more economical to consume, which allows more natural gas from Xinjiang to be transported to the eastern developed regions.

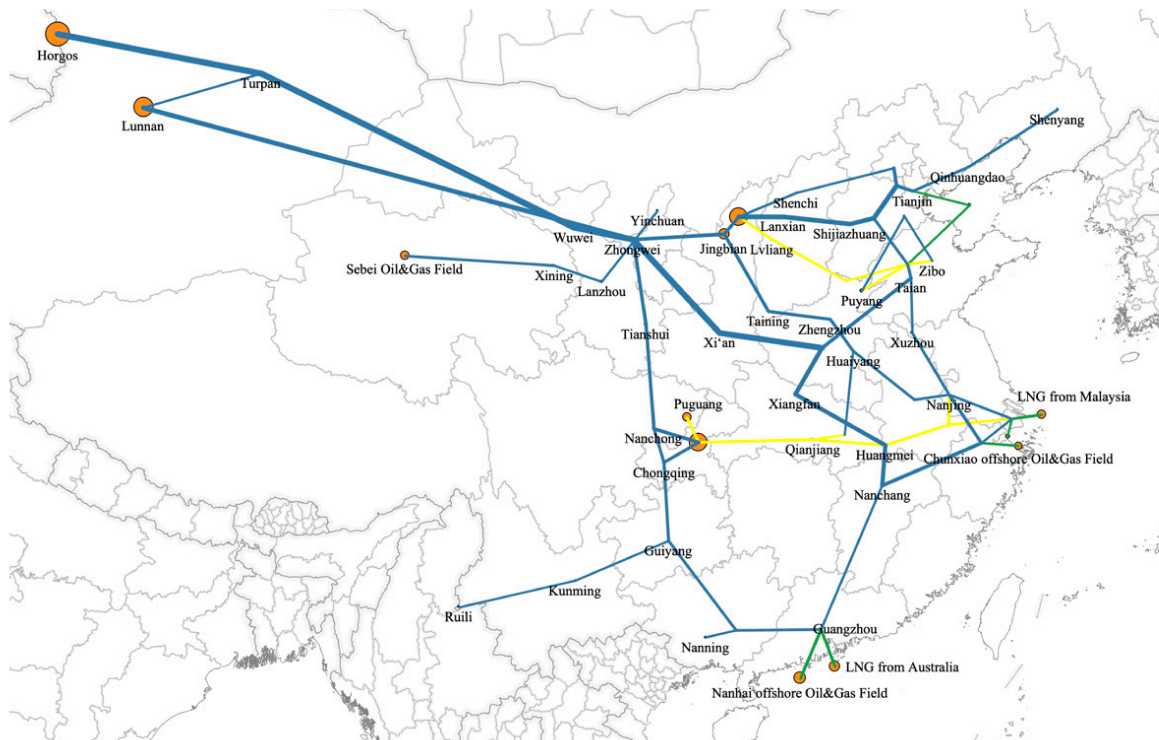


Figure 2. Simulated gas flow of China's natural gas pipeline network. (Line color denotes the operating company, line thickness is proportional to the simulated segment flow, and yellow node size indicates gas delivered from each source. Source: authors' own work).

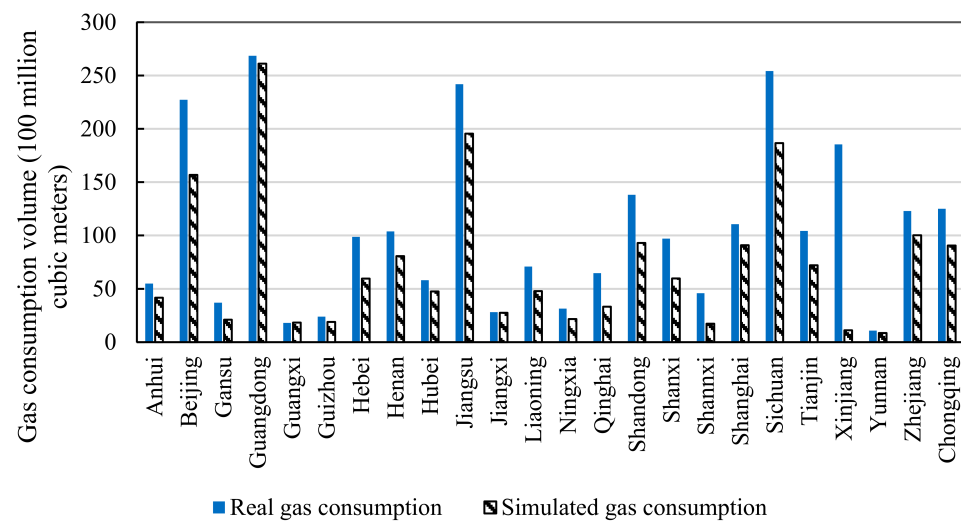


Figure 3. Simulated gas consumption results vs. real consumption in 2019. Source: authors' own work.

A comparison of the simulated gas transmission volumes obtained from the gas sources with their 2019 transmission capacity is presented in Figure 4. It can be seen that the simulated transmission volumes of most of the gas sources are at or close to the actual transmission capacity, indicating that the maximum transmission volumes of most of the gas sources in the statistics are fully allocated to the market. However, it is also noted that Myanmar gas imported from Ruili, Yunnan Province, does not generate actual transmission capacity in the empirical simulation, which is mainly because the price of imported gas from Myanmar is too high, and the market mechanism will prefer allocating natural gas with a low cost of the gas source to the market. The simulated output of pipeline gas

from Central Asia and the Sebei gas field is less than the actual supply in 2019, which is also because the model aims to maximize economic welfare. The deviation of the demand elasticity may cause the market to reach the equilibrium point of supply and demand earlier than it should, with an overall level of error that is within an acceptable range.

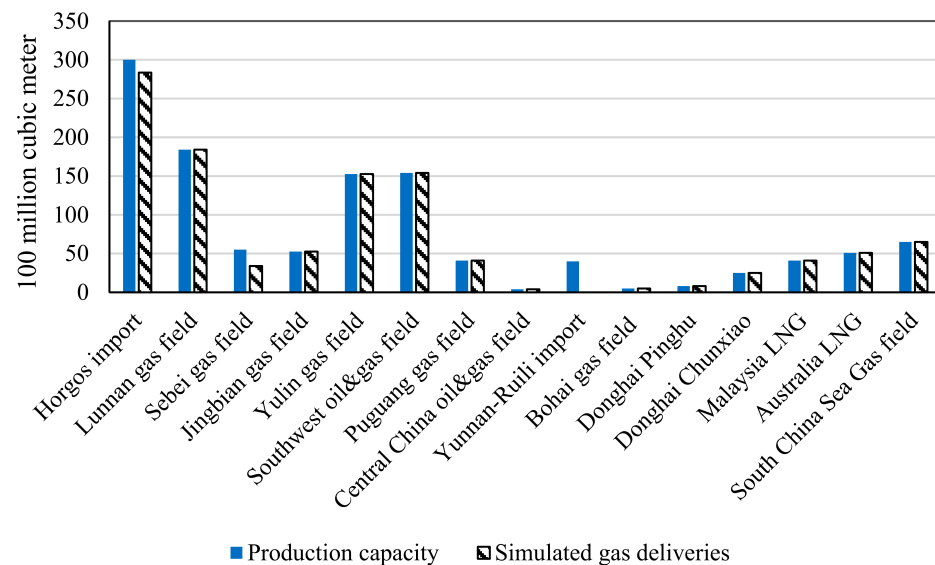


Figure 4. Simulated gas deliveries vs. supply capacity of gas sources. Source: authors' own work.

Combining the information from Figures 2–4, some characteristics of China's natural gas resource allocation can be found. The simulated natural gas consumption in Sichuan is 18.7 billion cubic meters, the natural gas consumption in Chongqing is 9.1 billion cubic meters, and the transmission gas of Southwest Oil & Gas Field is 15.4 billion cubic meters, which shows that most of the natural gas resources of Southwest Oil & Gas Field are allocated in the local region. There are two main reasons for this: on the one hand, the limited capacity of the Zhongxian–Wuhan pipeline restricts the amount of gas that can be transferred out of the Southwest Oil & Gas Field, and on the other hand, although Sinopec's "Sichuan Gas to the East" pipeline passes through the region, the lack of interoperability of the pipeline makes it difficult to transfer the field's resources to the eastern part of the country. The Puguang field produces 4.1 billion cubic meters of gas, all of which is transported to Nanjing and Shanghai through the "Sichuan Gas to the East" Pipeline. Although both the Southwest Oil & Gas Field and the Puguang Field are located in the Sichuan and Chongqing regions, the flow of their resources is restricted by different pipeline networks and distributors, with huge differences in allocation. It is conceivable that if the pipelines constructed by CNPC and Sinopec in the two fields were interconnected to allow the free flow of natural gas through the pipeline network, the natural gas from the Southwest Oil & Gas Field and the Puguang Field might be allocated more preferentially to the Sichuan and Chongqing regions, with the excess being transported to Shanghai through the "Sichuan Gas to the East" and the Zhongwu Line.

3.1.2. Natural Gas Prices by Regions

Figure 5 compares the simulated prices of natural gas in the distribution-city nodes with the corresponding regional benchmark provincial prices. Overall, the simulated gas prices in various regions are higher than the provincial prices. One reason for this difference is the incompleteness of the data. The model's estimation of natural gas transportation volume is lower than the actual supply volume in each region. Consequently, according to the law of supply and demand, the simulated prices are slightly higher than the actual

prices. On the other hand, it is observed that the prices in most regions reach the threshold of a 20% increase over the benchmark provincial prices. To some extent, this reflects the current situation of relatively low-regulated natural gas prices in the domestic market. The price mechanism is still insufficient to reflect the market supply and demand levels and needs further opening up towards a free market. In the context of carbon neutrality, it is necessary to accelerate the establishment of a sound natural gas market, in coordination with carbon emission trading systems, to leverage the role of natural gas in adjusting the energy structure. This finding, that the binding 20% ceiling suppresses price signals, is consistent with the rationale for the 2023 upstream–downstream linkage mechanism, which was introduced to let regulated prices move more flexibly with procurement costs [18].

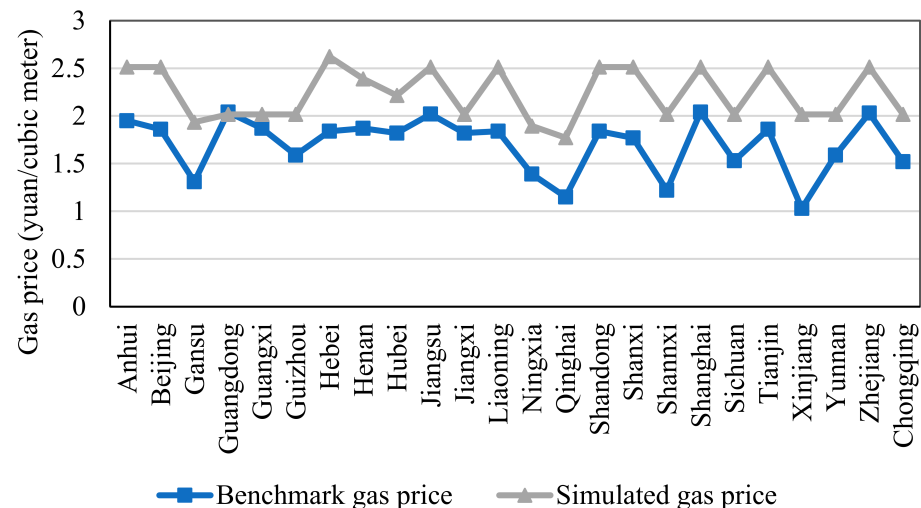


Figure 5. Simulated gas prices vs. benchmark provincial prices in 2019. Source: authors' own work.

3.1.3. Social Welfare Analysis

The total social welfare within the model boundaries amounts to 285.87 billion yuan, where the consumer surplus accounts for 125.93 billion yuan, while the producer surplus amounts to 17.47 billion yuan. Since the model combines the operating income of the pipeline and the production income under the ownership of integrated oil and gas enterprises, their total sum is 159.94 billion yuan. In addition, the natural gas consumed by the compressor station in the long-distance pipeline is approximately 1.84 billion cubic meters.

(1) Consumer surplus

Figure 6 shows the consumer surplus obtained from the model solution for different regions. It can be observed that the Guangdong and Jiangsu regions have higher levels of consumer surplus compared to other regions. By combining this with the consumption data shown in Figure 3, it can be noted that these regions have higher levels of natural gas supply. Furthermore, it is noticed that Sichuan ranks third in terms of natural gas consumption among all regions, with consumption levels similar to Jiangsu. However, its consumer surplus is significantly lower than that of Jiangsu. This reflects the differences in price elasticity of demand for natural gas consumption among different regions. Additionally, there is a direct correlation between the economic level of a region and its natural gas consumption. Data published by the National Bureau of Statistics reveals that Jiangsu had a per capita disposable income of 41,400 yuan in 2019, ranking fifth nationwide. In contrast, Sichuan had only 24,730 yuan, ranking 18th. This leads to differences in the willingness of residents in these two regions to pay for natural gas. The simulated natural gas price in Jiangsu is 2.51 yuan/m³, higher than the 2.01 yuan/m³ in Sichuan (Figure 5).

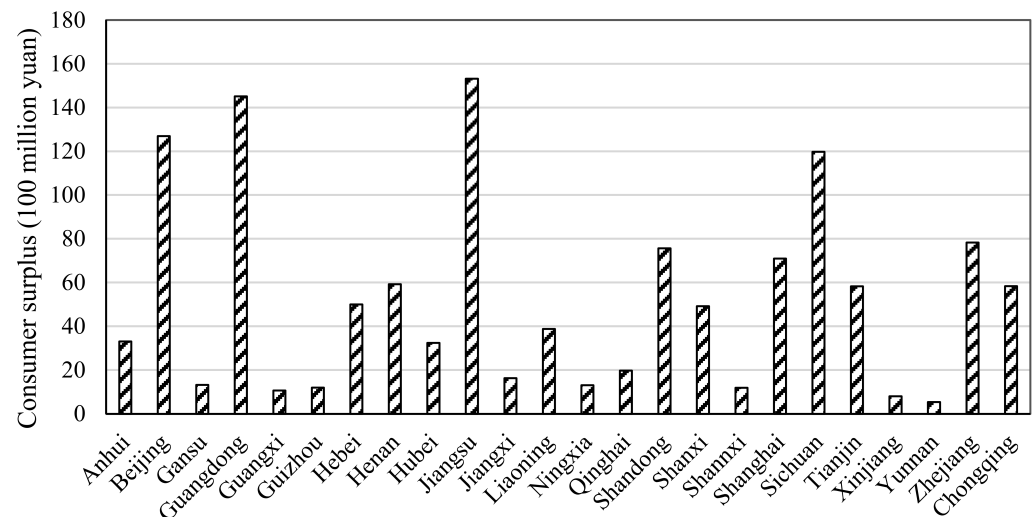


Figure 6. Consumer surplus among different cities. Source: authors' own work.

(2) Producer surplus

Producer surplus refers to the economic benefits enjoyed by natural gas producers. In this model, each gas source is treated as a producer entity. Figure 7 displays the simulated values of producer surplus for each producer. China National Petroleum Corporation (CNPC) benefits greatly from the import of natural gas from Central Asia via the Khorgos port, primarily due to the large quantity of gas supplied. On the other hand, the natural gas imported from Myanmar through the Ruili port does not generate economic benefits in the simulation due to its high import costs, which prevent the gas flow. In reality, the Myanmar pipeline was completed and put into operation in 2013, with a designed gas transmission capacity of 12 billion cubic meters. However, the actual gas transmission volume in recent years has fluctuated between 3–5 billion cubic meters, indicating that the cost-effectiveness of this channel for gas importation is not advantageous. Furthermore, the volatility of the political situation in Myanmar has contributed to high transportation risks associated with the pipeline, severely impacting the import and delivery of natural gas.

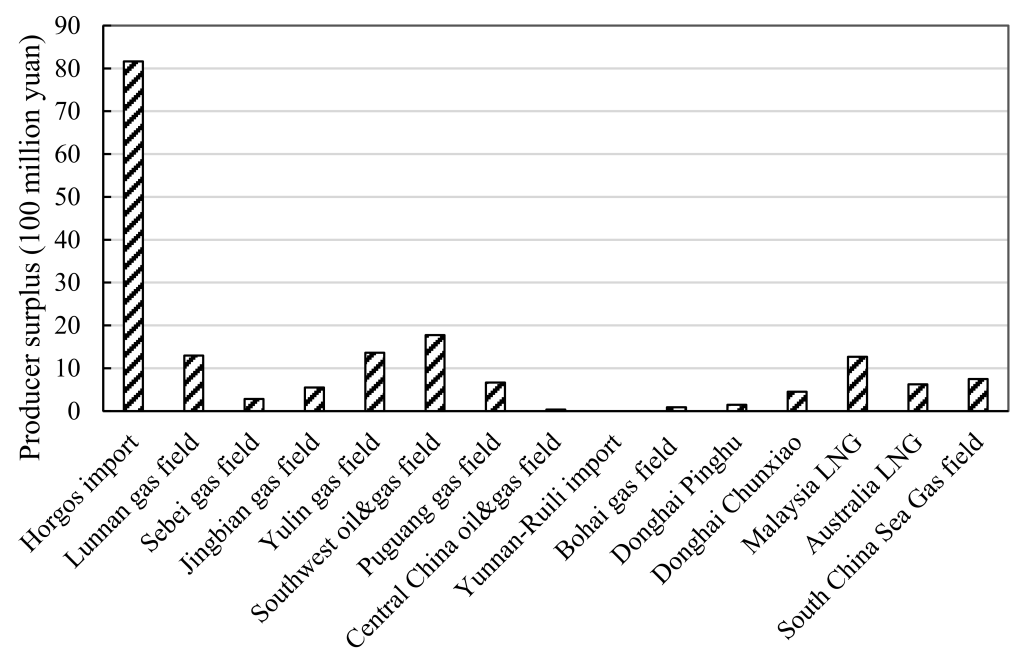


Figure 7. Producer surplus. Source: authors' own work.

(3) The distributor's revenue

The distributor's revenue refers to the economic surplus generated by the difference between the price the consumer willingly pays and the producer's selling price. In China, pipeline construction and operation are typically undertaken by integrated enterprises that are related to the relevant gas sources. Therefore, the revenue from pipeline operation can be attributed to the overall revenue of these integrated enterprises, which accounts for about 159.94 billion yuan (total social welfare minus consumer surplus) in the simulation.

3.2. Simulation Results Across the Three Scenarios (Base, Current-Stage and Full-Reform)

The pricing mechanism and pipeline operation model are policy factors that directly affect the competitive environment of the entire natural gas market. In this section, we will design and simulate scenarios involving "policy factors" to quantitatively analyze the impact of policy changes on the allocation of natural gas resources. On the one hand, the removal of fixed price control measures can allow the market to spontaneously determine prices based on supply and demand conditions. On the other hand, breaking the monopoly of pipeline operations and achieving interconnection among various pipelines will create a more open and competitive market environment.

3.2.1. Natural Gas Consumption and Supply Between Scenarios

The changes in consumption by region under the reform scenarios are shown in Figure 8. Regions with rising consumption include Anhui, Beijing, Hebei, Henan, Jiangsu, and Shanghai, and regions with decreasing consumption include Gansu, Xinjiang, Sichuan, and Guangdong. Theoretically, when the pipeline network is opened up, there is more freedom to deliver natural gas, and when the goal is to maximize economic efficiency, the resources are more inclined to be delivered to regions with high economic efficiency per unit, so the supply in North China, East China, South China and other regions is able to rise, which is in line with the results obtained from the simulation. Introducing the intermediate current-stage scenario (S1) shows that this reallocation is largely realized already at the partial-reform stage: total modeled consumption rises from 1760.7 (S0) to 1781.5 billion cubic meters in S1 and 1787.2 in S2, so S1 captures about 79% of the full-reform consumption gain. The regional pattern in S1 mirrors S2 in direction but is reshaped by the retained price caps. In the regulated, residential-heavy regions that keep the +20% ceiling (Beijing, Shanghai, Shandong, Henan, Anhui and Chongqing), consumption in S1 is held even higher than in S2 (for example, Beijing reaches 210.8 in S1 versus 191.5 in S2, and Guangdong falls only to 247.3 in S1 versus 226.0 in S2), because the capped price sustains local demand. In the deregulated regions, by contrast, S1 consumption settles between the S0 and S2 levels as prices rise toward market-clearing values.

Figure 9 shows that after the policy change, the "Bottle Neck" phenomenon was reduced in the case of single-source integrated operation. The Bottle Neck effect refers to the fact that demand is not sufficiently met because of pipeline capacity limits on the demand side or transmission limits on the supply side, which will increase the market transaction price and reduce the consumer surplus. The increased openness of the market after the policy change has allowed the demand for natural gas from all over the country to be better met, so that more natural gas from the Khorghos port can enter the market and be supplied to the consuming regions, which, to a certain extent, can alleviate the phenomenon of localized gas shortage. The same intermediate pattern appears on the supply side: cross-operator interconnection already relieves most of the bottleneck in S1, so Central-Asian imports through Khorghos rise from 283.4 (S0) to 295.0 billion cubic meters in S1, close to the 300.0 reached in S2. The small remaining gap to S2 reflects the over-network fee, which modestly discourages cross-operator transfers under the priced-access regime of S1.

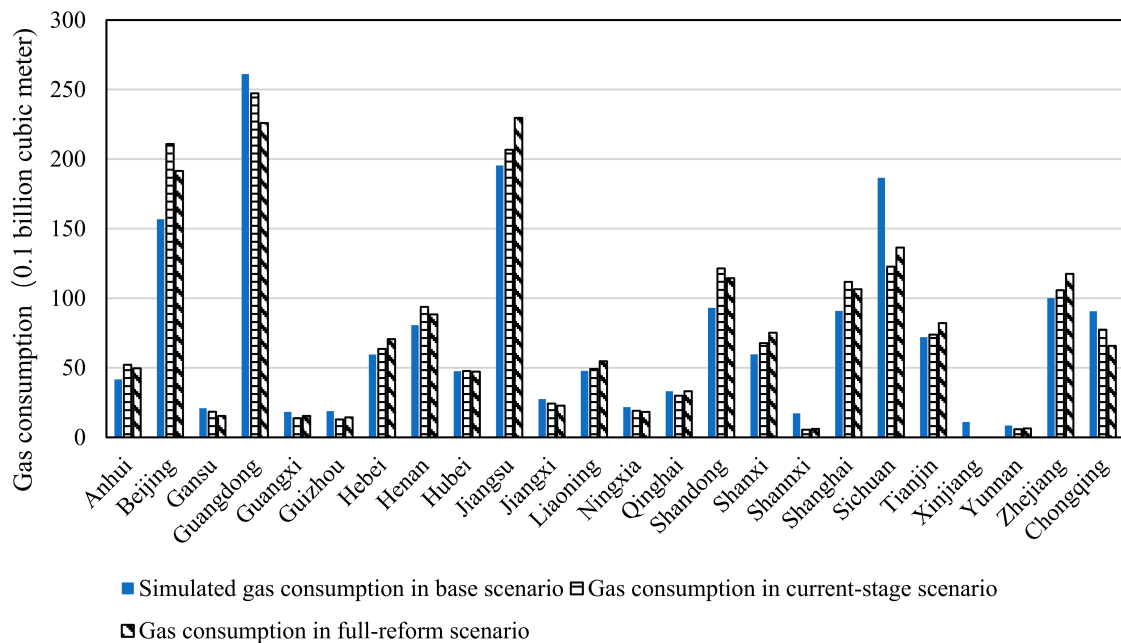


Figure 8. Gas consumption by region across the three scenarios (S0, S1, S2). Source: authors' own work.

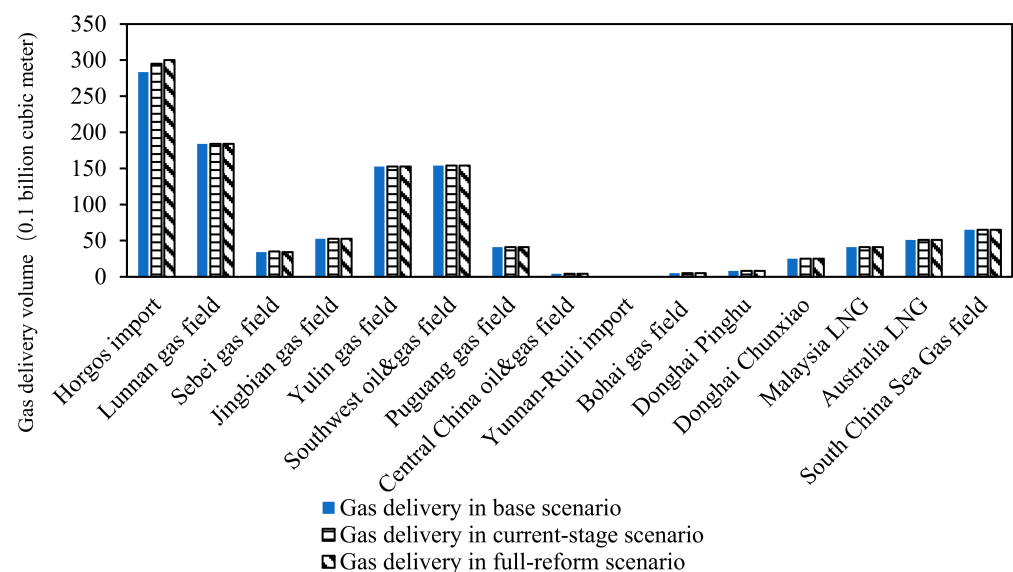


Figure 9. Gas deliveries by source across the three scenarios (S0, S1, S2). Source: authors' own work.

3.2.2. Natural Gas Price Changes Between Scenarios

Price control may lead to a serious supply–demand contradiction; in fact, the frequent gas shortage in the northern region of China in recent years supports this viewpoint. The open and accessible competitive environment after removing the provincial price cap has enabled price formation to more accurately and timely respond to market supply and demand conditions. Figure 10 shows that the average gas price level increases after the policy change, while the price difference between cities decreases significantly (standard error 0.14 in the new scenario vs. SE 0.27 in the base scenario). This suggests that the pipeline separation and interconnection improve the flexibility of natural gas transmission and reduce the price gap between regions. This simulated convergence is consistent with the 2024 move to a zonal cross-provincial transmission tariff, which replaces bespoke province-level arrangements with a small number of distance-based price zones and thereby

tends to narrow unexplained regional price differences [19]. Across the three scenarios, the average city-gate price rises monotonically, from 2.23 (S0) to 2.38 (S1) to 2.49 yuan per cubic meter (S2), so S1 already realizes most of the price adjustment. The cross-city price dispersion, however, narrows only partially in S1: the standard error falls from 0.27 (S0) to 0.22 in S1 and 0.14 in S2. Retaining the cap on the regulated regions while freeing the others creates a dual-track price structure, in which regulated regions such as Beijing, Shanghai, Shandong, Henan, Hubei, Gansu, Ningxia and Chongqing stay at their capped S0 level while the deregulated regions (e.g., Sichuan, Yunnan, Guangxi, Guizhou, Shaanxi and Xinjiang) move up toward market-clearing prices. This residual regulated–market price gap is a distinctive feature of the partial-reform stage, and narrowing it is precisely what the transition from S1 to S2 accomplishes.

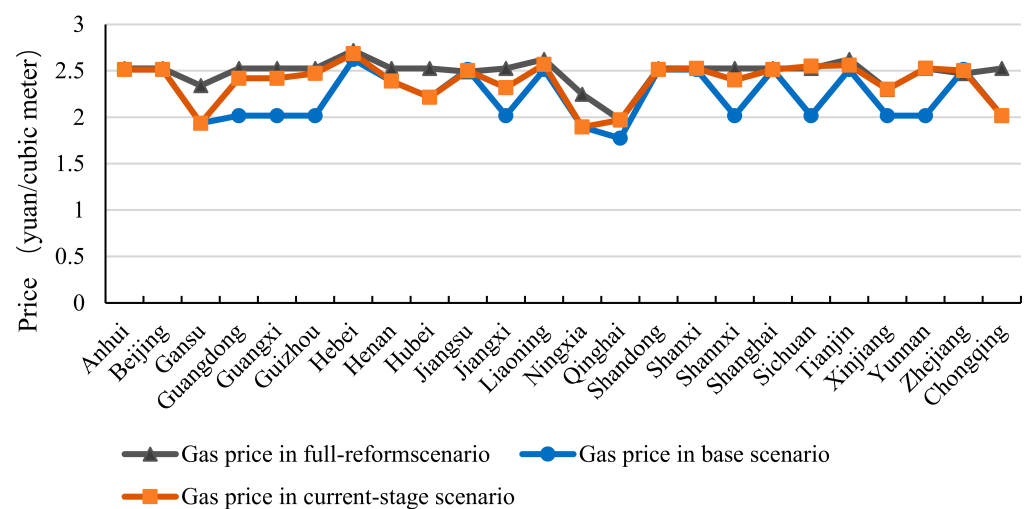


Figure 10. Gas prices by region across the three scenarios (S0, S1, S2). Source: authors' own work.

As shown in Figure 10, gas prices in most regions have risen, but in Jiangsu and Zhejiang, prices have fallen slightly; combined with Figure 8, this is likely due to the interconnection of pipeline networks, which has increased local supply and lowered prices.

3.2.3. Social Welfare Changes Between Scenarios

Table 1 presents the changes in economic benefits of the modeled pipeline network across the three scenarios.

Table 1. Social welfare across the three scenarios (billion yuan). Source: authors' own work.

(Billion Yuan)	Social Welfare	Consumer Surplus	Producer Surplus	Producer & Distributor Benefits
Base scenario(S0)	285.87	125.93	17.47	159.94
Current-stage scenario (S1)	288.44	117.72	17.63	170.72
Full-reform scenario(S2)	290.64	106.20	17.95	184.44

Table 1 reports the welfare decomposition for the three scenarios. Aggregate social welfare rises monotonically along the reform path, from 285.87 (S0) and 288.44 (S1) to 290.64 billion yuan (S2), consistent with the nested constraint sets; the current stage therefore already secures about 54% of the total potential welfare gain. The decomposition reveals the distributional logic of partial reform. Consumer surplus falls only modestly at

the current stage, from 125.93 (S0) to 117.72 billion yuan (S1), whereas full reform drives it down to 106.20 (S2), so the retained price caps shield consumers from roughly three-fifths of the surplus erosion that complete deregulation would impose. The mirror image appears on the supply side, where producer-and-distributor benefit rises from 159.94 (S0) to 170.72 (S1) to 184.44 (S2). Taken together, the move from S0 to S1 delivers a welfare gain of 2.57 at a consumer-surplus cost of only 8.21, whereas the further move from S1 to S2 adds 2.20 in welfare but costs consumers an additional 11.52. The final stage of liberalization therefore yields diminishing efficiency gains at a rising distributional cost, which is why completing it should be paired with explicit safeguards for regulated and residential users. This result differs markedly from that of Jianzhong and Weicheng [10], which did not consider price control in China's gas market. The decline in consumer surplus is closely related to the rise in gas prices: China's gas demand is strong, so the market equilibrium price rises once the price cap is lifted.

4. Discussion

The simulation results can be read against both the existing modelling literature and the reform experience of other markets. Earlier equilibrium models of China's gas market, including the Cournot analyses of oligopolistic competition [20–22] and the EUGAS, NATGAS and global-trade models [23], typically evaluate reform as a single move from a regulated to a competitive state. The three-scenario design used here refines that picture by separating the partially reformed present from the fully reformed frontier, which shows that the welfare and price effects of reform are not realized in one step but accrue along a path of diminishing returns. This staged view matches the incremental way China has actually sequenced its reforms, and it helps explain why substantial gains can be recorded before liberalization is complete.

The direction of the estimated effects is consistent with international evidence on gas-market liberalization. In the United States, unbundling transportation from sales under FERC Order 636 was followed by greater competition, better pipeline utilization and a functioning secondary market for capacity, although the transition also raised distributional concerns for captive customers [13]. In the European Union, ownership unbundling and third-party access under the Third Energy Package increased competition and improved security of supply, with the pace of gains varying across member states [14,35]. The present results echo both cases for China: separating transport from sales and relaxing price control raise aggregate welfare and improve allocation, while the associated rise in average prices shifts surplus from consumers toward producers and distributors. The regulatory-reform trajectory documented for China [36] thus produces effects that are qualitatively similar to those observed elsewhere, which lends external plausibility to the simulated magnitudes.

These findings also bear on the role of gas in energy transition. Because natural gas is a transitional rather than a terminal fuel [3], the efficiency gains from a better-functioning gas market are valuable insofar as they support an orderly substitution away from coal without locking in excess fossil capacity. The regional heterogeneity in the results is relevant here: where reform raises prices and curbs consumption, it can temper over-reliance on gas, whereas regions that retain regulated ceilings sustain their consumption. Read alongside the transition objective, the welfare results suggest that price and access reform should be coordinated with decarbonization policy, so that market efficiency and emission goals reinforce rather than work against each other.

Finally, the analysis underscores that the central difficulty of completing the reform is distributional rather than one of aggregate efficiency. Moving from the current stage to one of full reform yields a comparatively small additional welfare gain but a larger reduction in consumer surplus, concentrated in the regions and user groups that currently benefit

from regulated prices. This distributional profile, not any loss of total welfare, is what makes the remaining steps politically sensitive, and it motivates the safeguards set out in the conclusions.

5. Conclusions

This study examines the impact of market-oriented reform measures on the optimal allocation of natural gas and changes in the welfare of multiple market participants (i.e., producers, consumers, and distributors). First, we constructed a numerical simulation model of natural gas allocation in the long-distance pipeline network and conducted the analysis using China's natural gas market as a case study. Then, we evaluated provincial price deregulation and pipeline separation across three scenarios: a pre-reform baseline (2019), a current-stage scenario representing the partially reformed market, and a full-reform scenario, tracing their effects on gas allocation and market economics in China.

There are three main conclusions: (1) Total natural gas consumption tends to be higher under the reform scenarios, with gas consumption rising in some regions and falling in others; the overall price level increases in most regions. This indicates that the impact of pipeline separation and the removal of price control is complex with regional variations. (2) Pipeline separation and interconnection reduce the bottle-neck effect of gas transmission, which optimizes the efficiency of gas allocation and improves social welfare. Meanwhile, the benefit structure of market participants also changes, with welfare shifting from consumers to producers and distributors. In fact, this suggests that the original price regulation was beneficial to consumers but not optimal for the system as a whole. (3) Comparing the pre-reform, current-stage and full-reform stages shows that the reform path exhibits diminishing returns: the current stage already captures about 54% of the welfare gain (social welfare at 285.87, 288.44 and 290.64 billion yuan across the three stages) and most of the price adjustment, while cushioning consumer surplus (125.93, 117.72 and 106.20 billion yuan). The additional efficiency from completing liberalization is therefore smaller and falls disproportionately on consumers. This implies that China should continue to move toward fuller price liberalization and open third-party access but sequence the remaining steps with safeguards for residential and other regulated users.

The market-oriented reform improves total social welfare, but the gain is distributionally uneven: it accrues mainly to producers and distributors while eroding consumer surplus. This distributional shift, rather than any loss of aggregate efficiency, is what makes dismantling the established regulated arrangements socially and politically difficult. The reform of the North American and European gas markets did not happen overnight. They were implemented step by step through laws, regulations and other binding measures during a specific historical period, suggesting that the fair opening of China's natural gas market still requires a process of exploration. The reform directions examined here, pipeline separation with third-party access and the relaxation of gate-station price control, are now being implemented through the operation of PipeChina and the 2023–2024 pricing reforms. The directional changes produced by the model are consistent with the trends observed since these reforms began, which supports the reliability of the simulation and makes the quantified 2019 baseline a useful reference for tracking the welfare and price effects of the reforms as they continue to unfold.

Based on the conclusions of this study, we suggest the following policy implications for China's natural gas market reform. (1) Pricing: Continue phasing out city-gate price control toward market-based pricing. The 2023 upstream–downstream linkage mechanism and the 2024 zonal transmission tariff have already liberalized more than half of city-gate volumes; the priority now is to extend market pricing to the residual regulated (mainly residential) volumes in a sequenced manner, while deepening price discovery through

the Shanghai and Chongqing trading hubs and launching a natural-gas/LNG futures contract to establish a transparent national price benchmark. (2) Network and third-party access: With PipeChina now operating the unified national network and an open-access platform, the emphasis should shift from establishing separation to enforcing genuine non-discriminatory third-party access: transparent capacity release, published tariffs, and rules for secondary capacity trading. Over the longer term, diversifying PipeChina's ownership by admitting private and social capital as minority shareholders can sustain investment incentives without recreating an integrated monopoly. (3) Upstream: With roughly 90% of domestic blocks still held by the Big Three, accelerating competitive, time-bound assignment, relinquishing exploration blocks, and building on recent mineral-rights reforms would broaden the supplier base and spur innovation in exploration and recovery. (4) Storage and security: Address storage under-utilization and weak cost recovery through cost-reflective storage and seasonal tariffs and by allowing independent operators to build and run storage, coordinated with the energy-security objectives of the 14th and 15th Five-Year Plans and the carbon-neutrality transition, in which natural gas serves as a bridging fuel. (5) Sequencing and consumer protection: Because the analysis shows that liberalization delivers diminishing efficiency gains while shifting welfare from consumers to producers and distributors, the remaining steps should be paired with explicit safeguards for residential and vulnerable users, such as lifeline tariffs and targeted subsidies, so that efficiency gains are not secured at an unacceptable distributional cost.

This study has several limitations that also point to future work. The model is static and deterministic and is calibrated to 2019 market conditions, so it captures the direction and relative magnitude of reform effects rather than their realized values in any specific later year, and it abstracts from seasonality, storage, LNG flexibility and price uncertainty. Future research could extend the framework in three directions: adding dynamic and stochastic elements to capture seasonal demand, storage and supply risk; updating the calibration with post-reform data as it becomes available, so that simulated and realized outcomes can be compared directly; and applying the same approach to other emerging gas markets, or coupling it with power-sector and decarbonization models to examine the role of gas in the wider energy transition. Endogenizing infrastructure investment and the entry of new suppliers would further sharpen the assessment of long-run reform effects.

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Data Availability Statement: The data used in this study are derived from publicly available sources cited in the article, including the National Bureau of Statistics of China (<https://www.stats.gov.cn>). The processed data and model outputs are available from the corresponding author upon reasonable request.

Conflicts of Interest: The authors declare no conflicts of interest.

Appendix A

Table 1. China Natural Gas Pipeline Network Trunk Lines Information.

	Company	Pipeline	Starting Nodes	Intermediate Station Nodes	Ending Nodes
1	CNPC	West–East Gas Pipeline 1	Xinjiang Tarim Oilfield/Lunan Oil and Gas Field	Zhongwei (Ningxia)—Jingbian (Shaanxi)—Taining (Shanxi)—Zhengzhou (Henan)—Xuedian (Pingtai)—Huaiyang (Huaiwu Line Interchange)—Hefei (Anhui)—Nanjing (Jiangsu)—Hangzhou/Shanghai	Baihe Town, Shanghai
2	CNPC	West-1/Jining Liaison Line	Anping, Hebei	Jinan (Zhongji Line Interchange)—Tai'an (West Second Line Pingtai Branch Interchange)—Xuzhou (Jiangsu)	Nanjing
3	CNPC	West-1/Huaiwu liaison line	Huaiyang, Henan	--	Wuhan, Hubei
4	CNPC	West-1/Lan Yin Line	Lanzhou, Gansu	--	Yinchuan, Ningxia
5	CNPC	West–East Gas Pipeline 2	Khorgos, Xinjiang	Wuwei (Gansu)—Zhongwei 2 (Ningxia)—Jingbian/Xi'an—Pingdingshan—Xiangfan (Hubei)—Huangmei—Nanchang	Guangzhou
6	CNPC	West-2/Lunan branch trunk line	Lunan Station, Luntai County, Xinjiang	--	Turpan Sub-transmission Station of West Line 2
7	CNPC	West-2/Shanghai branch trunk line	Nanchang	Hangzhou (Zhejiang)	Shanghai
8	CNPC	West-2/Guangxi branch trunk line	Guangzhou	--	Nanning
9	CNPC	West-2/Tai'an branch trunk line	Pingdingshan	Xuedian (West 1st Line Interchange)	Shandong Tai'an
10	CNPC	Shaanxi–Beijing line 1	Shanxi Jingbian First Railway Station	Shenchi (Shanxi Sub-transmission Station)	Beijing Shijingshan
11	CNPC	Shaanxi–Beijing line 2	Shanxi Jingbian	Lanxian (Shanxi Sub-transmission Station)—Shijiazhuang (Hebei)—Anping (Jining Line Interchange)—Yongqing (Yongtang Qin Interchange)	Beijing Shijingshan
12	CNPC	Shaanxi–Beijing line 2/Yongtang Qin Pipeline	Yongqing County, Langfang, Hebei	Tianjin	Qinhuangdao Funing County

Table 1. Cont.

	Company	Pipeline	Starting Nodes	Intermediate Station Nodes	Ending Nodes
13	CNPC	Shaanxi–Beijing Line 3	Yulin, Shaanxi	Lanxian (Shanxi Sub-transmission Station)—Shijiazhuang (Hebei)—Anping (Jining Line Interchange)—Yongqing (Yongtang Qin Interchange)	Xishatun Terminal, Changping District, Beijing
14	CNPC	Zhongcang Line	Puyang (Zhongyuan)	Encheng (Zhongcang Line Intersection)	Cangzhou
15	CNPC	Zhonggui Line	Zhongwei, Ningxia	Tianshui—Nanchong—Chongqing—Chongqing	Guiyang, Guizhou
16	CNPC	China–Myanmar Pipeline	Kyaukphyu, Myanmar/Ruili, Yunnan	Kunming—Guiyang	Guigang, Guangxi
17	CNPC	Qin-Shen Line	Qinhuangdao, Hebei	--	Liaoning Shenyang Gas Transmission Mainline
18	CNPC	Taiqingwei Pipeline	Tai'an, Shandong	Qingdao (Shandong)	Shandong Weihai Preservation Island
19	CNPC	Shibining Lan Line and Duplicate Line	Qinghai Shibe Gas Field	Xining (Qinghai)	Lanzhou, Gansu
20	CNPC	Changhou and Duplicate Line	Surig Gas Field	--	Hohhot, Inner Mongolia
21	CNPC	Zhongwu Pipeline	Chongqing Zhongxian	Yixian (Hubei Subtransmission Station, Sichuan Gas Eastern Transmission Interchange)—Zhijiang (Sichuan Gas Eastern Transmission Interchange)—Xiangfan/Qianjiang—Wuhan/Xiangtan	Wuhan, Hubei
22	CNPC	Cangzi Line	Dagang	Cangzhou (Hebei)	Zibo, Shandong
23	Sinopec	Sichuan-East Gas Pipeline Network	Sichuan Puguang	Zhongxian (Chongqing)—Yichang (Hubei)—Zhijiang—Qianjiang—Huangmei—Xuancheng—Hangzhou—Nanjing/Shanghai	Baihe Town, Shanghai
24	Sinopec	Yuji Line	Yulin, Shaanxi	Luliang (Shanxi)—Anyang (Henan)	Jinan, Shandong
25	Sinopec	Anji Line	Da Niu Di	Yulin (Shaanxi)—Anping (Hebei)	Jinan, Shandong
26	Sinopec	Zhongji Line	Puyang (Zhongyuan)	--	Jinan

Sources: Open-source reports compiled by the authors.

Table 2. Each producer's gas supply cost and supply capacity.

Gas Field	The Producer	Supply Cost (c_i) (yuan/m ³)	Supply Capacity (T_j) (10 ⁸ m ³ /year)
Imports through Khorghos (S_1)	CNPC	2	300
Lunan Gas Field (S_2)	CNPC	0.49	184
Sebei Gas Field (S_3)	CNPC	0.58	55
Jingbian Gas Field (S_4)	CNPC	0.73	52.5
Yulin Gas Field (S_5)	CNPC	0.62	152.5
Southwest Oil & Gas Field (S_6)	CNPC	0.8	154
Puguang Gas Field (S_7)	Sinopec	1.13	41
Zhongyuan Oil & Gas Field (S_8)	Sinopec	0.62	4
Imports through Runli, Yunnan (S_9)	CNPC	2.6	40
Bohai Gas Field (S_{10})	CNOOC	1.26	5
East China Sea Pinghu Gas Field (S_{11})	CNOOC	1.26	8
Chunxiao Gas Field (S_{12})	CNOOC	1.26	25
LNG from Malaysia (S_{13})	CNOOC	2.15	41
LNG from Australia (S_{14})	CNOOC	0.85	51
South China Sea Gas Fields (S_{15})	CNOOC	0.8	65

Sources: 2019 company yearbooks published by CNPC and Sinopec, Xu [31] and other open-source reports compiled by the authors.

Table 3. The parameter values of the demand function of each consumer city.

Distribution City	Symbolic	c_i	m_i
Anping	d_1	3.96	−0.14
Anyang	d_2	4.02	−0.11
Beijing	d_3	4	−0.01
Cangzhou	d_4	3.96	−0.14
Tianshui	d_5	2.86	−0.16
Guangzhou	d_6	4.36	−0.01
Guigang	d_7	4.02	−0.31
Guiyang	d_8	3.42	−0.10
Hangzhou	d_9	4.34	−0.02
Hefei	d_{10}	4.18	−0.11
Huaiyang	d_{11}	4.02	−0.11
Huangmei	d_{12}	3.92	−0.19
Jinan	d_{13}	3.96	−0.06
Kunming	d_{14}	3.42	−0.22
Lanzhou	d_{15}	2.86	−0.16
Lanxian	d_{16}	3.82	−0.11
Tulufan	d_{17}	2.3	−0.01
Luliang	d_{18}	3.82	−0.11
Nanchang	d_{19}	3.92	−0.10
Nanjing	d_{20}	4.32	−0.03
Nanning	d_{21}	4.02	−0.31
Pingdingshan	d_{23}	4.02	−0.11
Qianjiang	d_{23}	3.92	−0.19
Qinhuangdao	d_{24}	3.96	−0.14
Shanghai	d_{25}	4.36	−0.03
Shenchi	d_{26}	3.82	−0.11
Shenyang	d_{27}	3.96	−0.04
Shijiazhuang	d_{28}	3.96	−0.14
Nanchong	d_{29}	3.3	−0.01
Tai Ning	d_{30}	3.82	−0.11

Table 3. Cont.

Distribution City	Symbolic	c_i	m_i
Tai'an	d_{31}	3.96	−0.06
Tianjin	d_{32}	4	−0.03
Wuhan	d_{33}	3.92	−0.19
Wuwei	d_{34}	2.86	−0.16
Xi'an	d_{35}	2.68	−0.04
Xining	d_{36}	2.54	−0.03
Xiangfan	d_{37}	3.92	−0.19
Xuzhou	d_{38}	4.32	−0.03
Xuancheng	d_{39}	4.18	−0.11
Yinchuan	d_{40}	3.02	−0.13
Yongqing	d_{41}	3.96	−0.14
Zhengzhou	d_{42}	4.02	−0.11
Zhongwei	d_{43}	3.02	−0.13
Chongqing	d_{44}	3.28	−0.02
Zibo	d_{45}	3.96	−0.06

Table 4. Designed gas transmission capacity of China's major long-distance pipelines.

Affiliated Company	Pipelines	Gas Transmission Capacity (10 ⁸ m ³ /year)
CNPC	Shaanxi–Beijing Line 1	33
CNPC	Shaanxi–Beijing Line 2	170
CNPC	West–East Gas Pipeline	170
CNPC	Zhongwu Line	30
CNPC	Shining Lan and Duplicate Line	68
CNPC	Lan–Yin Line	19
CNPC	West–East Gas Pipeline 2	300
CNPC	Yongtangqin	90
CNPC	Zhongcang Line	10
CNPC	Jining Line	90
CNPC	Huaiwu Line	15
CNPC	Zhonggui Line	150
CNPC	China–Burma Pipeline	120
CNPC	Qin–Shen Line	86
CNPC	West Second Line/Lunan Branch Trunk Line	120
CNPC	Shaanxi–Beijing Line 3	150
CNPC	Changhou Duplicate Line	80
CNPC	Cangzi Line	10
Sinopec	Sichuan–East Gas Pipeline Network	120
Sinopec	Yuji Line	30
Sinopec	Anji Line	30
Sinopec	Zhongji Line	10
Sinopec	Jizi line	28
CNOOC	Bohai–Tianjin	2
CNOOC	Bohai–Yantai	3
CNOOC	Pinghu–Shanghai	8
CNOOC	Chunxiao–Ningbo	30
CNOOC	Australia	50
CNOOC	LNG–Guangdong	50
CNOOC	Malaysia LNG–Shanghai	50

Source: Open-source reports compiled by the authors.

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