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Original Paper

A systematic two-stage optimization framework for congestion locating and multi-component expansion planning in natural gas pipeline networks

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A B S T R A C T

As global energy demand continues to rise, natural gas pipeline systems face significant challenges, including congestion during peak demand periods and the complexities of system expansion. This paper introduces an integrated congestion identification and expansion planning framework (ICIEPF) designed to enhance the hydraulic reliability of pipeline networks. The framework integrates two key models: a physics-based congestion location model (CL-Model) and a multi-component expansion optimization model (MCEO-Model). The CL-Model employs a flow relaxation variable to precisely identify congestion points, quantifying the severity of bottlenecks and providing a deterministic foundation for targeted investments. The MCEO-Model utilizes these insights to optimize expansion strategies—considering pipeline loops, new pipelines, and compressor station upgrades—while strictly enforcing equipment operational safety. The framework utilizes a two-stage sequential optimization strategy, incorporating convex relaxation and linearization techniques to enable a high-quality warm start, thereby accelerating solution speed and minimizing costs. Case studies demonstrate that, compared with the direct solving method, the ICIEPF achieves an average computational speedup of 12.37 times. Furthermore, it reduces expansion costs by 54.8% compared to single-component expansion strategies and significantly improves the compressor safety margins. These results demonstrate the framework's potential to address complex pipeline expansion challenges while improving system reliability and operational efficiency.

1. Introduction

1.1. Background

With the ongoing global energy transition, natural gas plays an increasingly significant role as a cleaner energy source within the global energy mix (Ding et al., 2023). According to the International Energy Agency, natural gas is projected to account for 26% of global energy demand by 2030 (Fan et al., 2022). Ensuring a stable and reliable natural gas supply is critical not only for national economic development but also for societal well-being (Jia et al., 2023). As the primary mode of natural gas transport, pipeline systems are essential for maintaining continuous and dependable energy delivery (Li et al., 2024).

However, the reliability of natural gas supply systems, particularly pipeline networks, faces substantial challenges. These include long lead times for design and construction, high operational costs, and various geographical and environmental constraints, all of which limit the capacity of existing infrastructure to meet growing demand (Wei et al., 2023). One of the most pressing issues is network congestion, which becomes especially problematic during peak demand periods. Inadequate transmission capacity during these times can significantly compromise the reliability and stability of the entire energy supply chain. Additionally, the increasing integration of intermittent renewable energy sources, such as solar and wind, has led to more frequent fluctuations in natural gas demand. This results in the underutilization of some pipelines while others experience recurrent congestion. Such inefficiencies not only threaten supply stability

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but also increase operational costs and reduce overall system resilience (Su et al., 2024).

Addressing these challenges requires advanced methods for precise physical congestion identification and the development of optimized expansion plans. Timely and accurate congestion identification is critical for implementing targeted interventions. However, simply identifying a bottleneck is insufficient; the subsequent expansion plan must be technically feasible. A critical oversight in many existing frameworks is the simplification of compressor station operations, which often neglects complex safety constraints such as surge and choke limits. This can lead to "optimal" expansion plans that are operationally unsafe or physically impossible to implement. Therefore, a comprehensive approach that integrates physics-based congestion identification with safety-constrained expansion planning is essential to maintaining the long-term reliability of natural gas networks.

This paper addresses this gap by proposing an integrated approach that combines congestion identification with expansion planning through a two-stage sequential optimization strategy. The framework not only targets the efficient identification of congestion points but also proposes multi-component expansion solutions to enhance the system's operational safety. The research focuses on improving the operational flexibility of pipeline systems to cope with evolving energy demands. By systematically analyzing congestion and devising effective expansion strategies, this study offers valuable insights and decision support for natural gas pipeline management, aiming to achieve both economic efficiency and enhanced system reliability in line with the broader goals of the global energy transition.

1.2. Literature review

Historically, natural gas pipelines were primarily constructed independently by individual companies. This fragmented approach often led to a lack of comprehensive planning, resulting in mismatches between pipeline capacity and actual demand. Particularly during peak hours, insufficient transmission capacity can cause network congestion, creating bottlenecks that hamper efficiency and pose risks to supply security and cost stability. Therefore, there is an urgent need for a holistic assessment of congestion and the implementation of capacity expansion measures to adapt to evolving supply-demand dynamics.

To address this, several scholars have conducted analyses of gas transmission congestion. Marmer et al. (2007) developed a simplified econometric model to identify congestion in the U.S. natural gas pipeline network, relying on market-driven indicators rather than technical operational data. Petrovich et al. (2017) employed the EWI TIGER model to simulate how European gas pipeline congestion evolves under varying conditions—including fluctuating demand, LNG imports, and Russian supply—but their analysis remained confined to scenario-based trends without investigating technical root causes. Lochner (2011) constructed an infrastructure model for the European gas market to calculate real-world flows and quantify congestion costs; however, they did not elaborate on specific congestion locations or the driving technical factors (e.g., pressure drops, compressor limits). While these market- or economics-focused studies offer guidance for mitigating congestion through policy or pricing, they fail to provide actionable technical measures for network expansion or upgrades.

Extending beyond gas systems, it is instructive to compare methodologies from other networks. Power systems, for example, often identify congestion using a dual-based economic approach, where a binding physical constraint in an optimal power flow model generates a non-zero shadow price (or Lagrangian multiplier). This quantifies the marginal economic cost of the bottleneck, often manifesting as regional price differentials (Li and Bo, 2009). Mount and Ju (2007) modeled nodal price stochasticity in the New York electricity market to assess congestion cost magnitude and risk via regional price differentials, but this framework cannot be directly transposed to gas networks due to their distinct hydraulic characteristics. Transportation networks, in contrast, frequently measure congestion by its consequences, such as using volume-to-capacity ratios within volume-delay functions to estimate travel delay, or applying queueing theory to quantify queue lengths and wait times (Li et al., 2020; Zarindast et al., 2022). Hauser et al. (2019) developed a coupled electricity-gas network model to evaluate how increased electricity demand impacts gas network congestion, yet their gas network sub-model was highly simplified—failing to accurately reflect real-world operational conditions or pinpoint specific congestion points. In summary, current congestion research primarily adopts market or economic lenses. While the field of system safety has produced detailed technical risk models for pipeline reliability (Zhao et al., 2025; Yang et al., 2023; Chen et al., 2024), few studies leverage detailed natural gas network models to analyze technical-level congestion (e.g., hydraulic constraints, equipment limits) or propose technically feasible expansion solutions. Consequently, it is necessary to distinguish technical congestion from economic congestion. Unlike market-based approaches that address contractual imbalances, analyzing congestion through the lens of physical constraints and operational safety is essential to identify hydraulic bottlenecks that physically prevent gas delivery, ensuring that subsequent expansion plans are engineeringly feasible and safe.

Pipeline expansion—encompassing the addition of new pipelines, compressors, or auxiliary facilities—emerges as a key technical solution to congestion (Ruan et al., 2009). Andre et al. (2009) optimized the placement and sizing of pipelines to minimize investment costs. Kabirian and Hemmati (2007) proposed a nonlinear optimization model considering the types, locations, and installation schedules of pipelines and compressor stations to minimize costs over multiple planning phases. Üster and Dilaveroğlu (2014) investigated the expansion of pipelines and compressors under multi-period supply and demand conditions, while Mikolajková et al. (2017) proposed expanding existing pipelines or connecting to LNG terminals. Despite these efforts, most studies focus on single expansion components (e.g., pipelines alone or compressors alone), lacking analysis of how multiple strategies interact to enhance overall network performance. Furthermore, pipe network expansion remains computationally challenging as it requires determining both the optimal location and key technical parameters (e.g., pipe diameters, compressor characteristics) (Oliver, 2015). A significant limitation in current literature is the excessive simplification of compressor modeling to reduce computational complexity. Most models treat compressors as simple pressure-boosting nodes, ignoring non-linear feasible operating regions (i.e., surge lines, choke lines, and speed limits). This simplification risks generating expansion schemes that operate compressors in unsafe regions, leading to potential equipment failure.

Scholars have attempted to solve these problems using methods such as preprocessing, relaxation (Wen et al., 2022), or iterative algorithms (Hamedi et al., 2009; Humpola et al., 2016). While convex relaxation techniques are widely used to handle hydraulic non-linearity (Humpola and Fügenschuh, 2015; Borraz-Sánchez et al., 2016), they are typically applied to standard transmission cost minimization problems and are rarely integrated into unified frameworks linking congestion diagnosis to expansion. Due to the slow speed of traditional optimization methods on large-scale models, many scholars have turned to intelligent algorithms (Zhang et al., 2017). Sanaye and Mahmoudimehr (2013) proposed a genetic algorithm for pipeline investment optimization; its optimal network design included 2660 km of pipelines and 26 compressor stations. He et al. (2019) combined an improved genetic algorithm with simulated annealing to mitigate local optimization bias. However, heuristic algorithms cannot guarantee global optimality. Critically, most of these studies simplify pipe network systems by neglecting key real-world constraints such as hydraulic pressure drops and complex compressor operating boundaries.

Table 1 summarizes the key methodological differences between this study and representative existing literature. While economic, policy, or management strategies for congestion mitigation have been proposed, they are rarely coupled with expansion optimization models. In expansion research, most studies focus on single components, overlook synergies between strategies, or simplify network models—providing theoretical support for specific scenarios but failing to address the root causes of physical congestion. As shown in Table 1, existing studies often simplify compressor modeling to linear costs or capacity limits. This gap risks producing expansion schemes that ignore real operational conditions (e.g., surge and choke boundaries), undermining feasibility and long-term benefits. Consequently, it is necessary to distinguish technical congestion from economic congestion and adopt a framework that strictly enforces hydraulic safety.

1.3. Contributions

The main contributions of this research are summarized as follows:

(1) A physics-based congestion location model is established. By introducing a flow relaxation variable, this model precisely quantifies network congestion from a physical perspective. It overcomes the limitations of economic-indicator-based methods, providing deterministic bottleneck locations for targeted expansion.
(2) A multi-component expansion optimization model embedded with safety constraints is developed. This model integrates complex, nonlinear compressor feasible operating envelopes as hard constraints. This integration ensures that the optimized expansion schemes are not only cost-effective but also strictly operationally safe.
(3) An integrated congestion identification and expansion planning framework is proposed. This framework achieves effective synergy between congestion diagnosis and expansion through a sequential coupling mechanism. By leveraging diagnostic information to narrow the solution space, the framework significantly reduces computational complexity, achieving an average 12.37-fold improvement in efficiency compared to direct solving methods.

1.4. Organization

The remainder of this paper is organized as follows. Section 2 provides a detailed system description, outlining the physical nature of network congestion, the principles of pipeline expansion planning, and the architecture of the proposed integrated framework. Section 3 presents the detailed mathematical problem formulation. Section 4 elaborates on the proposed optimization method. Section 5 validates the effectiveness of the framework through comprehensive case studies. Finally, Section 6 concludes the paper by summarizing the key findings and contributions.

2. System description

2.1. Network congestion

In natural gas pipeline networks, congestion is defined as a physical state where the system cannot meet demand without violating critical operational constraints. For the purpose of strategic infrastructure planning, it is crucial to note that network capacity requirements are governed by peak demand scenarios. Therefore, this study specifically focuses on congestion that materializes during these high-stress periods. These scenarios represent the "controlling case" for investment, as infrastructure capable of satisfying peak demand is inherently sufficient for off-peak operational conditions.

This paper focuses on two fundamental types of physical limitations that cause such congestion and directly impact system reliability and safety (Oliver et al., 2014). Analysis of the factors leading to pipeline congestion identifies several key elements (Liu et al., 2015):

(1) Pipeline hydraulic limits: Gas flow through a pipeline inherently causes a pressure drop due to friction. Under the high-flow conditions characteristic of peak demand, this pressure drop can become so severe that the gas pressure at a delivery point falls below the contractually or

Table 1
Summary of related works on natural gas network expansion and congestion.

Reference	Main objective	Congestion identification	Expansion components			Compressor modeling	Solution method
			New pipeline	Pipeline loop	Compressor station expansion		
Marmer et al. (2007)	Identify bottlenecks	Price co-integration	N/A	N/A	N/A	N/A	Statistical analysis
Petrovich et al. (2017)	Supply security scenarios	Capacity shortfall	N/A	N/A	N/A	Simplified (Capacity)	TIGER (Linear opt)
Lochner (2011)	Value infrastructure	Nodal price/mark-up	N/A	N/A	N/A	Simplified	Linear programming
Ruan et al. (2009)	Minimize life cycle cost	N/A	✓	×	×	Simplified	Heuristic algorithm
Kabirian and Hemmati (2007)	Strategic planning	N/A	✓	×	✓	Simplified (Linear cost)	Heuristic algorithm
Üster and Dilaveroğlu (2014)	Design and operation	N/A	✓	×	✓	Pressure ratios & flow limits	MINLP solver
Mikolajková et al. (2017)	Design and operation	N/A	✓	×	×	Thermodynamic	MINLP solver
Wen et al. (2022)	Multi-period planning	N/A	✓	✓	×	Simplified (Linear cost)	MILP solver
Borraz-Sánchez et al. (2016)	Expansion planning	N/A	✓	×	✓	Simplified	Convex relaxation (MISOCP)
This paper	Congestion locating & expansion	Physics-based (Flow relaxation)	✓	✓	✓	Operating envelopes	Two-stage (Warm start)

operationally mandated minimum, as depicted in Fig. 1(a). This constitutes a failure to meet supply obligations.

(2) Compressor operating constraints: Compressor stations are vital for boosting pressure, but their performance is restricted to a specific operational envelope defined by surge, choke, and speed limits (Fig. 1(b)). Peak demand conditions typically require high flow rates and substantial pressure ratios, pushing compressors toward these operational boundaries. When network conditions require a pressure boost and flow rate combination outside this feasible domain, the compressor is considered congested, posing risks of severe mechanical damage and widespread supply interruptions.

2.2. Network expansion planning

To mitigate the physical congestion described in Section 2.1, network expansion planning aims to determine the optimal investment strategies for infrastructure upgrades. The objective is to ensure system reliability under the governing peak demand scenario while minimizing total capital expenditure. This study specifically considers two primary categories of expansion measures to resolve hydraulic and mechanical bottlenecks (Fig. 2):

(1) Pipeline augmentation (Looping): This involves installing parallel pipelines along existing segments to share the gas flow. By increasing the aggregate cross-sectional area, looping significantly reduces frictional pressure losses, thereby maintaining nodal pressures above the required minimums even under high-flow conditions.

(2) Compressor station expansion: This involves specifically expanding the capacity of existing stations, typically by installing additional units. Expansion extends the feasible boundaries of the station, enabling it to provide the high pressure ratios or flow rates required to overcome increased resistance during peak demand.

However, determining the optimal expansion scheme presents a significant mathematical challenge. The problem is characterized by the combinatorial complexity of selecting discrete expansion candidates and the non-convex nature of hydraulic and safety constraints. A strategic planning framework must effectively co-optimize these discrete investment decisions with continuous operational variables to ensure the resulting network is both cost-effective and operationally feasible.

2.3. Integrated congestion identification and expansion planning framework

To mathematically locate these physical bottlenecks and address the inherent computational complexity of expansion planning, this paper proposes the integrated congestion

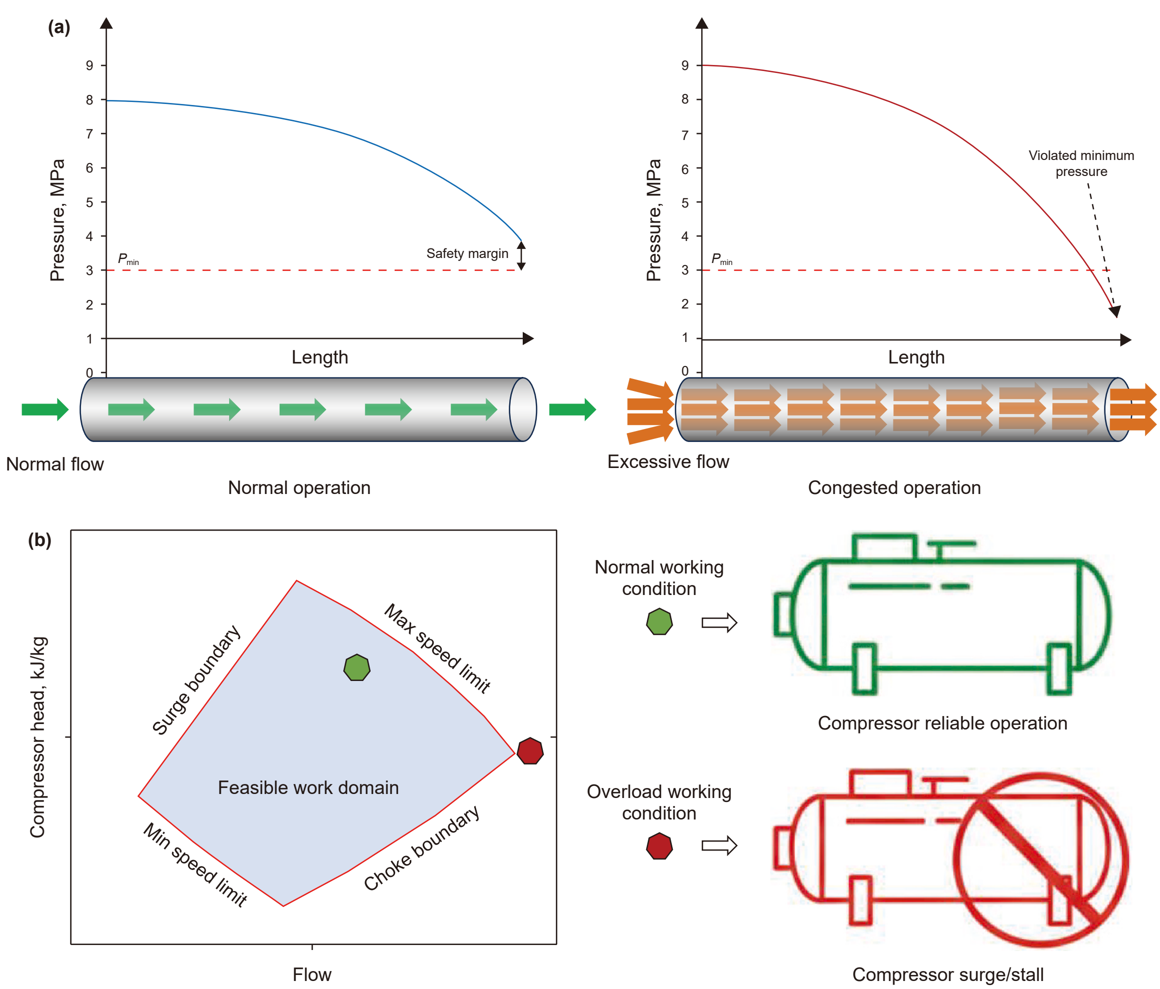

Fig. 1. Mechanisms of congestion in natural gas pipeline networks: (**a**) pipeline hydraulic limits; (**b**) compressor operational constraints.

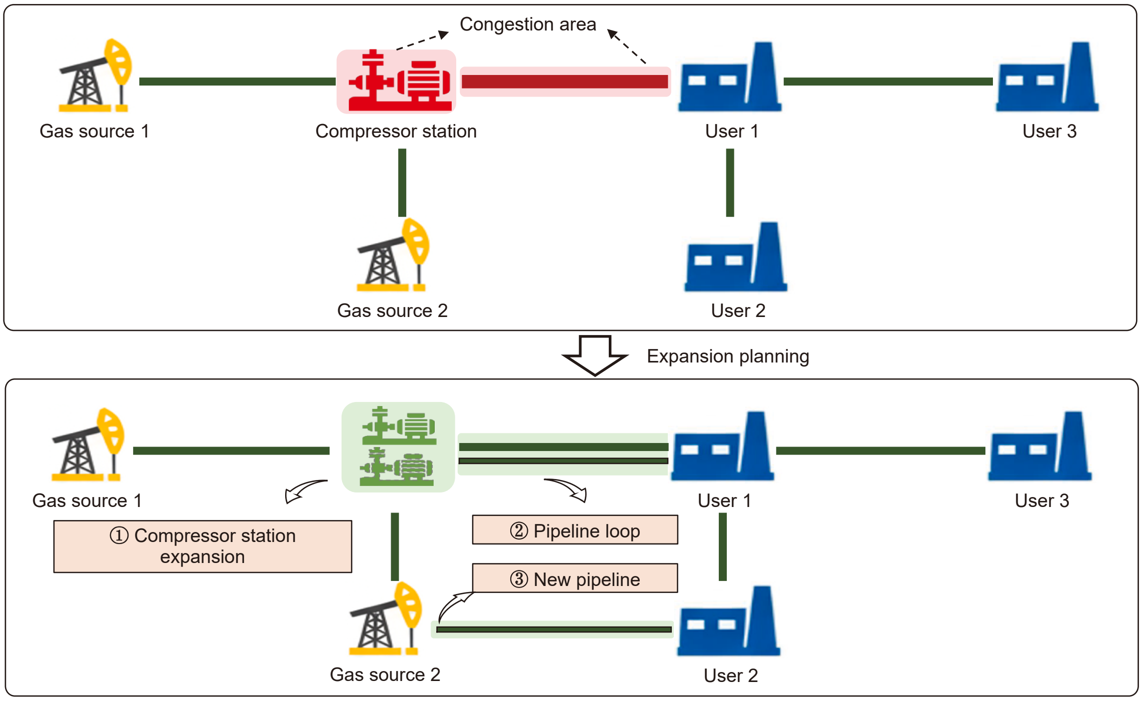

Fig. 2. Multi-component network expansion.

identification and expansion planning framework (ICIEPF). As illustrated in Fig. 3, this framework adopts a two-stage sequential optimization strategy. The integrated problem is decomposed into two logically linked stages: a congestion identification stage (Stage 1) and an expansion optimization stage (Stage 2).

First, to mathematically pinpoint the physical bottlenecks, the framework employs a congestion location model (CL-Model). This model introduces a flow relaxation variable, which acts as a quantitative indicator to precisely identify the location and severity of congestion within the network. Second, based on the findings of the CL-Model, a multi-component expansion optimization model (MCEO-Model) is solved to determine the most cost-effective expansion plan.

The core of the ICIEPF is the two-stage strategy that links these two models. The congestion results from the CL-Model (e.g., congestion location, relaxation flow, node pressures) serve as critical inputs that guide the MCEO-Model. By restricting the decision space exclusively to the identified problem areas, this targeted approach transforms an intractable global optimization problem into a computationally efficient one, providing a robust and practical tool for reliability-oriented pipeline expansion.

3. Problem formulation

Natural gas pipeline expansion fundamentally aims to ensure long-term hydraulic reliability and safety under evolving demand conditions. To create effective and secure expansion plans, mathematical models must accurately capture the system's complex physical behaviors. These include the non-linear physics of gas flow (hydraulic pressure drop), the discrete choices among multi-component expansion options, and, critically, the strict operational safety limits of equipment such as compressors. Integrating these factors results in a large-scale, non-convex mixed-integer non-linear programming (MINLP) problem, which is computationally challenging to solve.

Direct optimization of such complex models is often intractable for realistic networks. Therefore, this paper proposes the ICIEPF. This framework decomposes the expansion problem into two logically coherent and computationally tractable sub-problems: first, identifying the most critical congestion points in the pipeline network; second, formulating a safety-constrained expansion plan specifically for these identified locations.

3.1. Congestion location model

The first stage of the ICIEPF is the CL-Model, which identifies and quantifies physical congestion threatening the system's hydraulic reliability and demand satisfaction. The CL-Model is formulated based on fundamental physical laws governing network operation, including nodal mass balance, pipeline hydraulic pressure drop equations, and compressor operating constraints. The core mechanism of the CL-Model is the introduction of “flow relaxation variables” into these physical constraint equations. The model's objective is to minimize the sum of all relaxation variables across the entire network. This objective function is physically equivalent to minimizing the system's total deviation from a hydraulically feasible and safe operating state. For any given component (e.g., a pipe or compressor), the magnitude of its flow relaxation variable serves as a direct quantitative measure of congestion severity. A non-zero relaxation value indicates that the component cannot meet transport requirements without violating physical constraints, thereby strictly identifying it as a congestion point.

3.1.1. Objective function

Congestion in natural gas pipeline networks is primarily caused by hydraulic constraints, occurring when the pressure drop exceeds the permissible range for a given delivery capacity. To address congestion without altering the network structure, the typical operational solution is to decrease transport capacity or increase pressure at the pipeline inlet. The CL-Model simulates this by

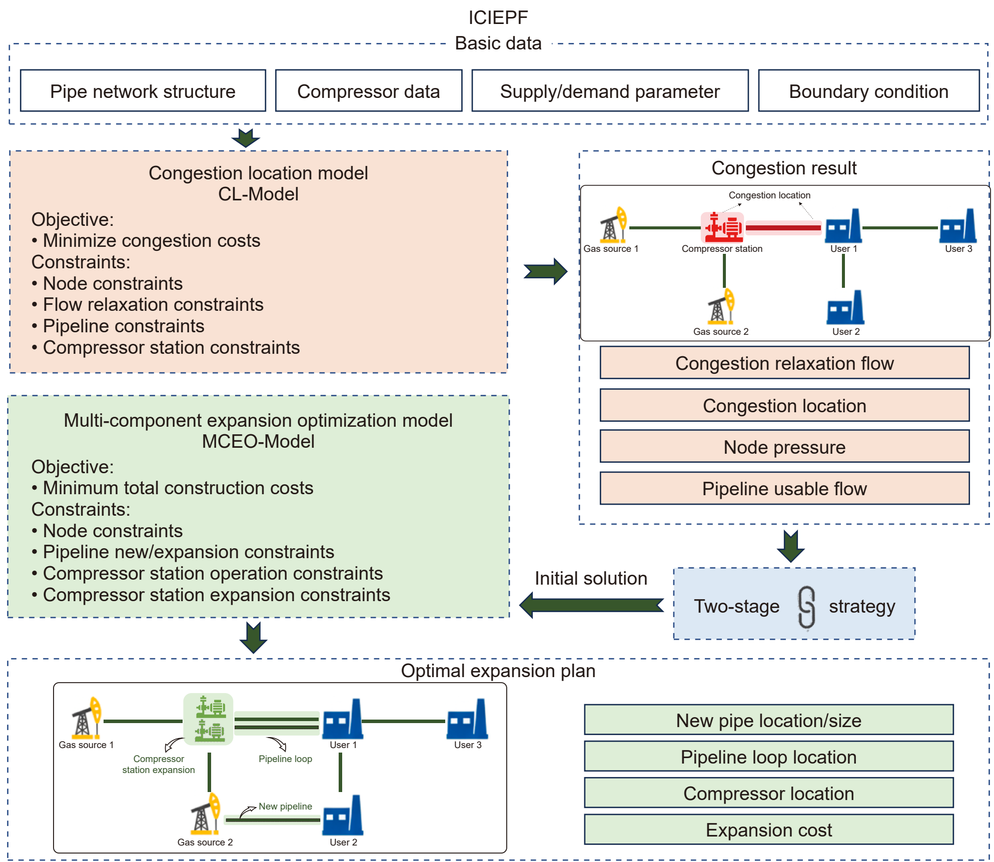

Fig. 3. Integrated congestion identification and expansion planning framework.

adding flow or pressure relaxation variables (often referred to as slack variables) to the optimization model. These variables mathematically "reduce" the required capacity or pressure drop to satisfy constraints. However, if these relaxation variables are not appropriately constrained, they may be assigned to arbitrary pipelines, including non-congested segments. Therefore, the key objective of the CL-Model is to minimize the values of these slack variables to accurately identify and locate true congestion points in the pipeline network. Eq. (1) shows the CL-Model objective function.

$$\min F^{\text{cong}} = \sum_{ij \in A} Q_{ij}^{\text{relax}} \tag{1}$$

where F^{cong} is the pipe network congestion value; Q_{ij}^{relax} is the pipe network element congestion slack flow, 10^4 m^3/d.

3.1.2. Constraints

(1) Nodal constraints

According to the law of conservation of mass, at any node, the flow rate into the node should be equal to the flow rate out of the node. The pipe network node flow balance constraint is shown in Eq. (2).

$$\sum_{i:(j,i) \in A} Q_{ji} + s_i = \sum_{i:(i,j) \in A} Q_{ij} + d_i \quad \forall i \in N \tag{2}$$

where Q_{ij} is the pipeline or compressor station flow rate, 10^4 m^3/d; s_i is the gas supply flow rate, 10^4 m^3/d; d_i is the user demand flow rate, 10^4 m^3/d; N is the node set.

To ensure safe operation of the pipe network system, the nodal pressure should not exceed the maximum allowable pressure. At the same time, the nodal pressure should also meet the minimum contract pressure at the user. The node pressure constraint is shown in Eq. (3).

$$p_i^{\min} \le P_i \le p_i^{\max} \quad \forall i \in N \tag{3}$$

where P_i is the node pressure, MPa; $p_i^{\min}$ is the node allows the minimum pressure, MPa; $p_i^{\max}$ is the node allows the maximum pressure, MPa;

(2) Congestion location constraint

By adding congestion relief flow, the pipeline capacity is "lowered" so that the pipeline hydraulic pressure drop constraint is satisfied again. The "reduced" flow rate is called the effective flow rate, which is mainly involved in the calculation of the hydraulic pressure drop of the pipeline and the allocation of the flow rate at the compressor station. The congestion location is determined by the congestion location 0–1 variable (B_{ij}^{loc}). The congestion location constraints are shown in Eqs. (4) and (5).

$$Q_{ij}^{\text{usable}} = Q_{ij} - Q_{ij}^{\text{relax}} \quad \forall (i,j) \in A \tag{4}$$

$$Q_{ij}^{\text{relax}} \Big/ M \le B_{ij}^{\text{loc}} \le Q_{ij}^{\text{relax}} M \quad \forall (i,j) \in A \tag{5}$$

where Q_{ij}^{usable} is the effective flow, 10^4 m^3/d; Q_{ij}^{relax} is the congestion relaxation variable, 10^4 m^3/d; B_{ij}^{loc} is congestion positioning 0–1 variable; A is the edge set; Physically, Q_{ij}^{usable} represents the actual gas volume participating in hydraulic pressure drop calculations; Q_{ij}^{relax} represents the virtual "excess" flow that exceeds the physical carrying capacity of the pipeline. A non-zero value implies that the current infrastructure cannot transport this portion of gas without violating pressure constraints. The variable B_{ij}^{loc} serves as a binary congestion indicator. It takes a value of 1 if $Q_{ij}^{\text{relax}} > 0$, effectively pinpointing the specific pipeline segment where a bottleneck occurs, and 0 otherwise.

Congestion relaxation variable, which is used to adjust the pipeline capacity to solve the congestion problem, should be set to a value greater than zero to ensure that it can effectively "reduce" the pipeline capacity. At the same time, the value of this variable should not exceed the maximum design capacity of the pipeline to keep the adjustment practicable, as shown in Eq. (6).

$$0 \le Q_{ij}^{\text{relax}} \le q_{ij}^{\max} \quad \forall (i,j) \in A \tag{6}$$

where $q_{ij}^{\max}$ is the maximum allowable flow of the pipeline, 10^4 m^3/d.

(3) Pipeline constraints

When natural gas flows through a pipeline, the pressure gradually decreases due to the roughness of the inner wall. To maintain computational tractability for the large-scale MINLP expansion model, we adopt an isothermal flow assumption and treat the gas composition (including the compressibility factor Z) as constant parameters derived from average operating conditions. The pipeline flow equation represents the relationship between pipeline flow, starting pressure, and ending pressure. To calculate the hydraulic pressure drop, use the term "effective flow" for both positive and negative pipeline flow, as shown in Eqs. (7) and (8).

$$R_{ij}^{\text{pipe}}\left(P_i^2 - P_j^2\right) = \lambda_{ij}\left|Q_{ij}^{\text{usable}}\right|Q_{ij}^{\text{usable}} \quad \forall (i,j) \in A_{\text{p}} \tag{7}$$

$$R_{ij}^{\text{pipe}} = 3.629\frac{d_{ij}}{\rho Z\tilde{T} l_{ij}} \tag{8}$$

where R_{ij}^{pipe} is the pipeline flow resistance coefficient, $(10^4\ \text{m}^3/\text{d}\cdot\text{MPa})^2$; d_{ij} is the pipe diameter, m; λ_{ij} is the pipe friction coefficient; l_{ij} is the pipe length, m; Z is the natural gas compression factor; $\tilde{T}$ is the natural gas temperature, K; ρ is the natural gas density, kg/m^3; A_{p} is the pipeline set.

The pipeline flow should meet the gas transmission capacity limit of the pipeline, as shown in Eq. (9).

$$-q_{ij}^{\max} \le Q_{ij} \le q_{ij}^{\max} \quad \forall (i,j) \in A_{\text{p}} \tag{9}$$

(4) Compressor station constraints

The compressor station has three states: Active, Close, and Bypass. "Active" means that the compressor station is pressurizing natural gas. "Close" means that the compressor station is closed and no gas flows through it. "Bypass" means that gas flows through the compressor station, but it is not pressurized, and all traffic passes through the bypass valve. To represent the state of the compressor station, we introduce the switch variable (B_{ij}^{station}), which indicates the overall switch state of the station. When the station is open, natural gas can either be pressurized or directly bypassed, but not both at the same time. Eq. (10) shows the state constraints of compressor stations.

$$B_{ij}^{\text{station}} = B_{ij}^{\text{active}} + B_{ij}^{\text{bypass}} \quad \forall (i,j) \in A_{\text{cs}} \tag{10}$$

where B_{ij}^{station} is the switching state variable of the compressor station; B_{ij}^{active} is the state variable of the compressor unit, which determines whether the natural gas is pressurized; B_{ij}^{bypass} is the status variable of bypass valve in compressor station; A_{cs} is the compressor station set.

There is a flow balance relationship between compressor station flow, compressor unit flow and bypass valve flow. At the same time, according to the state variables of the compressor unit and bypass valve, whether there is a flow value will be determined. Similarly, the flow of compressor station is relaxed to "reduce" the flow of compressor station, as shown in Eqs. (11)–(13).

$$Q_{ij}^{\text{usable}} = Q_{ij}^{\text{active}} + Q_{ij}^{\text{bypass}} \quad \forall (i,j) \in A_{\text{cs}} \tag{11}$$

$$B_{ij}^{\text{active}} q_{ij}^{\text{active,min}} \le Q_{ij}^{\text{active}} \le B_{ij}^{\text{active}} q_{ij}^{\text{active,max}} \quad \forall (i,j) \in A_{\text{cs}} \tag{12}$$

$$B_{ij}^{\text{bypass}} q_{ij}^{\text{bypass,min}} \le Q_{ij}^{\text{bypass}} \le B_{ij}^{\text{bypass}} q_{ij}^{\text{bypass,max}} \quad \forall (i,j) \in A_{\text{cs}} \tag{13}$$

where Q_{ij}^{active} is the pressurized flow of compressor station, 10^4 m^3/d; Q_{ij}^{bypass} is the bypass valve flow, 10^4 m^3/d.

When natural gas flows through the bypass valve, the pressure at the upstream and downstream nodes is equal. The maximum value is introduced to determine whether the constraint holds, as shown in Eqs. (14) and (15).

$$P_j \le P_i + \left(1 - B_{ij}^{\text{bypass}}\right)M \quad \forall (i,j) \in A_{\text{cs}} \tag{14}$$

$$P_j \ge P_i - \left(1 - B_{ij}^{\text{bypass}}\right)M \quad \forall (i,j) \in A_{\text{cs}} \tag{15}$$

where P_i is the upstream node pressure of the compressor station, MPa; P_j indicates the downstream node pressure of the compressor station, MPa.

When the compressor station performs the pressurization function, the upstream node pressure is related to the compressor inlet pressure, and the downstream node pressure is related to the compressor outlet pressure. The combination of compressor station flow direction variables in the following eight inequalities makes the correlation between pressures obey the compressor operating state, as shown in Eqs. (16)–(19).

$$P_i \le P_{ij}^{\text{in}} + \left(1 - B_{ij}^{\text{active}}\right)M \quad \forall (i,j) \in A_{\text{cs}} \tag{16}$$

$$P_i \ge P_{ij}^{\text{in}} - \left(1 - B_{ij}^{\text{active}}\right)M \quad \forall (i,j) \in A_{\text{cs}} \tag{17}$$

$$P_j \le P_{ij}^{\text{out}} + \left(1 - B_{ij}^{\text{active}}\right)M \quad \forall (i,j) \in A_{\text{cs}} \tag{18}$$

$$P_j \ge P_{ij}^{\text{out}} - \left(1 - B_{ij}^{\text{group}}\right)M \quad \forall (i,j) \in A_{\text{cs}} \tag{19}$$

where P_{ij}^{in} is the compressor inlet pressure, MPa; P_{ij}^{out} is the compressor outlet pressure, MPa.

When the natural gas is supercharged through the compressor station, the inlet and outlet pressure of the compressor should meet the maximum and minimum pressure ratio constraints, as shown in Eqs. (20) and (21).

$$P_{ij}^{\text{out}} \geq \varepsilon_{\min} P_{ij}^{\text{in}} - \left(1 - B_{ij}^{\text{active}}\right) M \quad \forall (i,j) \in A_{\text{cs}} \tag{20}$$

$$P_{ij}^{\text{out}} \leq \varepsilon_{\max} P_{ij}^{\text{in}} + \left(1 - B_{ij}^{\text{active}}\right) M \quad \forall (i,j) \in A_{\text{cs}} \tag{21}$$

where $\varepsilon_{\min}$ is the minimum pressure ratio of the compressor; $\varepsilon_{\max}$ is the maximum pressure ratio of the compressor.

The compressor station is usually composed of multiple compressor equipment, usually the compressor station runs in parallel, according to the number of compressor equipment, the flow of a single device can be calculated, as shown in Eq. (22).

$$Q_{ij}^{\text{active}} = I_{ij}^{\text{com}} Q_{ij}^{\text{com}} \quad \forall (i,j) \in A_{\text{cs}} \tag{22}$$

where I_{ij}^{com} represents the number of operating compressors; Q_{ij}^{com} is the flow rate of a single compressor, 10^4 m^3/d.

In the process of conveying gas from the lower pressure area to the high pressure area, the energy increase obtained by the unit mass of the gas is the pressure head, and the compressor pressure head is shown in Eq. (23).

$$H_{ij} = \frac{Z_{ij}^{\text{in}} R_{\text{g}} \tilde{T}}{m} \left[\left(\frac{P_{ij}^{\text{out}}}{P_{ij}^{\text{in}}} \right)^{m} - 1 \right], \ \forall (i,j) \in A_{\text{cs}} \tag{23}$$

where H_{ij} is the compressor pressure head, kJ/kg; Z_{ij}^{in} is compressor inlet natural gas compression factor; R_{g} is gas constant, J/(mol·K); m is expansion index of natural gas.

Compressor operation envelope defines the feasible boundary of compressor operation. The surge boundary curve, Stonewall boundary curve, maximum speed boundary and minimum speed boundary of compressor operation envelope are composed, as shown in Eqs. (24)–(28).

$$Q_{ij}^{\text{ac}} = \alpha^{\text{flow}} \frac{Z_{ij}^{\text{in}} Q_{ij}^{\text{com}}}{P_{ij}^{\text{in}}} \ \forall (i,j) \in A_{\text{cs}} \tag{24}$$

$$H_{ij} \geq a_{ij}^{\text{st}} \left(Q_{ij}^{\text{ac}}\right)^2 + b_{ij}^{\text{st}} Q_{ij}^{\text{ac}} + c_{ij}^{\text{st}} \quad \forall (i,j) \in A_{\text{cs}} \tag{25}$$

$$H_{ij} \leq a_{ij}^{\text{Nmax}} \left(Q_{ij}^{\text{ac}}\right)^2 + b_{ij}^{\text{Nmax}} Q_{ij}^{\text{ac}} + c_{ij}^{\text{Nmax}} \quad \forall (i,j) \in A_{\text{cs}} \tag{26}$$

$$H_{ij} \geq a_{ij}^{\text{Nmin}} \left(Q_{ij}^{\text{ac}}\right)^2 + b_{ij}^{\text{Nmin}} Q_{ij}^{\text{ac}} + c_{ij}^{\text{Nmin}} \quad \forall (i,j) \in A_{\text{cs}} \tag{27}$$

$$H_{ij} \leq a_{ij}^{\text{su}} \left(Q_{ij}^{\text{ac}}\right)^2 + b_{ij}^{\text{su}} Q_{ij}^{\text{ac}} + c_{ij}^{\text{su}} \quad \forall (i,j) \in A_{\text{cs}} \tag{28}$$

where Q_{ij}^{ac} is the compressor operating flow rate, m/s; a_{ij}^{st}, b_{ij}^{st}, c_{ij}^{st} are the surge boundary coefficient of the compressor; a_{ij}^{Nmax}, b_{ij}^{Nmax}, c_{ij}^{Nmax} are the boundary coefficient of the maximum speed of the compressor; a_{ij}^{su}, b_{ij}^{su}, c_{ij}^{su} are the compressor stagnation boundary coefficient; a_{ij}^{Nmin}, b_{ij}^{Nmin}, c_{ij}^{Nmin} are the boundary coefficient of the minimum speed of the compressor.

3.2. *Multi-component expansion planning optimization model*

The MCEO-Model is executed after the CL-Model provides detailed diagnostics on network congestion. By utilizing the feasible solution set derived from the congestion analysis as an initial solution (warm start), the model significantly mitigates the computational complexity of the global optimization problem. Building upon this foundation, the model rigorously balances technical feasibility with economic efficiency to determine the optimal pipeline network expansion scheme.

3.2.1. *Objective function*

The primary objective of the MCEO-Model is to determine the optimal expansion configuration by minimizing total capital expenditure (CAPEX). As detailed in Eq. (29), these costs encompass pipeline looping, new pipeline construction, and compressor station expansion. Since network capacity must be physically sufficient to handle the most demanding hydraulic conditions without violating safety constraints (e.g., compressor surge limits), the peak load serves as the controlling case for investment. Furthermore, incorporating multi-period operational costs into this high-fidelity, non-convex MINLP model would exponentially increase computational complexity. Consequently, this study prioritizes identifying the most cost-effective infrastructure configuration that guarantees system reliability and safety under worst-case demand scenarios.

$$\min F_2 = f_{\text{expand}} + f_{\text{new}} + f_{\text{cs}} \tag{29}$$

where f_{expand} is the cost of pipeline loop, CNY; f_{new} is the new pipeline construction costs, CNY; f_{cs} is the compressor station expansion cost, CNY.

The cost of pipeline loop mainly includes pipeline construction cost and pipeline procurement cost, as shown in Eq. (30).

$$f_{\text{expand}} = \sum_{ij \in A_{\text{p}}^{\text{old}}} B_{ij}^{\text{expand}} l_{ij} \left(C_{ij}^{\text{constr}} + C_{ij}^{\text{type}} \right) \tag{30}$$

where B_{ij}^{extend} is the binary variable of pipeline loop, 0 means not to expand pipeline ij, 1 means to expand pipeline ij; l_{ij} is the length of pipeline ij, km; C_{ij}^{constr} is the pipeline ij construction cost coefficient, CNY/km; C_{ij}^{type} is the pipeline ij procurement cost coefficient, CNY/km.

New pipeline is an effective way to increase the capacity of gas network. Unlike a pipeline loop, a new pipeline is a completely new pipeline laid between two points where a pipeline has not yet been built. The cost of new pipeline is also composed of pipeline construction cost and pipeline procurement cost, as shown in Eq. (31). The difference is that new pipelines need to select the appropriate specifications from the pipeline specification set to meet the specific gas transmission needs.

$$f_{\text{new}} = \sum_{ij \in A_{\text{p}}^{\text{new}}} \sum_{k \in K} B_{ij,k}^{\text{type}} l_{ij} \left(C_{ij,k}^{\text{constr}} + C_{ij,k}^{\text{type}} \right) \tag{31}$$

where $A_{\text{p}}^{\text{new}}$ is the potential possible new pipeline collection, detailed generation methodology of which is provided in Appendix C; K is the set of pipeline specifications; $B_{ij,k}^{\text{type}}$ is the new pipe specification binary variable, 1 indicates that a new pipe of specification k is created between nodes i and j.

The expansion of compressor stations is also a way to increase the total amount of gas transferred to the pipeline network. This study only deals with the addition of compressor units in the existing compressor station, and does not consider the situation of the new compressor station. The cost constraints of compressor station expansion are shown in Eq. (32).

$$f_{cs} = \sum_{ij \in A_{cs}} I_{ij}^{extend} B_{ij}^{cs} C_{ij}^{cs} \tag{32}$$

where B_{ij}^{cs} is the binary variable of compressor station expansion, and when it is 1, it means that a compressor unit is added in compressor station *ij*; I_{ij}^{extend} is the number of expanded compressors at the compressor station; C_{ij}^{cs} represents the new compressor cost of compressor station *ij*.

3.2.2. Constraints

Pipeline loop usually refers to the construction of a new subpipeline in parallel to an already constructed pipeline. This practice is mainly used to increase transmission capacity. In practice, the construction of a single pipeline with a larger diameter is usually preferred to the construction of multiple smaller diameter pipelines. This is because a single large-diameter pipeline can deliver higher economic efficiency and lower maintenance costs while providing the same amount of conveyance. Therefore, pipeline loop occurs only in the set of constructed natural gas pipelines, as indicated by the pipeline loop variable (B_{ij}^{extend}). The pipeline loop constraints are shown in Eqs. (33) and (34).

$$B_{ij}^{extend} \le 1 \quad \forall (i,j) \in A_p^{old} \tag{33}$$

$$B_{ij}^{extend} = 0 \quad \forall (i,j) \in A_p^{new} \tag{34}$$

MCEO-Model reflects the current state of the pipeline through the pipeline presence state variable (B_{ij}^{exist}). For natural gas pipelines that have been built and are in operation, the pipeline presence variable is set to 1, indicating that the pipeline has been built and is in service. For natural gas pipelines that have not yet been built, those in the planning stage or under consideration, the pipeline presence state variable is allowed to take a value less than or equal to one. When planning a new pipeline *ij*, if it is decided to build it, its pipeline presence state variable is set to 1 to indicate that the pipeline will be included in the future network. On the contrary, if a new pipeline *ij* is not planned, its enablement state variable is set to 0 to indicate that the pipeline will not be built in the current planning phase. Therefore, the pipeline existence state constraints are shown in Eqs. (35) and (36).

$$B_{ij}^{exist} = 1 \quad \forall (i,j) \in A_p^{old} \tag{35}$$

$$B_{ij}^{exist} \le 1 \quad \forall (i,j) \in A_p^{new} \tag{36}$$

where B_{ij}^{exist} is the existence state variable of pipeline.

The flow rate through the pipeline needs to be lower than the maximum capacity of the natural gas pipeline to ensure the safety of the delivery process, and the pipeline flow rate constraint is shown in Eq. (37).

$$0 \le Q_{ij} \le B_{ij}^{exist} q_{ij}^{max} \quad \forall (i,j) \in A_p \tag{37}$$

Set the hydraulic calculation flow (Q_{ij}^{flow}) of the pipeline between nodes for the hydraulic pressure drop calculation of the pipeline. When the pipeline is expanded, the main and secondary pipes will share the pipeline flow equally. When the pipeline is newly constructed, its calculated flow rate is equal to the pipeline flow rate. The pipeline hydraulic calculation flow constraint is shown in Eqs. (38)–(41).

$$Q_{ij}^{flow} \le 0.5 Q_{ij} + \left(1 - B_{ij}^{extend}\right) M \quad \forall (i,j) \in A_p^{old} \tag{38}$$

$$Q_{ij}^{flow} \ge 0.5 Q_{ij} - \left(1 - B_{ij}^{extend}\right) M \quad \forall (i,j) \in A_p^{old} \tag{39}$$

$$Q_{ij}^{flow} \le Q_{ij} + B_{ij}^{exist} M \quad \forall (i,j) \in A_p^{new} \tag{40}$$

$$Q_{ij}^{flow} \ge Q_{ij} - B_{ij}^{exist} M \quad \forall (i,j) \in A_p^{new} \tag{41}$$

For MCEO-Model, its pipeline hydraulic pressure drop formula is obtained by hydraulic calculation flow (Q_{ij}^{flow}). In the planning and analysis of natural gas pipeline network, the definition of pipeline flow direction is very important. Therefore, the bidirectional flow of pipeline natural gas is realized by increasing the absolute flow value, as shown in Eq. (42).

$$R_{ij}^{pipe}\left(P_i^2 - P_j^2\right) = \left|Q_{ij}^{flow}\right| Q_{ij}^{flow} \quad \forall (i,j) \in A_p \tag{42}$$

In order to ensure the economic benefits, this paper will consider using different specifications of pipelines when planning new pipelines. Meanwhile, the specifications of the auxiliary pipe and the main pipe are considered to be the same when planning the pipeline loop. Pipe specification constraints are shown in Eqs. (43)–(46).

$$d_{ij} = d_{ij}^{old} \quad \forall (i,j) \in A_p^{old} \tag{43}$$

$$d_{ij} \ge d_{ij,k}^{type} + \left(B_{ij,k}^{type} - 1\right) M \quad \forall (i,j) \in A_p^{new}, \forall k \in K \tag{44}$$

$$d_{ij} \le d_{ij,k}^{type} + \left(1 - B_{ij,k}^{type}\right) M \quad \forall (i,j) \in A_p^{new}, \forall k \in K \tag{45}$$

$$\sum_{k \in K} B_{ij,k}^{type} = B_{ij}^{exist} \quad \forall (i,j) \in A_p^{new}, \forall k \in K \tag{46}$$

where d_{ij}^{old} denotes the specifications of the existing pipeline, m; $d_{ij,k}^{type}$ represents new pipeline specifications, m.

In this study, the expansion of the compressor station was achieved by adding one or more new compressor units to enhance the capacity of the site to handle greater flow rate. The surge and stagnation curve of compressor is the relation between the pressure head *H* and the flow rate *Q*. Therefore, the compressor feasible region constraint is used to determine whether the compressor station needs to be expanded, and the compressor station expansion variable is expressed. Compressor station expansion constraints are shown in Eqs. (47) and (48).

$$0 \le I_{ij}^{extend} \le I_{ij}^{extend,max} \quad \forall (i,j) \in A_{cs} \tag{47}$$

$$I_{ij}^{com} = I_{ij}^{old} + I_{ij}^{extend} \quad \forall (i,j) \in A_{cs} \tag{48}$$

In short, CL-Model takes Eq. (1) as the objective function and Eqs. (2)–(28) as the constraint condition. MCEO-Model takes Eqs. (29)–(32) as the objective function, and Eq. (2), Eq. (3), Eqs. (12)–(28), Eqs. (33)–(48) as the constraint condition.

4. Optimization method

4.1. Model processing

The integrated problem, encompassing both the CL-Model and MCEO-Model, is formulated as a large-scale, non-convex MINLP. The computational intractability of this formulation arises primarily from several key sources of non-convexity and non-linearity embedded within the physical constraints. First, the pipeline hydraulic model (Eqs. (7) and (42)) is highly non-convex, involving squared pressure terms and a complex, flow-dependent friction factor. Furthermore, significant non-linearities arise from compressor station modeling, including the exponential head calculation (Eq. (23)) and, critically, the non-convex feasible region defined by the quadratic operating envelope (Eqs. (25)–(28)). Finally, a combinatorial challenge is introduced by the product of an integer variable (number of compressors, I_{ij}^{com}) and a continuous variable (flow per compressor, Q_{ij}^{com}) in the compressor flow distribution (Eq. (22)).

To render this problem computationally tractable for modern solvers, we employ a systematic reformulation strategy. For the complex pipeline hydraulics, the non-linear friction-flow relationship (Eqs. (B1)–(B3)) is first approximated by a convex quadratic function (Eq. (B4)), which is subsequently embedded within a disjunctive "big-M" formulation (Eqs. (B5)–(B9)) to create a set of convex quadratic constraints. For compressor constraints, the non-linear product in Eq. (22) is linearized using a standard disjunctive formulation (Eqs. (B10)–(B11)) that replaces the integer variable with a set of binary variables. Perhaps most critically, the non-convex operating envelope is addressed via a piecewise-linear outer approximation. This approximation distinguishes between convex boundaries (Stonewall, max speed), handled by simple linear inequalities (Eqs. (B12), (B13)), and non-convex boundaries (Surge, min speed), which require a more complex "big-M″ disjunction (Eqs. (B14)–(B21)) to model the valid feasible space.

The complete mathematical derivations for these transformations are detailed in Appendix B. These model-level reformulations are essential for computational tractability. In addition, we develop a two-stage solution strategy to further accelerate convergence, as described in Section 4.2.

4.2. Two-stage strategy

Convex relaxation and linearization techniques are used for the proposed CL-Model and MCEO-Model. However, the MCEO-Model system still presents significant challenges due to the numerous possible combinations of facility installation locations, piping specifications, and compressor models. The congestion location solution ($B_{ij}^{\text{loc}*}$) obtained from CL-Model serves as the starting point for MCEO-Model to solve, expediting the model's initial solution and convergence. Fig. 4 illustrates the proposed two-stage strategy flow. The first stage involves inputting the fundamental parameters of the pipeline network, including the node supply and demand relationships, and an infeasible pipeline transportation scenario. In the first stage, the network congestion area is located. In order to speed up the model solving time, the CL-Model is processed by convex relaxation and linearization techniques. Then, a potential network expansion scheme ($B_{ij}^{\text{extend}\#}$, $B_{ij}^{\text{cs}\#}$) is generated based on the solution of CL-Model. Then the second stage is solved, and the initial value of the expansion variable of the pipeline/compressor station is set to sum. Then, MCEO-Model is linearized by convex relaxation and linearization technology, and finally the optimal economic expansion scheme is obtained.

4.3. Solution framework

The overall solution framework of this paper is shown in Fig. 5. The main steps of the solution framework are as follows: (1) Network topology description. Sort out the topological layout of the natural gas pipeline network system, the location of facilities and pipeline connection relationships, and form a pipeline network node association matrix. (2) Pipeline network operation data input. Input gas source and user data, pipeline network parameters, compressor station parameters and infeasible pipeline operating conditions. (3) Model construction. Considering natural gas physical property constraints, node flow pressure constraints, pipeline hydraulic constraints, compressor station feasible domain constraints, and flow relaxation constraints, CL-Model and MCEO-Model are constructed. (4) Design of solution method. Convex relaxation and linearization techniques are firstly used to deal with the complex constraints in the model. Then two-stage strategy is adopted, and CL-Model is used in the first stage to perform pipeline congestion analysis and generate potential solution schemes for capacity expansion optimization. In the second stage, the generated potential solution is used as a starting point and optimized for pipe network expansion. Subsequently, the model is programmatically constructed by GAMS modeling software and iterative operations are performed using the MINLP solver. All calculations were run on a computer with an Intel Core i7 processor (2.90 GHz) and 16 GB of RAM. (5) Result Analysis. Congestion location analysis and potential capacity expansion schemes generation are performed by CL-Model solution. Multi-scenario sensitivity analysis and capacity expansion economic analysis are performed based on the MCEO-Model solution.

5. Case study

5.1. Basic data

5.1.1. Network structure

To validate the effectiveness of the ICIEPF proposed in this paper, two test cases are employed. Their topologies are illustrated in Fig. 6. Case 1 consists of two source nodes, seven demand nodes, three compressor stations, and 15 pipelines. The basic network parameters are detailed in Table A1, and the nodal flow data are provided in Table A2. Case 2 is a larger-scale network comprising three source nodes, 29 demand nodes, six compressor stations, and 39 pipelines. The basic parameters for Case 2 are listed in Table A3, with nodal flow data in Table A4.

5.1.2. Scenario analysis

To comprehensively validate the proposed models and methods, we investigate four key aspects across nine scenarios using the two test cases, as summarized in Table 2.

(1) Pipeline congestion location and analysis: Scenario 1 focuses on identifying pipeline network congestion. This involves analyzing flow directions to pinpoint potential bottlenecks caused by hydraulic limits and compressor station capacity constraints.
(2) Analysis of expansion optimization results: Scenario 2 analyzes the optimized expansion outcomes, including the network expansion plan (topology changes), flow distribution, compressor station operation schedules, and a detailed economic analysis of the expansion costs.
(3) Sensitivity analysis: Scenarios 3–8 evaluate the impact of different combinations of the three expansion components on network performance. Comparing Scenario 3 (new pipeline only) with Scenario 4 (pipeline looping only)

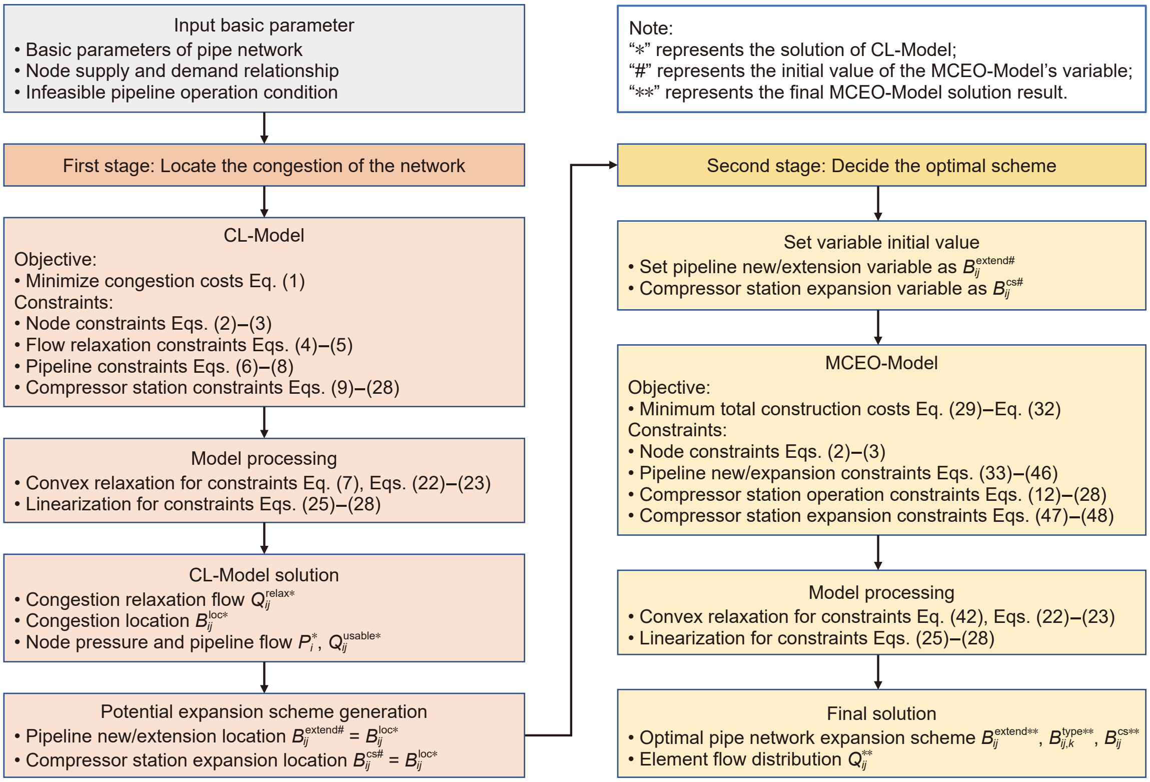

Fig. 4. Two-stage strategy flow of ICIEPF.

reveals differences in cost, efficiency, and implementation complexity between constructing new routes and expanding existing ones. Similarly, Scenario 5 assesses the standalone effect of compressor station expansion, while the hybrid approaches in Scenarios 6 through 8 allow for a comparative analysis of combined strategies. These analyses help determine the most beneficial investment portfolio.

(4) Iterative convergence analysis: Scenario 9 evaluates the computational performance of the proposed model and solution method. Since the small scale of Case 1 limits the insight into convergence behavior, the large-scale network (Case 2) is used to analyze the solver's performance and iterative convergence characteristics.

5.2. Results and discussion

5.2.1. Gas network congestion location and analysis

The proposed CL-Model was applied to Case 1 to identify congestion locations, with the resulting flow distribution plotted in Fig. 7(a). The results reveal that the critical congestion points in Case 1 are pipeline P6 and compressor station CS3. The congestion relaxation value and flow data for P6 indicate that its high flow rate (4200×10^4 m^3/d) causes a severe hydraulic pressure drop. This pressure drop violates the nodal pressure constraint, identifying P6 as a significant bottleneck. Simultaneously, as shown in Fig. 7(a), the required flow rate for compressor station CS3 is 3000×10^4 m^3/d, whereas the congestion relaxation value is 849×10^4 m^3/d. This indicates that CS3 cannot handle the excess flow, making it another critical congestion point. For Case 2, three congestion points are identified: P6, P15, and CS5 (Fig. 7(b)). Pipelines P6 and P15 are located in the downstream section of the network, where there is a lack of downstream pressure boosting capabilities. Consequently, excessive flow results in insufficient pressure to meet demand. Compressor station CS5 becomes a congestion point because it is required to maintain high outlet pressure to support this downstream demand, exceeding its operational limits.

The pressure profiles obtained from solving Case 1 and Case 2 are shown in Fig. 8(a) and (b). The figures show that pressures at the supply nodes in both cases have reached the maximum limit of 7.2 MPa, while pressures at several demand nodes approach the minimum allowable limit of 5 MPa. This indicates that the delivery capacity in both networks has reached its physical limit; any further increase in demand would violate constraints, leading to infeasibility. This confirms that the primary limitation on conveyance capacity is the hydraulic pressure drop. The introduction of flow relaxation variables mathematically "reduces" the required capacity, effectively locating congestion and determining the maximum feasible throughput, thus providing actionable guidance for operators.

To further investigate the causes of infeasibility, we compared compressor operating conditions with and without the operating envelope constraints (Eqs. (25)–(28)), as shown in Fig. 8(c) and (d). The results reveal that when constrained by the operating envelope, compressor operating points sit dangerously close to their boundaries. Specifically, for the medium-pressure station CS3 in Case 1, the operating point hits the maximum capacity limit, validating the CL-Model's accuracy in locating compressor congestion. Conversely, when the envelope constraints are removed, the required operating point for CS3 falls far outside the feasible region. This demonstrates an urgent need to install additional compressor units at CS3 to handle the massive flow. In Case 2, removing the constraints results in all compressor operating points falling outside the feasible domain. This underscores the necessity of considering the operating envelope during expansion planning. Crucially, operating points falling outside the feasible

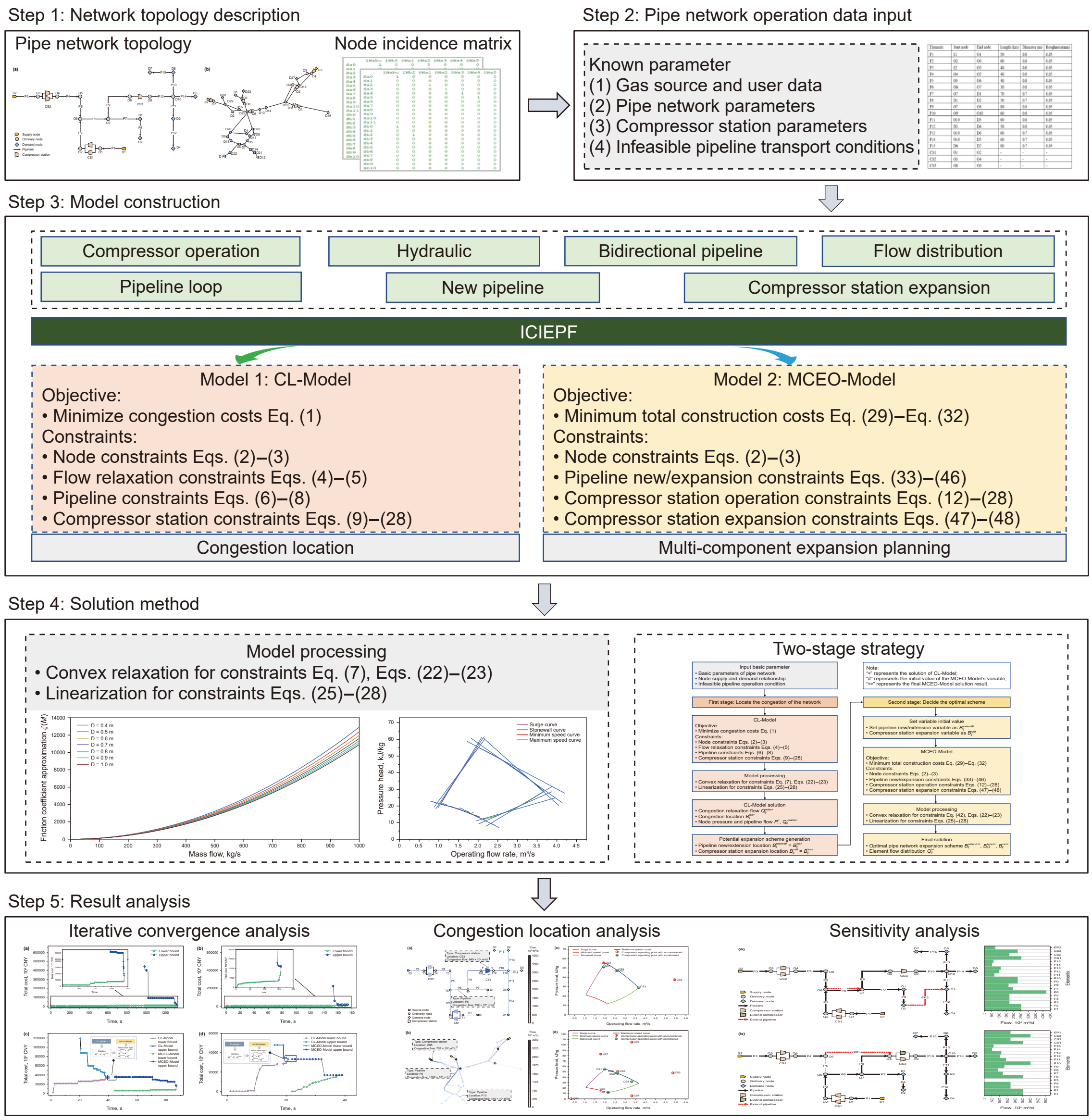

Fig. 5. Overall solution framework.

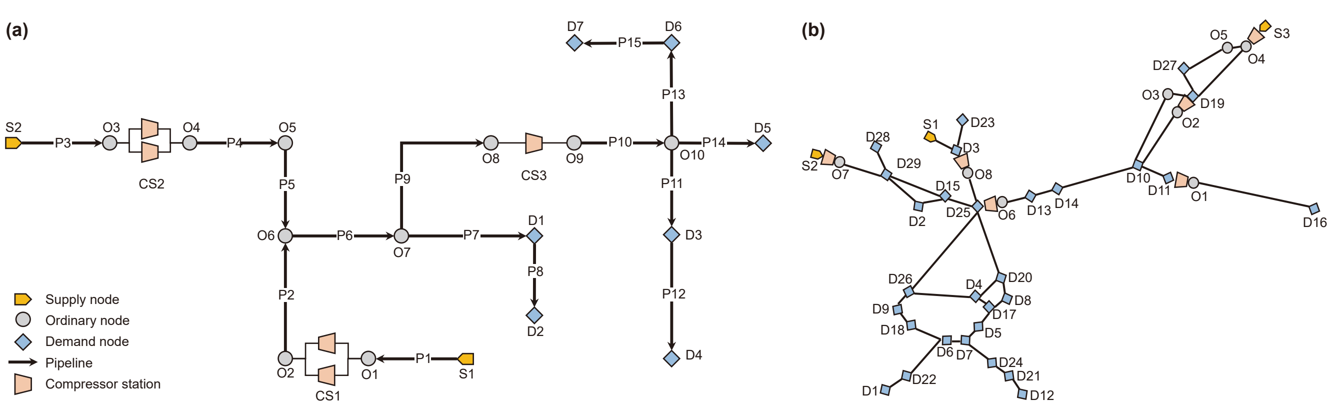

Fig. 6. Gas network topology: (**a**) Case 1; (**b**) Case 2.

Table 2
Scenario setting.

Scenario	Optimization strategy	Component			Case	Content
		New pipeline	Pipeline loop	Compressor station expansion		
Scenario 1	CL-Model	×	×	×	Case 1, Case 2	Pipeline congestion location and analysis
Scenario 2	MCEO-Model	✓	✓	✓	Case 1, Case 2	Analysis of expansion optimization results
Scenario 3	ICIEPF	✓	×	×	Case 1	Sensitivity analysis
Scenario 4	ICIEPF	×	✓	×	Case 1	Sensitivity analysis
Scenario 5	ICIEPF	×	×	✓	Case 1	Sensitivity analysis
Scenario 6	ICIEPF	✓	✓	×	Case 1	Sensitivity analysis
Scenario 7	ICIEPF	✓	×	✓	Case 1	Sensitivity analysis
Scenario 8	ICIEPF	✓	✓	✓	Case 1	Sensitivity analysis
Scenario 9	ICIEPF, MCEO-Model	✓	✓	✓	Case 2	Iterative convergence analysis

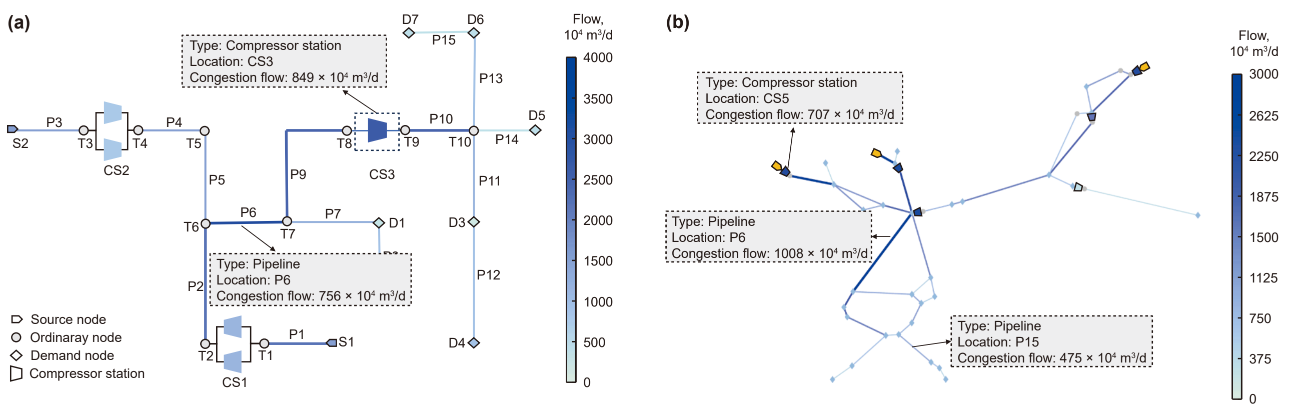

Fig. 7. Congestion location model results of distribution: (**a**) Case 1; (**b**) Case 2.

envelope represent severe physical hazards. Operating in the surge region causes violent flow reversals and vibrations that can lead to catastrophic compressor damage, while choke conditions result in a sharp drop in efficiency and pressure ratio. Therefore, embedding these safety constraints is not just a mathematical formality but a critical measure to prevent operational failures and ensure system safety.

The magnitude of the congestion relaxation value quantifies the extent of capacity deficiency, reflecting severe limitations in system efficiency without infrastructure upgrades. Although the CL-Model accurately identifies bottlenecks and suggests potential intervention areas, these suggestions are not necessarily the global optimal expansion plan. Therefore, further optimization via the MCEO-Model is required, using the preliminary strategy from the congestion analysis as a warm start to enhance solution efficiency and convergence speed.

5.2.2. Analysis of expansion optimization results

The MCEO-Model considers multiple expansion components—new pipelines, pipeline loops, and compressor station expansions—using the congestion location results as a starting point. The optimal network expansion schemes obtained are shown in Fig. 9. For Case 1, the optimal scheme involves expanding pipeline P6 (looping) and compressor station CS3. This directly resolves the congestion identified at these locations. The total expansion cost is 23784×10^4 CNY, comprising 17769×10^4 CNY for pipeline looping and 6015×10^4 CNY for compressor station expansion. For Case 2, the optimal scheme involves expanding pipelines P7, P8, P15, P18, P19 and compressor station CS5. Notably, the identified congestion points were P6, P15, and CS5, yet the optimal expansion plan covers a different set of pipelines. This discrepancy arises because the CL-Model minimizes relaxation values to locate bottlenecks, whereas the MCEO-Model minimizes cost. In Case 2, the solver found that expanding shorter (and thus cheaper) upstream or parallel pipes (like P7, P8) was a more cost-effective way to relieve the pressure on P6 than expanding P6 itself.

Fig. 10 illustrates the flow and pressure distribution for the expanded Case 1 network. Fig. 10(a) shows that looping pipeline P6 effectively splits the originally concentrated flow (4200×10^4 m^3/d) between the main and secondary lines. This dispersion resolves the bottleneck and improves overall transport efficiency, resulting in a more balanced flow distribution that mitigates risks associated with flow concentration. The addition of a compressor unit at CS3 significantly boosts the station's capacity, supporting the network's pressurization needs. As seen in Fig. 10(b) and (c), pressure in the upstream section is maintained at a high level (7.5–9 MPa); higher operating pressure reduces friction loss and energy consumption. Meanwhile, pressures at nodes D4 and D7 remain close to the minimum allowable limit, indicating that the network capacity is being fully utilized. Fig. 10(d) confirms that all compressor stations operate well within their feasible regions, maintaining a safety margin from the boundaries. This demonstrates that the expanded network not only meets current demand but also possesses sufficient operational flexibility to cope with fluctuations, ensuring stability. A similar analysis applies to Case 2 and is omitted here to avoid redundancy.

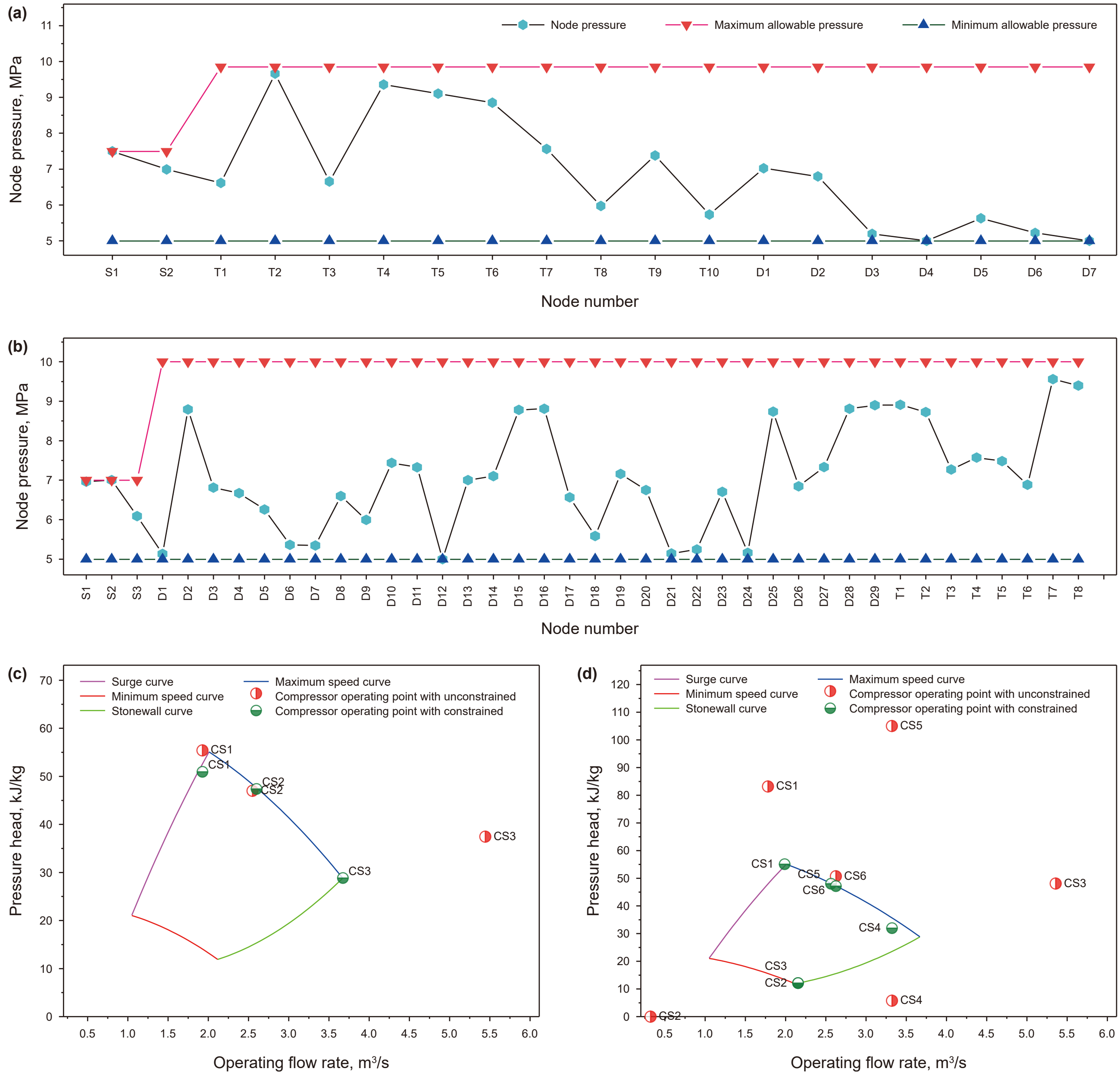

Fig. 8. Congestion location model results of pipelines and compressor stations: (**a**) node pressure in Case 1; (**b**) node pressure in Case 2; (**c**) compressor operating point in Case 1; (**d**) compressor operating point in Case 2.

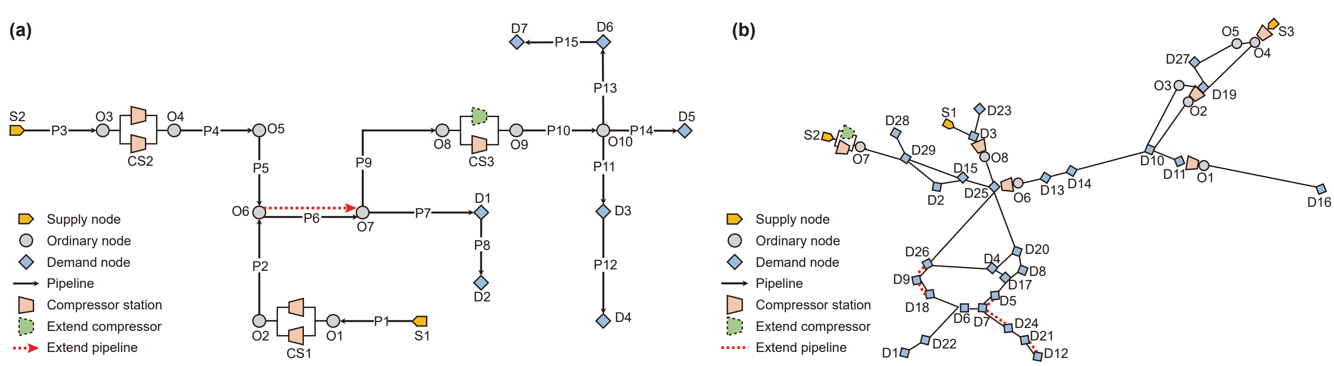

Fig. 9. Optimal expansion plan of network: (**a**) Case 1; (**b**) Case 2.

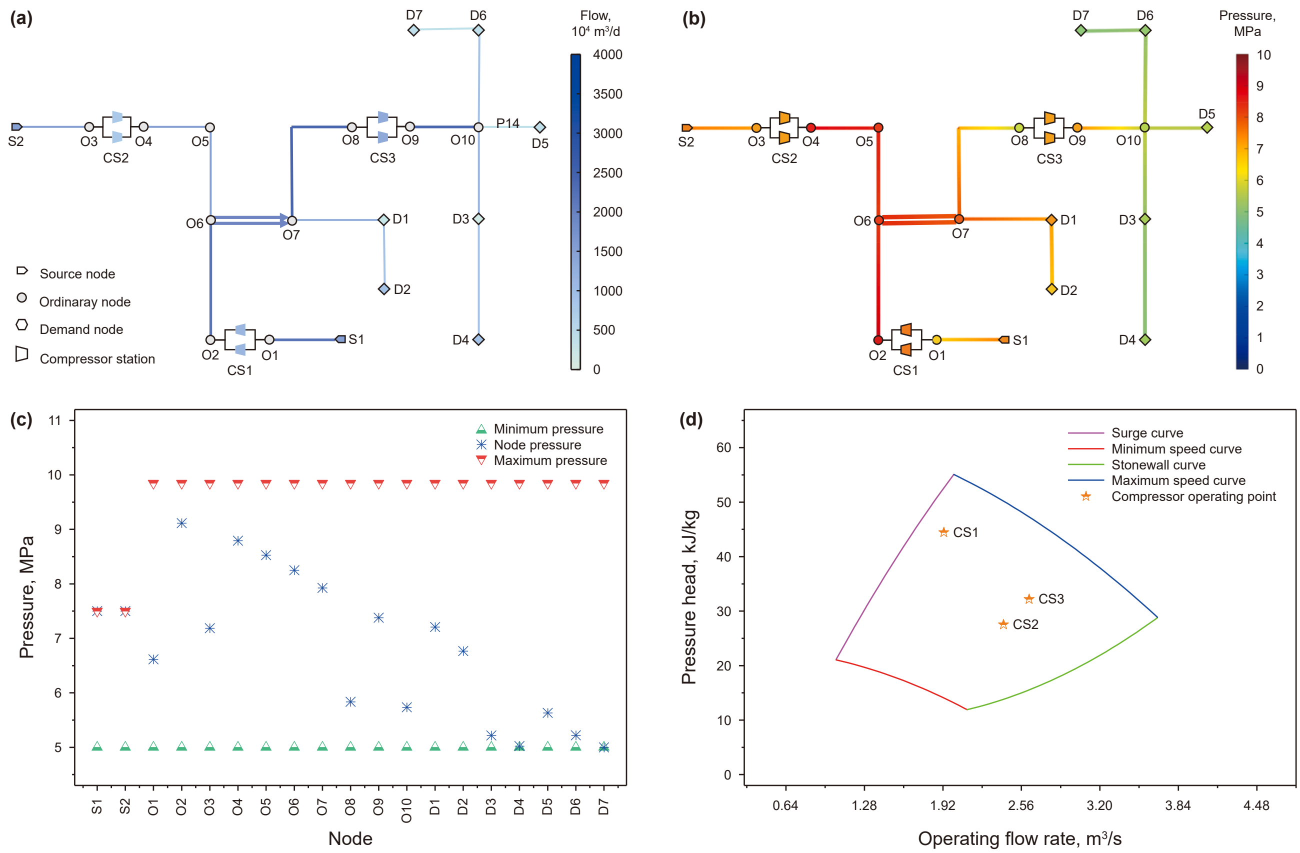

Fig. 10. Operating parameters of pipeline network under optimal expansion plan: (**a**) flow heat map; (**b**) pressure heat maps; (**c**) node pressure; (**d**) compressor operating point.

Table 3
Optimal solutions under different capacity expansion measures.

Scenario	Component			Feasibility	Optimal scheme
	New pipeline	Pipeline loop	Compressor		
Scenario 3	✓			Feasible	EP1+EP2
Scenario 4		✓		Infeasible	-
Scenario 5			✓	Infeasible	-
Scenario 6	✓	✓		Feasible	P6+EP2
Scenario 7	✓		✓	Feasible	EP1+CS3
Scenario 8	✓	✓	✓	Feasible	P6+CS3

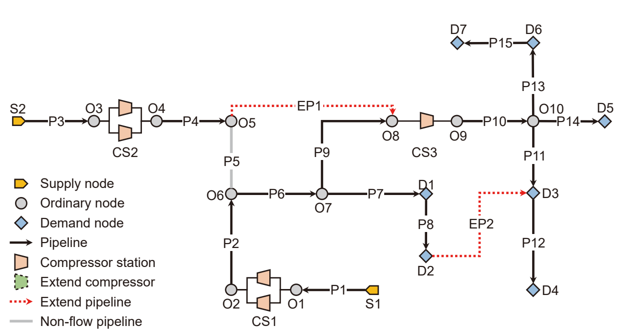

Fig. 11. Expansion optimization results in the single component expansion mode.

5.2.3. Sensitivity analysis

To evaluate the influence of different expansion modes on network performance, a sensitivity analysis of various combinations of the three expansion measures was conducted. Table 3 presents the feasibility results. Regarding single-component strategies, only Scenario 3 (new pipeline only) is feasible, whereas Scenario 4 (pipeline looping only) and Scenario 5 (compressor station expansion only) result in infeasibility.

The expansion optimization results for Scenario 3 are illustrated in Fig. 11. As shown, the solution involves constructing pipelines EP1 and EP2 between nodes (O5, O8) and (D2, D3), respectively. In this scheme, the initial flow direction of pipeline P5 reverses from O5→O6 to O6→O5. The entire flow from gas source S2 and a portion of the flow from gas source S1 are delivered directly to the inlet of compressor station CS3 via pipe EP1, thereby reducing the load on pipe P6. Pipeline EP3 bypasses compressor station CS3 to directly transport a portion of the flow (525.5×10^4 m^3/d) from node D2 to node D3, thus alleviating congestion at CS3. Analysis confirms that new pipeline construction can simultaneously resolve bottlenecks at pipeline P6 and compressor station CS3 by redistributing network flow. Conversely, detailed analysis indicates that relying solely on pipeline looping or compressor station expansion fails to

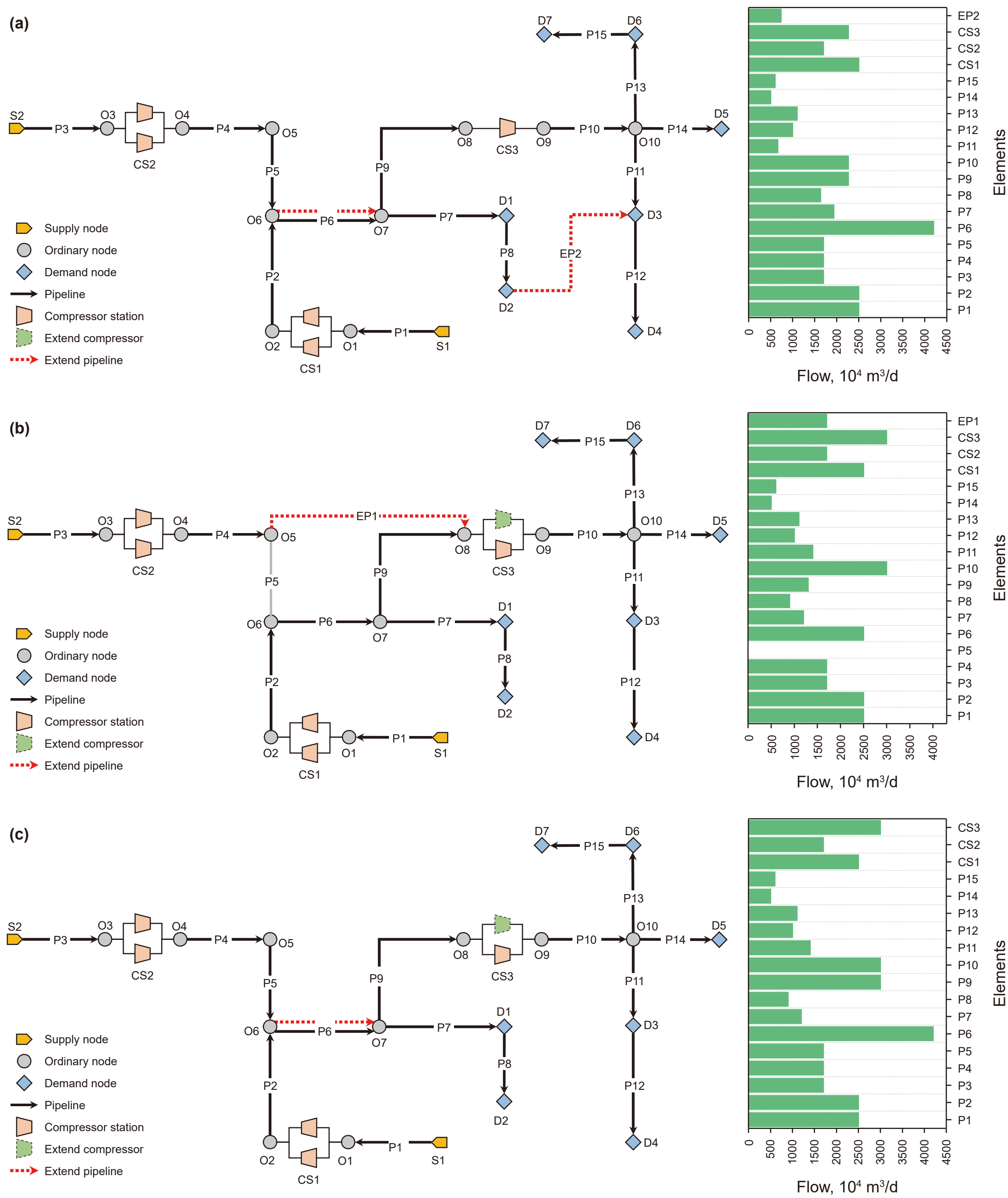

Fig. 12. Expansion optimization results in the multi-component expansion mode: (**a**) scenario 6; (**b**) scenario 7; (**c**) scenario 8.

sufficiently alter the flow distribution in this dendritic network, resulting in no feasible solution. This finding indicates that in complex networks, single-component measures are often insufficient to resolve systemic hydraulic bottlenecks. Pipeline looping reduces resistance but cannot actively boost pressure, while compressor expansion provides pressure lift but is constrained by maximum allowable operating pressures and hydraulic resistance. Consequently, multi-component coordinated expansion is essential to leverage the synergy between resistance reduction and pressure boosting, ensuring hydraulic feasibility.

Multi-component expansion modes yield feasible solutions, as shown in Fig. 12. When considering the combination of new pipeline and pipeline loop, the optimal solution is P6+EP3. When considering the combination of new pipeline and compressor station expansion, the optimal scheme is EP1+CS3. When considering the combination of pipeline loop and compressor station expansion, the optimal scheme is P6+CS3. For the combined expansion measures of “New pipeline and pipeline loop”, the optimal scheme is to expand pipelines P6 and new pipelines EP3 (D2, D3). Under this scheme, the expansion of pipeline P6 can

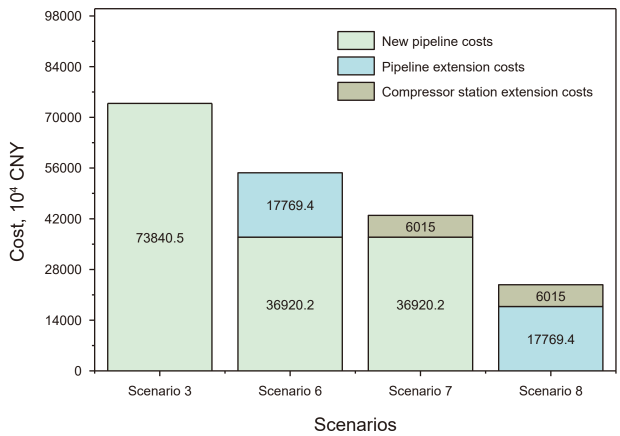

Fig. 13. Economic comparison of different scenarios.

alleviate the congestion of pipeline P6. The new pipeline EP3 may be to bypass some of the flow around compressor station CS3 to alleviate the congestion of compressor station CS3. For the combination of “Pipeline new and compressor station expansion”, the optimal is to build (O5, O8) pipeline EP1 and expand compressor station CS3. In this scheme, the flow of the gas source S2 is no longer transmitted through P6 pipeline, but directly to the compressor station CS3, effectively avoiding the congestion point formed by the confluence of the two gas sources of pipeline P6. The expansion of compressor station CS3 effectively increases the pressurization processing capacity and avoids the congestion of CS3. For the combination of “Pipeline loop + Compressor station expansion”, the optimal scheme is to expand pipeline P6 and compressor station CS3. In this expansion scheme, the congestion of pipeline P6 and compressor station CS3 is solved by means of expansion directly.

In summary, effective schemes are consistently achievable under multi-component expansion modes, whether by combining new pipelines, looping, or compressor upgrades. These schemes not only resolve capacity deficits at congestion points but also validate the importance of congestion location analysis. This refined analysis ensures the selection of the most appropriate expansion plan while elucidating the underlying logic of each strategy. The method provides not just a solution, but a comprehensive explanation aligning with the practical requirements of real-world network expansion projects.

Fig. 13 illustrates the expansion costs across various scenarios. Quantitative comparison reveals that the hybrid strategy combining Pipeline Looping + Compressor Station Expansion yields the lowest total investment (23784.4×10^4 CNY). In contrast, the “New Pipeline + Compressor Expansion” strategy costs 42935.5×10^4 CNY, while “Looping + New Pipeline” costs 54689.6×10^4 CNY. The single-component strategy involving only new pipeline construction is the most expensive (73840.5×10^4 CNY). These results demonstrate that multi-component strategies are significantly more cost-effective. Specifically, incorporating compressor station expansion reduces investment costs by

Table 4
Solution performance of MCEO-Model and ICIEPF in Case 2.

Optimization strategy	Solver	Optimal solution, 10^4 CNY	Solution times, s	Mean time, s
MCEO-Model	BARON	16804.03	1319.84	746.50
	SCIP	16804.16	174.00	
ICIEPF	BARON	16804.20	43.03	40.37
	SCIP	16804.03	37.70	

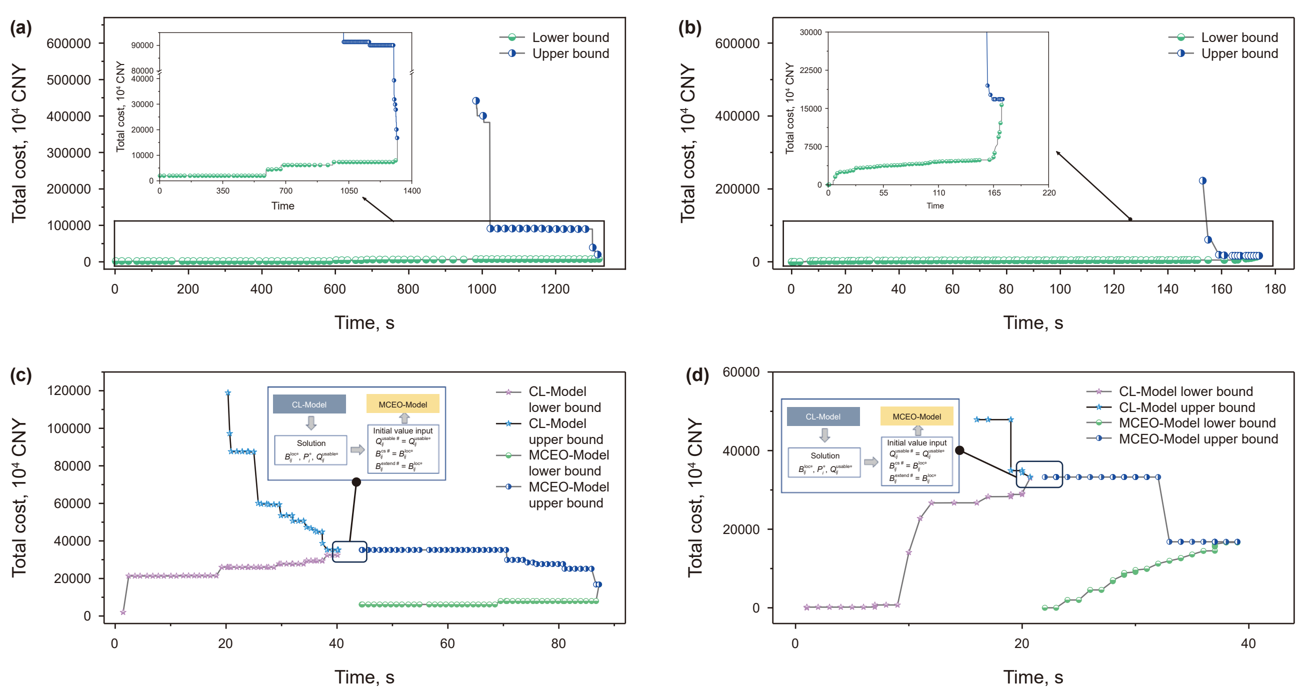

Fig. 14. Iterative convergence curve for Case 2: (**a**) BARON for MCEO-Model; (**b**) SCIP for MCEO-Model; (**c**) BARON for ICIEPF; (**d**) SCIP for ICIEPF.

approximately 54.8% compared to relying solely on new pipelines, primarily by avoiding the high capital expenditure associated with constructing entirely new routes. Beyond identifying the minimum-cost solution, the ICIEPF serves as a quantitative evaluation platform. It enables the analysis of trade-offs between strategy combinations, such as weighing the construction requirements of looping against the capacity enhancements of compressor expansion, thus facilitating decisions that balance economic efficiency with engineering feasibility.

5.2.4. Iterative convergence analysis

In this study, MCEO-Model and ICIEPF were used to solve Case 2, and the results are shown in Table 4. The data indicate that both methods yield optimal solutions converging to approximately 16804×10^4 CNY within a limited time. The MCEO-Model required 1319.84 s and 174 s using the BARON and SCIP solvers, respectively (average: 746.5 s). In contrast, the ICIEPF required only 43.03 s and 37.70 s, respectively (average: 40.37 s). This demonstrates that ICIEPF is significantly faster, achieving an average speed up of approximately 12.37 times (4.62 times faster on SCIP and 15.84 times faster on BARON). Consequently, the ICIEPF's two-stage strategy provides substantial performance enhancements for network expansion optimization.

Fig. 14 illustrates the iterative convergence process. For the MCEO-Model, the search for the first viable solution was slow: the BARON solver took 983 s to find the first feasible solution and 1319 s to reach global optimality; SCIP found the first feasible solution in 153 s and converged in 174 s. This highlights the significant impact of the initial solution on convergence. Fig. 14(c) and (d) demonstrate the convergence of ICIEPF. By using the first-stage CL-Model to quickly locate congestion and relax component flows, the ICIEPF provides a high-quality initial point (warm start) for the second stage. This allows the solver to rapidly locate the final solution, resulting in a drastic reduction in computation time compared to the MCEO-Model.

6. Conclusions

This paper developed and validated an Integrated Congestion Identification and Expansion Planning Framework (ICIEPF) to address the critical challenge of expanding natural gas pipeline systems in a targeted, safe, and computationally efficient manner. Research demonstrates that by precisely identifying congestion points and subsequently co-optimizing a suite of expansion options with embedded safety constraints, system reliability is significantly enhanced while investment costs are reduced. The key findings and implications are summarized below:

(1) The framework supports quantitative decision-making for infrastructure investment. Case studies indicate that the proposed targeted expansion strategy reduces investment costs by up to 54.8% compared to single-component methods. Regarding operational feasibility, the model strictly enforces compressor safety constraints (surge, choke, and speed limits), ensuring that planned equipment operates within feasible physical envelopes. Additionally, the average 12.37-fold reduction in computation time validates the method's efficiency for large-scale network analysis.

(2) The primary contribution is the two-stage sequential optimization structure. The deterministic location of physical congestion points in the first stage defines the decision space for the second stage. This replaces heuristic capacity additions with a calculated process based on physical constraints, ensuring investment is explicitly directed toward verified bottlenecks and avoiding redundant construction.

(3) Future work will extend this framework to incorporate life-cycle economics and uncertainty. While the current model minimizes capital expenditure (CAPEX) to ensure capacity under peak loads, incorporating operational expenditure (OPEX) significantly influences decisions. For instance, an integrated model might prioritize larger pipeline diameters or high-efficiency compressors to minimize long-term frictional pressure drops and fuel consumption, balancing higher initial investments against lower operating costs. Consequently, subsequent research will utilize the efficient computational basis established here to develop multi-period stochastic models accounting for demand fluctuations and operational costs, further enhancing the economic robustness of expansion plans.

CRediT authorship contribution statement

Jun Zhou: Writing – review & editing, Writing – original draft, Validation, Methodology, Funding acquisition, Formal analysis. **Can Qin:** Writing – review & editing, Writing – original draft, Methodology, Investigation, Formal analysis. **Jing-Hong Peng:** Writing – review & editing, Writing – original draft, Validation, Methodology, Investigation. **Shi-Tao Liu:** Writing – original draft, Visualization, Investigation. **Ying He:** Writing – original draft, Visualization, Investigation. **Guang-Chuan Liang:** Writing – review & editing, Supervision, Resources, Conceptualization.

Statement of data availability

All data, models, and code generated or used during the study appear in the submitted article.

Conflict of interest

The authors declare that there is no conflict of interests regarding the publication of this paper.

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Nomenclature

Abbreviations

CL-Model	Congestion location model
MCEO-Model	Multi-component expansion optimization model
MINLP	Mixed integer nonlinear programming
ICIEPF	Integrated congestion identification and expansion planning framework

Indexes and sets

A	Edge set
A_p	Pipeline set
A_p^{new}	Potential new pipeline set
A_p^{old}	Existing pipeline set
A_{cs}	Compressor station set
N	Node set,
K	Pipe specification set

Parameters

C_{ij}^{extend}	Pipeline construction cost coefficient
C_{ij}^{type}	Pipeline procurement cost coefficient
C_{ij}^{cs}	New compressor costs for compressor station
d_{ij}	Pipe diameter, m
d_{ij}^{old}	Specifications of existing pipelines, m
$d_{ij,k}^{\text{type}}$	Potential new pipeline specifications, m
l_{ij}	Pipe length, m
$p_i^{\min}$	Node allows the minimum pressure, MPa
$p_i^{\max}$	Node allows the maximum pressure, MPa
R_g	Gas constant, J/(mol·K)
s_i	Gas supply flow rate, 10^4 m^3/d
λ_{ij}	Pipe friction coefficient
$\varepsilon_{\min}$	Minimum compressor pressure ratio
$\varepsilon_{\max}$	Maximum compressor pressure ratio
a_{ij}^{st}, $b_{ij}^{\text{st}}c_{ij}^{\text{st}}$	Compressor surge boundary coefficient
a_{ij}^{Nmax}, $b_{ij}^{\text{Nmax}}c_{ij}^{\text{Nmax}}$	Compressor maximum speed boundary coefficient
a_{ij}^{su}, b_{ij}^{su}, c_{ij}^{su}	Compressor stagnation boundary coefficient
a_{ij}^{Nmin}, $b_{ij}^{\text{Nmin}}c_{ij}^{\text{Nmin}}$	Compressor minimum speed boundary coefficient

Continuous variables

f_{expand}	Pipeline loop cost, CNY
f_{new}	New pipeline cost, CNY
f_{cs}	Compressor station expansion cost, CNY
F^{cong}	Pipe network congestion cost
H_{ij}	Compressor head, kJ/kg
P_i	Nodal pressure, MPa
P_{ij}^{in}	Compressor inlet pressure, MPa
P_{ij}^{out}	Compressor outlet pressure, MPa
Q_{ij}^{relax}	Congestion relaxation flow, refers to the reduction of pipeline throughput in order to solve the congestion problem of the network, 10^4 m^3/d
Q_{ij}	Pipeline or compressor station flow, 10^4 m^3/d
Q_{ij}^{usable}	Effective flow, refers to the actual flow involved in the calculation of pipeline hydraulic pressure drop or compressor station, 10^4 m^3/d
Q_{ij}^{active}	Compressor station pressurization flow rate, 10^4 m^3/d
Q_{ij}^{bypass}	Bypass valve flow, 10^4 m^3/d
Q_{ij}^{com}	Flow of a single compressor, 10^4 m^3/d
Q_{ij}^{ac}	Compressor operating flow, m/s
R_{ij}^{pipe}	Pipeline flow resistance coefficient, $(10^4$ (m^3/d)·MPa$)^2$
Z_{ij}^{in}	Compressor inlet natural gas compression factor

Integer variables

B_{ij}^{extend}	Binary variable of pipeline loop, 0 means not to expand pipeline ij, 1 means to expand pipeline ij
$B_{ij,k}^{\text{type}}$	Binary variable of new pipe specification, 1 means that a new pipe of size k is created between nodes i and j
B_{ij}^{cs}	Binary variable of compressor station expansion, 1 indicating that a compressor unit is added in compressor station ij
B_{ij}^{exist}	Presence state variable of the pipeline
B_{ij}^{station}	Compressor station state variable
B_{ij}^{active}	Pressurization state variable of compressor station
B_{ij}^{bypass}	Status variable of compressor station bypass valve
I_{ij}^{com}	Number of compressors on
I_{ij}^{extend}	Number of expansion compressors in compressor station

Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.petsci.2026.02.011.

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