

*INDUSTRY & FACILITY REPORT*

China LNG Value Chain

Natural Gas Resources, Domestic Liquefaction, Imports, Pipelines, Storage and Markets

UPSTREAM Domestic gas	SUPPLY Pipeline + LNG	CONVERSION Liquefaction / regas	NETWORK Transmission + storage	MARKETS Industry + cities
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Prepared as a strategic and engineering overview

Data cut-off: 1 September 2026 | Monetary values and capacities are indicative unless otherwise noted

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Executive Summary

China's LNG industry is one part of a broader, increasingly interconnected natural-gas system. The country combines large and growing domestic production, pipeline imports from Central Asia, Russia and Myanmar, seaborne LNG imports, underground storage, coastal and inland LNG storage, and a national transmission network. The operating question is therefore not simply “how much LNG does China need?” but “which source is cheapest, secure and deliverable to each regional market at a given time?”

The structural center of gravity differs from the United States. China is principally an LNG importer, receiver, regasifier and distributor. Its coastal terminals connect global supply to the Bohai Rim, Yangtze River Delta, southeast coast and Guangdong. Inland liquefaction plants, usually small to medium scale, convert domestic or pipeline natural gas into truckable LNG for off-grid industry, city-gas peak shaving and heavy-duty transport.

2025 system indicator	Reported level	Interpretation
Domestic natural-gas output	262.06 bcm (national statistical bulletin)	A record; up 6.3% year on year.
LNG imports	About 67–70 Mt, depending on dataset/method	Down materially from 2024 as domestic and Russian pipeline supply strengthened.
PipeChina natural-gas pipelines	~63,800 km; ~420 bcm/y one-time transmission capability	Backbone network connecting 30 provinces/regions and Hong Kong.
PipeChina LNG receiving assets	10 terminals operated directly	The wider system connects 25 receiving terminals, including third-party assets.
Russia–China East Route flow	38.8 bcm in 2025	At/slightly above original 38 bcm/y contractual design level.

Strategic conclusion. LNG remains essential for coastal diversity, winter balancing and supply optionality, but it competes at the margin with domestic gas and pipeline imports. Terminal nameplate capacity should not be treated as demand. Utilization, access rights, contract flexibility, pipeline connectivity and downstream market capture are often more decisive than berth or tank capacity alone.

1. Scope, Definitions and Units

This report follows natural gas from geological resource to final market and separates four frequently confused facility classes: gas processing, domestic liquefaction, LNG receiving/regasification, and satellite/vehicle-fueling facilities. Large export liquefaction—common on the U.S. Gulf Coast—is not a major Chinese industry segment.

Term	Meaning in this report
bcm	Billion standard cubic metres of natural gas.
Mtpa	Million metric tonnes of LNG per year.
LNG receiving terminal	Marine unloading, storage, boil-off-gas handling, regasification, pipeline send-out and often truck loading.

Term	Meaning in this report
Domestic LNG plant	Onshore liquefaction of domestic or pipeline gas; commonly modular and truck-distributed.
Nameplate capacity	Design throughput; not the same as actual imports, production or send-out.
1 Mt LNG	Approximately 1.35–1.40 bcm of natural gas; actual conversion depends on composition and reference conditions.

2. China's Integrated LNG and Natural-Gas Value Chain

The value chain has multiple entry points and two principal logistics modes: molecules moving by pipeline and LNG moving by ship or road tanker. Imported LNG generally enters at coastal terminals; domestically produced LNG generally leaves inland liquefaction plants by road.

Supply source	Processing / conversion	Logistics hub	Primary delivery route	Typical customers
Conventional, tight and shale gas	Field separation, sweetening, dehydration, NGL recovery	Gas processing plant	Gathering and national/regional pipeline	City gas, industry, power, chemicals
Coalbed methane / coal-derived gas	Purification and specification control	Regional gas hub or liquefaction plant	Pipeline or LNG road tanker	Industry, transport, off-grid users
Central Asia / Russia / Myanmar gas	Border metering and compression	Cross-border interconnect	Long-distance pipeline	National and regional markets
Seaborne LNG	Unloading, storage, BOG handling, regasification	Coastal receiving terminal	Pipeline send-out and truck loading	Coastal cities, power, industry, distributors
Domestic / pipeline gas to LNG	Pretreatment and liquefaction	Inland LNG plant	Cryogenic road tanker	Satellite stations, peak shaving, LNG trucks

3. Major Natural-Gas Resources in China

3.1 Resource types

China's upstream portfolio is diversified across conventional gas, tight gas, shale gas, coalbed methane (CBM), associated gas and coal-derived synthetic natural gas. Commercial production is concentrated in large onshore basins, with offshore gas adding an important coastal source.

Basin / province cluster	Resource character	Representative fields / plays	System role
Ordos Basin — Shaanxi, Inner Mongolia, Ningxia	Conventional and tight sandstone gas; CBM in adjacent coal regions	Changqing area; Sulige gas field	Large-volume northern supply; feed to trunk pipelines and inland LNG.

Basin / province cluster	Resource character	Representative fields / plays	System role
Sichuan Basin — Sichuan, Chongqing	Conventional gas, sour gas and world-scale shale gas	Fuling shale; Changning–Weiyuan; Puguang	Core southwest production base; supplies Sichuan–Chongqing and eastbound markets.
Tarim Basin — Xinjiang	Deep conventional gas, condensate and complex high-pressure reservoirs	Kela-2, Tazhong and other Tarim fields	Anchor western source for West–East Gas Pipeline.
Junggar and Tuha — Xinjiang	Conventional gas and associated gas	Northwest field clusters	Regional supply and feedstock for pipeline / LNG plants.
Qaidam Basin — Qinghai	High-altitude conventional gas	Sebei and surrounding fields	Northwest regional supply and balancing.
Songliao / Bohai Bay / northeast	Conventional and associated gas	Daqing and Liaohe areas	Northeast industrial and city-gas markets.
Offshore Bohai, East China Sea, South China Sea	Offshore conventional gas	Bohai fields; Yacheng/Deep Sea No. 1; East China Sea fields	Direct coastal supply; reduces inland transport requirement.
Shanxi–Shaanxi–Inner Mongolia coal belt	CBM and coal-derived gas	Qinshui CBM; Ordos-edge projects	Mine safety, local supply, pipeline injection or liquefaction.

3.2 Production structure and growth

The National Bureau of Statistics reported 262.06 bcm of natural-gas output in 2025, 6.3% above 2024. The “above-designated-size industrial enterprise” series was 261.9 bcm, up 6.2%; the slight difference reflects statistical scope. China has recorded more than 10 bcm of annual incremental production for nine consecutive years.

- CNPC/PetroChina is strongest in the Ordos, Tarim, Sichuan and Qaidam systems and remains the largest domestic gas producer.
- Sinopec is prominent in Sichuan Basin conventional and shale gas, including Fuling, and in sour-gas development and processing.
- CNOOC supplies offshore gas and is also a leading LNG importer and terminal operator, connecting upstream and coastal markets.
- Provincial and private producers participate in CBM, coal-derived gas, regional pipelines and inland LNG, although data transparency is lower than for the national oil companies.

4. Domestic Small- to Medium-Scale LNG Production

4.1 Why inland LNG exists

Domestic LNG production solves a logistics problem rather than creating an export commodity. Liquefaction shrinks natural gas to roughly 1/600 of its gaseous volume, making road transport practical where pipelines are absent, constrained or temporarily uneconomic. China’s large geography, western gas resources, industrial clusters and extensive heavy-truck market support a substantial “virtual pipeline” business.

4.2 Typical plant scale and configuration

Class	Indicative capacity	Typical application	Configuration
Micro / peak-shaving	<0.05 Mtpa	City-gas peak shaving, remote supply, captive fuel	Packaged pretreatment; nitrogen-expander or mixed-refrigerant module; bullet or small tank storage.
Small scale	0.05–0.30 Mtpa	Regional trucked LNG and industrial supply	One or more modular trains; molecular-sieve dehydration; CO ₂ /H ₂ S removal as needed.
Medium scale	0.30–1.0 Mtpa	Basin-linked merchant LNG or larger regional hub	Multiple trains, larger storage and truck bays; often pipeline-connected.
Large domestic / special case	>1.0 Mtpa	Large basin monetization or integrated project	Less common; economics converge toward larger liquefaction-project discipline.

Public estimates of national inland-liquefaction capacity vary because plants are numerous, ownership is fragmented, many units operate intermittently, and compilations differ on coal-derived gas, peak-shaving plants and mothballed assets. For investment work, plant-by-plant verification is preferable to a single national capacity number.

4.3 Process flow and equipment

- Feed receiving and metering → inlet separation and compression.
- Acid-gas removal to control CO₂/H₂S freezing and product specification.
- Molecular-sieve dehydration; mercury removal when feed analysis requires it.
- Heavy-hydrocarbon removal or dew-point control, depending on gas composition.
- Liquefaction using mixed refrigerant, single mixed refrigerant, nitrogen expander or cascade-derived modular schemes.
- LNG storage → truck loading → satellite stations, industrial tanks or LNG fueling stations.

Economics are driven by delivered feed-gas cost, plant utilization, electricity, road distance, tolls, seasonal spreads and competition from pipeline gas. The relevant benchmark is delivered RMB per cubic metre (or RMB per tonne) at the customer—not plant-gate liquefaction cost alone.

5. LNG Imports and Coastal Receiving Terminals

5.1 Import role and supply portfolio

China's LNG imports fell in 2025 after a strong 2024. Published totals differ—roughly 67 to 70 Mt—because customs, ship-tracking and industry datasets apply different timing and re-export conventions. The directional conclusion is robust: weaker industrial demand, a mild period, record domestic production and higher Russian pipeline deliveries reduced the call on imported LNG.

In 2024, the largest suppliers were Australia (about 26.2 Mt), Qatar (18.3 Mt), Russia (8.3 Mt), Malaysia (7.7 Mt) and the United States (4.2 Mt). In 2025, Qatar's relative role increased while direct U.S. deliveries largely stopped amid trade tensions; contract holders could redirect cargoes to other markets.

5.2 Terminal clusters

Coastal cluster	Representative locations / terminals	Demand served	Operating logic
Bohai Rim / North China	Dalian, Caofeidian/Tangshan, Tianjin, Qingdao, Yantai/Longkou	Winter heating, Beijing–Tianjin–Hebei, Shandong industry	High seasonal value; pipeline connectivity and storage are critical.
Yangtze River Delta	Shanghai, Rudong, Jiangsu Binhai, Ningbo/Zhoushan, Wenzhou	Dense urban, industrial, power and petrochemical demand	Strong base load; multiple owners and network access points.
Fujian / Guangdong	Fujian, Dapeng, Shenzhen, Huizhou, Zhuhai, Jieyang	China's largest coastal gas markets; power and chemicals	Early LNG hub; terminal-to-power/chemical integration is common.
Guangxi / Hainan and south coast	Beihai, Fangchenggang area, Hainan Yangpu	Regional diversification, power, cities and industry	Growing infrastructure; can support western Guangdong/Guangxi/Hainan balancing.

5.3 Typical receiving-terminal process

- LNG carrier berth, trestle, unloading arms, emergency release and ship–shore systems.
- Full-containment storage tanks, commonly 160,000–270,000 m³ in modern projects.
- Low-pressure pumps, boil-off-gas compressors, recondenser and high-pressure send-out pumps.
- Open-rack vaporizers (ORV) for base-load seawater service; submerged-combustion vaporizers (SCV) or other units for backup/peak duty.
- Fiscal metering, odorization where required, pipeline tie-in, truck loading and utilities/offsites.

A receiving terminal is not simply the reverse of a liquefaction plant. It normally does not need feed-gas CO₂ removal, dehydration, mercury removal or refrigerant compression. Its critical risks are marine availability, storage cycling, BOG balance, send-out hydraulics, seawater/environmental constraints and downstream market access.

6. Major Natural-Gas Import Pipelines

Corridor	Origin / entry	Nominal or reported scale	Chinese integration and role
Central Asia–China Gas Pipeline (Lines A/B/C)	Turkmenistan, Uzbekistan and Kazakhstan → Horgos, Xinjiang	A/B/C system commonly cited around 55 bcm/y	Connects into West–East corridors; historically the largest pipeline-import route.
China–Russia East Route / Power of Siberia 1	Eastern Siberia → Heihe, Heilongjiang	Original contract/design level 38 bcm/y; 38.8 bcm delivered in 2025	Feeds northeast, Beijing–Tianjin–Hebei, Yangtze Delta and eastern grid after full-route completion.
China–Myanmar Gas Pipeline	Kyaukpyu → Ruili, Yunnan	Commonly cited design around 12 bcm/y	Diversifies southwest supply; throughput has generally remained below design.

Corridor	Origin / entry	Nominal or reported scale	Chinese integration and role
Far East Route (planned / under development)	Russia Far East → northeast China	Contract concept around 10 bcm/y	Would add northeastern supply; timing and realized capacity depend on project execution.
Power of Siberia 2 (proposed)	Western Siberia via Mongolia	Concept around 50 bcm/y	Not an operating source; commercial terms, financing and schedule remain project risks.

Pipeline capacity is not the same as annual imports. Flows depend on upstream production, take-or-pay contracts, maintenance, border facilities, domestic pipeline constraints and demand. Proposed routes should not be included in firm supply balances until contracts, permits, financing and construction are sufficiently mature.

7. National Pipeline, Storage and Market Integration

PipeChina's 2025 corporate data describe a “four strategic corridors plus five north–south and five east–west” backbone. At year-end 2025 it reported approximately 63,800 km of natural-gas pipelines and one-time transportation capability of about 420 bcm/y. The network covered 30 provinces/regions and Hong Kong, connecting 25 major domestic sources, the three principal cross-border pipeline systems, 25 LNG receiving terminals and 21 underground gas-storage sites.

7.1 Network functions

- Source aggregation: blend domestic, pipeline-import and regasified LNG supply.
- Long-haul transport: move western and northern gas toward eastern demand centers.
- Seasonal balancing: combine underground storage, LNG tanks, linepack and interruptible demand.
- Market access: enable third-party access and competition, subject to capacity allocation, tariffs and interconnection rules.
- Emergency resilience: reroute molecules among corridors and regions when infrastructure and gas quality permit.

7.2 Key domestic trunk systems

System	Primary function
West–East Gas Pipelines	Move Tarim, Ordos and imported Central Asian gas to central/eastern and southern markets.
Shaan–Beijing systems	Connect Ordos/Changqing supply to Beijing–Tianjin–Hebei and northern markets.
Sichuan–East Gas Pipeline	Move Sichuan Basin gas, including sour-gas developments after processing, toward central/eastern China.
China–Russia East Route domestic section	Distribute Russian gas from Heilongjiang through northeast/north China toward the Yangtze Delta.
Regional coastal grids	Connect receiving terminals with provincial pipelines, city-gas gates, power plants and industrial parks.

8. Downstream Markets and Distribution

Market	Supply route	Commercial characteristics
City gas and residential/commercial	Pipeline gate stations; LNG satellite/peak-shaving backup	Regulated/contracted pricing; strong winter seasonality in the north.
Industrial fuel	Pipeline gas or trucked LNG	Price-sensitive substitution versus coal, LPG, fuel oil and electricity.
Power generation	Pipeline and terminal-linked gas	Valued for flexibility and local air quality; utilization depends on gas/power spreads.
Chemicals and fertilizers	Primarily pipeline gas; sometimes terminal-integrated supply	Requires stable long-term supply; feedstock economics are decisive.
LNG heavy-duty transport	Road-distributed LNG and fueling stations	Can displace diesel when LNG price advantage covers vehicle premium and infrastructure.
Marine fuel / bunkering	Coastal terminals, small carriers, tank trucks or ISO containers	Emerging segment; requires product quality, custody transfer and port coordination.

China's road-LNG ecosystem is unusually important. LNG-fueled heavy trucks reached a very high share of new heavy-truck sales during periods of favorable gas/diesel spreads. This creates a material, but cyclical, demand outlet for inland LNG plants and terminal truck-loading bays.

9. Ownership, Commercial Structure and Regulation

9.1 Key participants

- CNPC/PetroChina: upstream production, gas processing, long-term imports, marketing and major receiving terminals.
- Sinopec: upstream conventional/shale gas, pipelines and markets, LNG terminals and downstream integration.
- CNOOC: offshore gas, international LNG procurement/trading and a pioneering coastal terminal portfolio.
- PipeChina: national oil-and-gas infrastructure operator, including trunk pipelines, selected LNG terminals and storage; central to third-party access.
- Provincial energy groups, city-gas companies and private companies: terminal stakes, regional pipelines, LNG trading, inland liquefaction, satellite stations and end-use markets.

9.2 Development and approvals

A major project may require national and/or provincial investment approvals, land and sea-use rights, port and navigation approvals, environmental impact assessment, safety assessment, fire review, energy-conservation review, water and marine permits, pipeline interconnection, grid connection, construction permits and operating licenses. Exact routing depends on project scale, location, ownership and current delegated authority.

For third-party infrastructure, commercial feasibility also depends on capacity booking, tariff methodology, gas-quality specifications, balancing obligations, nomination rules and access to downstream pipeline

capacity. These issues should be advanced in parallel with FEED rather than left until mechanical completion.

10. Facility Economics and Investment Logic

Facility type	Principal revenue / value	Major cost drivers	Critical utilization risk
Inland LNG liquefaction	Margin between delivered LNG price and feed gas + conversion/logistics cost	Feed gas, power, pretreatment, trucking and storage	Road-market competition; seasonal or policy-driven curtailment.
Coastal receiving terminal	Throughput/tolling, commodity margin, storage and truck-loading value	Marine works, tanks, send-out, pipeline tie-in and financing	Overbuild; weak downstream access; high imported-LNG price.
Pipeline	Transportation tariff and system value	Diameter/pressure, terrain, compression and rights of way	Underutilization and source/demand mismatch.
Underground storage	Seasonal spread, security and balancing value	Geology, cushion gas, wells and compression	Insufficient commercial compensation for system value.
Satellite / fueling station	Retail/industrial LNG margin	Tank, vaporization/dispensing, land and logistics	Local competition and low station throughput.

Screening economics should use delivered-cost stacks for each competing source: domestic field gas, pipeline imports and imported LNG. For imported LNG, include contract or spot price, shipping, terminal toll, regasification, pipeline tariff and losses. For inland LNG, include feed gas, liquefaction energy, plant fixed cost, loading, road freight, boil-off/losses and satellite-site cost.

11. Risks, Constraints and Strategic Outlook

Issue	Why it matters	Practical response
Demand and capacity mismatch	Receiving and liquefaction nameplate capacity can exceed economic throughput.	Model monthly—not only annual—supply, demand and pipeline constraints.
Price exposure	Oil-linked contracts, JKM/spot prices, exchange rates and regulated downstream prices can diverge.	Use portfolio contracts, destination flexibility, hedging and demand optionality.
Pipeline connectivity	A terminal without sufficient evacuation capacity may strand tank/berth capability.	Secure interconnection and firm downstream capacity early.
Seasonality and storage	Winter peaks can exceed production and pipeline flexibility.	Integrate underground storage, LNG inventory, linepack and interruptible demand.
Gas quality	Multiple sources differ in heating value, CO ₂ /N ₂ and hydrocarbon dew point.	Define blending, metering, interchangeability and custody-transfer specifications.
Policy and geopolitics	Tariffs, sanctions, supplier concentration and maritime disruption alter flows.	Diversify suppliers/routes and preserve cargo redirection rights.
Carbon and methane	Lifecycle emissions increasingly influence finance and procurement.	Measure methane intensity; improve leak detection, electrification and efficiency.

Outlook. China's gas system is likely to become more networked and more flexible. Domestic output and Russian pipeline flows reduce the minimum LNG requirement, while coastal demand growth, supply security and seasonal balancing preserve LNG's strategic value. The strongest LNG assets will be those with

deep downstream integration, flexible contracts, adequate storage, efficient BOG management, strong marine availability and access to multiple pipeline markets.

12. Project-Development Checklist

- Define the market first: customer, daily/seasonal profile, competing fuel and delivered-price ceiling.
- Build a source portfolio: firm domestic gas, pipeline imports, term LNG and spot flexibility.
- Confirm physical connectivity: pipeline diameter/pressure, compressor duty, custody transfer and gas-quality envelope.
- Select facility scale from realistic utilization—not forecast peak demand or announced regional capacity.
- Complete feed-gas and LNG compositional studies before freezing pretreatment, vaporizer and metering design.
- Perform marine, geotechnical, seismic, flood, typhoon, cold-energy and facility-siting studies appropriate to the site.
- Integrate permitting, land/sea use, port approvals, EIA, safety and fire work with FEED and schedule logic.
- Stress-test economics for high JKM, weak industrial demand, low pipeline-gas prices and trucking-distance escalation.
- Secure terminal/pipeline capacity rights, nomination rules and downstream offtake before FID.
- Plan commissioning gas/LNG, cooldown, BOG disposition, truck logistics, emergency response and operating organization.

Appendix A. Simplified Facility Comparison

Feature	Domestic LNG liquefaction plant	Coastal LNG receiving terminal
Feed	Pipeline/domestic natural gas	LNG carrier cargo
Core conversion	Natural gas → LNG	LNG → natural gas
Pretreatment	Acid gas removal, dehydration; Hg/HC removal as needed	Normally minimal product treatment
Main rotating equipment	Feed/refrigerant compressors	BOG compressors and LNG send-out pumps
Storage	Usually small/medium tanks	Large full-containment tanks
Outbound logistics	Cryogenic road tankers	Pipeline send-out plus road tanker loading
Primary risk	Feed/energy cost and road-market utilization	Cargo economics, marine availability and pipeline evacuation

Appendix B. Sources and Data Notes

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Data note: Chinese infrastructure statistics change rapidly and different sources may count terminals, expansions, trial operations, re-exports and industrial enterprises differently. Capacity figures in this report are intended for industry orientation and pre-FEED screening; investment decisions require current asset-level due diligence.