enalyt.

GAS / FREE TRIAL REPORT

India gas intelligence: the gap between infrastructure and economic demand

India's gas opportunity depends on more than adding terminals and pipeline kilometres. This free trial report examines the price, connectivity, utilisation and contract conditions that turn physical infrastructure into sustainable demand. It combines dated regulatory evidence with transparent LNG cost and fuel-switching calculations, giving commercial teams a practical way to test growth assumptions and procurement exposure.

15 NOVEMBER 2026 / ENALYT RESEARCH

A public-source research sample with original analysis, stated assumptions and reproducible decision tools. Prepared independently; no affiliation with the organisations discussed is implied.

THE DECISION IN BRIEF

Executive perspective

01 A long-term gas-growth thesis does not imply uninterrupted annual growth: dated regulatory data and older forecast vintages must be examined separately.

02 Regasification nameplate capacity is not the same as usable delivery at a customer's gate; contracted slots, evacuation, distribution and offtake must all work.

03 Our hypothetical industrial switching example gives a delivered-gas parity ceiling near $15.33/MMBtu under stated fuel-oil, efficiency and currency assumptions.

04 An expanded terminal denominator can depress reported utilisation even when throughput falls much less; compare physical energy before interpreting the ratio.

68.542 bcm	Regulatory gas balance - PNGRB FY2025-26 table; its reported consumption definition.
34.216 bcm	LNG imports - PNGRB FY2025-26; same statistical table.
$11.45/MMBtu	Illustrative delivered gas - Assumed DES10 + regas 0.60 + pipeline 0.65 + marketing 0.20.
$15.33/MMBtu	Illustrative switching ceiling - Delivered gas parity with assumed fuel oil; not a market quote.

HOW TO READ THIS REPORT

Source dates and reporting boundaries matter. Observed evidence, derived indicators and illustrative scenarios are identified in the exhibits and notes. Use the source register and methodology before applying a result to a procurement or investment decision.

01 / The growth thesis needs an affordability test

The first distinction for an Indian gas strategy is physical access versus economic demand. A pipeline reaching a geographical area creates the option to consume gas; it does not guarantee that every customer can switch profitably, that all connections are active, or that gas is available on the required commercial terms. An LNG terminal can add regasification capability while local demand remains price-sensitive. A useful market view therefore links infrastructure to customer economics and contract flexibility, rather than treating kilometres and nameplate tonnes as a direct demand forecast.

PNGRB's FY2025-26 statistical report shows gas consumption of 68.542 bcm and LNG imports of 34.216 bcm in its aggregate table, compared with consumption of 71.314 bcm in FY2024-25. That table's definitions and reported production balance should be retained with the observations. The IEA's 2025 report projects 103 bcm of calendar-year consumption in 2030 under its forecast assumptions. These are different periods and statistical contexts: a historical contraction does not disprove every long-term growth scenario, and a long-term projection does not turn the following year into a guaranteed recovery. [S1] [S2]

> **ANALYST VIEW**
>
> The investable commercial question is which customer segments remain economic across a delivered-price range, with confirmed network access and manageable contractual obligations. Infrastructure alone cannot answer it.

02 / Build one reconciled gas balance before modelling the future

Gas datasets are unusually vulnerable to false precision. Gross field production, net production after flaring and losses, LNG imports, sales and consumption are not always reported on one identical boundary. Energy and volumetric units introduce another layer: a tonne of LNG, a standard cubic metre of gas and a million British thermal units measure different things. Conversion requires a stated calorific value or composition assumption. The ministry's statistical compendium and PNGRB's regulatory report should therefore remain separate source vintages unless their definitions are explicitly reconciled. [S1] [S10]

EXHIBIT 1 / A source-consistent regulatory comparison

Indicator	FY2024-25	FY2025-26	Unit
Gross natural gas production	35.594	34.326	bcm
LNG imports	35.720	34.216	bcm
Reported gas consumption	71.314	68.542	bcm

PNGRB Annual Statistical Report 2025-26, Table 1.2. Values converted from MMSCM to bcm by dividing by 1,000. The table's gross-production balance is retained; it is not substituted for a net-delivered series. [S1]

For a commercial database, attach the gas basis, temperature and pressure reference where available. Preserve whether a price is on gross or net calorific value, and whether a volume is measured before or after regasification or distribution losses. A small conversion inconsistency can matter when bids compete on a narrow delivered-price difference. Data quality is not an appendix to the investment case: it determines whether the fuel-cost comparison is actually comparing the same useful energy.

The operational balance should also distinguish contracted availability from physical flow. An annual LNG supply agreement is not the same as a confirmed cargo delivery date, and a regasification reservation is not evidence that downstream transmission capacity is available at the same time. Track the chain from source commitment through berth, storage, send-out, pipeline and customer nomination. That exposes the bottleneck that can prevent a physically abundant molecule from reaching a commercially attractive customer.

03 / A demand-to-import bridge with explicit assumptions

The scenario table begins with PNGRB's 68.542 bcm FY2025-26 consumption observation and compounds assumed growth for four fiscal intervals to FY2029-30. It then subtracts an independently assumed domestic supply contribution. These inputs are not fitted forecasts and should not be confused with the IEA's calendar-2030 projection. Their purpose is to reveal what an LNG procurement requirement would look like under different combinations of demand and domestic availability. The residual is a simplified import requirement, not a cargo schedule or a precise trade forecast.

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Illustrative demand = 68.542 x (1 + g)^4; simplified LNG requirement = demand - assumed domestic supply
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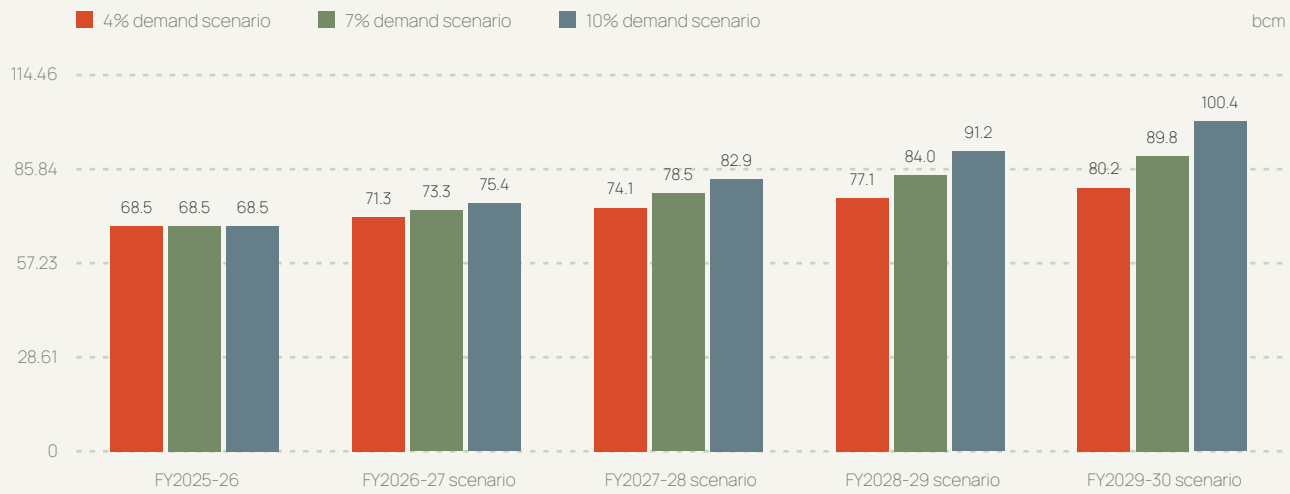
bcm/year. Four intervals from FY2025-26 to FY2029-30. Assumed domestic supply is an analytical input, not a field-development forecast.

EXHIBIT 2 / Illustrative FY2029-30 market balances

Scenario	Demand CAGR	Demand, bcm	Assumed domestic supply, bcm	Residual LNG, bcm
Slower uptake	4.0%	80.2	32.0	48.2
Middle sensitivity	7.0%	89.8	35.0	54.8
Faster uptake	10.0%	100.4	38.0	62.4

Enalyt mechanical scenarios. Figures rounded. No likelihood ranking is attached to the three cases. Baseline from PNGRB. [S1]

EXHIBIT 3 / A transparent range, rather than a single promised market



The first point is historical. All later points are illustrative Enalyt calculations; they are not observed years.

The important sensitivity is not just the demand endpoint but the distribution of that demand. An incremental industrial customer with an alternative fuel can reduce gas offtake when the spread changes. A customer using gas as a process feedstock may have a different response. Procurement commitments should be matched to the resilience of the underlying load, not only its expected annual volume. A growth case supported by highly interruptible demand warrants different contract flexibility from one supported by stable, creditworthy baseload.

04 / The delivered LNG stack: avoid the FOB versus DES trap

The starting point in our cost model is an assumed delivered-ex-ship LNG commodity price of $10/MMBtu. Because that price already includes the voyage to the receiving terminal under the assumed contract basis, we do not add another full ocean-freight charge. We then assume regasification of $0.60, transmission of $0.65 and marketing/service costs of $0.20 per MMBtu. The resulting gas-gate cost is $11.45/MMBtu before taxes and any local distribution or customer-specific charges not included in those inputs. None of these amounts is a current tariff or executable quote.

EXHIBIT 4 / Illustrative LNG delivered-price bridge

Cost component	Assumption, $/MMBtu	Treatment
DES LNG commodity	10.00	Ocean transport assumed already included
Regasification	0.60	Scenario input, not terminal quote
Pipeline transmission	0.65	Scenario input, not current regulated tariff
Marketing / service	0.20	Scenario input
Total before excluded charges	11.45	Equivalent INR 973.25 at assumed INR 85/$

All inputs are Enalyt assumptions. Actual taxes, tariff basis, losses, booking charges and distribution costs must be checked for the contract and delivery location.

A FOB offer requires a different bridge, including shipping, voyage fuel and any relevant loss allowance that is not already priced. A seller's commodity formula may reference oil, a gas hub or a negotiated fixed price; a buyer's effective cost can also include take-or-pay exposure and unused capacity. Domestic gas is not interchangeable with an LNG spot quote. The April 2023 pricing notification established a specific APM framework, while PPAC publishes applicable price notices; eligibility, allocation, category and current amendments need verification for the actual buyer. [S6] [S7]

This means a quoted gas price needs metadata. Record the delivery point, energy basis, index, averaging window, currency, tax treatment and contractual quantity obligations. A procurement dashboard that ranks an upstream regulated price against a fully delivered industrial tariff without those fields will identify false bargains. The correct comparison is customer-gate cost for a common date, volume profile and useful-energy requirement.

05 / Industrial fuel switching: compare useful heat, not nominal units

Consider an entirely hypothetical fuel-oil alternative priced at INR 45/kg, with an assumed calorific value of 40 MJ/kg and a boiler efficiency of 82%. Its useful-heat cost is approximately INR 1,447.49 per MMBtu. At 90% gas efficiency, the base delivered-gas assumption of INR 973.25/MMBtu becomes INR 1,081.39 per useful MMBtu. The apparent gas advantage is approximately INR 366.10 per useful MMBtu before burner-conversion investment, incremental distribution charges, taxes, downtime and operating differences. The calculation is useful precisely because every input can be challenged.

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Fuel-oil useful-heat cost = (INR/kg x 1,055.056 MJ/MMBtu) / (MJ/kg x efficiency)
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Gas useful-heat cost = delivered INR/MMBtu / gas efficiency. Use consistent gross/net energy bases; assumed efficiencies must be replaced with site measurements.

EXHIBIT 5 / Illustrative gas-price switching sensitivity

DES LNG, $/MMBtu	Delivered, $/MMBtu	Gas useful heat, INR/MMBtu	Saving vs assumed fuel oil
8.00	9.45	892.50	554.99
10.00	11.45	1,081.39	366.10
12.00	13.45	1,270.28	177.21
15.00	16.45	1,553.61	-106.13

Enalyt assumptions: other gas costs 1.45$/MMBtu, INR 85/$, gas efficiency 90%, oil INR 45/kg,40 MJ/kg and 82% efficiency. Costs exclude taxes and conversion capital; no current fuel prices are asserted.

Under those assumptions, delivered gas reaches parity at about $15.33/MMBtu. Subtracting the assumed non-commodity gas costs gives a DES commodity threshold near $13.88/MMBtu. This is a sensitivity result, not a universal switching price. It changes with foreign exchange, alternative-fuel quality, actual efficiency and the cost of a disrupted process. The procurement decision should also consider whether the plant can switch back, whether operators can maintain quality, and whether the gas contract permits lower offtake when the fuel spread reverses.

Power generation needs its own conversion. At an assumed heat rate of 7.5 MMBtu/MWh, $11.45 gas and INR 85/$, the fuel-only cost is about INR 7.30/kWh. That excludes fixed charges, start-up fuel, part-load efficiency, transmission and other costs. It is not a forecast of an electricity exchange price or a claim about an existing plant. It demonstrates why a national gas-growth thesis should not assume every unit of gas-fired capacity will dispatch economically at every LNG price.

06 / Connections and terminal capacity need denominator discipline

PNGRB's 31 March 2026 CGD snapshot reports 1.69 crore domestic PNG connections but 1.07 crore billed connections. Those counts imply a billed-to-connected ratio near 63% using rounded inputs. They do not establish that every unbilled connection is physically disconnected or has zero potential demand: billing periods, reporting conventions and customer activation matter. The October 2025 MIS also separates targets, actual connections and billed connections, reinforcing the need to retain each field rather than use a single network headline. [S1] [S5]

Terminals have a related denominator problem. Petronet's Q1 FY2026-27 release explicitly states that Dahej's nameplate base increased from 17.5 to 22.5 MMTPA. Its reported utilisation therefore cannot be interpreted against an earlier percentage without adjustment. The commissioning notice dates the additional facilities to 31 March 2026. Compare physical TBTU, the available capacity denominator, period length and contracted availability together. An expanded denominator can lower a utilisation percentage even when the change in physical throughput is much smaller. [S3] [S4]

The practical implication is to model a network as a chain of constraints. Nameplate capacity is only the first screen. A buyer also needs reliable berth access, storage, send-out capability, a matching pipeline route, distribution capability and customer offtake. Each constraint can have a different counterparty and charging structure. A national capacity sum cannot establish deliverability to one plant, just as a map of authorised geographical areas cannot establish that a customer's connection is commissioned and economic.

DECOMPOSITION LIMIT

This is an order-dependent counterfactual: changing capacity first and throughput second attributes the utilisation change differently from changing throughput first. The activity-first path gives roughly an 18.9 percentage-point capacity effect, rather than 20.4 points. Neither is a unique causal decomposition; both demonstrate why utilisation cannot be read as a pure demand measure.

07 / Commitment risk: when growth assumptions become payment exposure

A simplified take-or-pay stress makes the issue concrete. Assume a contractual daily quantity of 100,000 MMBtu and an 85% minimum obligation, with actual demand falling to 60,000 MMBtu/day for 30 days. The arithmetic shortfall against the assumed floor is 25,000 MMBtu/day, or 750,000 MMBtu for the month. At an assumed $10/MMBtu commodity price, gross exposure is $7.5 million before make-up rights, resale, mitigation, scheduling rules and the actual settlement formula. That amount is not automatically a payable invoice under every contract.

The useful procurement question is how much demand can fall before the business crosses its quantity floor, and how quickly it can respond. Keep customer-load sensitivity, supplier commitment, terminal reservation and pipeline booking in the same stress model. If contracts settle on different timing or energy bases, a perfectly balanced annual portfolio can still create monthly cash pressure. A cheaper long-term slope should be evaluated alongside flexibility, destination options, credit and the resilience of the underlying end-use load.

EXHIBIT 6 / A procurement diligence matrix

Question	Evidence to request	Failure mode exposed
What is the stable minimum load?	Measured customer profile and alternative-fuel response	Over-contracting interruptible demand
Is capacity usable end to end?	Terminal slot, send-out and route confirmation	Stranded upstream booking
How does quantity flexibility work?	Take-or-pay, make-up and nomination clauses	Unexpected payment or storage exposure
What changes the gate price?	Index, FX, tariff and tax bridge	False commodity-price comparison
Who bears interruption risk?	Operating and contractual contingency plan	Production loss despite nominal supply

Enalyt analytical checklist. Commercial treatment depends on the actual contract and current applicable rules.

08 / A practical research agenda for gas buyers and developers

Start with customer economics rather than a market-size target. Segment demand into process-critical, economically switchable and discretionary loads, then test each against delivered gas prices and operational constraints. A supplier can use this to design flexibility; a network developer can use it to prioritise activation rather than simply connections; an industrial buyer can use it to negotiate the right balance of cost and optionality. The evidence required is granular but not mysterious: comparable energy prices, measured efficiency, actual load shape, current capacity availability and contract terms.

For market surveillance, maintain separate observations for national supply, LNG imports, terminal throughput, billed connections, gas price categories and customer-sector activity. Date-stamp each dataset and preserve revisions. Research should explain a change before extrapolating it: lower imports may reflect demand, domestic availability, inventory, price response or timing. The source period and boundary should be visible wherever a number is used. That habit is the difference between a useful intelligence service and a plausible-looking collection of growth claims.

The forward view remains constructive only under conditions that can be tested. Infrastructure must become usable capacity, customer-gate pricing must support competitive operations, and procurement commitments must remain robust when demand disappoints. The scenarios here identify those dependencies rather than promise a market trajectory. A company can replace the assumptions with its own operating evidence and reach a different conclusion while retaining the same transparent analytical method. That is the purpose of the trial report.

METHOD & LIMITATIONS

The evidence behind the analysis

Public primary sources were checked on 15 November 2026. PNGRB FY2025-26 observations are a dated regulatory snapshot; IEA2030 values are a 2025 external forecast vintage. Fiscal-year data, calendar-year projections, gross production, net production and customer sales are not treated as interchangeable. MMSCM values are divided by 1,000 to obtain bcm. Our FY2029-30 scenarios compound the stated baseline for four periods at assumed 4%,7% or 10% annual growth and subtract separately assumed domestic supply; they are not field-development forecasts or probability-weighted predictions. LNG commodity prices, regasification, transport, service fees, exchange rates, fuel-oil prices, energy content, boiler efficiencies and heat rate are hypothetical model inputs. The conversion 1 MMBtu=1,055.056 MJ is used consistently. Useful-heat costs exclude conversion capital, taxes and charges outside the stated boundary. The take-or-pay example demonstrates quantity exposure before contractual mitigation rather than estimating an actual liability. Company throughput and capacity statements remain company-reported and do not imply a customer relationship. Current pricing eligibility, applicable tariffs, allocation and contract terms must be verified for each delivery point.

The downloadable evidence tables and online edition accompany this report. Original public-source rights remain with their respective owners. This is research for evaluation and internal discussion, not a live price feed, an audited forecast or an executable commercial offer.

Source register

S1 / Annual Statistical Report 2025-26

Petroleum and Natural Gas Regulatory Board | FY2025-26; network snapshot 31 March 2026; published September 2026 | Accessed 2026-11-15

https://www.pngrb.gov.in/pdf/e-publication/20260930_PNGRB_Statistical_Booklet.pdf

Entity-reported regulatory statistics; aggregate gas table uses its own production/consumption definitions.

S2 / India Gas Market Report: Executive Summary

International Energy Agency | Published 2025; outlook from 2023 to calendar 2030 | Accessed 2026-11-15

https://www.iea.org/reports/india-gas-market-report/executive-summary

Forecast vintage; not current actual demand or a guaranteed outcome.

S3 / Q1 2026-27 Financial Results

Petronet LNG | Quarter ended 30 June 2026; published 13 August 2026 | Accessed 2026-11-15

https://www.petronetlng.in/w/press-release-q1-2026-27-financial-results

Company-reported throughput and utilisation; capacity base changed.

S4 / Commissioning of Additional Regasification Facilities at Dahej

Petronet LNG stock-exchange disclosure | Disclosure 1 April 2026; commissioning 31 March 2026 | Accessed 2026-11-15

https://www.petronetlng.in/documents/d/pertonetlng/cdcommissioningsign-pdf

S5 / City Gas Distribution MIS: October 2025

PNGRB Statistics Division | October 2025 monthly snapshot | Accessed 2026-11-15

https://pngrb.gov.in/data-bank/20251031-CGD-MIS-Report.pdf

MWP targets, actual connections and billed connections are different fields.

S6 / Review of New Domestic Gas Pricing Guidelines, 2014

Ministry of Petroleum and Natural Gas / Gazette of India | Notification 7 April 2023 | Accessed 2026-11-15

https://egazette.gov.in/WriteReadData/2023/245017.pdf

Historical pricing framework; consult the latest monthly orders and applicable amendments for current procurement.

S7 / Natural Gas Price Notifications

PPAC | Monthly notice repository accessed November 2026 | Accessed 2026-11-15

https://ppac.gov.in/natural-gas/gas-price

Repository for current applicable price notices; no current price quote is assumed in our scenarios.

S8 / About Petronet LNG

Petronet LNG | Company operating-capacity description, accessed November 2026 | Accessed 2026-11-15

https://www.petronetlng.in/about-us

S9 / Earnings Conference Call Transcript

Petronet LNG | 13 February 2026 | Accessed 2026-11-15

https://www.petronetlng.in/documents/d/pertonetlng/intimationtranscript2

Management commentary, not independent verification of every operating statement.

S10 / Indian Petroleum and Natural Gas Statistics 2024-25

Ministry of Petroleum and Natural Gas | FY2024-25; published February 2026 | Accessed 2026-11-15

https://www.mopng.gov.in/files/TableManagements/2026-02-25-141451-b06fw-IPNG_Statistics-Report_2024-25.pdf