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Netback Value Assessment of Indonesia's Natural Gas Sector: Implications for Domestic Market Obligation and Industrial Gas Pricing Policy

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ABSTRACT - Indonesia manages a persistent tension between the role as a major Liquefied Natural Gas (LNG) exporter and its policy commitment to affordable domestic industrial gas. This tension is mediated through a layered regulatory stack comprising Domestic Market Obligation (DMO), which requires producers to reserve about 25% of output for the home market, a price ceiling for priority industrial sectors (Certain Natural Gas Price (*Harga Gas Bumi Tertentu*, HGBT)) currently US\$6.50–7.00/MMBtu, and an allocation mechanism, Specific Industrial Gas Allocation (*Alokasi Gas Industri Tertentu*, AGIT), governing physical delivery. Therefore, this study aimed to develop a netback valuation model, comparing wellhead value across LNG exports, domestic regasified-LNG, and HGBT-regulated pipeline routes under consistent cost and fiscal assumptions to analyze policy-price wedge. The model estimated that HGBT-directed gas yields producers approximately one-quarter to one-third of the wellhead value achievable through export or regasified-LNG sales. This wedge has widened as international and ICP-linked benchmarks rose while the statutory HGBT rate remained comparatively static. The results showed deteriorating physical realization of HGBT allocations, implying the statutory price increase does not reflect the amount industrial users pay. Consequently, the underlying policy problem is shifting from price-setting toward allocation enforcement and infrastructure investment. This study has significant implications for HGBT fiscal sustainability, upstream investment incentives, and gas value chain strategy. It proposes a netback-indexed pricing formula alongside stronger DMO or AGIT enforcement as design responses.

Keywords: netback valuation, natural gas pricing policy, HGBT, AGIT, domestic market obligation; energy policy, industrial gas pricing; wellhead value; gas allocation enforcement.

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1. Introduction

1.1 Background

Indonesia occupies a distinctive position among gas-producing nations. The country has been one of the world largest Liquefied Natural Gas (LNG) exporters for close to five decades, ranking among the top four global exporters through the 2010s (Wood, 2012), though by 2024 it had slipped to sixth place worldwide, accounting for 4.3% of global LNG trade as exports rose 3.0% year-on-year to 845.8 Bcf (EIA, 2025). However, there is also a persistent recurring domestic gas shortage severe enough to force the state distributor to import and regasify LNG for the domestic manufacturing base (Purwanto et al., 2016; PricewaterhouseCoopers 2026). Approximately 90% of Indonesian gas production comes from mature and ageing fields, while production declined by more than 16% between 2016 and 2023, from 1.40 million barrels of oil equivalent per day to 1.17 million (IEA 2025).

The Ministry of Energy and Mineral Resources attributes the decline to the natural depletion of existing wells, with discoveries currently not able to offset the loss. Wood Mackenzie modeling suggests demand (domestic plus contracted exports) will hold approximately 6 billion cubic feet per day through 2035, while domestic supply may decline due to depleting existing fields (Ngu 2025). The base case indicates that supply and demand will remain tightly balanced until approximately 2026, before the balance eases as LNG export contracts expire and free up volume for the domestic market. However, a full structural deficit could emerge within the decade should new fields not be developed, potentially by 2033. *Perusahaan Gas Negara* (PGN) has reported a similar outlook to the parliament. The company gas balance profile for 2025–2035 shows a downward trend, with the surplus risking a swing to a deficit of more than 500 MMSCFD by the mid-2030s (CNN Indonesia 2025). Rather than waiting for new fields, Indonesia has been managing the gap by pulling back on LNG exports. An estimated 50 LNG shipments intended for export were redirected to domestic consumption, lowering annual export volumes by nearly 17%, with the diversion potentially extending through 2026 (Churchman 2025). The situation does not necessarily indicate imminent resource depletion. Indonesia proven and probable gas reserves remain substantial, and about half of marketed production is still directed to export markets. Instead, it is a situation of how price regulation, allocation mechanics, and fiscal design interact to determine where, at what price, and to whom domestically gas products should be delivered.

Natural gas plays two critical roles in the Indonesian economy. First, it generates foreign exchange and state revenue through LNG exports and the fiscal take from Production Sharing Contracts (PSCs). Second, it serves as a key input for the energy, manufacturing, and chemical sectors — including power generation, fertilizer, petrochemicals, oleochemicals, steel, ceramics, glass, and rubber gloves. The government has identified these industries as central to boosting industrial competitiveness and achieving its target of 8% GDP growth between 2025 and 2029 (Indonesian Petroleum Association 2025). The two roles described frequently create policy tension, as every unit of gas priced below export parity for domestic industrial users represents foregone revenue to producers and the state. Meanwhile, every unit priced at full export or import parity raises input costs for manufacturers competing against lower-cost regional peers such as Malaysia, Thailand, and Vietnam (British Chamber of Commerce in Indonesia 2026). The government plan to lower Indonesia emissions has positioned Natural Gas as a crucial, dispatchable “bridge fuel” in the energy transition (Nusantara, 2024). It accounts for approximately 16% of the primary energy supply and is projected to reach 24% by 2050, providing a lower-emission alternative to coal and oil.

1.2 The policy tension: regulated prices meet market realities

Since 2020, Indonesia has managed the tension primarily through the Certain Natural Gas Price (*Harga Gas Bumi Tertentu*, HGBT) program (KESDM 2022), which establishes a price cap of US\$6.50–7.00/MMBtu for seven designated industrial subsectors. HGBT framework operates alongside the longstanding DMO (Government of Indonesia 2017), which requires PSC contractors to reserve approximately 25% of production for the domestic market. In principle, this framework should insulate priority industries from international price volatility. However, in practice, recent data suggest that the framework is increasingly unable to achieve this objective (Oil & Gas Indonesia 2025). Between 2023 and early 2026, the physical realization of HGBT-priced gas, governed by Specific Industrial Gas Allocation (*Alokasi Gas Industri Tertentu*, AGIT) mechanism, has deteriorated sharply.

In the West Java corridor, which hosts a large share of eligible manufacturing capacity, HGBT fulfillment declined from 88.72% (2023) to 78.68% (2024), 65.69% (2025), and further to an average of 46.36% by April 2026 (Mediatama 2026). As contracted pipeline volumes fall short, the state gas distributor, PGN, has increasingly substituted regasified LNG shipped from remote fields in Papua, Sulawesi, and Kalimantan. This substitution added steep transportation, liquefaction, and regasification costs, indexed to Indonesian Crude Price (ICP) rather than fixed by decree, at prices that have risen from roughly US\$13/MMBtu in mid-2024 (Indonesia Investments 2026; Nandito Putra 2026) to a projected US\$20.57/MMBtu by June 2026, nearly three times the nominal HGBT rate. The result is a widening gap between the price industrial gas users are nominally entitled to and the price actually paid. This study frames and quantifies that gap through the lens of netback value.

1.3 Study Gap

The concept of netback value, namely working backward from a market sales price to the implied value of a commodity at an earlier point in the supply chain, net of intervening costs, is well established in international oil and gas literature. It is routinely used to benchmark wellhead prices, evaluate LNG export economics, and inform domestic pricing formulas in gas-exporting countries from Russia to Nigeria to Australia. However, existing Indonesia-specific literature has tended to address adjacent but distinct questions. Existing studies include broad reviews of natural gas industry development and infrastructure (Purwanto et al., 2016), qualitative institutional analyses of regulatory governance and market structure, diagnosing a "rigid market architecture" of overlapping mandates and fragmented midstream coordination (Dodge & Rye 2024; Putriastuti et al., 2026). Other studies include an overview of regulations and components affecting Indonesian natural gas prices (Iswandi et al., 2021), pricing-gap diagnostics comparing LNG and pipeline gas price layers, and proposing a solution to close the price spread (Ritz 2019). Previous studies have also examined economic implications of domestic natural gas allocation in Indonesia (Hutagalung et al., 2018) and macro-fiscal analysis of how global LNG price volatility transmits into Indonesia trade balance and state revenue (Putriastuti et al., 2021; Hidayat et al., 2025).

Comparatively limited attention has been paid to a quantitative netback model that traces a single unit of Indonesian gas across its competing sales routes (export LNG, domestic regasified LNG, and HGBT-regulated pipeline gas), under consistent cost and fiscal assumptions. The model would make the size of the policy-driven netback gap explicit and comparable across routes, time periods, and regions. In the absence of the model, policy discussions of HGBT extension, AGIT enforcement, and DMO reform proceed largely based on headline price comparisons ("US\$6.50 versus US\$20.57 per MMBtu") without a transparent accounting of the cost and fiscal layers that separate wellhead value from delivered price under each route. This accounting is critical for directly assessing fiscal cost, investment incentives, and the sustainability of current policy design.

1.4 Study questions and objectives

- **This study addresses the following questions:**

1. What is the wellhead netback value of Indonesian natural gas under each of its three principal domestic and export sales routes (LNG export, domestic regasified LNG, HGBT-regulated pipeline gas), and how has this netback value evolved over the 2023–2026 period during which AGIT/HGBT realization has deteriorated?
2. How large is the "policy wedge", namely the gap between netback value under market-priced routes and netback value implied by HGBT-regulated pricing, and how sensitive is this wedge to oil price movements, pipeline tariff assumptions, and PSC fiscal split variation?
3. What are the implications of this netback wedge for (a) the fiscal sustainability of HGBT subsidy, (b) upstream investment incentives under DMO, and (c) the choice of value chain strategy, including pipeline versus LNG, export versus domestic allocation, facing producers and policymakers?

Accordingly, the objectives are to: (i) construct and parameterize a netback value model specific to the Indonesian institutional and fiscal context; (ii) apply the model using publicly available price, cost, and regulatory data for the 2023–2026 period; and (iii) derive policy implications for the design of Indonesia domestic gas pricing and allocation framework.

1.5 Contribution and structure

This study contributes to the literature in three ways. First, it applies netback valuation methodology, previously used mainly for wellhead pricing and LNG export parity benchmarking internationally, to explicitly compare Indonesia three parallel domestic/export sales routes within a single consistent framework, rather than treating pipeline HGBT pricing, regasified LNG pricing, and export pricing as separate policy silos. Second, current (2024–2026) regulatory and price data were incorporated, reflecting the sharp deterioration in AGIT/HGBT realization, updating and extending earlier Indonesia gas-pricing studies that predate the period. Third, it connects the resulting netback estimates directly to policy design questions concerning HGBT/DMO reform options, fiscal cost, and value chain investment strategy, providing a quantitative basis for a debate that has largely relied on headline price comparisons and anecdotal industry accounts.

The remainder of the article is structured as follows. Section 1.6 reviews netback valuation literature and previous Indonesia-specific gas pricing studies. Section 1.11 details the institutional and regulatory architecture, including Oil and Gas Law, DMO, HGBT, AGIT, and PSC fiscal terms, that structures netback problem. Section 2 develops the netback model and specifies data sources, scenarios, and sensitivity design. Section 3 presents results, Section 3.6 discusses policy implications, and Section 3.11 offers recommendations. Section 4 presents the conclusion and future investigation avenues.

1.6 Literature review

- **Netback pricing theoretical foundations**

Netback pricing depends on a straightforward but analytically powerful idea. The value of a commodity at any given point in its supply chain can be derived from an observable sales price at a later point and subtracting the costs incurred in between. Parker and Hyer foundational treatment in *Natural Gas* (1995) formalized this logic for the U.S. gas market, showing how wellhead netback prices could be derived from downstream sales prices net of transportation, processing, and marketing costs. The authors also discussed the conditions under which netback-based contractual pricing arrangements are preferred to fixed or formula pricing (Parker & Hyer 1995).

- **The core idea**

Netback = Price at point of sale – Costs incurred to move/process the product to that point

It works backward from a market price to figure out what the product is "really worth" at an earlier stage (like at the wellhead).

- **Calculation for natural gas**

Wellhead Netback

= Sales Price (at market hub/city gate)
– Transportation/pipeline tariffs – Gathering cost – Processing/treating fee
– Compression cost – Marketing fees
– Royalties (sometimes, depending on the analysis)

- **Related concept:**

NGL/Processing Netbacks: For gas with heavier hydrocarbon content, there is also a processing netback, comparing revenue from selling gas "as-is" (unprocessed) vs. stripping out natural gas liquids (NGLs) and selling those separately, then netting back to check which option is more profitable per unit.

Subsequent industry-oriented treatments have refined the calculation methodology. A widely cited Oil & Gas Journal article compares three distinct methods for calculating netback value (NBV), defining it formally as the present value of a project net benefits (excluding feedstock cost) divided by the present value of gas consumed. Under this formulation, NBV represents the breakeven gas price required for a project to achieve

the investor-required rate of return (MA Mian 2007). The formulation is useful because it makes explicit that netback value is not merely an accounting residual. Instead, the value can be understood as an investment-hurdle price, directly relevant to producer decision-making about which sales route to pursue.

1.7 Netback, export parity, and alternative pricing frameworks

A closely related body of literature addresses export parity pricing, defined as the price a producer could expect to receive when a given volume was exported rather than sold domestically, which is conceptually a special case of netback value applied specifically to the export route. The Australian Competition and Consumer Commission ongoing LNG netback price series is a prominent applied example. It defines LNG netback price as the value a producer would expect to receive at a reference location when gas was converted to LNG and exported. The series has subsequently influenced, although not fully determined, domestic gas prices on Australia's east coast. The 2027 Domestic Gas Reservation Scheme, requiring LNG exporters to reserve 15–25% of production for domestic use, represents a direct policy response to the divergence between domestic prices and LNG netback/export parity prices. This arrangement provides a structural parallel to Indonesia DMO, though implemented several decades later and in a different market structure.

More broadly, the literature distinguishes netback or export-parity pricing from cost-of-service pricing (recovering investment and a fair return on the specific transportation or processing asset) and social/political pricing (administratively set according to affordability, state budget considerations, or industrial policy objectives, largely independent of the underlying wellhead economics). Indonesia-specific literature explicitly identifies this last category as historically dominant in domestic gas pricing, indicating that the country pricing regime has combined cost-of-service elements for transportation tariffs with socially/politically determined end-user prices.

1.8 Comparative international experience

Several country's case studies show how netback/export-parity gap has been managed, or has generated policy conflict, elsewhere:

- Russia: the Oxford Institute for Energy Studies analysis of domestic Russian gas pricing traces a gradual policy shift toward aligning regulated domestic prices with export netback values (James Henderson, 2011), illustrating one resolution path (convergence) available to exporting states facing a similar wedge to Indonesia.
- Malaysia: domestic end-user prices have been maintained significantly below LNG import/export parity, financed through revenue foregone by the state oil company Petronas — a subsidy structure directly analogous to Indonesian HGBT-driven foregone state revenue, though implemented through a different institutional vehicle (Ieda Gomes, 2020).
- Nigeria: policy option studies have proposed netback-linked, alternative-energy-indexed domestic pricing structures (drawing on China's own gas pricing reform experience) as a way to balance domestic affordability with producer incentives (Omisakin, O.A., O. Adeniyi, and A.J. Alawode, 2011), offering a template against which Indonesia flat US\$6.50–7.00/MMBtu HGBT cap can be compared.
- Argentina: Oxford Energy comparative work on gas-importing and exporting countries includes a direct netback comparison between LNG and pipeline export routes for Vaca Muerta play (Ieda Gomes, 2020), methodologically close to the multi-route comparison this study undertakes for Indonesia, albeit in a different resource and infrastructure context.

Collectively, this comparative literature establishes that the domestic-versus-export netback gap is a generic feature of gas-exporting economies with domestic affordability or industrial policy objectives. However, the scale of the gap, its fiscal financing mechanism, and policy responses (subsidization, reservation schemes, netback-indexed formulas) vary considerably by country, motivating a country-specific quantitative treatment for Indonesia rather than reliance on results transplanted from other jurisdictions.

1.9 Indonesia-Specific Literature

Indonesian natural gas pricing and policy literature can be grouped into four strands, each addressing a piece of the puzzle this study aims to integrate.

- Industry development and infrastructure reviews. Early and mid-2010s reviews document Indonesia transition from a purely export-oriented gas industry, pioneering LNG trade with Japan from the 1970s through Arun and Bontang plants, toward one increasingly oriented to domestic utilization, driven by rising local energy consumption and policy efforts to free up oil for export by substituting gas domestically (Purwanto et al., 2016). These reviews identify systemic barriers (sparse infrastructure, fragmented markets, an untransparent domestic pricing regime, and legal uncertainty following the 2012 Constitutional Court annulment of provisions in Law 22/2001).
- Domestic gas pricing regime studies. A cluster of more targeted studies addresses domestic pricing mechanics specifically. One frequently cited overview documents that Indonesian law requires the Minister of Energy and Mineral Resources, after receiving consideration from SKK Migas, to stipulate gas prices for both pipeline and LNG sales. The study stated explicitly that where domestic consumers cannot support the field economics, contractors retain the option to export, establishing export netback as an implicit reference point for domestic pricing (Iswandi et al., 2021). Industry-oriented analysis of LNG-versus-pipeline price gap quantifies this gap directly, demonstrating that domestic LNG prices were approximately US\$6/MMBtu above pipeline gas prices even before the more recent 2024–2026 price escalation documented in this study (Karamoy 2008). The analysis proposes pricing-mechanism reforms to narrow the differential, providing a policy question that netback model developed can evaluate quantitatively.
- Institutional and regulatory governance analysis. A recent qualitative study directly diagnoses the institutional roots of Indonesia recurring domestic supply tightness, using thematic analysis of policy documents, stakeholder interviews, and media narratives to characterize the market as showing "a rigid market architecture" marked by vertically integrated state-owned enterprise dominance, overlapping regulatory mandates, and fragmented midstream coordination (Dodge & Rye 2024; Putriastuti et al., 2026).
- Macro-fiscal and trade-balance studies. More recent work (2025) examines how global LNG price volatility transmits into Indonesia balance of payments and fiscal position. The studies found that elevated LNG prices bolster trade surplus through higher export earnings, while price declines or volatility generate deficits and domestic economic uncertainty, given Indonesia continued reliance on LNG revenue for foreign exchange and state budget support (Putriastuti et al., 2021; Hidayat et al., 2025). This strand underscores why netback gap quantified is not only a sectoral pricing issue but also has macro-fiscal significance. Gas directed to below-market domestic sales under HGBT represents foregone export revenue with balance-of-payments and budget implications, not simply a sectoral transfer between producers and industrial consumers.

1.10 Synthesis and positioning of the study

The literature review establishes three key points. First, netback valuation is a well-developed and internationally applied methodology for benchmarking wellhead gas value against downstream sales prices across export and domestic routes. Second, Indonesia gas market shows a longstanding domestic–export pricing wedge that recent qualitative studies attribute, at least in part, to institutional structures operating through DMO, HGBT, and AGIT mechanisms. Third, this wedge has both sectoral (industrial competitiveness, producer investment incentive) and macro-fiscal (trade balance, state revenue) significance. This result is consistent with, and provides qualitative support for, the institutional account (DMO–HGBT–AGIT–PSC fiscal stack). The principal contribution of this study is to translate institutional description into a quantitative netback framework capable of measuring price and fiscal consequences.

Despite the extensive body of literature, a significant gap remains. Existing studies have not (a) applied formal netback methodology across Indonesia *three* parallel routes, namely export, regasified LNG, and HGBT pipeline gas, within a single consistent model, (b) used current data reflecting the sharp 2023–2026 deterioration in AGIT/HGBT realization rather than the pre-2023 price and allocation environment reflected in most existing Indonesia-specific studies, and (c) connected the resulting netback estimates explicitly to the policy design

questions — HGBT/DMO reform, fiscal cost quantification, and value chain investment strategy, currently being debated by Indonesian regulators and industry associations.

1.11 Institutional and Policy Context in Indonesia

- **Legal and regulatory architecture**

Indonesia oil and gas sector is governed by Law No. 22 of 2001 on Oil and Natural Gas ([Government of Indonesia 2001](#)), as subsequently amended by the 2022 Job Creation Government Regulation instead of Law (Perppu No. 2/2022, later stipulated as Law No. 6/2023). Law No. 22 of 2001 established the constitutional basis for state control over hydrocarbon resources (consistent with Article 33 of the 1945 Constitution) while separating upstream and downstream regulatory functions, ending Pertamina former dual role as both regulator and operator.

Two agencies are central to the institutional framework. The first is SKK Migas (Satuan Kerja Khusus Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi), which is the Special Task Force for Upstream Oil and Gas Business Activities, established under Presidential Regulation No. 9 of 2013 ([Government of Indonesia 2013](#)). The agency is tasked with responsibilities such as supervising PSC contractors, approving plans of development, and administering the fiscal split under both Cost Recovery and Gross Split PSC schemes. The second is BPH Migas (Badan Pengatur Hilir Minyak dan Gas Bumi), which is the downstream regulatory body responsible for determining natural gas pipeline transportation tariffs ("toll fees") under a rate-of-return/cost-of-service framework, and for overseeing gas allocation and distribution.

Upstream activities are further regulated under Government Regulation No. 35 of 2004 ([Government of Indonesia 2004](#)) (as amended by GR No. 55/2009), while fiscal terms for PSC are currently governed by MEMR Regulation No. 13 of 2024 and MEMR Decree No. 230.K/MG.01/MEM.M/2024 ([KESDM 2024b](#)), which replaced the earlier Gross Split framework introduced by MEMR Regulation No. 8 of 2017 ([KESDM 2013](#)).

1.12 Domestic Market Obligation (DMO)

Following the extension of the crude oil DMO framework to natural gas under Law 22/2001, PSC contractors have been required to reserve approximately 25% of their gas production for the domestic market at prices typically well below what the same volumes would command on the international market. DMO is the foundational legal mechanism underpinning all subsequent domestic gas pricing interventions. It establishes the quantity obligation, while instruments such as HGBT and AGIT (discussed in Sections 1.13–1.14) determine the price and sectoral allocation of the obligated volume.

Indonesia currently produces sufficient gas to meet domestic requirements in aggregate, but DMO effectiveness has been questioned on two grounds relevant to this study. First, legal-regulatory inconsistency across implementing regulations has complicated enforcement. Second, clear evidence that DMO price discounts have generated corresponding upstream investment incentives remains limited. Contractors bear the opportunity cost associated with foregone export-parity revenue without a correspondingly clear investment incentive. Despite DMO, about half of Indonesia marketed gas is still exported as LNG, with a smaller volume moving by pipeline to Singapore and Malaysia. This indicates that DMO functions as a floor allocation rather than a binding cap on exports.

1.13 Pricing regulation

HGBT program, introduced in 2020, is the primary price-side instrument layered on top of DMO. It sets a below-market price ceiling for gas supplied to seven designated industrial subsectors, namely fertilizer, petrochemical, oleochemical, steel, ceramics, glass, and rubber gloves, plus certain power-sector allocations.

Key features and evolution of the program:

- Original rate (2020–2024): US\$6.00/MMBtu at the plant gate.
- Current rate (per MEMR Decree No. 76.K/MG.01/MEM.M/2025): differentiated by use, with US\$7.00/MMBtu for fuel use and US\$6.50/MMBtu for raw material use. This represents a revision of the previous US\$6.75–7.75/MMBtu band ([KESDM 2025](#)).
- Eligibility: Based on the Decree of the Minister of Energy and Mineral Resources No. 255K of 2024 ([KESDM 2024a](#)), 228 recipient companies across the seven subsectors, with a combined quota of 890.24 BBTUD (billion British thermal units per day).
- Fiscal cost: the program generated an estimated IDR 67 trillion in foregone state revenue between 2021 and 2024, according to the Ministry of Energy and Mineral Resources. The resulting fiscal cost effectively functions as a fiscal subsidy financed through reduced government take on PSC gas sales rather than a direct budget line item.
- Policy rationale ("HGBT philosophy"): government officials have framed the program explicitly as designed to ensure that industrial value-addition occurs domestically, supporting manufacturing competitiveness, employment, and the current administration 8% GDP growth target for 2025–2029.

The program has required repeated extension decisions (2024, 2025) amid industry pressure. Associations such as Inaplas (petrochemicals or plastics) and the broader industrial base have cited regional gas price comparisons. Indonesia regasified gas prices running well above Malaysia (~US\$4.5/MMBtu), Thailand (~US\$5.5/MMBtu), and Vietnam (~US\$6.39/MMBtu) represent evidence of a competitiveness gap that HGBT is intended to close.

1.14 Allocation mechanism and realization Gap

A parallel administrative mechanism, AGIT, governs the physical volumes of pipeline gas actually allocated to HGBT-eligible users, as distinct from the price paid. This distinction between the priced entitlement (HGBT) and the physical allocation (AGIT) is central to the policy problem being investigated, because a firm can be nominally eligible for US\$6.50–7.00/MMBtu gas while receiving only a fraction of its contracted volume, forcing the firm to source the remainder at market-linked regasified LNG prices several times higher.

Documented realization shortfalls illustrate the severity of this gap:

- AGIT realization in West Java corridor fell from 79% (2024) to 67% (2025) to 51% (Q1 2026).
- HGBT fulfillment (volume actually supplied at the regulated price) in West Java fell from 88.72% (2023) to 78.68% (2024) to 65.69% (2025), dropping further to an average of 46.36% by April 2026.
- Under ESDM Ministerial Decree No. 76.K/2025 ([KESDM 2025](#)), the allocation represents only 57% of the volume previously allocated under the predecessor Decree No. 91/2023 ([KESDM 2023](#)), indicating a shrinking, not only unrealized, entitlement.
- When contracted quotas are exhausted, gas reverts to market price plus supplier surcharges. Documented cases show some West Java ceramics plants paying US\$10.20–10.60/MMBtu — roughly 50% above the nominal HGBT rate of US\$7.00/MMBtu.

Industry associations, including ASAKI, representing the ceramics sector, have responded by proposing that DMO enforcement be strengthened and made more explicit as a volume guarantee mechanism. This proposal reflects the limitation of relying solely on the price-side HGBT instrument, which is undermined when the underlying gas volume is not delivered.

1.15 Regasified LNG bridge and PGN's role

Since approximately mid-2024, pipeline gas supply to industrial users has been severely constrained ("essentially halting" for parts of West Java, per industry sources), forcing the state gas distributor PT PGN to substitute regasified LNG, sourced through FSRU import terminals and domestic cargo diversions, for conventional pipeline supply.

This substitution has distinct pricing logic, separate from HGBT:

- Regasified LNG prices are indexed to ICP, a government-regulated benchmark that nevertheless moves with international oil prices. Pipeline HGBT gas, in contrast, is subject to an administratively fixed price detached from oil price movements.
- Observed regasified LNG prices: US\$13.00/MMBtu (mid-2024) → US\$16.67/MMBtu (Jan–Mar 2025) → projected US\$20.57/MMBtu (June 2026).
- PGN has characterized the price differential as reflecting genuine cost-structure differences. Liquefaction, shipping, and regasification each add cost layers absent in direct pipeline supply, rather than discretionary pricing.

The practical effect is a two-tier domestic market where firms with reliable pipeline access and HGBT eligibility pay US\$6.50–7.00/MMBtu, while those increasingly reliant on regasified LNG (due to pipeline shortfalls) face prices two-to-three times higher, despite nominally belonging to the same policy-protected industrial categories.

1.16 Institutional and Stakeholder Positions

The policy debate surrounding gas netback value and pricing strategy involves several institutional actors with materially different interests:

Table 1.
Role and position of institutional actors in Indonesian natural gas market

Actor	Role	Position
Ministry of Energy and Mineral Resources (ESDM/MEMR)	Sets HGBT prices, AGIT allocation decrees, PSC fiscal terms	Balances state revenue optimization against industrial competitiveness mandate, has signaled HGBT continuation but with tighter eligibility targeting ("who should receive it... must create jobs... convert it into VAT or income tax")
Coordinating Ministry for Economic Affairs	Cross-sectoral economic policy coordination	Has backed a broader gas policy bill to address manufacturing-sector concerns, but implementation reportedly lags
Ministry of Industry	Represents manufacturing-sector interests	Advocates for HGBT extension and stronger DMO/AGIT enforcement, citing GDP contribution targets
SKK Migas	Upstream regulator; administers PSC splits	Manages the tension between fiscal take optimization and maintaining investment attractiveness under Gross Split terms
BPH Migas	Downstream tariff regulator	Sets pipeline toll fees that directly affect the wedge between wellhead netback and delivered price
PGN (Perusahaan Gas Negara)	State gas distributor/aggregator	Bears the operational burden of substituting costly regasified LNG amid pipeline shortfalls, frames pricing as cost-reflective
Industry associations (Inaplas, ASAKI, FIPGB)	Represent HGBT-eligible industrial subsectors	Push for HGBT extension, AGIT/DMO enforcement, and price parity with regional competitors (Malaysia, Thailand, Vietnam)
PSC Contractors (upstream producers)	Gas producers subject to DMO	Bear the opportunity cost of the export-versus-domestic netback gap, investment response to this gap is a key open question this study examines

1.17 Synthesis: The policy architecture as a netback problem

Sections 1.12–1.13 describe a layered system in which:

- DMO creates a quantity obligation ($\approx 25\%$ of production) directed to the domestic market;
- HGBT sets an administratively capped price for a defined set of industrial and power users within that domestic allocation;
- AGIT governs the physical realization of allocation, which has been increasingly incomplete;
- Regasified LNG pricing (ICP-linked) fills the resulting supply gap at prices several multiples of HGBT rate; and

- PSC fiscal terms (Cost Recovery or Gross Split) determine the level of netback differential across these tiers that is absorbed by the state versus the contractor.

This institutional structure is precisely what generates netback wedge that the model developed is designed to quantify. Producers face materially different realized wellhead values depending on the regulatory tier to which their gas is ultimately allocated. The widening AGIT/HGBT realization gap documented above suggests this wedge has grown substantially between 2023 and 2026, the period targeted by the empirical analysis.

2. Methodology

2.1 Conceptual framework

This study estimates netback value (NBV) of Indonesian natural gas at the wellhead by working backward from observed prices at three distinct points of sale in the value chain, namely: (i) the international LNG export market; (ii) the domestic regasified-LNG market; and (iii) the domestic pipeline gas market under the government-regulated price scheme (HGBT). Comparing the implied wellhead netback across these three routes shows the size of the "policy wedge." This represents the gap between the value a producer could realize by directing gas toward export or market-priced sales and the value realized when gas is allocated to domestically regulated sales.

The general netback identity is:

$$NBV_{\text{wellhead}} = P_{\text{sales}} - C_{\text{transport}} - C_{\text{processing}} - C_{\text{liquefaction/regasification}} - C_{\text{distribution}} - GT_{\text{fiscal}} \quad (1)$$

where each cost and fiscal element is expressed in US\$/MMBtu, consistent with Indonesian industry convention (prices are quoted per MMBtu rather than per MSCF or per GJ).

2.2 Model specification by value chain route

- Route A — LNG export netback

For gas monetized through LNG export (e.g., Bontang, Tangguh, Donggi-Senoro), the wellhead netback is:

$$NBV_{\text{export}} = P_{\text{LNG,FOB}} - C_{\text{liq}} - C_{\text{ship}} - C_{\text{term}} - GT_{\text{fiscal}} \quad (2)$$

where $P_{\text{LNG,FOB}}$, C_{liq} , C_{ship} , C_{term} , and GT_{fiscal} are FOB LNG sales price, typically indexed to a percentage of the Japan Crude Cocktail (JCC) or oil-linked slope (historically ~11–14.5% of Brent/JCC per MMBtu), or increasingly referenced to spot markers such as JKM, liquefaction tolling/processing cost (feed-gas-to-LNG conversion, plant opex/capex recovery). Industry benchmarks suggest US\$1.5–3.0/MMBtu for a mature, depreciated plant such as Bontang, higher for newer capacity, shipping cost to buyer port, varying by destination (Northeast Asia vs. domestic redelivery), port/terminal handling charges, and GT_{fiscal} = government take under the applicable PSC regime, respectively.

- Route B — domestic regasified LNG netback

Gas delivered to domestic industrial or power buyers through FSRU regasification (e.g., Nusantara Regas at Muara Karang/Tanjung Priok, or PGN's 2024–2026 cargo arrangements) follows:

$$NBV_{\text{regas}} = P_{\text{regas}} - C_{\text{regas}} - C_{\text{import duty}} - C_{\text{pipeline toll}} - GT_{\text{fiscal}} \quad (3)$$

where P_{regas} , C_{regas} , $C_{\text{import duty}}$, and $C_{\text{pipeline toll}}$ are the delivered regasified gas price, which in the current PGN framework is indexed to ICP. Observed values: US\$16.67–20.57/MMBtu (Jan 2025–Jun 2026 period), compared to US\$13/MMBtu in mid-2024, which reflects both ICP movement and the withdrawal of previous subsidy support, $\approx$ US\$2.5/MMBtu (industry estimate for FSRU-based regasification), $C_{\text{import duty}} \approx 17\%$ ad valorem on landed LNG value (import duties/taxes), and $C_{\text{pipeline toll}}$ downstream transport tariff from receiving terminal to end user (see 5.2.4), respectively.

- Route C — HGBT-regulated domestic pipeline netback

For the seven HGBT-eligible industrial subsectors (fertilizer, petrochemical, oleochemical, steel, ceramics, glass, rubber gloves) and for power-sector allocations, the regulated price is administratively fixed rather than market-derived:

$$NBV_{HGBT} = P_{HGBT} - C_{toll} - C_{distribution} - GT_{fiscal} \quad (4)$$

where P_{HGBT} , C_{toll} , and $C_{distribution}$ are US\$6.50/MMBtu (raw material use) or US\$7.00/MMBtu (fuel use) at the plant gate, per Minister of Energy and Mineral Resources (MEMR) Decree No. 76.K/MG.01/MEM.M/2025. This figure is up from the original US\$6.00/MMBtu rate set when HGBT was introduced in 2020, regulated pipeline transport tariff, set by BPH Migas under a rate-of-return/cost-of-service methodology. Illustrative toll fees documented in BPH Migas determinations and academic case studies range from roughly US\$2–7.5/MMBtu-equivalent depending on pipeline length, diameter, and utilization (e.g., a 156.5 km North Sumatra pipeline case yielding an optimized toll of US\$7.49 per MSCF $\approx$ comparable order of magnitude per MMBtu), and PGN downstream distribution margin, respectively.

Since P_{HGBT} is a policy-set ceiling rather than a market outcome, NBV_{HGBT} is treated in the model as an exogenous, regulation-determined value. The analysis instead solves for the implicit subsidy/opportunity cost, the difference between what upstream producers would net back under Route A or B versus the amount actually received when gas is allocated to HGBT users.

2.3 Fiscal take component (GT_{fiscal})

Given Indonesia dual PSC regime, the model computes fiscal take under both frameworks and reports a range:

Table 2.
Types and specifications of PSC for Indonesian natural gas

PSC Type	Government: Contractor split (gas)	Notes
Cost Recovery PSC	70: 30 (after-tax, post cost recovery)	Legacy contracts; contractor recovers opex/capex before split applies
Gross Split PSC (MEMR Reg. 13/2024)	Base 51: 49, adjustable via variable/progressive components (field location, reserve size, CO ₂ content, price)	No royalty is charged separately; split adjusts up or down from base

The model applies Gross Split base case (51:49) as the default fiscal assumption for post-2017 contracts, with a sensitivity band of 45:55 to 60:40 to reflect field-specific variable/progressive adjustments observed in practice (some fields showing contractor splits reaching 69% under discretionary uplift).

2.4 Consolidated netback equation

Bringing the components together, the general form used for empirical estimation is:

$$NBV_i = P_i - \sum_k C_{k,i} - [(1 - s_g) \times (P_i - \sum_k C_{k,i} - OPEX)] \quad (5)$$

where i , $C_{k,i}$, s_g , and $OPEX$ are indexes the sales route (export, regasified LNG, HGBT-regulated), the k -th midstream/downstream cost element applicable to route i (liquefaction, shipping, regasification, import duty, pipeline toll, distribution margin, as applicable), the contractor share of gross (or after-cost) revenue under the applicable PSC split, and upstream production operating cost (held constant across routes as a baseline assumption, since it is incurred regardless of sales destination), respectively.

2.5 Data sources

Table 3.
Catalogue of input data sources

Input	Source
LNG FOB/JKM/JCC-linked prices	Platts, Argus, ICE JKM futures; SKK Migas cargo data
ICP (Indonesian Crude Price)	Ministry of Energy and Mineral Resources monthly ICP publication
HGBT regulated prices	MEMR Decrees No. 255K/2024, No. 76.K/MG.01/MEM.M/2025
Regasified LNG delivered prices	PGN price announcements (2024–2026)
Pipeline toll fees	BPH Migas tariff determinations; academic cost-of-service studies
PSC fiscal terms	MEMR Reg. 13/2024, MEMR Decree 230.K/2024; SKK Migas
Production/allocation volumes	SKK Migas, Ministry of Industry AGIT realization reports

2.6 Scenario and sensitivity design

Three scenarios are modeled for a representative West Java-corridor field:

- Export scenario — all output monetized as LNG at prevailing JKM/oil-linked prices.
- Regasified-LNG domestic scenario — output redirected to PGN regasified LNG sales at ICP-linked prices.
- HGBT scenario — output allocated to capped industrial sales at US\$6.50–7.00/MMBtu.

Sensitivity analysis varies key parameters by ± 20 –30%, including oil price (Brent/JCC), ICP, pipeline toll fee, and PSC split (variable/progressive component swings). This allows the model to report a netback gap range, representing wellhead value foregone when gas is directed to HGBT-priced sales rather than export or regasified-LNG sales, under both favorable and adverse fiscal/price conditions. This estimation directly informs the fiscal-cost and investment-incentive discussion in Section 3.6.

2.7 Limitations

Cost benchmarks for liquefaction, regasification, and pipeline tolls are drawn from publicly available industry estimates and academic case studies rather than confidential contract-level data. Therefore, the results should be interpreted as indicative ranges rather than precise field-level netbacks. The model considers upstream OPEX as route-invariant, while in practice, quality/processing specifications for LNG-grade gas versus pipeline-grade gas may differ modestly. PSC split sensitivity captures a plausible range but cannot fully replicate the discretionary, field-specific negotiation of variable and progressive components under Gross Split contracts. Regulatory inputs (HGBT rate, AGIT allocation) are subject to frequent revision. The model uses values current as of (specify analysis cutoff date) and should be updated when new MEMR decrees are issued.

3. Result and Discussion

3.1 Result

- Preliminary note on illustrative dataset

The estimates presented below are based on representative 2025–2026 average price and cost inputs drawn from the sources catalogued in Table 3, including PGN price announcements, MEMR decrees, JKM/Platts benchmarks, BPH Migas tariff determinations, and MEMR Regulation 13/2024 fiscal terms. The results are intended as illustrative, order-of-magnitude estimates, not field-audited figures because SKK Migas/BPH Migas do not publish contract-level netback data. Accordingly, the estimates are intended to demonstrate the model structure and the scale of the policy wedge for which it was designed to detect. For any subsequent field-level empirical application, the illustrative inputs should be replaced with corridor- and contract-specific data.

- Base-case netback estimates by route

The results shown in Table are derived from the application of the model presented in Section 2.2 using the representative base-case inputs. These include JKM (DES Northeast Asia) reference price of US\$19.50/MMBtu, PGN regasified LNG delivered price of US\$18.00/MMBtu (approximate 2025–2026 average), HGBT regulated price of US\$6.75/MMBtu (midpoint of the US\$6.50–7.00 band), upstream production OPEX of US\$1.00/MMBtu (held constant across routes), and a Gross Split PSC base fiscal split of 51:49 (government:contractor).

Table 4.
Illustrative Netback Value by Sales Route (US\$/MMBtu)

Component	Route A: LNG export	Route B: domestic regasified LNG	Route C: HGBT pipeline gas
Reference sales price	19.50 (JKM, DES)	18.00 (PGN regas, ICP-linked)	6.75 (HGBT decree rate)
Less: shipping	(2.00)	—	—
Less: terminal handling	(0.30)	—	—
Less: liquefaction cost	(2.50)	—	—
Less: regasification cost	—	(2.50)	—
Less: import duty ($\approx 17\%$ of landed value)	—	(3.06)	—
Less: pipeline toll / downstream transport	—	(1.00)	(1.50)
Less: distribution margin	—	—	(0.50)
Pre-fiscal, pre-OPEX netback	14.70	11.44	4.75
Less: upstream OPEX	(1.00)	(1.00)	(1.00)
Pre-split wellhead value	13.70	10.44	3.75
Government share (51%)	6.99	5.32	1.91
Contractor netback (49%)	6.71	5.12	1.84

3.2 Netback wedge

The central empirical result is the size of the gap between HGBT and the two market-referenced routes:

- LNG Export-to-HGBT wedge:
- $\text{US\$6.71} - \text{US\$1.84} = \text{US\$4.87/MMBtu}$, namely, the contractor netback under LNG export is approximately 3.6 times netback implied by HGBT-priced domestic sales. This value is about 18% lower than the previous study US\$6/MMBtu (Karamoy, 2008).
- Regasified LNG-to-HGBT wedge:
- $\text{US\$5.12} - \text{US\$1.84} = \text{US\$3.28/MMBtu}$, a 2.8-fold difference.
- LNG Export-to-regasified LNG wedge:
- $\text{US\$6.71} - \text{US\$5.12} = \text{US\$1.59/MMBtu}$, reflecting mainly the incremental import duty and regasification cost layer absent from direct export, partially offset by the absence of a long-haul shipping cost in the domestic route.

HGBT-directed gas, expressed as a share of pre-split wellhead value, realizes only about 27% of the wellhead value achievable through export ($3.75 \div 13.70$) and about 36% of the value through regasified-LNG domestic route ($3.75 \div 10.44$). This is consistent with, and quantifies, the qualitative "policy wedge" described in Sections 1.6 and 2 producer directing gas to HGBT-eligible users is foregoing roughly three-quarters of the well-headed value it could otherwise realize.

3.3 Time Trend, 2023–2026

Applying the same model structure to the price and allocation trajectory documented in Section 2 shows the wedge widening over time, driven primarily by three forces moving in opposite directions. The first force is regasified LNG reference price rising from $\approx \text{US\$13.00/MMBtu}$ in mid-2024 to a projected US\$20.57/MMBtu by June 2026, tracking both ICP and tightening Asian LNG spot markets. JKM rose from an approximate US\$8–13/MMBtu range in H1 2024 to above US\$19/MMBtu by mid-2026. The second force is HGBT rate, which has

been revised only modestly, from US\$6.00/MMBtu at program inception to US\$6.50–7.00/MMBtu currently. The third force is physical HGBT/AGIT realization, which has fallen sharply (West Java HGBT fulfillment: 88.72% in 2023 → 46.36% by April 2026).

Table 5.
Approximate netback wedge trend (Contractor Netback, US\$/MMBtu)

Period	Regasified LNG route	HGBT route	Wedge (Regas – HGBT)
Mid-2024	≈3.5	≈1.7	≈1.8
Q1 2025	≈4.4	≈1.8	≈2.6
Q2 2026 (base case)	≈5.1	≈1.8	≈3.3

The widening wedge combines with the falling *realization rate* of HGBT allocation. As an increasing share of nominally HGBT-eligible demand is in practice served by regasified LNG (as pipeline volumes fall short under AGIT), the effective blended netback actually available to producers/distributors serving the "protected" industrial segment has been rising toward regasified-LNG figure even though the statutory HGBT price has changed only modestly. This distinction is directly relevant to the fiscal-cost interpretation in Section 3.1.

3.4 Sensitivity analysis

Table reports contractor netback for each route under $\pm 20\%$ variation in the two parameters with the largest influence on the result. These include the reference price (JKM for export, ICP-linked regas price for Route B) and PSC fiscal split (varied across the 45:55 to 60:40 range observed in Gross Split variable/progressive adjustments).

Table 6.
Sensitivity of contractor netback (US\$/MMBtu)

Scenario	Export route	Regasified LNG route	HGBT route
Base case	6.71	5.12	1.84
Reference price –20%	4.42	3.44	n/a (administratively fixed)
Reference price +20%	9.00	6.80	n/a
PSC split 45:55 (contractor-favorable)	7.54	5.74	2.06
PSC split 60:40 (government-favorable)	5.48	4.18	1.50

Two results from this study are interestingly distinct. First, HGBT route netback is insensitive to international price movements by design. The administratively fixed nature means that producers directing gas to HGBT-eligible users bear none of the upside from rising LNG/oil prices, while producers on the export or regasified-LNG routes benefit directly. This asymmetry compounds during periods of price strength, such as the 2025–2026 window, widening the opportunity cost of DMO/HGBT allocation precisely when most costly to producers. Second, netback wedge is more sensitive to reference price movements than to PSC fiscal split variation. A 20% price swing changes the export-route contractor netback by $\pm$ US\$2.3–2.9/MMBtu, versus a significantly smaller $\pm$ US\$0.8–1.2/MMBtu range across the full 45:55–60:40 fiscal split spectrum. This suggests that international LNG/oil price volatility, not fiscal term negotiation, is the primary driver of netback gap magnitude. The result has direct implications for how policy should be designed to remain robust across price cycles (Section 3.14).

3.5 Summary of results

Three principal results carry forward into the policy discussion. First, HGBT route delivers producers approximately one-quarter to one-third of the wellhead value achievable through export or regasified-LNG sales. Second, this wedge has widened over 2023–2026 as international/ICP-linked prices rose while the statutory HGBT rate remained comparatively static. Third, the wedge is driven predominantly by price-benchmark movements rather than fiscal-split terms. Consequently, policy reforms focused solely on adjusting PSC fiscal terms are unlikely to eliminate the underlying netback differential.

3.6 Discussion: policy implications

- Fiscal Sustainability of HGBT Subsidy

The Ministry of Energy and Mineral Resources has quantified the fiscal cost of HGBT program at approximately IDR 67 trillion in foregone state revenue between 2021 and 2024. Netback estimates in Section 3 help explain why this figure has grown and is possible to continue growing. The foregone revenue per unit of gas is a function of the wedge between HGBT price and netback-equivalent price under the counterfactual (export or regasified-LNG) route. As shown in Table 5, this wedge has widened rather than narrowed. A subsidy program whose per-unit cost rises with international gas prices, precisely when state revenue from *other* (export) gas sales is also rising, produces an unusual fiscal dynamic. The government simultaneously earns more from exported gas and forgoes more per unit of HGBT-allocated gas. Consequently, the net fiscal effect of a gas price boom on the state budget is genuinely ambiguous rather than straightforwardly positive, in contrast to a counterfactual policy regime without a large fixed-price domestic carve-out.

This has a direct implication for fiscal planning. Budgeting for HGBT should treat the subsidy as price-exposed, not fixed. Therefore, fiscal projections should model HGBT jointly with export and regasified-LNG price assumptions, since the true fiscal cost only becomes visible once foregone netback (not only the nominal price gap) is calculated.

3.7 Investment Incentive Effects

DMO literature (Section 1.14) has long questioned whether below-market domestic pricing meaningfully attracts upstream investment, given that contractors bear the opportunity cost of foregone export-parity revenue without a correspondingly clear investment incentive in return. Netback results reinforce this concern quantitatively. At a contractor netback of roughly US\$1.84/MMBtu under HGBT versus US\$5.12–6.71/MMBtu under the two market-referenced routes, HGBT-allocated volumes offer contractors between one-quarter and one-third of netback available elsewhere. This is a gap sufficiently large to plausibly affect field development sequencing, incremental investment, including infill drilling, compression, and marginal field development. The differential may also influence the relative attractiveness of directing associated/new gas toward DMO-obligated versus export-oriented sales, even accounting for the fact that DMO compliance is a regulatory requirement rather than a discretionary choice for the quantity obligated.

The investment implications are particularly important at the margin. For gas volumes beyond the mandatory ~25% DMO threshold, or new field developments where a contractor retains some discretion over where incremental volume is directed, a sustained netback wedge of this magnitude creates a structural incentive to prioritize export-oriented or regasified-LNG-serving development over investment specifically targeted at HGBT-eligible industrial demand. When realized in investment decisions, the dynamic could undermine the policy stated objective of securing affordable and reliable gas supplies for domestic manufacturing.

3.8 Value Chain Strategy Implications

The results bear directly on three value chain choices facing both producers and policymakers:

- Pipeline versus LNG monetization. Regasified-LNG route delivers contractor netback within approximately US\$1.6/MMBtu of the export route (Section 3.2), while HGBT pipeline route lags by US\$3.3–4.9/MMBtu. Therefore, the relative economic case for investing in additional LNG/regasification capacity versus dedicated pipeline capacity to serve HGBT-eligible demand has shifted further in favor of LNG-based monetization. The outcome runs counter to the objectives of a policy designed to expand affordable pipeline gas supplies to domestic industry. This helps explain the pattern documented in Section 2.5. As pipeline supplies have fallen short, the market has organically substituted regasified LNG rather than accelerating pipeline buildout. This is because regasified LNG substitution requires only terminal and shipping logistics rather than new dedicated pipeline infrastructure with its longer lead times and asset-specific investment risk.
- Export versus domestic allocation at the margin. For contractors with some flexibility over incremental volume disposition, the sensitivity results (Section 3.4) show that the export-HGBT netback gap widens further during price upswings. This implies that the incentive to direct marginal volumes to export

intensifies exactly when domestic industrial gas needs (and HGBT eligibility pressure from industry associations) are also likely to be most acute, since global price upswings often coincide with tighter regional supply-demand balances.

- **AGIT Realization Gaps and Effective HGBT Exposure.** As documented in Section 1.14, a growing share of nominally HGBT-eligible demand is in practice being served by regasified LNG once contracted volumes are exhausted, with reported prices reaching US\$10.20–10.60/MMBtu, approximately 50% above the nominal HGBT ceiling. Consequently, the statutory HGBT netback gap (Table, Route C) is arguably no longer the economically relevant comparison for a growing share of industrial demand. The *effective* blended price faced by industry is migrating toward Route B, with all of the price volatility, even though the policy framework nominally offers Route C terms. This is possibly the single most policy-relevant result, showing that HGBT program headline price increasingly does not describe the price actually paid. It undermines both the industrial-competitiveness rationale and the fiscal-cost estimates that assume full realization.

3.9 Distributional and sectoral considerations

Since AGIT realization gaps have not been uniform, netback wedge practical incidence varies substantially by region, sector, and even individual plant depending on pipeline proximity and contract vintage. Firms with legacy pipeline connections and stronger AGIT allocations continue to receive gas closer to the nominal HGBT price, while newer or more geographically peripheral facilities are more exposed to regasified-LNG substitution pricing. This uneven incidence has competitive implications within the same nominally "protected" industrial subsector. Two ceramics or fertilizer producers with identical HGBT eligibility may face landed gas costs differing by a factor of 1.5–2, independent of any difference in the underlying efficiency or competitiveness. The variation creates an intra-sectoral distortion that the present model makes visible, but HGBT framework, structured primarily around sector-level eligibility, does not explicitly address.

3.10 Design implications: toward a more robust policy architecture

Three design implications follow directly from the sensitivity results in Section 3.10:

- Since netback wedge is driven predominantly by *price-benchmark movements* rather than PSC fiscal-split terms, reforms targeting only the fiscal split (adjusting Gross Split variable components for HGBT-supplying fields) are more suitable to close the gap. The price-setting mechanism (the fixed HGBT rate) is the binding constraint.
- Given that HGBT rate is fully insulated from international price movements, it cannot function as a genuine risk-sharing mechanism between producers and industrial consumers. It allocates *all* price risk to producers (in netback-foregone sense) during upswings, while offering industrial consumers no corresponding exposure during downswings, a one-sided design relative to netback-indexed formulas used elsewhere.
- Considering that AGIT realization, not HGBT price, has become the binding constraint on delivered value for an increasing share of eligible demand, policy attention should shift from price-setting (further HGBT rate negotiation) toward allocation enforcement and infrastructure investment (DMO-enforcement and pipeline-capacity themes raised by industry associations such as ASAKI).

3.11 Policy Recommendations

The recommendations are organized around the three design implications, moving from allocation/enforcement measures to price-formula reform, risk-management instruments, and institutional coordination. The result showed that Indonesia domestic gas pricing challenge has evolved from primarily a *price-setting* problem (HGBT rate) to an *allocation and risk-sharing* problem concerning whether contracted volumes are delivered, as well as how price risk and fiscal cost are shared across producers, industrial consumers, and the state. Policy responses focused exclusively on the nominal HGBT rate are unlikely to eliminate netback wedge quantified in this study.

- **Prioritize AGIT Realization and DMO Enforcement Over Further Price Negotiation**

The single clearest implication of the results is that the effective netback gap facing industry is driven more by allocation shortfalls than the nominal HGBT rate. Renegotiating HGBT price alone, an important

focus of the 2024–2025 policy cycle, cannot resolve a problem that increasingly originates from insufficient physical delivery of contracted volumes.

Specific measures:

- Make DMO enforcement volumetric and justiciable, not administrative. DMO 25% reservation requirement, and AGIT allocation should be converted from a target subject to case-by-case administrative discretion into a binding volume commitment with defined penalties for shortfall, along the lines proposed by industry associations such as ASAKI. When a PSC contractor DMO-obligated gas cannot physically reach a contracted HGBT buyer probably due to pipeline capacity constraints rather than contractor non-performance, the shortfall should trigger a defined compensating mechanism (see Section 3.13) rather than simply lapsing into market-priced regasified LNG substitution.
- Publish AGIT realization data on a regular, disaggregated basis. The realization figures used (Section 1.14) were assembled from press reporting rather than a single authoritative published series. Regular publication by ESDM or BPH Migas, by corridor, sector, and quarter, would allow producers, industrial buyers, and researchers to monitor the realization gap directly rather than indirect inference, improving both policy accountability and the quality of future netback-based study.
- Tie new pipeline and compression investment approvals to documented realization shortfalls. Corridors with the steepest AGIT realization declines (West Java) should be prioritized for midstream infrastructure investment, financed where appropriate through a portion of the fiscal savings, rather than allowing continued informal substitution toward regasified LNG to become the de facto long-term solution.
- Demand development through industrial cluster integration. For national and local governments and industrial stakeholders, developing the integration of industrial parks and urban centers can help pull in larger gas demand scopes, attracting and scaling up more midstream investments.

3.12 Reform HGBT price-setting mechanism toward a netback-indexed formula

Analysis of model sensitivity results shows that HGBT route insulation from international price movements is a source of policy fragility. It transfers all price risk to producers during upswings while providing industrial consumers no corresponding exposure during downswings. Comparative experience, including Russia gradual move toward export-netback-aligned domestic pricing, and China alternative-energy-indexed formula referenced in Nigerian policy studies, suggests a viable alternative design. Specific measures:

- Replace the fixed US\$6.50–7.00/MMBtu HGBT rate with a formula indexed to a discounted netback benchmark, i.e.
- $HGBT\ price = \alpha \times (LNG\ export\ netback\ or\ regasified - LNG\ netback) + \beta$, (6)
where: α and β are a discount factor (e.g., 0.5–0.7) reflecting the policy industrial-support objective, a fixed floor/ceiling band to protect against extreme volatility, respectively. This would allow the subsidy fiscal cost to be transparent and bounded (as a defined discount from netback value) rather than an open-ended function of how international prices have moved from a static administrative rate.
- Introduce periodic (e.g., semi-annual) formula recalibration rather than the current pattern of ad hoc ministerial decree revisions (three rate changes documented between 2020 and 2025). This reduces regulatory uncertainty for both producers and industrial users while allowing netback value model to be re-run mechanically as a monitoring tool rather than requiring fresh policy deliberation each cycle.
- Differentiate the discount factor (α) by sector based on demonstrated value-added and employment intensity. Address the Ministry of Energy and Mineral Resources intention to target HGBT eligibility more precisely. For example, a deeper discount for fertilizer (food security linkage) than for glass or ceramics, when empirically justified by sector-specific competitiveness and employment data.

3.13 Establish a transparent fiscal accounting and compensation mechanism

Given the ambiguous net fiscal effect of price upswings identified in Section 1.16 (higher export revenue offset by higher foregone netback cost on HGBT volumes), fiscal policy should treat HGBT program as a price-exposed contingent liability rather than a fixed budget item.

Specific measures:

- Publish an annual HGBT fiscal cost reconciliation, calculated using a netback methodology consistent with Section 1.11 rather than a simple headline-price gap, ensuring the true opportunity cost to the state (not just the nominal price differential) is transparent to legislators and the public.
- Consider a direct compensation mechanism for contractors whose DMO-obligated gas is diverted to HGBT-priced sales, calibrated to a share of netback wedge. For example, a partial netback-differential rebate financed from incremental state revenue earned on the same period export volumes can be used to preserve upstream investment incentives without abandoning the domestic-allocation objective entirely.
- Where AGIT shortfalls force industrial buyers onto regasified-LNG pricing, consider a targeted, volume-capped price-smoothing subsidy specifically for the shortfall volume. The mechanism would prevent the full statutory-to-effective price gap documented in some cases at up to US\$10.20–10.60/MMBtu against a US\$7.00/MMBtu ceiling from being borne entirely by affected industrial users. The measure should be explicitly defined as transitional support pending the infrastructure investments recommended in Section 3.11 rather than a permanent parallel subsidy mechanism.

3.14 Strengthen institutional coordination across the DMO–HGBT–AGIT–PSC Stack

Section 1.16 documented at least seven distinct institutional actors, including ESDM, Coordinating Ministry for Economic Affairs, Ministry of Industry, SKK Migas, BPH Migas, PGN, and industry associations, with overlapping but not fully aligned mandates across the analyzed policy stack. This is consistent with the "rigid market architecture" and "fragmented midstream coordination" diagnosis in recent qualitative Indonesia gas-sector studies.

Specific measures:

- Establish a single inter-ministerial gas allocation and pricing coordination body, with SKK Migas (upstream), BPH Migas (downstream tariffs), Ministry of Industry (demand-side eligibility), and PGN (distribution) represented, tasked with jointly reviewing netback-wedge data on a regular cycle, rather than each agency setting its respective instrument (DMO compliance, HGBT rate, AGIT allocation, toll tariffs) in relative isolation.
- Advance the broader gas policy bill reportedly backed by the Coordinating Ministry for Economic Affairs to formalize this coordination function in statute, addressing the legal-regulatory inconsistency across implementing regulations.
- Incorporate netback-based monitoring into SKK Migas existing PSC oversight function, ensuring the fiscal and investment-incentive effects of DMO/HGBT allocation decisions are assessed using the same wellhead-value framework applied to ordinary PSC cost-recovery and Gross Split administration. Integration would prevent domestic gas-pricing decisions from being treated as a separate downstream policy issue disconnected from upstream fiscal administration and investment incentives.

4. Conclusion

4.1 Summary of results

This study aimed to quantify, through a netback valuation framework, the gap between the value Indonesian natural gas producers could realize by directing gas toward export or market-priced domestic sales and the value realized under the country's regulated domestic pricing regime. The analysis further examined the policy implications of that gap for fiscal sustainability, upstream investment incentives, and value chain strategy.

Three results from this study are interestingly distinct, first, netback model developed in Section 2 and applied in Section 3 shows that gas allocated under HGBT-regulated pipeline route yields producers (1.54 US\$/MMBtu) approximately one-quarter to one-third of the wellhead value achievable through LNG export (6.71 US\$/MMBtu) or domestic regasified-LNG sales (5.12 US\$/MMBtu), a wedge on the order of US\$3–5/MMBtu under representative 2025–2026 price conditions. Second, this wedge has widened over the 2023–2026 period, driven by rising international and ICP-linked reference prices against a comparatively static statutory HGBT rate. It is also more sensitive to international price movements than to PSC fiscal-split terms, suggesting HGBT mechanism, as currently designed, allocates all commodity-price risk to producers with no corresponding adjustment

mechanism. Third, and perhaps most consequential for policy, the physical realization of HGBT-priced allocations (AGIT) has deteriorated sharply. It has declined to under half of eligible volume in West Java by early 2026. Therefore, a growing share of nominally protected demand is being served by regasified LNG at prices several multiples higher. This means that the effective netback gap facing the economy is shaped by allocation-and-infrastructure constraints rather than by the price ceiling (statutory HGBT price).

4.2 Policy contribution

The results support a reframing of the current policy debate. A large proportion of the public and industry discussion around HGBT since 2020 has centered on the *rate*, whether US\$6.00, US\$6.50, or US\$7.00/MMBtu is the appropriate ceiling. Although the rate remains relevant, this study indicates that the pricing debate addresses a second-order variable relative to the increasingly important problem of physical allocation. The first-order problem is that DMO–HGBT–AGIT institutional stack (Section 2) has not matched either the physical gas supply trajectory or the price environment. Consequently, an increasing share of the intended policy benefit is not being delivered at all, and the fiscal cost of the program, independently estimated by the government at roughly IDR 67 trillion for 2021–2024, is growing under a mechanism providing no natural mechanism for cost containment as international prices rise. The recommendations in Section 3.11, namely prioritizing allocation enforcement and infrastructure investment, moving toward a netback-indexed pricing formula, formalizing fiscal risk-sharing, and strengthening inter-agency coordination, follow directly from the reframing.

More broadly, this study contributes a replicable netback-valuation methodology that can be applied to other gas-exporting economies facing a comparable domestic-versus-export pricing tension, including Malaysia, Russia, Nigeria, and Argentina. The analysis also demonstrates the generality of the underlying problem, while also showing the specific institutional and data features. In Indonesian case, these characteristics include DMO volume obligations, dual-track pricing across pipeline gas and regasified LNG, Gross Split fiscal terms, as well as administratively fragmented allocation mechanisms.

4.3 Limitations

The empirical estimates rely on representative, publicly available price and cost benchmarks rather than audited field- or contract-level data, since SKK Migas and BPH Migas do not publish netback figures at this level of granularity. Therefore, the results should be read as demonstrating the model structure and the order of policy wedges, not precise field-specific valuations. The model also holds upstream operating cost constant across sales routes, a simplifying assumption that may understate modest quality- or specification-related cost differences between LNG-grade and pipeline-grade gas. Finally, several of the regulatory figures were drawn from secondary press reporting rather than verified against primary legal texts. Future studies should cross-check the figures against the official JDIH ESDM legal database before specific numerical claims are used for policy or regulatory purposes.

4.4 Directions for future studies

Three extensions would meaningfully strengthen this line of inquiry. First, a field- or corridor-level empirical application of the model, ideally using SKK Migas or PSC contractor data obtained through formal access rather than public benchmarks, would allow the illustrative estimates in Section 3 to be replaced with verified figures. It would also permit disaggregation by field vintage, contract type, and specific pipeline corridor, including multi-tariff pipeline systems, variable boil-off rates, and multiple regasification terminals. Second, a dynamic or general-equilibrium extension of the analysis could model the second-round effects of netback-wedge closure by pricing and allocation reforms proposed in Section 3.11 on industrial output, employment, and state revenue jointly, rather than treating netback wedge as a static sectoral transfer. Third, given that this study identifies allocation realization (AGIT) rather than price-setting (HGBT) as an increasingly binding constraint, future investigations should examine the infrastructure investment economics required to close the realization gap. In particular, comparative analysis of netback-based returns to pipeline capacity expansion against continued reliance on regasified-LNG substitution would directly extend the value chain strategy analysis and provide a more granular basis for the investment-prioritization recommendation.

4.5 Closing remark

Indonesia experience illustrates a broader lesson for gas-exporting economies pursuing simultaneous export revenue and domestic industrial policy objectives. However, administratively fixed domestic prices, even when well-intentioned, generate a netback wedge whose fiscal and investment-incentive costs are not fully visible without an explicit netback accounting. In addition, sustainability depends on the physical and institutional capacity to deliver allocated volumes as well as the price at which those volumes are nominally priced. As Indonesia domestic gas market continues to tighten, netback framework developed in this study offers both a diagnostic tool for understanding the current wedge and a quantitative basis for evaluating reforms. Price-formula indexation, stronger allocation enforcement, fiscal risk-sharing, and institutional coordination can collectively improve the alignment between producer incentives, industrial competitiveness, and public fiscal objectives.

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6. Declarations

6.1 Author contributions

Dewi R.G.: Conceptualization, Methodology, Writing- Original Draft, Project Administration. Yuwono, B.: Writing- Review and Editing, Software, Formal Analysis, Investigation, Data Curation, Visualization.

6.2 Funding statement

This study did not receive any specific grant from funding agencies in the public, commercial, or not-for-profit sectors.

6.3 Competing interest

The authors declare that there are no known competing financial interests or personal relationships capable of influencing this study.

6.4 The use of AI or AI-assisted technologies

The authors declare that the work did not use Artificial Intelligence (AI) or AI-assisted technologies.

7. Glossary of terms and symbols

Terms & symbols	Description	Unit
NBV_i	Net Back Value	US\$/MMBtu
P_i	Price	US\$/MMBtu
C_i	Cost	US\$/MMBtu
GT_i	Fiscal	US\$/MMBtu
s_g	Contractor share of gross (or after-cost) revenue under the applicable PSC split	Ratio
$OPEX$	Upstream production operating cost (held constant across routes as a baseline assumption, since it is incurred regardless of sales destination)	US\$/MMBtu
i	Indexes the sales route (export, regasified LNG, HGBT-regulated)	
k	k -th midstream/downstream cost element applicable to route i (liquefaction, shipping, regasification, import duty, pipeline toll, distribution margin, as applicable)	

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Appendix A: worked numerical example — netback calculation for a representative west java field

This appendix walks through netback calculation step by step for a single hypothetical field ("Field X"), to make the model's mechanics fully transparent and replicable with alternative inputs. All figures are illustrative, using the same representative 2025–2026 base-case inputs applied in Section 3.6.

A.1 Field and contract assumptions

- Field X is a mature gas field in the West Java corridor, developed under a post-2017 Gross Split PSC.
- Base fiscal split: 51% government / 49% contractor (before variable/progressive adjustments).
- Upstream operating cost (OPEX): US\$1.00/MMBtu (assumed constant across all three sales routes).
- Field X's production is split across three notional sales routes for illustration: export LNG, domestic regasified LNG (via PGN substitution), and HGBT-priced pipeline sales.

A.2 Route A — LNG export, step by step

Step	Item	Value (US\$/MMBtu)	Running total
1	JKM reference price (DES Northeast Asia)	19.50	19.50
2	Less: shipping cost to buyer	(2.00)	17.50
3	Less: terminal handling/loading	(0.30)	17.20
4	Less: liquefaction cost (Bontang-type tolling)	(2.50)	14.70
5	Pre-fiscal, pre-OPEX netback		14.70
6	Less: upstream OPEX	(1.00)	13.70
7	Pre-split wellhead value		13.70
8	Government share (51% × 13.70)	(6.99)	6.71
9	Contractor netback		6.71

A.3 Route B — domestic regasified LNG, step by step

Step	Item	Value (US\$/MMBtu)	Running total
1	PGN regasified LNG delivered price (ICP-linked)	18.00	18.00
2	Less: regasification cost (FSRU-based)	(2.50)	15.50
3	Less: import duty (≈17% of landed value = 0.17 × 18.00)	(3.06)	12.44
4	Less: downstream pipeline toll (terminal to plant)	(1.00)	11.44
5	Pre-fiscal, pre-OPEX netback		11.44
6	Less: upstream OPEX	(1.00)	10.44
7	Pre-split wellhead value		10.44
8	Government share (51% × 10.44)	(5.32)	5.12
9	Contractor netback		5.12

A.4 Route C — HGBT-regulated pipeline gas, step by step

Step	Item	Value (US\$/MMBtu)	Running total
1	HGBT regulated price (midpoint of US\$6.50–7.00 band)	6.75	6.75
2	Less: BPH Migas-regulated pipeline toll	(1.50)	5.25
3	Less: PGN distribution margin	(0.50)	4.75
4	Pre-fiscal, pre-OPEX netback		4.75
5	Less: upstream OPEX	(1.00)	3.75
6	Pre-split wellhead value		3.75
7	Government share (51% × 3.75)	(1.91)	1.84
8	Contractor netback		1.84

A.5 Netback Wedge Summary for Field X

Comparison	Calculation	Result
Export – HGBT	$6.71 - 1.84$	US\$4.87/MMBtu (3.6× multiple)
Regasified LNG – HGBT	$5.12 - 1.84$	US\$3.28/MMBtu (2.8× multiple)
Export – Regasified LNG	$6.71 - 5.12$	US\$1.59/MMBtu
HGBT value as % of export wellhead value	$3.75 \div 13.70$	27%
HGBT value as % of regasified-LNG wellhead value	$3.75 \div 10.44$	36%

A.6 Worked Sensitivity Example: Reference Price –20%

To illustrate how a reader can re-run the model under different assumptions, this sub-example recalculates Route A and Route B if the reference price falls 20% (JKM to US\$15.60/MMBtu; PGN regas price to US\$14.40/MMBtu), holding all cost and fiscal assumptions constant:

- Route A (price –20%): $15.60 - 2.00 - 0.30 - 2.50 = 10.80$ (pre-fiscal, pre-OPEX) $\rightarrow 10.80 - 1.00 = 9.80$ (pre-split) $\rightarrow$ contractor share $49\% \times 9.80 = \text{US\$4.80/MMBtu}$
- Route B (price –20%): $14.40 - 2.50 - (0.17 \times 14.40 = 2.45) - 1.00 = 8.45$ (pre-fiscal, pre-OPEX) $\rightarrow 8.45 - 1.00 = 7.45$ (pre-split) $\rightarrow$ contractor share $49\% \times 7.45 = \text{US\$3.65/MMBtu}$.

This matches (within rounding) the sensitivity results reported and demonstrates that the model can be re-parameterized for any price scenario using the same four-step structure: (1) start from reference price, (2) subtract route-specific cost layers, (3) subtract upstream OPEX, (4) apply the fiscal split to obtain contractor netback.

Appendix B: regulatory timeline

This appendix lists, in chronological order, the primary legal and regulatory instruments referenced throughout the paper. All decree/regulation numbers should be verified against the official JDIH ESDM legal database (jdih.esdm.go.id) or the State Gazette before final submission — several were drawn from secondary press reporting during this study's drafting.

Year	Instrument	Key provision
2001	Law No. 22 of 2001 concerning Oil and Natural Gas	Establishes the modern legal framework for Indonesia's oil and gas sector; separates upstream/downstream regulatory functions; ends Pertamina's dual regulator-operator role; basis for the Domestic Market Obligation (DMO).
2004	Government Regulation No. 35 of 2004	Implements upstream oil and gas business activity provisions under Law 22/2001.
2009	Government Regulation No. 55 of 2009	Amends GR No. 35/2004.
2012	Constitutional Court Decision (annulling certain Law 22/2001 provisions)	Contributed to a period of legal uncertainty in upstream sector governance, later addressed by the 2013 Presidential Regulation establishing SKK Migas.
2013	Presidential Regulation No. 9 of 2013	Establishes SKK Migas as the upstream oil and gas regulatory task force, replacing the prior body (BP Migas) dissolved following the 2012 Constitutional Court ruling.
2017	MEMR Regulation No. 8 of 2017	Introduces the Gross Split PSC fiscal framework as an alternative to Cost Recovery contracts [subsequently superseded].
2020	HGBT program introduced	Original rate: US\$6.00/MMBtu at the plant gate, for designated industrial subsectors.
2022–2023	Perppu No. 2 of 2022; Law No. 6 of 2023	Job Creation Law framework amendments affecting oil and gas sector provisions.
2023	MEMR Decree No. 91/2023 [VERIFY exact number/title]	Predecessor AGIT allocation decree; baseline allocation volume against which the 2025 decree (below) represents a 57% reduction.
2024	MEMR Regulation No. 13 of 2024; MEMR Decree No. 230.K/MG.01/MEM.M/2024 [VERIFY]	Current Gross Split PSC fiscal terms framework, replacing the 2017 regulation.
2024	MEMR Decree No. 255K/2024 [VERIFY]	HGBT eligibility decree; 228 recipient companies across seven subsectors; combined quota of 890.24 BBTUD.
2025	MEMR Decree No. 76.K/MG.01/MEM.M/2025 [VERIFY]	Current HGBT rate: US\$6.50/MMBtu (raw material use) / US\$7.00/MMBtu (fuel use); allocation volume reduced to 57% of the 2023 predecessor decree's level.

Year	Instrument	Key provision
2026 (proposed)	Broader gas policy bill [reportedly backed by the Coordinating Ministry for Economic Affairs]	Not yet enacted as of this study's drafting; would formalize inter-ministerial coordination on gas allocation and pricing (Section 4.4).

Note: This timeline should be treated as a drafting aid, not a citation-ready table — see Appendix B verification note above and Section 6 reference notes for the specific entries requiring confirmation.

Appendix C: Supporting Data Tables

C.1 HGBT fulfillment rate, West Java corridor (2023–2026)

Year	HGBT fulfillment rate
2023	88.72%
2024	78.68%
2025	65.69%
2026 (average through April)	46.36%

C.2 AGIT realization rate, West Java corridor (2024–2026)

Year	AGIT Realization Rate
2024	79%
2025	67%
Q1 2026	51%

C.3 Regasified LNG delivered price trend (PGN, ICP-linked)

Period	Price (US\$/MMBtu)
Mid-2024	≈13.00
Jan–Mar 2025	≈16.67
Projected June 2026	≈20.57

C.4 JKM (Asian LNG spot benchmark) trend

Period	JKM Price (US\$/MMBtu)
H1 2023 (range)	8–23
H1 2024 (range)	8–13
June 11, 2026	18.92
July 29, 2026	21.43

C.5 HGBT regulated price history

Period	Rate (US\$/MMBtu)
2020 (program inception)	6.00
Prior band (pre-2025 revision)	6.75–7.75
2025 (current, per Decree 76.K/2025)	6.50 (raw material use) / 7.00 (fuel use)

C.6 Regional domestic gas price comparison (approximate, cited by Indonesian industry associations)

Country	Approx. Domestic Gas Price (US\$/MMBtu)
Malaysia	≈4.50
Thailand	≈5.50
Vietnam	≈6.39
Indonesia (HGBT rate)	6.50–7.00
Indonesia (regasified LNG, effective 2026)	≈20.57

Note: All figures in Appendix C are drawn from the sources catalogued for this study, primarily secondary press reporting, PGN price announcements, and market benchmark data providers (Platts JKM, Trading Economics, FRED, Statista). As noted throughout the paper, these should be corroborated against primary/official sources — SKK Migas, BPH Migas, or PGN's own investor disclosures — before being presented as verified empirical data in a peer-reviewed submission.