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Bridging the Macro-Micro Gap in Energy Transition: The Role of a National Gas Integrator in Decarbonizing Indonesia's Nickel Smelting Industry

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ABSTRACT

Indonesia's aggressive mineral downstreaming policy has successfully established the country as a global nickel powerhouse, yet this industrial expansion faces a critical paradox: the processing of transition metals relies heavily on carbon-intensive, off-grid captive coal-fired power plants. Under impending international climate trade barriers, including carbon-border measures such as carbon-border measures such as the European Union's Carbon Border Adjustment Mechanism (CBAM), although nickel itself is not currently among the CBAM-covered sectors, Indonesia's high-carbon nickel exports face severe financial penalties and risk market exclusion. This paper evaluates natural gas, specifically Liquefied Natural Gas (LNG) delivered via maritime virtual pipelines, as a vital transitional fuel to decarbonize remote smelting hubs in Central Sulawesi and North Maluku. Using an integrated macro-microeconomic modelling framework, this study quantifies the economic feasibility thresholds of fuel switching at the plant level and designs an optimal institutional architecture to overcome current midstream logistical market failures. Microeconomic simulations demonstrate that under standard market conditions, natural gas is financially unviable due to a low domestic coal price cap ($90/ton under the Domestic Market Obligation), yielding an unadjusted Gas Parity Price (GPP) threshold of $7.36/MMBTU against fragmented LNG delivery costs exceeding $12.00/MMBTU. However, when global carbon taxes ($85/ton CO_2) and product green premiums (7.5%) are internalized as shadow prices, the maximum allowable delivered gas price expands significantly to $16.34/MMBTU. To bridge this macro-micro gap and compress the high logistical costs of archipelagic supply chains, this paper proposes the establishment of a centralized National Gas Integrator. By simulating a Weighted Average Cost of Gas (WACOG) price pooling model that aggregates regional industrial demand and cross-subsidizes remote infrastructure with mature domestic pipeline gas, the Integrator can reliably deliver LNG to remote industrial clusters at a socialized tariff of $10.75/MMBTU. This centralized institutional mechanism eliminates structural Take-or-Pay contractual deadlocks and successfully aligns national resource optimization with industrial decarbonization, securing the long-term global competitiveness of Indonesia's green commodity supply chain without relying on direct state fiscal subsidies.

Keywords: Industrial Downstreaming, Captive Coal, Virtual Pipeline LNG, Gas Integrator, Price Pooling (WACOG), Carbon Border Measures, Indonesia.

INTRODUCTION

Background of the Study

Over the past decade, Indonesia has pursued an ambitious industrial downstreaming policy (hilirisasi), positioning itself as a major hub of the global nickel supply chain. By restricting the export of unprocessed minerals and requiring greater levels of domestic processing, the country has successfully attracted billions of dollars in foreign direct investment, particularly in the development of Rotary Kiln-Electric Furnace (RKEF) smelters for Nickel Pig Iron (NPI) and High-Pressure Acid Leaching (HPAL) plants for electric vehicle (EV) battery materials. (Nugroho et al., 2026a, 2026b; Widyastuti et al., 2026)

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However, this economic achievement has created a critical structural paradox: the processing of a metal increasingly associated with the global green transition is itself heavily dependent on one of the most carbon-intensive fossil fuels—coal. In the remote locations of major industrial parks in Central Sulawesi, such as Morowali, and North Maluku, such as Weda Bay, access to the national electricity grid remains limited. Consequently, smelter operators have developed large, dedicated, off-grid captive coal-fired power plants to ensure a reliable supply of electricity for energy-intensive metallurgical processes. As of 2026, approximately 10 GW of captive coal-fired generation capacity is reportedly dedicated to nickel-processing operations, making this sector an increasingly significant component of Indonesia's industrial carbon footprint. (RMI, 2025; WRI, 2026; Sato, 2026)

This coal-intensive processing model poses a growing risk to the long-term competitiveness and marketability of Indonesia's nickel exports. The global market is undergoing a rapid paradigm shift in which the environmental footprint and carbon intensity of mineral production are receiving increasing scrutiny. Mechanisms including carbon-border measures such as carbon-border measures such as the European Union's Carbon Border Adjustment Mechanism (CBAM), although nickel itself is not currently among the CBAM-covered sectors, together with increasingly stringent Environmental, Social, and Governance (ESG) requirements across global automotive supply chains, could expose high-carbon nickel to higher compliance costs, financial penalties, or exclusion from premium markets. To safeguard macroeconomic stability and preserve its industrial competitiveness, Indonesia therefore needs to accelerate the decarbonization of its nickel-smelting sector. (European Commission, 2026; WRI, 2026)

Given the long development timelines and substantial capital requirements associated with large-scale renewable energy infrastructure, particularly geothermal and hydropower projects in remote regions, natural gas—especially Liquefied Natural Gas (LNG)—offers a potentially viable near- to medium-term transition fuel. Replacing coal-fired generation with natural gas could reduce direct thermal carbon dioxide emissions substantially, potentially by approximately 50–55% depending on plant efficiency, fuel characteristics, and operating conditions, while maintaining the stable, 24/7 electricity supply required by energy-intensive metallurgical processes. (IEA, 2022; World Bank, 2025; Kementerian PPN/Bappenas, 2025; WRI, 2026)

Problem Statement

The transition from cheap and readily available captive coal to natural gas in remote smelting hubs faces a profound structural deadlock that market forces alone are unlikely to resolve. This study identifies two interrelated dimensions of this energy-transition bottleneck.

The Microeconomic Viability Gap. At the microeconomic level, private smelter operators face a substantial economic penalty when switching from coal to natural gas. Coal supplied under Indonesia's Domestic Market Obligation (DMO) policy provides an exceptionally low-cost source of energy and, consequently, a highly competitive Levelized Cost of Electricity (LCOE). By contrast, switching to natural gas requires significant upfront capital expenditure (CapEx), including investments in boiler and turbine retrofits, gas-handling systems, and, in remote locations, dedicated regasification facilities. These challenges are compounded by high operating expenditures (OpEx). Because many smelters are located on remote islands without access to pipeline infrastructure, operators must rely on small-scale and fragmented LNG supply chains, resulting in relatively high delivered gas costs. Consequently, private operators have little economic incentive to undertake the transition unless natural gas can achieve a clearly defined price-parity threshold relative to coal or the additional transition costs are otherwise compensated.

The Meso-Macro Market Failure. At the meso-macro level, Indonesia's domestic gas market is characterized by geographic fragmentation and an asymmetric allocation of investment and market risks. Significant gas resources are located in Western and Eastern Indonesia, including major producing areas such as Tangguh, Bontang, and the Masela development, while rapidly growing industrial demand is increasingly concentrated in the country's central industrial corridors. Under the prevailing bilateral market structure, this spatial mismatch creates a classic coordination failure. Upstream gas producers or contractors (KKKS) are reluctant to invest in dedicated transportation and distribution infrastructure or commit to long-term supply arrangements without sufficiently large and reliable volumes backed by long-term Take-or-Pay (ToP)

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commitments. Individual smelters, however, generally lack the scale and risk-bearing capacity to provide such guarantees because their demand is fragmented and exposed to fluctuations in global nickel prices. They also typically lack the specialized midstream capabilities required to manage complex LNG procurement, transportation, storage, and regasification operations.

The result is a self-reinforcing market deadlock: gas producers require large and reliable demand before committing to supply infrastructure, while individual industrial consumers require reliable and competitively priced gas infrastructure before they can commit to large and long-term demand**.** Neither side can efficiently overcome this coordination problem on its own.

Consequently, the central policy question is not simply how to make natural gas cheaper, but how Indonesia can bridge the institutional and economic gap between macro-level gas-resource management and the micro-level energy-transition requirements of individual industrial consumers.

Research Questions

To address the core policy and economic bottlenecks, this research answers the following questions: What is the precise economic parity price and financial threshold at which natural gas/LNG can competitively substitute captive coal within Indonesia's nickel smelting sector, when factoring in global carbon penalties (CBAM) and green price premiums? Why does the conventional, bilateral market mechanism fail to deliver natural gas to remote industrial clusters, and what are the specific institutional limitations of the current regulatory framework? How can a centralized institutional architecture, specifically a designated National Gas Integrator, utilize market aggregation, price pooling mechanisms, and virtual pipeline networks to unlock the economic feasibility of natural gas for industrial downstreaming?

Research Objectives and Novelty

Research Objectives

The primary objective of this study is to develop an integrated macro–microeconomic framework that demonstrates the rationale for establishing a **National Gas Integrator** to support the decarbonization of Indonesia's industrial smelting sector. The study specifically aims to:

1. Quantify the levelized cost of energy substitution at the microeconomic level for energy-intensive Rotary Kiln–Electric Furnace (RKEF) and High-Pressure Acid Leaching (HPAL) smelters, with particular attention to the economic conditions under which natural gas can substitute for more carbon-intensive energy sources.

2. Develop an institutional and operational model for a National Gas Integrator capable of coordinating upstream and downstream gas markets while mitigating Take-or-Pay (ToP) risks for both upstream suppliers and downstream industrial consumers.

3. Simulate a gas price-pooling mechanism, based on a Weighted Average Cost of Gas (WACOG) approach, to demonstrate how centralized market aggregation and integration could reduce the delivered cost of LNG to remote industrial regions without requiring direct fiscal subsidies from the state.

Academic Novelty

The academic novelty of this study lies in its integration of macroeconomic, institutional, and microeconomic perspectives within a single analytical framework. Existing literature on Indonesia's energy transition has generally examined gas-market regulation and energy policy at the macro-policy level, while studies of industrial energy efficiency have tended to focus on individual technologies or engineering-level cost structures. This study bridges these two levels of analysis by explicitly connecting macro-level institutional and regulatory design—represented by the proposed National Gas Integrator—with sectoral microeconomics,

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including smelter cost structures, energy-substitution decisions, and potential international trade penalties associated with carbon-intensive production. (Nugroho et al., 2026b; Putriastuti et al., 2026)

The study therefore contributes an interdisciplinary framework tailored to the structural characteristics of Indonesia as a developing, geographically dispersed, and archipelagic economy. By linking institutional market integration with firm-level energy economics, it seeks to demonstrate not only why gas integration may be necessary, but also how an appropriately designed gas aggregation and price-pooling mechanism could improve the economic feasibility of industrial decarbonization while reducing market and contractual risks across the gas value chain. (World Bank, 2025; IEA, 2022)

LITERATURE REVIEW & THEORETICAL FRAMEWORK

The Theory of Natural Monopoly and Market Fragmentation in Archipelagic Energy Systems

The deployment of energy infrastructure in archipelagic states is inherently constrained by geography, giving rise to distinctive forms of spatial market fragmentation. In classical regulatory economics, network industries such as natural gas transmission exhibit characteristics of a natural monopoly, in which a single firm can supply the entire market at a lower sub-additive cost than any combination of two or more firms because of substantial economies of scale (Baumol, 1977). In a contiguous landmass, this natural-monopoly structure is traditionally managed through fixed pipeline networks, where average costs tend to decline as network utilization and network density increase.

In an archipelagic setting such as Indonesia, however, the natural-monopoly characteristics of gas transmission infrastructure are disrupted by maritime barriers. As linear pipeline extensions across deep seas and between widely separated islands become technically complex and economically prohibitive, the gas market tends to fragment into geographically isolated nodes. To serve these dispersed demand centres, the energy sector must substitute conventional fixed pipeline networks with maritime "virtual pipelines," including small-scale LNG carriers, LNG bunker vessels, and ISO-containerized LNG transport. (Sommeng et al., 2023; World Bank, 2025)

From an economic perspective, virtual pipelines fundamentally alter the cost structure of gas distribution. Instead of relying predominantly on fixed capital expenditure (CapEx) associated with permanent pipeline infrastructure, the system incurs relatively high recurring operating expenditure (OpEx), particularly for maritime transportation, fuel, liquefaction, regasification, and terminal handling. The resulting cost structure can make gas supply to remote islands significantly more expensive than supply to interconnected mainland markets. (Sommeng et al., 2023)

Without appropriate regulatory intervention, such fragmentation can generate significant coordination failures. Upstream producers and midstream logistics providers may face localized monopoly or monopsony conditions, while individual industrial consumers possess insufficient purchasing power to negotiate competitive supply contracts. The resulting market structure can produce high transaction costs, thin trading liquidity, limited investment incentives, and weak price discovery across geographically separated markets (Spulber, 1999). Consequently, the economic problem is not simply one of insufficient gas resources, but also one of coordinating geographically dispersed supply and demand within a fragmented energy system. (Spulber, 1999; Putriastuti et al., 2026)

Natural Gas as a Transitional Bridge and the Risk of Lock-in

Renewable energy remains the preferred long-term alternative to coal, particularly geothermal, hydropower, and solar power. However, the geographical mismatch between renewable resources and Indonesia's nickel-smelting centres creates significant constraints. In Sulawesi, geothermal development remains limited and geographically concentrated. The Lahendong geothermal complex in North Sulawesi currently operates six units with a combined capacity of only 120 MW, while nickel smelters across Sulawesi require electricity on a much larger scale. Moreover, Sulawesi's electricity system has historically consisted of separate regional subsystems, with further interconnection required to transmit renewable electricity from resource-rich areas to major industrial loads. The Ministry of Energy and Mineral Resources has specifically identified the need to strengthen interconnection between northern and southern Sulawesi to supply renewable electricity to nickel-smelting centres. (MEMR, 20

Hydropower provides another important source of relatively stable, low-carbon electricity; however, its deployment is limited by the geographic availability of suitable water resources, lengthy project development requirements, seasonal fluctuations in water availability, and the need for adequate transmission infrastructure. Hydropower projects located far from industrial centres require substantial investment in transmission networks to evacuate their output. Thus, even where renewable generation capacity can be developed, insufficient interconnection may limit its ability to serve rapidly growing industrial demand. Indonesia's current electricity planning accordingly places considerable emphasis on expanding transmission infrastructure alongside renewable generation. Solar power, meanwhile, faces challenges of intermittency and reliability for energy-intensive smelters operating continuously.

Under these circumstances, natural gas may provide a more realistic transitional option. Gas-fired and combined-cycle gas turbine (CCGT) plants can supply relatively large, stable, and reliable quantities of electricity while producing substantially lower emissions than coal-fired generation. The International Energy Agency (IEA, 2020) estimates that, on average, switching from coal to natural gas for electricity generation can reduce emissions by approximately 50%, although the actual benefit depends on gas supply-chain methane emissions. A gradual shift from coal-fired power plants to gas-fired generation could therefore reduce emissions while allowing time for renewable generation, transmission networks, and energy-storage technologies to reach the scale and reliability required by the nickel industry.

However, natural gas infrastructure presents its own investment and coordination challenges. Gas resources are often located far from nickel-smelting centres, requiring pipelines, LNG transportation, storage, and regasification facilities. The transition is therefore not simply a matter of replacing generation technology but also of developing an integrated gas-supply system. Such infrastructure would be difficult for individual smelters to finance independently, while gas producers require sufficient and predictable demand to justify investments in production and transportation infrastructure. This creates a coordination problem involving gas producers, infrastructure providers, power generators, and industrial consumers.

The key policy challenge is consequently to prevent a transitional gas system from creating long-term fossil-fuel lock-in. This can be addressed through flexible contracting, infrastructure designed to be hydrogen-ready, and investment decisions aligned with the economic life of smelters and available nickel resources. LNG-based virtual pipelines and modular regasification facilities can further reduce dependence on rigid, long-lived pipeline infrastructure. Moreover, the flexibility of CCGT generation can support the integration of intermittent renewable energy by providing balancing and backup capacity, a role that the IEA identifies as increasingly important as the share of variable renewables rises (IEA, 2025). Properly designed, therefore, natural gas integration should function as a temporary and flexible bridge toward a low-carbon electricity system rather than as a new source of fossil-fuel dependence.

The Economics of Regulatory Intervention: Demand Aggregation and Price Pooling

To address market fragmentation and the suboptimal allocation of natural resources, regulatory economics provides a useful framework based on demand aggregation and price pooling. When a market is highly fragmented and characterized by small, geographically isolated buyers—such as individual nickel smelters located in remote industrial areas—the transaction volumes and credit profiles of individual consumers may be insufficient to meet the minimum economic threshold required to stimulate capital-intensive gas infrastructure investment. (Laffont & Tirole, 1993; Putriastuti et al., 2026)

The introduction of a centralized institutional agent, referred to here as a Demand Aggregator, can address this problem by contractually bundling fragmented individual demand curves into a single, more predictable aggregate demand schedule. By consolidating demand, the aggregator can create sufficient purchasing volume and greater contractual certainty to improve the bargaining position of consumers while reducing the commercial risks faced by upstream gas suppliers. (Laffont & Tirole, 1993)

This consolidation can generate several economic benefits. First, it reduces the volume risk and credit risk that upstream gas suppliers would otherwise face when contracting individually with numerous smaller industrial consumers (Laffont & Tirole, 1993). Second, it enables the aggregator to exploit economies of scale in procurement and transportation, potentially reducing the average delivered cost of gas. Third, the aggregation of demand creates a more predictable market signal, which can strengthen investment incentives for LNG logistics, regasification facilities, storage, and other midstream infrastructure.

Once demand has been consolidated, the aggregator can implement a Price Pooling mechanism, formally represented through a Weighted Average Cost of Gas **(WACOG)**. If the aggregator procures gas from n different sources with varying production costs (C_i) and volumes (V_i), the pooled gas price distributed to consumers can be expressed as:

$$P_{pool} = \left\{\sum_{i=1}^{n} C_i V_i\right\} / \left\{\sum_{i=1}^{n} V_i\right\} + T_{avg}$$

where P_{pool} represents the pooled gas price charged to consumers, $\mathbf{C_i}$ represents the procurement or production cost of gas from source i, $\mathbf{V_i}$ represents the volume procured from source i, and T_{avg} represents the socialized average midstream transmission, transportation, storage, and regasification tariff.

In regulatory design, price pooling functions as an internal cross-subsidization mechanism (Kahn, 1988). It enables the aggregator to combine relatively low-cost gas from mature domestic fields or existing pipeline systems with higher-cost gas supplied through remote LNG chains. Rather than requiring each geographically isolated consumer to bear the full cost of its individual supply chain, the pooled pricing mechanism distributes costs across the aggregated customer base.

This mechanism can reduce spatial price disparities and provide greater price stability to industrial consumers. The economic rationale is particularly relevant in archipelagic energy systems because the physical cost of delivering gas varies substantially between locations. Price pooling therefore transforms geographic fragmentation from a purely market-driven disadvantage into a manageable regulatory and institutional problem. By smoothing differences in procurement and logistics costs, the mechanism can improve the equity and predictability of industrial energy access across geographically disadvantaged regions while preserving incentives for suppliers to participate in the aggregated market. (Kahn, 1988)

Industrial Fuel Substitution and the Economics of Green Premiums

The microeconomic decision of an industrial firm to substitute one fuel source for another is traditionally governed by the principle of relative thermal and economic efficiency. A profit-maximizing firm will substitute one input fuel for another when the marginal economic benefit of substitution exceeds its marginal cost. (Baumol & Oates, 1988)

In the context of energy-intensive metallurgical processing, such as nickel smelting, this decision can be particularly difficult because firms may have substantial sunk capital invested in existing coal-fired boilers, furnaces, and associated infrastructure. In addition, coal has historically benefited from relatively low nominal energy costs in Indonesia. The economic parity condition for fuel substitution can be modelled by extending the standard cost-minimization framework to incorporate environmental externalities and international carbon-related trade costs as shadow prices (Baumol & Oates, 1988).

Let $LCOE_{coal}$ and $LCOE_{gas}$ represent the levelized costs of generating an equivalent unit of useful thermal energy from coal and natural gas, respectively. When international carbon-related trade penalties and market-based environmental incentives are incorporated, the net economic advantage of substituting natural gas for coal can be expressed as:

$$\mathbf{\Delta S = (LCOE_{coal} + \tau_C \times E_{coal}) - (LCOE_{gas} + \tau_C \times E_{gas}) + GP}$$

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where:

- ΔS represents the net economic advantage of switching from coal to natural gas.
- $LCOE_{coal}$ represents the levelized cost of generating a unit of useful thermal energy from coal.
- $LCOE_{gas}$ represents the levelized cost of generating the equivalent unit of useful thermal energy from natural gas.
- τ_C represents the applicable carbon tax, carbon price, or border-adjustment penalty per tonne of CO_2-equivalent emissions, such as a carbon-related trade adjustment.
- E_{coal} and E_{gas} represent the specific emission intensities of coal and natural gas, respectively, where $E_{coal} > E_{gas}$ under the assumed system boundary.
- GP represents the Green Premium, defined as the additional market value or price premium that lower-carbon commodities may command in environmentally regulated or sustainability-conscious supply chains.

Under traditional market conditions, where $LCOE_{coal} < LCOE_{gas}$ and the carbon price ($\boldsymbol{\tau_C}$) is relatively low, the value of $\boldsymbol{\Delta S}$ may be negative. In such circumstances, switching from coal to natural gas increases the firm's immediate operating costs and therefore provides insufficient economic justification for fuel substitution.

However, as international trade regimes increasingly incorporate mandatory carbon accounting and carbon-related border measures, the effective cost of carbon-intensive production rises. An increase in $\boldsymbol{\tau_C}$ raises the relative economic cost of coal because its higher emission intensity generates a larger carbon-related liability. At the same time, downstream automotive manufacturers and other environmentally sensitive industries may increasingly be willing to pay a premium (**GP > 0**) for certified lower-carbon materials to meet Scope 3 emissions targets and broader supply-chain decarbonization objectives (Porter & van der Linde, 1995). (European Commission, 2026; WRI, 2026)

The combined effect of these two mechanisms—rising carbon-related penalties and the emergence of green premiums—can change the relative economics of fuel substitution. Natural gas may therefore become economically attractive even when its direct energy cost is higher than coal's. The economic rationale for fuel switching consequently extends beyond conventional fuel-cost minimization. For export-oriented nickel producers, investment in gas-based energy systems can increasingly be understood as a strategic measure to preserve international market access, reduce exposure to carbon-related trade barriers, and capture potential premiums for lower-carbon products. (Porter & van der Linde, 1995; WRI, 2026)

Accordingly, the theory of green premiums provides an important economic justification for industrial fuel switching. The upfront cost of transitioning from coal to natural gas should not be evaluated solely as an additional operating expense. Rather, it can be interpreted as a strategic investment that potentially generates three forms of economic value: lower carbon-related trade exposure, improved access to environmentally sensitive international markets, and enhanced product differentiation through lower-carbon production. This perspective is particularly relevant to Indonesia's nickel industry, where the competitiveness of downstream products increasingly depends not only on production costs but also on the carbon intensity and environmental attributes of the production process.

METHODOLOGY

This study employs an integrated mixed-methods quantitative and structural economic modelling approach to evaluate the micro-to-macro-economic dynamics of fuel substitution in Indonesia's nickel smelting sector. The methodological architecture is constructed in three sequential stages: (1) quantification of microeconomic industrial energy demand, (2) formalizing the levelized cost of energy substitution under global climate policy shocks, and (3) structural optimization of an archipelagic midstream virtual pipeline logistics and price pooling

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framework.

Data Sources and Empirical Parameters

The empirical modelling is calibrated using industry baseline data reflective of standard operating parameters in major Indonesian industrial hubs (e.g., Indonesia Morowali Industrial Park/IMIP, Weda Bay Industrial Park/IWIP). The key input parameters utilized across the structural equations are defined in Table 1. (RMI, 2025; World Bank, 2025)

Table 1. Baseline Empirical Modelling Parameters

Parameter	Description	Baseline Value	Source / Justification
$LCOE_{coal}$	Baseline levelized cost of electricity (LCOE) of captive coal-fired power generation (PLTU)	USD 0.065/kWh	Industry average for off-grid mining sites
$Price_{coal}$	Domestic coal price under the Domestic Market Obligation (DMO)	USD 90/metric ton	Ministry of Energy and Mineral Resources (ESDM)
HR_{coal}	Heat rate of a subcritical captive coal-fired power plant (PLTU)	10,500 BTU/kWh	Low-efficiency subcritical configurations
HR_{gas}	Heat rate of a combined-cycle gas turbine power plant (PLTGU)	7,200 BTU/kWh	Standard modern gas-turbine thermal efficiency
η_{gas}	Thermal efficiency of gas-fired power generation	47.5%	Mid-size industrial generation configurations
EI_{coal}	CO_2 emission intensity of coal-fired electricity generation	0.95 kg CO_2/kWh	Subcritical bituminous/sub-bituminous coal generation
EI_{gas}	CO_2 emission intensity of natural-gas-fired electricity generation	0.40 kg CO_2/kWh	Standard natural-gas combined-cycle gas turbine (CCGT) profile
P_{carbon}	Global carbon penalty/carbon price relevant to CBAM exposure	USD 85/t CO_2	Projected long-term EU CBAM carbon-price assumption
R_{green}	Green product premium value	7.5%	Assumed premium over the standard LME nickel price

Note: LCOE = Levelized Cost of Electricity; PLTU = coal-fired power plant; PLTGU = gas-fired combined-cycle power plant; HR = heat rate; η = thermal efficiency; EI = emission intensity; CCGT = combined-cycle gas turbine; CBAM = Carbon Border Adjustment Mechanism; LME = London Metal Exchange; DMO = Domestic Market Obligation.

Microeconomic Demand and Cost Substitution Equations

To model the microeconomic switching conditions for an individual operator of a Rotary Kiln-Electric Furnace (RKEF) or High-Pressure Acid Leaching (HPAL) smelter, we define the Gas Parity Price Threshold **(GPP)**. This threshold represents the maximum delivered natural gas price that an operator can tolerate before natural gas generation becomes more expensive than electricity generated from legacy captive coal.

First, the baseline generation cost equation is adjusted to incorporate localized investment amortization associated with plant conversion:

$$LCOG_{delivered} = ((LCOE_{coal} \times \eta gas) / HR_{gas}) - \Omega_{capex}$$

where Ω_{capex} represents the levelized annual amortization cost of converting subcritical coal boilers to natural gas or constructing modular greenfield gas-fired power blocks. It is calculated as:

$$\Omega capex = \{CapEx_{retrofit} \times [r (1 + r)^t / ((1 + r)^t - 1)]\} / \text{Annual MWh Output}$$

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where **r** is the weighted average cost of capital (WACC) for industrial metal producers, and **t** is the economic or depreciation life of the asset.

To evaluate the impact of external trade-policy pressures, the Carbon-Adjusted Parity Equation integrates the shadow price of cross-border carbon penalties ($\mathbf{P_{carbon}}$) and the potential premium associated with lower-carbon products (Rgreen):

$$\Delta\Phi = [(LCOE_{coal} + P_{carbon} \times EI_{coal}) - (LCOG_{delivered} + P_{carbon} \times EI_{gas})] + \Psi_{premium}$$

where $\mathbf{\Psi_{premium}}$ represents the marginal revenue expansion per unit of energy resulting from certified low-carbon nickel products trading at a premium in the global market.

The green-product premium can be expressed as:

$$\Psi_{premium} = (\Delta Revenue_{green} \times Volume_{output}) / \text{Total Annual MWh}$$ (World Bank, 2025; Putriastuti et al., 2026)

where $\Delta Revenue_{green}$ represents the additional revenue attributable to the green product premium, and $Volume_{output}$ represents the annual volume of nickel output associated with the lower-carbon production pathway.

Under this framework, substitution from coal-based to gas-based electricity generation is economically optimal for the private operator when: (Putriastuti et al., 2026)

$\mathbf{\Delta\Phi > 0}$ (Putriastuti et al., 2026)

In other words, fuel switching becomes economically rational when the combined savings from lower carbon exposure and the additional market value of lower-carbon nickel products exceed the incremental cost of generating electricity from natural gas.

Meso-Macro Virtual Pipeline and Price Pooling Optimization Model

Due to Indonesia's archipelagic geography, gas cannot be delivered to remote smelter hubs via continuous pipelines. Hence, we introduce a midstream logistics model driven by a centralized National Gas Integrator.

The Delivered Cost Structure of Virtual Pipelines

The actual cost of delivering unintegrated natural gas to a remote industrial cluster via a maritime virtual pipeline, denoted as $LCOG_{delivered}$, is a function of the wellhead gas price, liquefaction costs, maritime transportation costs, and localized small-scale regasification overheads:

$$LCOG_{delivered} = P_{wellhead} + C_{liq} + ((Q_{ship} * D_{miles})/V_{cargo}) + C_{regas\_small}$$

Where:

Q_{ship} represents the daily time-charter rate of specialized Small-Scale LNG Carriers,

D_{miles} is the maritime transit distance from supply terminals (e.g., Bontang or Tangguh) to the smelter jetty,

V_{cargo} represents the small cargo capacity typical of archipelagic shipping.

Because V_{cargo} is low, the term $((Q_{ship} * D_{miles})/V_{cargo})$ expands exponentially due to a loss of economies of scale, pushing $LCOG_{delivered}$ well beyond the market-clearing parity threshold defined in the previous Section. (Putriastuti et al., 2026)

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The Centralized Institutional Integrator Optimization Model

To compress this logistical premium, the National Gas Integrator coordinates multiple gas supply centres and centralizes remote industrial demand nodes. The institutional mechanism applies a Weighted Average Cost of Gas (WACOG) price-pooling equation:

$$P_{\text{pooled}} = \frac{\sum_{i=1}^{m}(P_{\text{wellhead},i} \cdot V_{\text{domestic},i}) + \sum_{j=1}^{k}(P_{\text{LNG},j} \cdot V_{\text{LNG},j})}{\sum_{i=1}^{m} V_{\text{domestic},i} + \sum_{j=1}^{k} V_{\text{LNG},j}} + \bar{T}_{\text{socialized}}$$

Where $T_{socialized}$ represents a uniform midstream network tariff managed by the integrator:

$T_{socialized} = (\sum C_{macro\_hub} + \sum C_{virtual\_fleet}) / \sum V_{total}$

By socializing the high infrastructure and shipping costs across a diversified domestic gas allocation portfolio (including cheap legacy pipeline gas from Western Indonesia), the integrator calculates a uniform pooled price (**P_{pooled}**). To ensure the macro-micro linkage closes successfully, the integrator optimizes delivery schedules to guarantee: (RMI, 2025; WRI, 2026)

To ensure the macro-micro linkage closes successfully, the integrator optimizes delivery schedules to guarantee: (RMI, 2025; WRI, 2026)

$P_{pooled} \leq GPP - P_{carbon} (EI_{coal} – EI_{gas})$

This operational framework forms the analytical backbone for the empirical analysis and policy evaluation presented in the subsequent chapters.

Microeconomic Analysis: Cost Optimization and De-Carbonization Thresholds at The Smelter Level

This chapter models the financial and operational implications of fuel switching at the plant level. Using the mathematical formulations established in the previous Chapter, we analyze the traditional cost of captive coal-fired power generation, calculate the economic parity price threshold for natural gas, and simulate how international carbon border taxes and green premiums reshape the microeconomic incentives for Indonesian nickel smelter operators.

Baseline Microeconomics: The Intractable Dominance of Captive Coal

To understand why private smelter operators are reluctant to transition to cleaner energy sources, we must first evaluate the economic efficiency of existing captive coal infrastructure. Major industrial complexes in Morowali, Weda Bay, and Konawe operate off-grid, utilizing subcritical and supercritical captive coal-fired power plants (PLTU) due to the absence of a high-voltage national grid infrastructure in eastern Indonesia.

Applying the standard baseline engineering parameters, the Levelized Cost of Electricity for an off-grid subcritical captive coal plant ($LCOE_{coal}$) is calculated as follows:

$LCOE_{coal} = ((Price_{coal} / EnergyContent_{coal}) \text{ x } HR_{coal}) + OpEx_{non\text{-}fuel} + CapEx_{sunk}$

Given that domestic coal prices are heavily protected under Indonesia's Domestic Market Obligation (DMO) policy—which caps coal prices for domestic industrial power generation at approximately $90 per metric ton—the variable fuel cost component remains exceptionally low.

Assuming an average subcritical heat rate (HR_{coal}) of 10,500 BTU/kWh, the variable fuel cost is:

$\text{Fuel Cost}_{coal} = (\$90/26{,}455{,}463 \text{ BTU}) \text{ x } 10{,}500 \text{ BTU/kWh} \sim \$0.0357 / \text{kWh}$

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When factoring in fixed and variable operational expenditures ($OpEx_{non\text{-}fuel}$) of $0.015/kWh and fully depreciated or subsidized capital costs ($CapEx_{sunk}$), the actual baseline production cost is approximately **$0.055 to $0.065 per kWh** (or $55 to $65 per MWh), or is very low. This low cost provides Indonesian nickel producers with a tremendous cost advantage in the global market, making any alternative fuel source commercially unappealing under standard market conditions.

Calculating the Unadjusted Gas Parity Price Threshold (GPP)

For an RKEF or HPAL smelter operator considering a transition to natural gas via an on-site gas turbine combined-cycle (PLTGU) system, natural gas must achieve cost parity with the baseline coal cost. Using the conversion equation from Chapter III, we isolate the maximum allowable delivered gas price ($GPP_{nominal}$) without carbon pricing or external incentives:

$$GPP_{nominal} = ((LCOE_{coal} - \Omega capex)/HR_{gas}) \times 1{,}000{,}000$$

Converting a coal-fired setup to a gas-fired setup requires substantial new capital expenditure ($CapEx_{retrofit}$). This expenditure includes modifying the boilers, constructing localized cryogenic storage tanks, and building regasification facilities. Levelizing this capital cost (Ωcapex) over a standard 15-year asset lifespan with an industry-standard WACC of 9.5% adds approximately $0.012 per kWh to the cost of gas generation.

Substituting our empirical values into the formula yields:

$$GPP_{nominal} = (\$0.065 - \$0.012) / 7{,}200 \text{ BTU/kWh}) \times 1{,}000{,}000 \sim \$7.36/\text{MMBTU}$$

Conclusion of Nominal Parity Analysis

Under a pure, unadjusted market mechanism, natural gas is only viable for Indonesian smelters if it can be delivered to the remote island jetty at or below **$7.36 per MMBTU**.

However, because these remote locations rely on small-scale, fragmented maritime supply chains, the actual unintegrated delivered cost of LNG often exceeds $12.00 to $14.00 per MMBTU. This creates a massive commercial viability gap of $4.64 to $6.64 per MMBTU, resulting in a complete standstill for private-sector energy transitions. (Sommeng et al., 2023)

Carbon-Adjusted Parity: The Impact of CBAM and Green Premiums

This structural standstill changes dramatically when we introduce international climate trade barriers and market preferences into our cost minimization model. Export-oriented Indonesian nickel smelters face significant risks from the full implementation of the European Union's Carbon Border Adjustment Mechanism (CBAM) and similar carbon-border policies being developed by other major economies. (European Commission, 2026)

The Financial Penalty of CBAM (P_{carbon})

Captive subcritical coal plants emit approximately 0.95 kg of CO_2 per kWh generated, whereas a modern natural gas PLTGU emits only 0.40 kg of CO_2 per kWh. This represents a net carbon reduction of 0.55 kg (or 0.00055 metric tons) of CO_2 per kWh. (IPCC, 2006; RMI, 2025)

Assuming a projected global carbon penalty (P_{carbon}) of **$85** per metric ton of CO_2, the carbon tax penalty added directly to the operating cost of coal is calculated as:

$$\text{Carbon Cost}_{coal} = 0.95 \text{ kg CO2/kWh} \times (\$85/1{,}000\text{kg}) \sim \$0.0807/\text{kWh}$$

Meanwhile, the carbon tax penalty added to natural gas is:

$$\text{Carbon Cost}_{gas} = 0.40 \text{ kg CO2/kWh} \times (\$85/1{,}000\text{kg}) \sim \$0.034007/\text{kWh}$$

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The net carbon cost penalty differential heavily penalizes the continued use of coal:

ΔCarbon Penalty = \$0.0807 - \$0.0340 = \$0.0467/kWh

The Revenue Expansion of Green Premiums ($\Psi_{premium}$)

Simultaneously, downstream electric vehicle (EV) manufacturers are increasingly willing to pay a **7.5%** Green Premium (R_{green}) for certified low-carbon nickel to meet their corporate Scope 3 sustainability targets. Given a baseline London Metal Exchange (LME) nickel price of \$18,000 per metric ton, this premium grants an additional \$1,350 per metric ton of refined nickel product. (WRI, 2026)

When converted back to energy utilization units based on the processing intensity of an RKEF/HPAL plant, this adds an effective revenue offset **($\Psi_{premium}$)** of approximately \$0.018 per kWh to the gas option.

The Shift in the Gas Parity Price

By inserting these carbon penalties and green premiums back into the comprehensive switching equation ($\Delta\Phi$) from Section 3.2, we recalculate the Carbon-Adjusted Gas Parity Price ($GPP_{adjusted}$):

$$GPP_{adjusted} = ((LCOE_{coal} + \text{Carbon Cost}_{coal}) - \Omega_{capex} - \text{CarbonCost}_{gas} + \Psi_{premium}) / HR_{gas}) \times 1{,}000{,}000$$

$$GPP_{adjusted} = (\$0.1177/7{,}200) \times 1{,}000{,}000 \sim \$16.34/MMBTU$$

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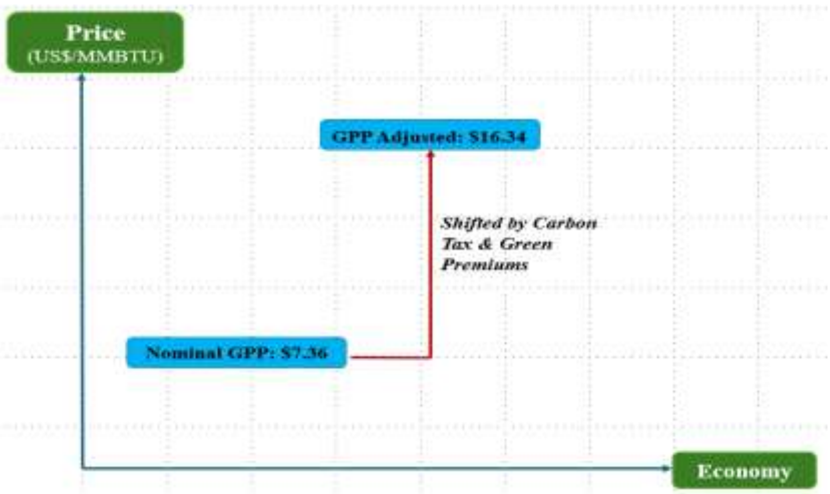
$$GPP_{adjusted} = (\$0.1177/7{,}200) \times 1{,}000{,}000 \sim \$16.34/MMBTU$$

The incorporation of carbon costs and potential green premiums substantially changes the economic conditions for fuel switching. Once these environmental and market factors are internalized, the effective cost advantage of coal over natural gas is significantly reduced. The resulting Carbon-Adjusted Gas Parity Price therefore provides a more comprehensive measure of the maximum gas price that a smelter operator could economically accept while remaining competitive. The following figure illustrates this shift in the gas parity threshold and highlights how carbon pricing and green-market premiums can improve the economic viability of natural gas as a transition fuel.

Figure 1. Shift in the Carbon-Adjusted Gas Parity Price under Carbon and Green-Premium Adjustments



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Section Summary and Policy Insight

As demonstrated by the model, when international carbon constraints and market preferences are properly factored into the microeconomic equation, the maximum economic threshold for delivered gas jumps from an unrealistic \$7.36 per MMBTU to a highly accommodating \$16.34 per MMBTU. This means that if natural gas can be delivered to remote smelter locations at a final cost below \$16.34/MMBTU, switching from coal to gas becomes the profit-maximizing choice for private operators over the medium-to-long term. However, even though private smelters can now afford higher-priced gas on paper, a second major bottleneck appears. The current fragmented, uncoordinated domestic gas market cannot reliably deliver midstream LNG to these remote regions within this price bracket. Individual smelters lack the logistical network and market power to secure stable supplies on their own. This failure of market delivery leads directly to our macro institutional solution: the necessity of a National Gas Integrator, which will be analysed in the following Chapter. (European Commission, 2026; WRI, 2026)

MACRO & INSTITUTIONAL ANALYSIS: THE ARCHITECTURE AND BUSINESS MODEL OF A NATIONAL GAS INTEGRATOR

This chapter addresses the structural supply-side bottlenecks that prevent natural gas from reaching remote industrial locations at scale. While the previous Chapter demonstrated that nickel smelters can economically tolerate an adjusted gas price of up to \$16.34/MMBTU, the current fragmented market structure cannot deliver gas within this threshold due to high logistical risks and coordination failures. This section presents an institutional design and operational model for a centralized National Gas Integrator (Gas Aggregator) to resolve these market failures and optimize gas allocation across Indonesia.

Market Failures in the Fragmented Bilateral Gas Market

Under Indonesia's legacy decentralized framework, gas allocation relies on direct, bilateral negotiations between Upstream Production Sharing Contractors (KKKS) and individual industrial consumers. In an archipelagic setting, this decentralized approach leads to severe market failures, creating a structural deadlock: The Volume and Sunk-Cost Dilemma: Upstream producers (e.g., operators in Tangguh, Bontang, or the upcoming Masela block) require long-term, high-volume Take-or-Pay (ToP) contracts to justify the multi-billion-dollar investments needed for gas production and liquefaction. Conversely, individual nickel smelters cannot sign high-volume ToP contracts due to volatile global nickel prices and highly localized energy needs. The Infrastructure Gap (Diseconomies of Scale): If each private smelter attempts to build its own maritime supply chain, the market fragments into dozens of sub-scale operations. Ordering small, isolated ISO-tank shipments or renting small-scale LNG carriers (SSLNGCs) independently drives up daily time-charter rates. This pushes logistical costs above \$6.00–\$8.00/MMBTU, making unintegrated gas deliveries too expensive for industrial use. Because the private sector cannot pool these risks, natural gas remains trapped at supply sources, while remote industrial hubs continue to rely on captive coal. (Putriastuti et al., 2026)

Institutional Architecture of the National Gas Integrator

To correct these market failures, the government can designate a centralized state entity—such as PT Perusahaan Gas Negara (PGN) as the Gas Subholding of Pertamina—to serve as the National Gas Integrator. This entity acts as a single, centralized intermediary between upstream production and downstream industrial demand. (Pertamina, 2025)

To operationalize the National Gas Integrator concept, a clear institutional architecture is required to define the roles and relationships among upstream gas producers, the national gas integrator, LNG suppliers, transmission and distribution infrastructure, and downstream industrial consumers. The proposed architecture is designed to reduce market fragmentation, facilitate portfolio-based gas procurement, and ensure that gas can be delivered to strategic industrial users at competitive and predictable prices. Figure 2 illustrates the proposed institutional structure and the flow of gas and commercial coordination from upstream supply sources to downstream industrial demand.

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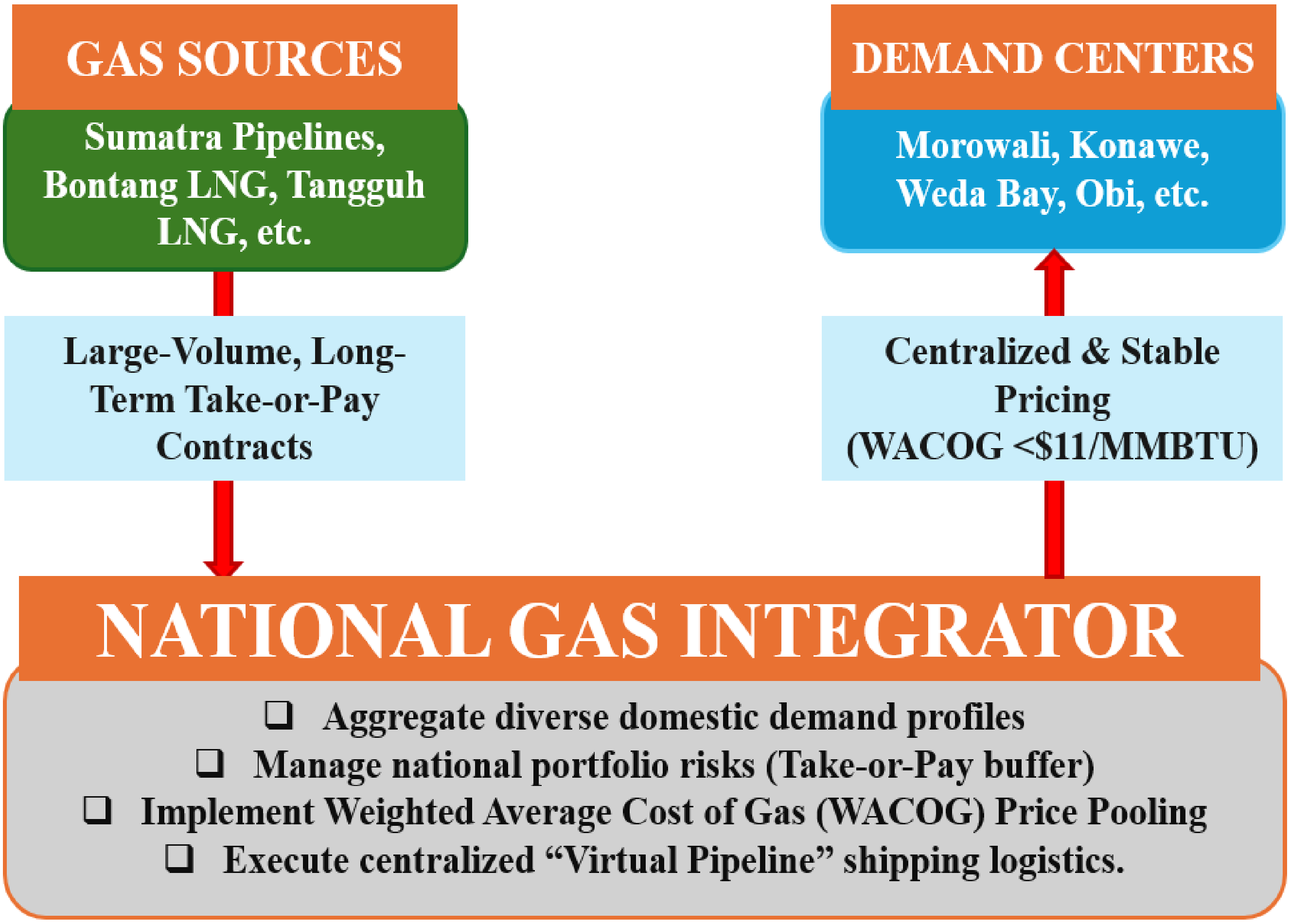
Figure 2. Proposed Institutional Architecture of the National Gas Integrator



Operationalizing the Weighted Average Cost of Gas (WACOG) Price Pooling

The primary financial tool of the National Gas Integrator is Price Pooling, which socializes geographical price disparities across a national portfolio. Instead of charging remote smelters the exact, high cost of small-scale maritime transport, the Integrator uses a Weighted Average Cost of Gas (WACOG) model. Using the methodology from the previous Section, we simulate a portfolio optimization where the Integrator blends low-cost domestic pipeline gas with more expensive remote LNG resources: (Kahn, 1988; Putriastuti et al., 2026)

$$P_{pooled} = (((P_{pipe} \text{ x } V_{pipe}) + (P_{LNG} \text{ x } V_{LNG})) / (V_{pipe} + V_{LNG})) + T_{socialized}$$

Table 2. Portfolio Price Pooling Simulation

Supply Source	Component Price (Wellhead/FOB)	Annual Allocation Volume	Total Component Cost
Sumatra Legacy Pipelines	USD 6.00/MMBtu	350,000 MMBtu	USD 2,100,000
Bontang LNG (FOB)	USD 8.50/MMBtu	400,000 MMBtu	USD 3,400,000
Tangguh Expansion LNG (FOB)	USD 9.00/MMBtu	250,000 MMBtu	USD 2,250,000
Portfolio Aggregate	WACOG: USD 7.75/MMBtu	1,000,000 MMBtu	USD 7,750,000

By averaging these costs, the basic wellhead portfolio price is stabilized at $7.75/MMBTU. Next, the Integrator adds a socialized midstream network tariff ($T_{socialized}$) of $3.00/MMBTU. This tariff covers large-scale bulk shipping, operations at a central hub terminal, and local distribution via maritime virtual pipelines (Sommeng et al., 2023)

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The Macro-Micro Alignment

This simulation demonstrates the power of institutional integration:

While the pooled price of $10.75/MMBTU is higher than the nominal cost of cheap domestic coal, it sits well below the carbon-adjusted threshold of $16.34/MMBTU calculated in Chapter IV. This model provides an economically viable path for industrial fuel switching without requiring direct, ongoing financial subsidies from the state budget.

Risk Allocation and Commercial Sustainability Framework

To ensure long-term commercial sustainability, the National Gas Integrator balances and reallocates contract risks between upstream producers and downstream buyers through two primary mechanisms:

1. The Take-or-Pay Financial Buffer: The Integrator acts as a shock absorber for Take-or-Pay (ToP) risks. If a specific nickel smelter temporarily reduces its production due to an economic downturn, the Integrator can redirect the excess gas volume to more flexible domestic buyers, such as PLN peak-load power plants or chemical industries in Western Indonesia. This portfolio diversification protects upstream producers from localized defaults.

2. LME Commodity Price Indexation: To protect smelters from sudden drops in commodity prices, the Integrator can index a portion of the downstream gas tariff to global nickel prices on the London Metal Exchange (LME). When global nickel prices are high, the gas tariff adjusts upward within a set range to help fund infrastructure expansions. Conversely, if nickel prices decline, the gas tariff lowers toward the baseline portfolio cost, protecting the smelter's operational margins and preventing a relapse into coal usage. By decoupling rigid upstream supply contracts from volatile downstream commodity markets, the National Gas Integrator creates a stable, resilient framework for long-term industrial decarbonization.

POLICY IMPLICATIONS AND STRATEGIC RECOMMENDATIONS

Regulatory Harmonization and Inter-Ministerial Governance

The National Gas Integrator would perform two complementary functions: first, as an aggregator, consolidating diverse gas supplies—including domestic production, LNG, and, where necessary, imports; and second, as an integrator, connecting these supplies to the infrastructure required to deliver gas efficiently to major centres of consumption. Under this model, the geographical distance between gas sources and nickel-smelting centres would no longer need to be managed individually by each smelter. Instead, transmission pipelines, regasification terminals, storage facilities, and small-scale LNG systems could be planned and developed as an integrated infrastructure network, thereby reducing investment duplication, improving supply security, and enabling more efficient and coordinated gas delivery to industrial consumers.

The transition from captive coal-based energy systems to natural gas in Indonesia's smelting sector requires close coordination across two distinct but interdependent policy domains: energy supply governance and industrial development policy. At present, a regulatory disconnect persists between the Ministry of Energy and Mineral Resources (ESDM), which is responsible for gas allocation, pricing, and domestic supply policies, and the Ministry of Industry (Kemenperin) and the Ministry of Investment & Downstream, which oversee industrial development, industrial park licensing, investment facilitation, and downstream mineral-processing targets. (Putriastuti et al., 2026)

To implement the proposed National Gas Integrator model effectively, the government should establish a permanent cross-sectoral Industrial Decarbonization Task Force. The Task Force should coordinate national gas allocation and infrastructure planning with the projected energy requirements of major smelting and downstream industrial clusters. Such coordination would help ensure that gas-supply planning reflects the

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location, scale, and timing of industrial demand rather than being determined solely by upstream supply considerations.

In addition, the government should establish a clear regulatory mandate defining the Integrator's authority and responsibilities as the principal gas aggregator for designated energy-intensive industrial zones. A coordinated aggregation framework would reduce market fragmentation, avoid unnecessary duplication of midstream

infrastructure, and create the demand scale required for effective gas procurement and price pooling. At the same time, the regulatory framework should preserve transparent access and appropriate competition safeguards to prevent the Integrator from becoming an inefficient or exclusionary market intermediary.

Tailored Fiscal Incentives and Carbon Accounting Frameworks

Although gas price pooling can reduce the delivered cost of natural gas, the transition from coal to gas also requires substantial upfront capital expenditure for the conversion or replacement of existing energy infrastructure. The government should therefore complement market-based gas integration with targeted fiscal and regulatory incentives that reduce the initial financial burden on smelter operators.

Accelerated Depreciation and Tax Allowances

Smelter operators that invest in converting coal-fired boilers and captive power systems to natural gas, or that develop new gas-based combined-cycle power plants (PLTGU), should be considered for accelerated depreciation, investment tax allowances, and, where appropriate, import-duty exemptions for eligible gas turbines, gas-handling systems, and other specialized equipment. These measures would improve the investment case for fuel switching by reducing the effective payback period of conversion projects.

Carbon Tax Credits and Transitional Incentives

As Indonesia strengthens its carbon-pricing framework, the government could consider introducing targeted carbon-tax credits or transitional rebates for industrial facilities that demonstrably reduce their emissions through fuel substitution. Smelters that achieve verified and substantial reductions in carbon intensity by replacing coal with natural gas could receive credits that are applied against eligible domestic tax liabilities. Such incentives should be linked to independently verified emissions reductions and designed as transitional instruments rather than permanent subsidies.

National Green Certification System

The Ministry of Industry, in coordination with relevant environmental authorities and international standard-setting and trade institutions, should establish a credible **"Indonesian Low-Carbon Nickel"** certification system. The certification should incorporate transparent methodologies for measuring, reporting, and verifying the carbon intensity of nickel production across the value chain. (WRI, 2026; World Bank, 2025)

A robust certification framework would provide internationally comparable evidence of emissions reductions and strengthen the ability of Indonesian nickel producers to respond to increasingly stringent environmental requirements in major export markets. It could also improve the prospects of Indonesian nickel products for obtaining green premiums or preferential market access, particularly in jurisdictions with increasingly stringent carbon-accounting and supply-chain requirements, including the European Union and the United States.

Taken together, these measures would shift industrial decarbonization policy from a narrow focus on fuel substitution toward a broader framework combining regulatory coordination, market integration, investment incentives, and internationally credible carbon accounting. The proposed National Gas Integrator would consequently function not merely as a gas procurement mechanism, but as an institutional instrument for aligning Indonesia's energy policy with its industrial decarbonization and downstream-processing objectives.

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CONCLUSION

Concluding Remarks

This study demonstrates that successful decarbonization of Indonesia's nickel-smelting sector requires a closer integration of macro-level energy governance and micro-level industrial economics. Under a conventional market framework, private smelters remain strongly dependent on relatively inexpensive captive coal-fired power because the unadjusted gas-parity gap can reach approximately US$6.64/MMBtu. However, once the

economic effects of carbon-related trade measures, such as the European Union Carbon Border Adjustment Mechanism (EU CBAM), together with potential green price premiums, are incorporated into the analysis, the economically viable threshold for natural gas increases substantially, reaching approximately US$16.34/MMBtu. This finding suggests that the competitiveness of gas-based energy substitution cannot be evaluated solely based on short-term fuel prices; it must also account for the growing economic value of lower-carbon production in international markets. (European Commission, 2026; WRI, 2026)

Capturing this opportunity requires Indonesia to move beyond fragmented and predominantly bilateral approaches to gas procurement. The analysis indicates that a designated National Gas Integrator could address important structural coordination and market-integration problems by aggregating demand, coordinating supply, and optimizing logistics across geographically dispersed industrial clusters. Through demand aggregation, centralized virtual-pipeline logistics, and a Weighted Average Cost of Gas (WACOG) price-pooling mechanism, the proposed Integrator could potentially deliver gas to remote industrial clusters at an optimized cost of approximately US$10.75/MMBtu. This price remains below the modelled gas-parity threshold after accounting for carbon-related trade costs and green premiums, thereby creating an economically credible pathway for fuel switching. (Putriastuti et al., 2026)

The proposed institutional model therefore provides a mechanism for bridging the micro–macro gap in Indonesia's industrial energy transition. At the firm level, it improves the economic feasibility of replacing coal with natural gas; at the system level, it addresses supply fragmentation, geographical disparities, and contractual risks within the gas market. More broadly, the model can help protect the international competitiveness of Indonesia's mineral-downstreaming strategy while supporting the country's broader energy-transition and emissions-reduction objectives. The National Gas Integrator should consequently be understood not simply as a gas procurement institution, but as a potential strategic coordination mechanism linking energy security, industrial competitiveness, and decarbonization. (IEA, 2022; World Bank, 2025)

LIMITATIONS AND FUTURE RESEARCH DIRECTIONS

Despite providing an integrated institutional and financial framework, this study has several empirical limitations. First, the pricing and logistics simulations are calibrated to 2026 economic baselines and therefore represent scenario-based estimates rather than forecasts. Second, the analysis assumes a relatively stable global carbon penalty of US$85 per tonne, whereas actual carbon prices and trade-related adjustment costs may vary considerably across jurisdictions and over time. Third, the model does not fully capture all potential sources of uncertainty, including changes in LNG supply availability, shipping costs, exchange rates, infrastructure utilization, and the technological evolution of alternative low-carbon energy systems. (Author's scenario assumptions; see also IEA, 2022)

Future research should therefore employ dynamic and stochastic modelling to examine how fluctuations in international LNG spot prices, shipping charter rates, exchange rates, carbon prices, and industrial demand affect the financial resilience and risk profile of the proposed National Gas Integrator. Further research could also incorporate real-options analysis to evaluate investment timing and infrastructure expansion under uncertainty.

Finally, the proposed gas infrastructure should be assessed within a longer-term energy-transition perspective, with particular attention to avoiding fossil-fuel lock-in. As Indonesia progressively develops low-carbon fuels and hydrogen-based energy systems, future studies should investigate whether elements of the proposed midstream gas architecture—including storage, regasification, transportation, and industrial distribution networks—could be adapted or integrated into future blue-ammonia, green-ammonia, or liquid-hydrogen supply chains. Infrastructure investment should therefore be designed with sufficient flexibility to avoid creating long-lived assets that become economically or technologically stranded as decarbonization accelerates. Such an approach would help ensure that investments made for the transitional role of natural gas retain strategic value as Indonesia moves toward deeper decarbonization. In this way, the National Gas Integrator could potentially serve not only as a near- to medium-term mechanism for industrial fuel switching, but also as a foundation for a more flexible, adaptable, and resilient archipelagic energy infrastructure compatible with Indonesia's long-term pathway toward net-zero emissions.

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