



# Abatement or Reallocation? Unilateral Methane Standards in a Globally Traded Gas Market

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*Natural gas is often treated in policy and commercial analysis as a single fuel category with a broadly predictable emissions profile. The evidence provided in this article does not support that assumption. Using a harmonised lifecycle dataset covering 333 gas fields across major exporting regions, this paper compares LNG, pipeline gas, thermal coal and light fuel oil within consistent system boundaries from production to combustion. Upstream emissions, which cover extraction, processing, domestic transport and international delivery, vary by a factor of two across supply chains. For example, median upstream emissions for Norwegian and North African pipeline gas lie in the range of 60-70 gCO<sub>2</sub>e/kWh, while Russian pipeline gas delivered to Europe is around 104 gCO<sub>2</sub>e/kWh in the median case. Selected high-intensity LNG supply chains exceed 200 gCO<sub>2</sub>e/kWh upstream emissions alone. These differences arise before combustion and are large enough to materially affect lifecycle comparisons.*

Conventional fuel rankings typically place pipeline gas below LNG, below light fuel oil, with coal highest on a full lifecycle basis. Combustion emissions remain broadly stable across gas sources and continue to dominate total lifecycle emissions under a 100-year global warming potential. However, once upstream heterogeneity is incorporated, the margin between fuels narrows substantially for high-intensity supply chains. Under median assumptions, export-oriented gas supply chains (e.g., North America) do not exceed coal in total from production to combustion. Under upper-bound methane intensities, however, some supply chains narrow the gap with coal and in the most extreme cases (e.g., Southeast Asia) close it entirely. The fuel hierarchy is therefore conditional on origin and asset performance rather than intrinsic to the fuel type. Treating gas as homogeneous obscures differences that are relevant to both climate accounting and regulatory design.

Upstream emissions are not evenly distributed across producers. In Russia, the top quintile of fields by methane intensity accounts for roughly one-quarter of regional upstream emissions, from around 12% of production. In Southeast Asia, the top quintile accounts for approximately 38% of emissions from 27% of output. In North America, dispersion is broader but still material: the top quintile represents around 10% of emissions from roughly 6% of production. This concentration has practical implications. Differentiated accountability can exert pressure on a relatively small subset of high-intensity assets without requiring disengagement from entire regions.

These findings are directly relevant to the EU Methane Regulation (Regulation (EU) 2024/1787), which introduces traceability of origin and producer identity, monitoring, reporting and verification equivalence, methane intensity

disclosure from 2028 and the possibility of maximum intensity thresholds from 2030. The Regulation creates transparency and a screening mechanism at the point of import. Whether it generates global abatement or primarily reshapes trade flows depends on the scale of upstream heterogeneity, abatement costs relative to the discount required to place high-intensity gas in non-EU markets, the price elasticity of demand in those markets, and the EU's share of basin-level offtake, which together determine whether reshuffling is cheaper than mitigation.

The principal risk is trade reshuffling: higher-emissions gas displaced from EU trade is redirected to less-regulated destinations. In coal-dominated markets such as China and India, LNG competes mainly with thermal coal, and in the base carbon price scenario shown in the box below, LNG remains materially above coal parity, meaning large-scale diversion would require deep discounts and sharply reduce producer revenues. Under prevailing 2024 cost and price assumptions, seamless redirection at scale therefore appears

constrained. This conclusion weakens if climate policies in China and India become much more stringent: under the high carbon price scenario, rising coal costs close the gap with LNG, making diversion more plausible. The climate effect then depends on which supply chains are diverted. Under GWP100, gas emissions generally remain lower than coal emissions, so switching still reduces emissions on average. Under GWP20, methane carries greater weight, and the gap narrows for methane-intensive supply chains, strengthening the case for upstream-inclusive carbon pricing or for the EU-type methane regulation.

A separate, supply-side adjustment channel lies within exporting jurisdictions (e.g., North America). Where methane intensities vary significantly across assets, producers can route lower-intensity supply to regulated markets while absorbing higher-intensity production domestically. This portfolio sorting improves the average methane intensity of gas entering Europe without necessarily reducing aggregate production or basin-level methane emissions. Import intensity

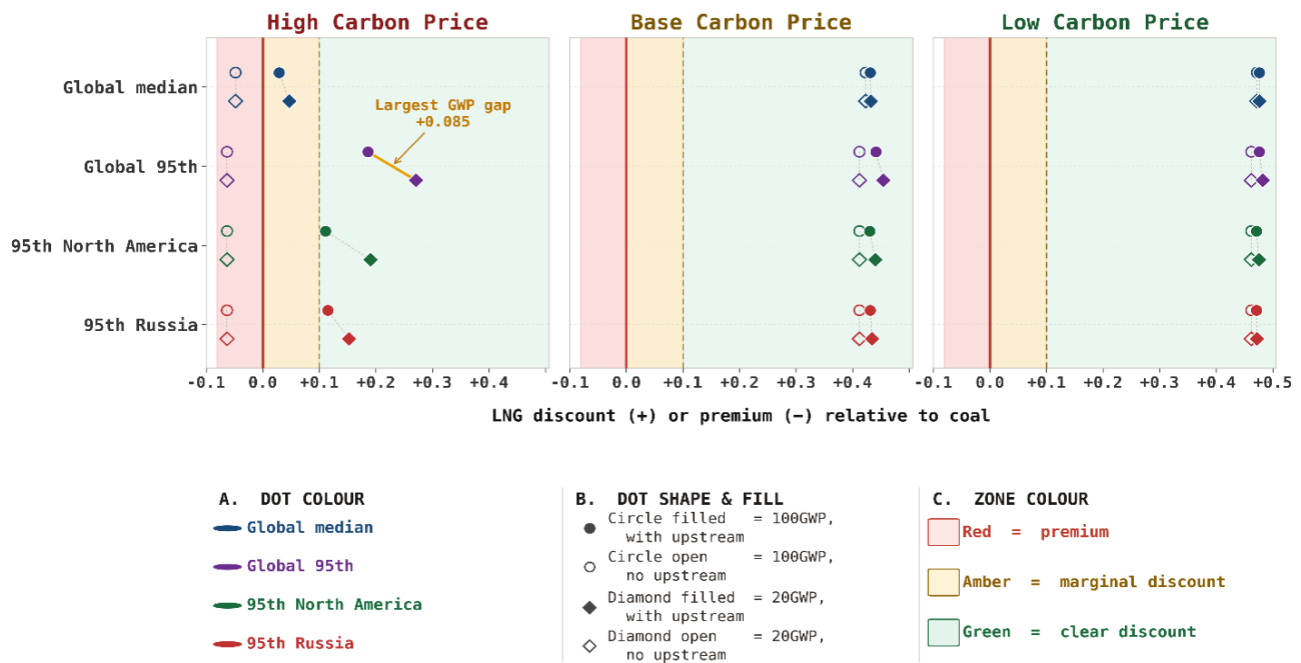


Figure 1. LNG-Coal Breakeven Under Carbon Price and Methane Accounting Scenarios for China and India.

Notes: Each panel represents a carbon price scenario (**High**: China and India - €75/tCO<sub>2</sub>e; **Base**: China and India - €10/tCO<sub>2</sub>e; **Low**: China and India - €5/tCO<sub>2</sub>e). Within each panel, the x-axis shows the price adjustment LNG would need relative to coal to reach lifecycle emissions-cost parity. Positive values indicate LNG is more expensive than coal and would require a price discount to compete; negative values indicate LNG is already cheaper than coal and no discount is needed. Each row corresponds to a regional upstream methane emissions profile; Dot colour identifies the region. Dot shape distinguishes the GWP metric. Dot fill indicates whether upstream methane emissions are included in carbon pricing. Background shading signals the competitiveness of LNG vs coal. Connecting lines between a circle and a diamond of the same fill type illustrate the sensitivity of the breakeven point to the choice of GWP metric: a longer line indicates greater sensitivity to methane accounting.

can fall even if global emissions remain broadly unchanged, provided high-intensity assets continue operating at capacity for non-EU markets. The distinction between asset-level abatement and portfolio reallocation is therefore central to evaluating the Regulation's climate impact.

Shipment-level disclosure alone cannot resolve this distinction. Import statistics reveal what enters the EU market, but not how emissions evolve across producing regions as a whole. If EU import intensity declines while methane intensity across exporting basins remains unchanged, the evidence points to supply rerouting rather than genuine emissions reduction. To address this issue, we propose a Commission-led monitoring function that publishes production-weighted methane intensity and absolute emissions for major exporting regions supplying the EU, drawing on producer disclosures, production data, and satellite verification. This would serve an evaluative rather than a compliance purpose. It will provide policymakers with the evidence base to assess whether the Regulation is driving real mitigation or portfolio reallocation, and to progressively tighten intensity thresholds where rerouting is observed.

For policymakers, the results suggest that unilateral methane regulation does not mechanically induce leakage, but neither does it automatically deliver global abatement. The effectiveness of demand-side standards depends on upstream heterogeneity, abatement costs, the price elasticity of alternative destination markets, and the EU's

share of exporting basin offtake. Carbon pricing amplifies lifecycle cost differentials between high- and low-intensity supply chains, thereby strengthening the commercial case for abatement over relocation. Contract structures and domestic demand conditions in exporting jurisdictions will further shape adjustment pathways.

For producers and traders, methane intensity is increasingly a competitive parameter within fuel types. Asset-level performance and portfolio composition affect market access under emerging screening regimes. The concentration of emissions in a limited subset of high-intensity fields implies that targeted mitigation investments can materially shift relative positioning. When emissions are concentrated in a few high-intensity fields, relatively small operational changes at those fields can significantly lower a producer's overall emissions.

The design of methane accountability frameworks needs to anticipate portfolio responses and build in mechanisms to verify whether reductions in import intensity reflect genuine mitigation or commercial reallocation. Differences in upstream methane intensity across supply chains are large enough to warrant differentiated accountability rather than average-based treatment. The central question is not simply whether methane standards alter trade flows, but whether they change the economics of high-intensity assets. That answer determines whether unilateral methane regulation results in abatement or reallocation.

## References

*Link to the full working paper discussed in this brief:*

Shahabuddin, M. and Chyong, C.K. (2026), "Abatement or Reallocation? Unilateral Methane Standards in a Globally Traded Gas Market," [MIT CEEPR Working Paper 2026-09](#), May 2026

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