Will the U.S. Become the Home of LNG Price Formation?

Adila Mchich
Director, Research and Product Development, CME Group

The nature of price formation in the global liquefied natural gas (LNG) market is increasingly the subject of both industry and academic attention. As the market shows greater appetite to gradually transition from oil indexation towards gas-to-gas pricing, many alternative price references have emerged as regional price signals reflecting respective markets; the question remains as to which region or market among the three – Europe, Asia, or the U.S. – is best positioned to host the core price-discovery benchmark.

This article examines how a new U.S. business model is moving the LNG market toward greater competitiveness and efficiency by transforming the anatomy of LNG trading transactions, also referred to as the market microstructure. This has positioned the U.S. to be the most likely anchor for price formation for the global LNG market.

Price formation in the LNG market is a complex process as the landscape is still evolving. Building a benchmark for LNG depends on the well-functioning, competitiveness, and efficiency of three endogenous and exogenous factors: supply chain, sound delivery system/infrastructure relevance, and market participation.

U.S. LNG developers are innovating in their contractual arrangements and project structuring. This has given birth to a new U.S. institutional model founded around three pillars: volume flexibility, destination optionality, and market competitiveness.

U.S. LNG Supply Chain

The current natural gas supply level has positioned the U.S. among the world's top gas producers. This has considerably reduced the marginal cost of producing LNG and has substantially lowered the price of an LNG cargo. Additionally, U.S. output is produced through new supply chain models. The commercial structure of the supply chain of an LNG project is very important in understanding the LNG market because it defines the return and risk allocation among the investors or stakeholders at each link of the chain.

LNG projects are capital intensive investments that require financing typically through forming joint ventures or partnerships. The decision to adopt any project structure depends on a confluence of various considerations including legal, fiscal, financing, commercial, and the risk appetite of participants. U.S. LNG developers have adopted innovative business models and novel contractual clauses to enhance flexibility and competitiveness.

1. Traditional Integrated Market Structure

LNG project structures have traditionally relied on a vertically-integrated model centered around ownership concentration. As such, project owners control assets throughout the supply chain: from upstream resources, the liquefaction plants, to sometimes even the shipping element. Project developers share costs and revenues across the supply chain and hold the title of the natural gas from the wellhead to the sale of the LNG.

This integrated market structure is based on long-term rigid agreements known as LNG sale and purchase agreements (SPAs), which typically contain destination restrictions that ensure that a specific gas volume is liquefied and shipped to a specific market via commercial transactions with long-term buyers such as utilities or gas companies. While this point-to-point chain offers the buyer reliability of delivered volumes and secures the seller a constant cash-flow stream, this design is solely for supply security and is consumption driven. This model does not enable suppliers or buyers to capture any arbitrage opportunity as the market price moves.

2. U.S. Merchant Market Structure

Under the merchant market structure, a project developer owns the liquefaction facility and procures feedstock gas from producers via natural gas sales agreements at market prices. The merchant then liquefies the gas into LNG and subsequently sells it to different off-takers including portfolio players (aggregators), utilities, and others under LNG SPAs. This business model is driven by a series of arm's length transactions that aim to capture any potential gain based on the competitiveness of the spread between the input (gas) and the output (LNG).

3. U.S. Tolling Model

Under the U.S. tolling model, the liquefaction plant does not take title of the LNG. Instead, it processes feedstock gas supplied by the LNG buyer/off-taker for a tolling fee based on a negotiated rate. This is analogous to the role of the natural gas pipeline which does not own gas but provides transportation services to shippers. Among the benefits of this project structure is the flexibility and diversity in ownership throughout the supply chain. The LNG plant operator is not tied to any particular upstream source and marketer.

Under both market frameworks, each component of the supply chain operates independently and efficiently through competitive market offerings. In addition, the ownership structure is also diverse.

4. Equity or Tellurian Market Model

This market model was recently introduced by two main project developers: Tellurian and LNG Canada in 2018. This structure offers the buyer an equity stake in the project (e.g., 65-70% in the case of Tellurian) with its integrated components: upstream equity gas, through liquefaction to shipping, marketing and trading. This project structure looks at return and risk across the supply chain instead of looking at each chain link separately. LNG buyers buy equity and receive LNG in proportion to their ownership stake. Designing such a novel model was an attempt to attract investors with equity ownership to secure financing in a low-priced environment that currently favors the buyer.

Volumetric Flexibility & Destination Optionality

The U.S. model fundamentally relies on volumetric and destination optionality, which is the cornerstone of spot trading. The U.S. SPA is based on an enhanced version of the take-or-pay (ToP) contract structure. This contract construct stipulates that the buyer is contracted to lift an annual quantity called the "annual contract quantity" or "ACQ" at a pre-determined price or else to pay any shortfalls. With enough advance notice – usually two months – the ACQ is subject to downward/upward adjustment rights or cancellation rights that can be exercised by the buyer based on global seasonal demand. The contract structure of SPAs offers flexibility to both the buyer and the seller. The buyer has the optionality to lift LNG or not, depending on current demand, without breaching any contractual obligations. The seller will collect cash flows either as LNG sale proceeds or as cancellation fees, irrespective of whether the buyer takes delivery of LNG or not. The embedded destination flexibility of U.S. SPAs allows cargoes to be redirected where it is economically favorable depending on spot price signals. This means they can be sold multiple times before they are lifted from the terminal. These factors have contributed to the rise of LNG spot trading and created new permutations between buyers and sellers.

New Developments of LNG Cargo Trading

1. Rise of Portfolio Optimization

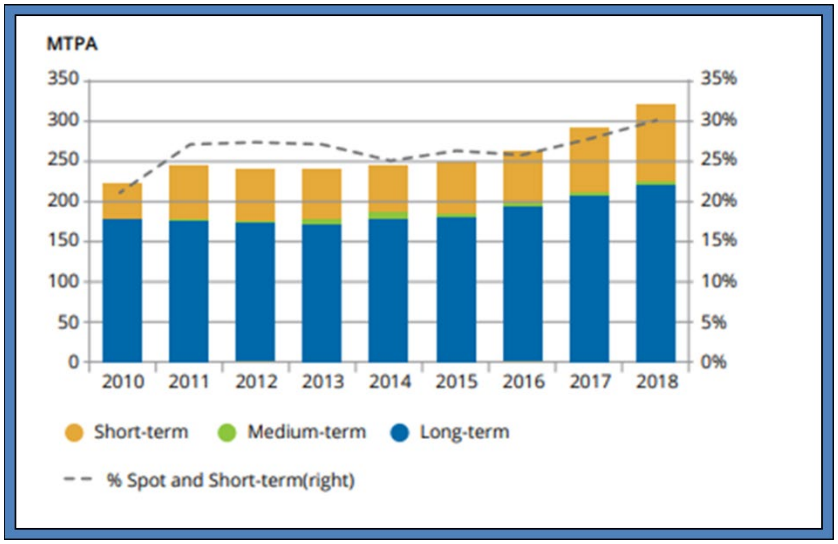
Significant volumes of contracted U.S. LNG are owned by portfolio optimizers. These aggregators are generally large energy companies such as Shell, BP, and Total, which own upstream assets or capacity and have long term off-take agreements. These aggregators are driven by margin optimization and act as market makers. They engage in short-term trading to capture price arbitrages using sophisticated strategies like buying cargoes on term contracts and selling on a spot basis or vice versa. LNG portfolio optimizers play a key role in reshaping the microstructure of LNG trade as they act as market makers. Their importance is analogous to the role played by traditional marketers in the natural gas market back in the 1990s. Portfolio optimizers' ability to raise capital at lower costs enhances their marketing capabilities and enables them to be the conduit between the primary market and the secondary/resale market. This has led to a progressive increase in LNG spot trading, which is also referred to as the swing market.

2. Short-Term Trade Duration

While the LNG market has traditionally relied on long-term contracts, spot trading has been growing for the second consecutive year and reached 99 MT in 2018. This represents an increase of 31% of global trade. However, the largest growth came from the U.S. where approximately 70% of Sabine Pass exports were traded spot in 2017 due largely to the flexibility of U.S. LNG volume that facilitated cargo diversions coupled with the increasing activity of portfolio optimizers who own significant capacity in

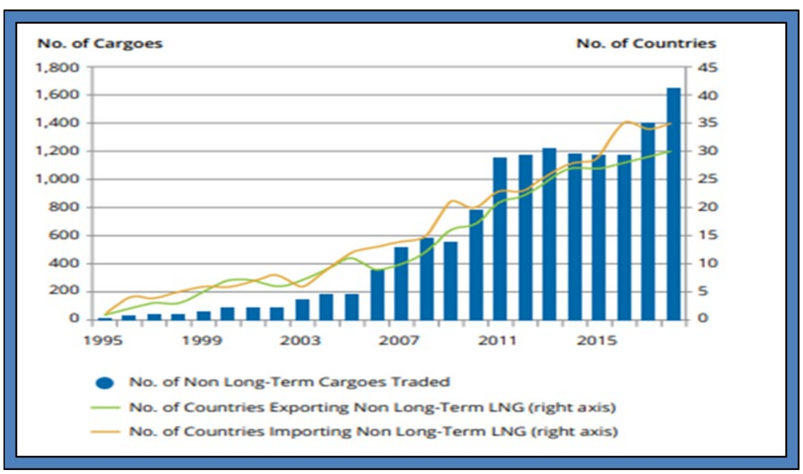
U.S. Gulf Coast ("USGC"). Figures 1 and 2 show that cargoes traded with short-term duration are getting momentum while the medium term is increasing at a slower pace.

Figure 1
Short, Medium and Long-Term Trade, 2010-2018



Source: International Gas Union (IGU).

Figure 2
Short-Term/Spot Trading by Number of Cargoes & Countries



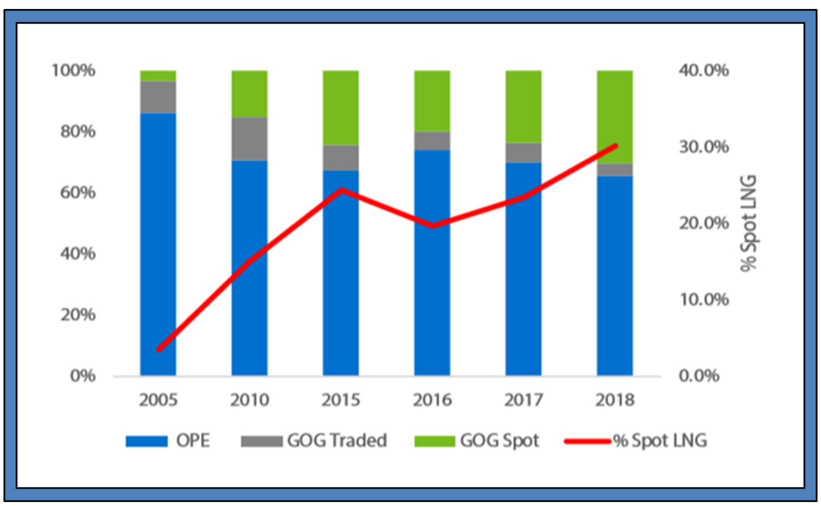
Source: IGU.

3. Price Discovery

The global LNG market is based mainly on two structurally different pricing regimes: oil-indexation and gas-to-gas pricing. This is in addition to regulated prices, which are more relevant in state-run economies. Historically, oil indexation was a cornerstone of long-term LNG contracts, especially in Asia and some parts of Europe. LNG was linked to oil prices with a three- or four-month lag. While linking oil to gas made sense in the 1960s as oil was used as a substitute in power generation, this rationale is increasingly obsolete. Additionally, this mechanism has failed to accurately reflect the fundamental values of the gas market and limits the possibility of arbitrage. Due to these shortcomings, European Union energy policies and major suppliers have started to substitute oil index contracts with hub-based ones. Also, since 2015, Asian buyers have sought to diversify the pricing structures of their LNG agreements, shifting away from long-term oil-linked contracts with traditional fixed-destination clauses.

In contrast, under a gas-on-gas pricing mechanism, the price is determined by the interplay of supply and demand either at a physical hub (e.g., Henry Hub) or at a virtual hub (e.g., NBP). Hub pricing as a price formation model is prominent in the U.S., U.K., and other parts of continental Europe. Netback pricing is an important concept, and it is derived by estimating the net revenue from the sale of LNG in destination markets less all costs including sourcing, regasification, and shipping. As shown in Figure 3, gas-on-gas ("GOG") competition for spot LNG imports increased 10% globally in 2018 compared to Oil Price Escalation ("OPE") or oil indexation.

Figure 3
World Price Formation 2005 to 2018 – Spot LNG Imports



Source: IGU.

U.S. SPAs introduced a new pricing approach based on a Henry Hub-linked LNG formula. Cheniere was the first U.S. supplier to introduce a Henry Hub-linked LNG formula. This formula is based on off-takers that are contracted to lift LNG and pay an approximate fixed fee between $2.25 to $3.5 per MMBtu plus a charge of 115% of the Henry Hub (HH) price. The fixed "take-or-pay" fee is paid irrespective of lifted volume and can be considered as a sunk cost as it is designed to cover the capital investment to build the liquefaction plant. The decision to export is determined by the arbitrage window or the netback margin between the variable costs for delivered LNG to a market and the prevailing regional spot price at the same destination. The variable costs include (1) a 115% Henry Hub charge, which represents the cost of procuring feedstock gas that is variable depending on the volume lifted, (2) shipping costs, which in turn include the charter rate and bunker fuel cost, and (3) regasification costs, which can be considered as either variable or sunk costs depending on the downstream participant and destination.

An important implication of such a structure is that the trading determination process is driven by the short-term marginal cost; an off-taker elects to export LNG when the spot price at the destination is greater than the delivered variable costs (including, as noted, 115% of the HH price as well as the shipping and regasification costs.) Consequently LNG will be delivered to whatever location has the highest netback spot price. However, when the spot price at the destination is high enough and exceeds both variable and sunk costs (i.e., the fixed fee), trading and cargo diversion is based on the full cost of the exported LNG.

This pricing structure can essentially be viewed as a complex spread option where the strike price is LNG delivered variable costs (again, including 115% of the HH price as well as the shipping and regasification costs.) Sometimes the shipping and regasification costs can be considered as sunk costs when the off-taker has in-house transportation and an existing contract with the regasification terminal. In this case, the payoff of the spread option depends on the spread between the regional spot price and Henry Hub.

Interconnectivity & Infrastructure Relevance

The development of price benchmarks in energy in general is intrinsically linked to the physical market and its commercial implications. Well-developed infrastructure and the proximity to supply ensure three elements: (1) alignment to the balance of supply and demand, (2) smoothness of price discovery formation, and (3) enhancement of the price response.

Most U.S. projects are situated in the Gulf of Mexico except Cove Point, which is in the northeast. The Gulf of Mexico has logistical and infrastructural advantages and encompasses one of the most developed energy infrastructures in the world. The region has a concentration of facilities throughout the gas supply chain, including production upstream, gathering and processing plants, extensive pipeline system, storage, and industrial access. In addition, the U.S. Gulf Coast possesses a highly-skilled workforce.

The competitiveness of U.S. LNG exports was also enhanced by the recent Panama Canal expansion, which has substantially reduced the voyage time, distance and costs of LNG vessels to travel from the USGC to the Pacific Basin. According to the U.S. Energy Information Administration (EIA), the newly expanded canal will be able to handle 90% of the world's current LNG tankers with a shipping capacity of

3.9 Billion cubic feet (Bcf). The expansion considerably reduces the voyage time to Japan from 34 days to 20 days and shortens the distance from 16,000 to 9,000 miles compared to traversing the Suez Canal or around the Cape of Good Hope, which adds 12-13 days to the shipping time and more cost. With respect to the voyage to South America, transit through the Panama Canal shortens the duration from 20 days to 8-9 days and from 25 days to 5 days going to Chile and Colombia/Ecuador respectively. Therefore, the USGC has both physical capabilities and robust supply, which allows it to attract the strong physical trade volume needed for benchmark creation.

Conclusion

Oil indexation is losing its luster and becoming an archaic mechanism that is less likely to survive against hub pricing in the long run. With the U.S. LNG institutional model profoundly changing LNG contractual, pricing, and trading apparatus, the USGC has the potential to become a major physical hub for global LNG price formation due its strategic location and easy access to flexible supply.

Endnote

For further coverage of the natural gas markets, the reader is invited to read past *GCARD* articles on these markets.

Author Biography

ADILA MCHICH
Director, Research and Product Development, CME Group

Adila Mchich is a Director in Research and Product Development at the CME Group. She focuses on the fundamentals of energy markets. She has over 10 years of experience serving multiple roles in Market Research & Development, Risk Management, and Product Valuation at the CME Group. Ms. Mchich started her career as a Quantitative Analyst.

Ms. Mchich has also authored a series of articles on derivatives and energy markets. She is a member of the International Association for Energy Economics and United States Association for Energy Economics. She received her M.S. degree in Financial Engineering from NYU Tandon School of Engineering.