The Effect of U.S. LNG Exports on U.S. Domestic Prices: A European Perspective

January 2023

Jan-Hein Jesse
Owner
JOSCO Energy Finance & Strategy Consultancy
jan-hein.jesse@kpnmail.nl

The following content is a summary of available third-party information. While this paper was commissioned by the Energy Futures Initiative (EFI), EFI has not endorsed or approved the statements and conclusions contained in these documents but will be sharing this work as part of the project process.

About the Authors

Jan-Hein Jesse

Jan-Hein Jesse's career spans over 36 years, including thirteen years with Shell, ten years in banking (Chase Manhattan Bank, ING, ABN AMRO, all of which centered on energy and commodity finance), five years with Heerema Marine Contractors and four years in non-executive roles. Jan-Hein Jesse has a commercial, financial, and technical background and is an expert in new business development, corporate finance and mergers and acquisitions, and corporate strategy in the energy industry. He has worked on energy projects in over 35 countries, all over the globe. He is the owner of JOSCO Energy Finance & Strategy Consultancy, a Dutch company that advises select number of private equity and industrial clients in new business development in the energy sector.

He is a nonexecutive director for the Dutch organization of Centerbridge Partners, a $25 billion New York and London based private equity firm and an advisor to the owner of OneUp, a company helping large corporations to develop and manage digital business solutions. Prior to 2020, he held positions as a senior banker in ABN AMRO's Energy, Commodities and Shipping division, Chief Financial Officer of Heerema Marine Contractors, and Senior Manager at Royal Dutch/Shell (both in the gas and power and the upstream division), responsible for the execution of large-scale acquisitions and divestments, and new business developments leading transactions over $1 billion. Mr. Jesse is the founder and global head of the Energy Finance Department at ING Bank. He also served as a non-executive board member for Oceanteam ASA, an Oslo Bors stock-listed oil services company active in deepwater installation work and in the offshore wind space, and as a board member of AT Capital (Singapore) and HelloFlex Group (The Netherlands). As a consultant, Mr. Jesse worked amongst others for Carlyle, VTTI (a VITOL affiliate), PricewaterhouseCoopers, HAL, SBM Offshore, Barclays Energy Fund, and Tulip Oil. His primary focus area is energy in the widest sense, including: oil and gas, LNG, renewables and offshore wind, oil services, upstream and downstream. Since the early 1990s, Mr. Jesse has been actively involved in the financing and development of many LNG liquefaction, regasification, LNG trading and LNG shipping projects throughout the world. He has served as a senior expert for the International Energy Agency ("IEA") since 2006, a visiting fellow to Clingendael International Energy Program in the Netherlands, a member of Chief Economic Roundtable Group at the Ministry of Economic Affairs and a member of the Editorial Advisory Board for GCARD, JP Morgan Center for Commodities, University of Colorado Denver Business School.

Mr. Jesse received his bachelor's degree in civil engineering, with a focus on offshore engineering, at HTS Haarlem, The Netherlands, and his MBA at Nijenrode Business School, the Netherlands, where he participated in the Wharton Business School Exchange Program. At Chase Manhattan Bank, he received a 12-month full-time corporate finance and investment banking education. At Shell, he participated in the Shell Group Leadership Program at the Wharton Business School, the Executive Negotiation Program at the Harvard Business School, and Executive Mergers and Acquisitions Program at Insead, France. He also did a two-year New Board Program for non-executives at Nijenrode Business School, The Netherlands and Leadership programs at Yale University and the Avicenna World Class, Chennai, India. Mr. Jesse lives near Amsterdam, The Netherlands.

Abstract

To understand the impacts of U.S. LNG exports on U.S. domestic prices, one must first analyze the motivations for driving key investment decisions in the natural gas sector. Given the recent black swan events of a global pandemic followed by Russia's invasion of Ukraine, the trifecta of energy – national security, economic development, and environmental responsibility – has come into stark focus. Both government and industry players face the dilemma of balancing competing objectives. Thus, it is instructive to analyze both the political and economic considerations that directly impact price formation and thus investment decisions in the sector.

Table of Contents

1. A Look Back at LNG and World Energy in the 21st Century

A. Recent Evolution of Natural Gas in North America

As recently as 10 years ago, no one predicted that the United States would achieve a dominant position in the world LNG business. In the mid-2000s, analysts ranging from ExxonMobil to the U.S. Federal Reserve saw the U.S. entering a bleak period of energy tightness, not able to produce enough oil and gas to keep the economy running without increasing imports. For that reason, Exxon decided to build Q-max LNG carriers for bringing large volumes of Qatari gas to the East Coast and the Texas Gulf. Some were advocating for the construction of an LNG import terminal every 500 miles along the entire Eastern Seaboard.

At that time, it was thought that the U.S. was rapidly running out of oil and gas and would become dependent on imports, especially from the Middle East. The opening of the largest oil field outside the Middle East in the Caspian in 2000 created the possibility of a new energy source but development has been fraught with territorial and other disputes, which delayed development.

With the construction of Russian-controlled pipelines to the West, Moscow was the clear winner of Caspian Sea resources. The consumer, Europe, had no alternative but to embrace Russia as an energy supplier. The Turkish government realized large benefits in allowing the construction of the Bluestream pipeline[1], not only to become independent from the Balkans and East European transit countries but also to win a larger stake in all the deals they could do in Russia and the Former Soviet Union (FSU). Germany, seeking a reliable supply for industrial needs, has imported energy resources from the Russian and Ottoman empires since the 1870s. Of note is that President Putin had made it clear to FSU presidents that he would never accept their countries favoring new relations with the West

[1] Hydrocarbons Technology, https://www.hydrocarbons-technology.com/projects/bluestream-pipeline/.

over Russia. Europe, however, decided to accept the new situation knowing the potential consequences of their dependence on Russia for energy needs.

In 2002, CSIS released a report on “The Geopolitics of Energy into the 21st Century[2]”. The report presented three broad conclusions:

- The United States, as the world’s only superpower, must accept its special responsibilities for preserving the worldwide energy supply.
- Developing an adequate and reliable energy supply to realize the promise of a globalized twenty-first century will require significant investments, and they must be made immediately.
- Decisionmakers face the special challenge of balancing the objectives of economic growth with concerns about the environment. This challenge has multiple parts: finding ways to increase the security and reliability of supply; ensuring greater transparency in energy commerce; and strengthening the role of international institutions in matters of energy and the environment.

Since the tragic 9/11 attacks, oil and gas became even more of a core integral part of U.S. foreign policy. The Persian Gulf would remain the key supplier of oil to the world market. At the same time, the share of energy consumption in North America and Europe was projected to decline. It was clear that the Caspian oil and gas contribution to world supply would be significant but not pivotal. Asian dependence on Persian Gulf oil would rise significantly, and the resulting necessity for longer tanker journeys would put more oil at risk in international sea lanes. More importantly, China’s demand was poised to rise. The European need for natural gas would be covered by a handful of suppliers, Russia being the most significant, which underscored a worrisome dependency. In addition, U.S. net oil imports would continue their steady growth. Anticipated growth in the use of natural gas – largely for as an electric power feedstock – would raise a new series of geopolitical issues, leading to new political alignments.

The Global War on Terrorism, mostly in Iraq and Afghanistan, slow Caspian resource development, and major risk uncertainties in the new Russia of President Putin, were all part of creating energy supply uncertainty and wide price instability. At that time, LNG was still a 100Mtpa market, with 80% of consumption concentrated in OECD Asia. Exxon had just

---

[2] Ebel, Robert E., “Geopolitics of Energy into the 21st Century,” (presentation, IGAD Symposium, August 16-18, 2010).

bought Mobil for its international gas business to catch up with Shell, together jockeying for supremacy in the energy business. LNG was sold through a “vertically integrated virtual gas pipeline” at oil (product) indexed prices with tight destination clauses attached to it.

Most of what was written in the 2002 CSIS study came out as predicted. The only thing that they could never have imagined was the development of horizontal drilling in shale for oil and gas in the United States. For many observers, it came out of the blue.

In 2005, the consensus view was that the technically recoverable resource of shale gas was in the order of 140tcf, and by 2010 583tcf. Today, it stands at 862tcf.[3] In 2005, predictions of the long-term prices at Henry Hub were $5.98 (2005$/mcf) for 2010-2020 and $6.42 for 2021-2030.[4] With this price, production started around 2005 in earnest because the prediction was that it will rapidly grow to slightly over 8tcf/year in 2023. Even with this growth, the U.S. would continue to be an LNG importer.

However, like with anything new, making projections about how big shale production would become in the future is a complex exercise. According to an EIA forecast from 2010, shale gas would supply 25% of U.S. domestic demand, but imports would still be needed.[5]

Hence in the first years, none of the super majors were interested in shale at all as it was marginal and too expensive to develop. Developing the biggest project on earth, the Kashagan’s, Sakhalin’s, Brazilian sub-salt developments, and the Gorgon’s of this world was far more interesting to developers. The independents – both family owned and listed – had nothing to fear from their big competitors.

Only one year later, British Gas Group (BG) and Cheniere made their announcement in October 2011 that Sabine Pass, in Port Arthur on the border between Louisiana and Texas, would become the first North American LNG export project since Kenai in Alaska in 1969. The agreement for 3.5mmtpa of LNG for 20 years underpinned the first 4.5mmtpa liquefaction train[6] at Sabine Pass.

---

[3] Central Energy Resources Science Center, April 26, 2019, https://www.usgs.gov/centers/central-energy-resources-science-center/science/world-oil-and-gas-resource-assessments.
[4] Medlock, Ken, “The Shale Gas Revolution and What It Means for Global Energy Markets,” (presentation, Baker Institute, Houston, TX, March 2, 2010).
[5] Newell, Richard, “Annual Energy Outlook 2010,” (presentation, March 2, 2010).
[6] A series of heat exchangers that gradually reduce the temperature of natural gas to -160°C. The liquefied gas can be transported by an LNG carrier.

The decision reflected strong Asian LNG demand, particularly post Japan's Triple Disaster (earthquake, tsunami, and nuclear meltdown) on March 11, 2011, and low North American gas prices. With mostly long-term contracts (LTC) in place, Asian LNG prices were typically linked to oil, and oil prices were expected to remain high at that time. So, a golden opportunity presented itself for North American LNG exporters to arbitrage the low North American gas prices and high world oil prices. Although it was recognized that there was a risk that this spread may not exceed the full costs of liquefaction and transport for the duration of a 20-year sales and purchase agreement, it was anticipated that the differential between U.S. gas and Asian LNG pricing in the immediate period following project commencement would enable BG to realize positive returns on its investment well before the 20-year term is up. Instead of staying a net LNG importer, now it was clear that from 2015 onwards, the U.S. would become a serious LNG exporter, recognizing that this LNG first was likely to spur others into following BG's lead.

Also in 2011, Citi wrote that same month on "the Impact on North American gas demand from the BG-Cheniere deal to build a new LNG liquefaction plant for exporting natural gas – the additional demand of 0.9-Bcf/d from LNG exports in 2015/2016 from the BG and a potentially similarly-sized deal to get financing, would probably coincide with the start of the MACT[7] rule expected to be implemented by the U.S. Environmental Protection Agency. Both would increase North American gas demand at a time when gas production on the continent is still expected to be robust. Couple this with the nearly inevitable extra demand for natural gas for industrial feedstock, higher demand for residential/commercial space heating, and the potential additions of other LNG export terminals, such as Freeport in Texas, the result could be a suddenly tighter market, although higher prices still hinge on how quickly North American gas production would grow between now and then." Citi was actively testing the commercial rationale behind the deal as the project required high selling prices at a time when domestic gas prices could start rising due to strong expected demand growth with lagging supplies and forward curves[8] for oil (and oil-linked natural gas) and U.S. natural gas moving toward convergence.

At a $6 feedstock cost, the breakeven to Europe and Asia would rise to over $10.65 and $12.90/MMBtu, respectively (Figure 1). To what degree are these potentially crossing oil

[7] Maximum Achievable Control Technology standards and other criteria to reduce air pollutants.
[8] Forward Curve is a function graph in finance that defines the price at which a contract for a future delivery can be settled at today.

and gas curves providing clues to the future? To be sure, a good argument can be made that gas-on-gas competition in North America and the robust supply response of unconventional natural gas would keep North American natural gas prices perpetually lower than traded gas in Europe or Asia. Indications are that BG, with perhaps an unrivaled ability to take advantage of regional market price discrepancies – is well placed to monetize an off-take agreement at Sabine Pass. However, beyond the year 2020, current forwards point to Australian LNG being very competitive with Gulf Coast LNG, reducing the cost advantage LNG from Sabine Pass has over projects closer in proximity, at least as far as base load competition in the Pacific Basin goes. Moreover, in 2018, Sabine Pass had already delivered 350 cargoes (~1250 TBtu) delivered to 26 countries and regions around the world since its startup.

Figure 1: Estimated Cost of Delivered LNG to Europe and Asia from Cheniere's Sabine Pass Project.

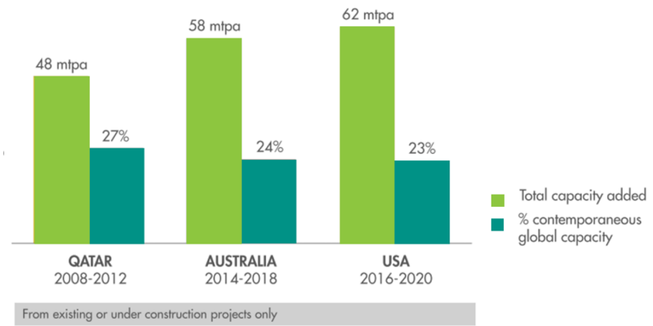
	Europe		Asia	
($/MMBtu)	**Low**	**High**	**Low**	**High**
Henry Hub Gas	4.00	6.00	4.00	6.00
Fuel (15%)	0.60	0.90	0.60	0.90
Liquefaction	2.25	2.25	2.25	2.25
Shipping	1.00	1.50	3.25	3.75
Delivered Cost	7.85	10.65	10.10	12.90
Equivalent to the Australian LNG procured at JCC price (USD/bbl) of			66	85

Source: Cheniere, Oil and Gas Journal, Citi Investment Research and Analysis.

B. LNG Market Dynamics: Setting the Scene

On January 12, 2014, Citi wrote a report titled: "The New American (Gas) Century – transforming sectors, redefining the global gas order and setting new long-term prices." Only four years after a reluctant start, North American LNG became a competitive option in the global market as domestic prices for gas had decreased while liquefaction development costs elsewhere in the world were on a rising trend, e.g., with Australia having taken project sanction on 35mmtpa of new LNG capacity in 2013, cost inflation was a growing concern. Therefore, the U.S. came out on top in developing new liquefaction plants (Figure 2).

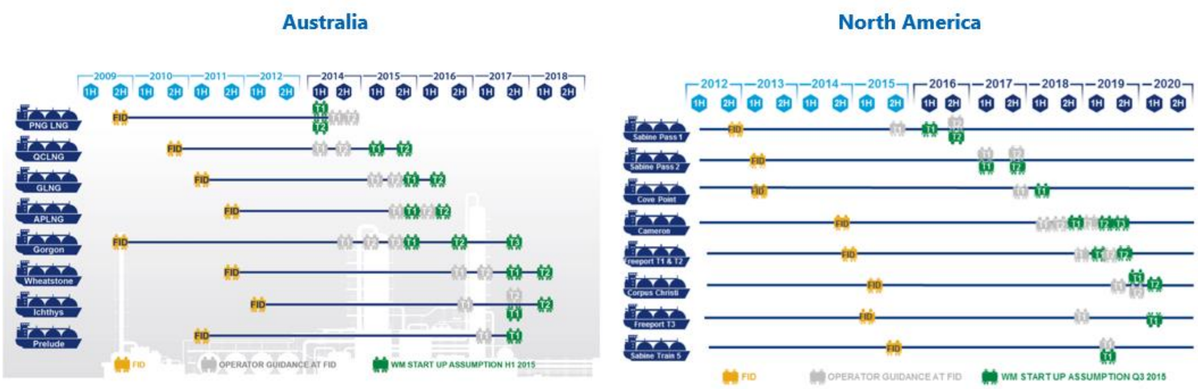
Figure 2. Comparison of LNG capacity additions over 5-year periods.



Source: Wood Mackenzie, May 2016

From this exhibit, one could already distill how gas projects were developed, built, and put into operation in short-term 5-year chunks. From the start, the LNG upstream business was characterized by a continuous series of waves, each wave being absorbed over several years during the exploitation phase when prices were generally low, until market became tighter and prices started to rise, triggering a new investment phase, when all companies with undeveloped gas resources simultaneously sanction the next wave of developments. At the same time, the commercial structure was evolving to the next arena of competition, this time driven by a new set of terms best suited for the American companies active in this space. Over 100 MMtpa of new LNG would come onstream between 2015 and 2020 from only 2 countries (Figure 3).

Figure 3. Comparison of Australia and North America capacity addition.



US Projects	Location	JV partners	bcf/d	mtpa	Offtake	Scope	Status	FERC Status	FID	Prob
Sabine Pass T1-4	Louisiana	Cheniere Energy	2.2	18.0	18	Regas	Construction	Approved Apr-12	2012	N/A
Cameron LNG T1-3	Louisiana	Sempra, GDF Suez, Mitsubishi, Mitsui	1.7	12.0	12	Regas	Construction	Approved Jun-14	2014	N/A
Freeport T1-3	Texas	M. Smith, Chubu Electric, Osaka Gas, GIP	1.8	13.2	13.2	Regas	Construction	Approved Jul-14	2014	N/A
Cove Point	Maryland	Dominion	0.8	5.8	4.6	Regas	Construction	Approved Sep-14	2014	N/A
Corpus Christi T1-3	Texas	Cheniere Energy	1.7	13.5	3	Greenfield	FEED	Approved Dec-14	2015	H

Source: Wood Mackenzie, May 2016.

C. The U.S.: Changing the Game

Players in the new natural gas space had to accept that U.S. LNG exports would redefine pricing and structure in the global LNG markets. Because of the new wave of developments in the mid-2010s, global LNG prices fell and major gas producers that rely on high global prices lost bargaining power. The breaking of decades-old oligopolies boosted supply and lower prices further. With U.S. LNG having no destination restrictions, a robust spot LNG market emerged. As the U.S. evolved from a net gas importer into one of the largest exporters, the then-current gas importers did well but existing exporters faced structural challenges.

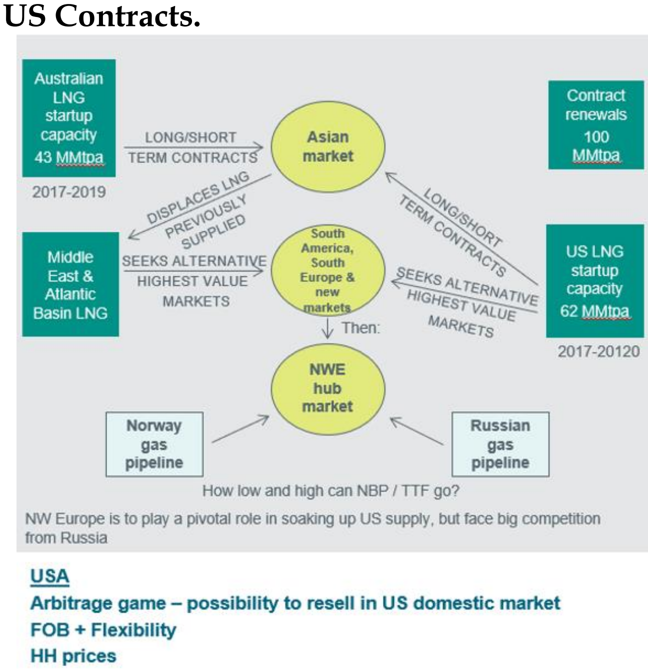
This first wave of new LNG supplies from the U.S., now in full development, will not only bring new supply but also will also change the traditional business model. This new business model is characterized by:

- Tolling agreements for LNG liquefaction + gas origination from a very large group of (shale) gas producers
- Full flexible delivery – freight on board (FOB), no destination restrictions
- New price formulas – based on HH natural gas prices, and other gas hub prices
- Smaller volumes contracted, more tailored-made – spot, short-term, medium-term, and long-term
- Hedging is possible
- Take-or-Pay for ~85% of capacity, not necessarily from end consumers, but also from portfolio players and aggregators
- Willing to deliver against marginal cash cost – capex and contract investments are “sunk”
- Sales based on arbitrage dynamics and opportunities – the arb is open or closed
- Sales and delivery to the buyer who is willing to pay the highest price
- Excellent characteristics for portfolio players and aggregators

Consequently, the following observations were made in 2018:

- Is "US LNG liquefaction" behaving like an airline business – where a seat is sold if it adds cash?
- While the common view was that most of U.S. LNG would land in Europe, in hindsight, Europe was not willing to pay for the LNG – or Russian gas was cheaper - and was outpriced by Asia
- At times of oversupply, the arbitrage game is defining the flow and the direction thereof (Figure 4)
- A new second wave of LNG liquefaction is working towards FID
    - The biggest issue for sanctioning the probable and possible projects is the marketing and sales of the LNG to underpin finance and to create visibility for investors
    - But will these contracts be forthcoming and if not will financially strong upstream and portfolio players then absorb more volume risk by still building these projects without the same volumes as the percentage of capacity firmly contracted?

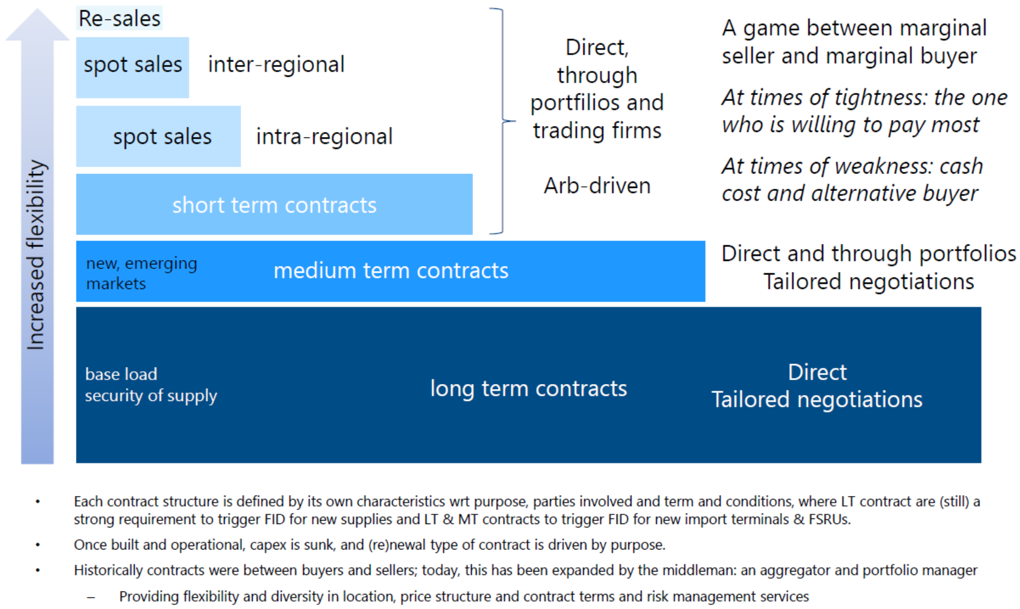
Figure 4. Arbitrage of US Contracts.



Given the structure of boom-and-bust investments in natural resources, massive investment in markets around the world in the last five years was not only triggered by the construction of new plants in Australia, just before the U.S. market development, but also because of the collapse of the oil price in the second half of 2014. At that time the oil market could not maintain artificially high prices as they may have been in the initial exploitation and investment phases. Further liberalization in downstream markets and the dominant role of the U.S. created new supplies that didn't match with all incumbents and new entrants who were expanding their business into LNG.

Together, resulting in buyers, large and small, in incumbent and in the new emerging markets, shifting from a rigid single size fits all portfolio of LNG contracts to a tailored and much more flexible package of contracts that suit their needs and meet their strategic worldview on the speed of the energy transition towards alternative fuels (Figure 5).

Figure 5. Schematic contract structures.



Source: JOSCO, 2016.

2. Price Formation and Structures

A. Price Structures and Discovery

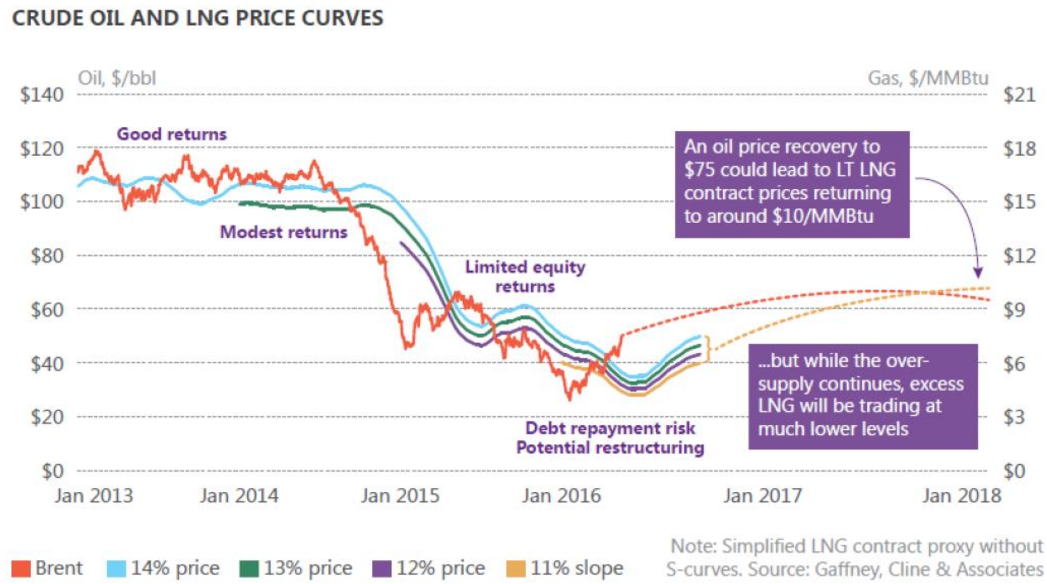
Historically, liquefaction projects were developed as a vertically virtual integrated value chain, i.e., a big and financially strong oil and gas company (or consortium of oil companies) with plenty of ‘stranded’ gas resources started to develop its upstream development by pushing this gas in the market through one or a few long-term gas contracts being signed with one or a few high-creditworthy customers. Generally, these LNG liquefaction contracts were for parties in developing countries. To strengthen the connection, buyers were invited or demanded to have a small stake in upstream development. The first LNG train was a loss-making venture due to the high infrastructure costs, especially if the gas was dry, and could not profit from the sales of wet gas and condensates. Only the next trains made these projects increasingly profitable, generating long-term dividend streams for their shareholders. Gas was generally sold against an oil price marker.

It is important to understand the global framework as well as some of the historical practices that have influenced the natural gas industry and the development of an associated market. Within the Middle East, natural gas markets have evolved from what had historically been the flaring of associated gas from the production of oil into the local use of this low-cost energy source to produce electricity and water and attract industry, i.e., direct foreign investment, then ultimately evolving into what has become a key export from the region through either pipeline gas or LNG sales. As both local and global demand for natural gas has grown, the interconnectivity of markets has occurred and many non-associated gas resources within the region have already developed or are currently in development. While natural gas is not completely fungible, this interconnectivity of markets has shaped the overall pricing of natural gas and hastened its evolution toward global liquidity. It is in this context and in addition to the cost of supply that the pricing of natural gas must be evaluated to ensure the full value and potential of this resource.

In the United States and Canada, due to market liquidity (the ready availability of gas buyers and sellers), competition has come mainly from other gas suppliers. Price is set by gas-to-gas competition, with the long-term floor and ceiling prices set by alternative fuels, e.g., coal and fuel oil. In these markets, pricing is established primarily on short- and medium-term gas supply/demand fundamentals. Transparent gas prices (i.e., prices that are both accepted by the market as valid and available to the market on a timely basis) are provided through gas price surveys published as daily and monthly indices by third parties and through the prices of publicly traded commodity futures markets.

The underlying principle for European and Japanese gas pricing, which established the foundation for Asian LNG pricing practices for many years, was that the market price for gas is set by competing energies at the burner tip, primarily and preferentially linked to oil products. In periods of a supply surplus, prices below oil parity would be expected to cause a reduction in new gas developments, exerting a supply-driven price rise over the long run. Gas prices above oil parity, on a thermal or Mbtu basis, would result in a shift from gas to alternative fuels, thereby exerting a demand-driven price drop. Over time, gas prices would theoretically gravitate toward oil parity (Figure 6).

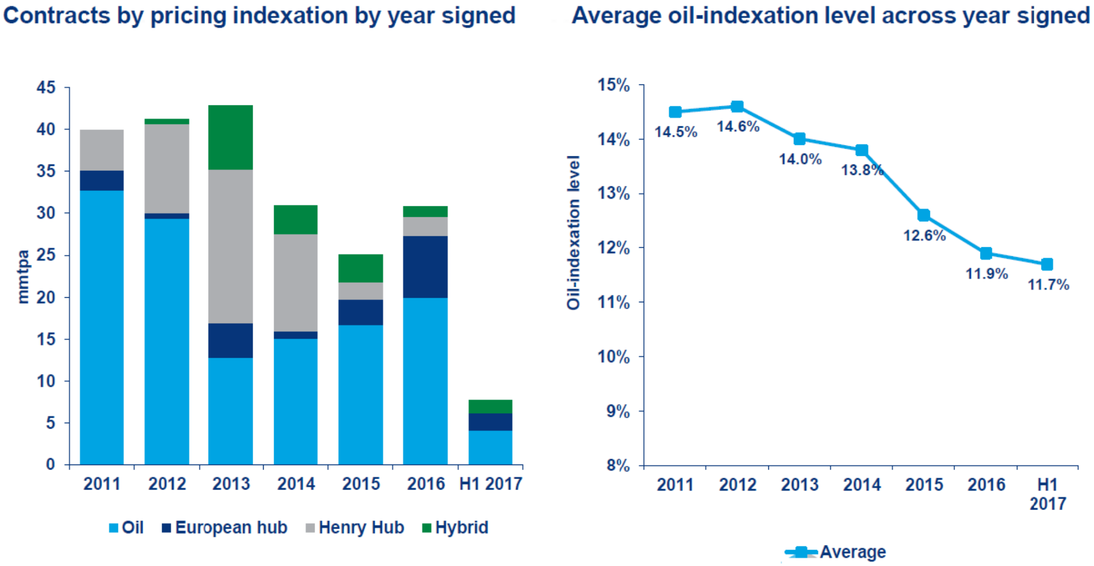
Figure 6. Type of Price Mechanisms in LNG Pricing.



Source: Gaffney, Cline, & Associates, July 2016.

Figure 7 is an overview of different contracts that were signed between 2011 and 2016 and the shift away from predominantly oil-indexed to a mix of contract types. Also, the impact of the lower oil prices since 2014 on the oil-indexation level is in the right panel.

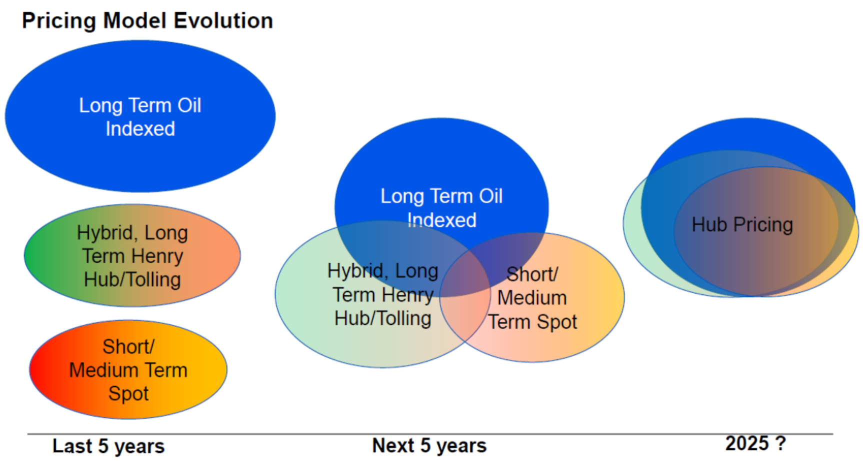
Figure 7. Oil Price Indexation.



Source: Wood Mackenzie, October 2017.

However, for small U.S. upstream producers, this international model would never work. Basically, they are not interested in entering the complicated and expensive arena of international business. Moreover, for a small domestic producer, international consumers would not hedge the price risk, which is a key element for bank funding. So why would small domestic producers bother with international markets when in the U.S. domestic market was well developed? To evolve internationally new price models had to be developed that would match American producers with international needs. Over time, the distinction between pricing models has become increasingly blurred (Figure 8).

Figure 8. Pricing Model Evolution.



Until recently, this structure worked whereby LNG was sold to the highest bidder. In a globalized economy, however, LNG supply and demand could be delinked from the price through the development of deep trading markets in each region. Particularly Amsterdam-based TTF[9] became a big success, meeting all requirements that the European Commission in Brussels demanded, namely a deep, liquid, transparent market that has no signs or proof of hoarding behavior, that also provides all the elements to meet instant supply with instant demand. Moreover, prices were no longer set by an oil-priced index. Price discovery took place at the TTF under tough gas-to-gas market dynamics. At the same time, it was understood that with declining indigenous reserves, especially after the Dutch government decided to start closing in the Groningen gas field because of earthquakes caused by gas exploitation. In addition, Russia's Gazprom priced its pipeline gas to keep competition at bay, it was just a matter of time before Russia would strengthen its supply and trading position in the European market. The Russian price was too good to ignore and other geopolitical risk considerations were relegated to a lower priority. Moreover, given all the energy transition programs that the European Commission announced, the "uncomfortable" position of Russia on the EU gas market was foreseen as temporary and hence not to worry too much about.

It was seen that building more pipelines would only help to avoid parts of Europe that could be closed off in case of an emergency and otherwise would avoid upward price pressures stemming from a single point of failure. Moreover, pipelines were seen as a purely economic phenomenon, detached from politics. Thus Europe was well aware of its vulnerability but

[9] Dutch Title Transfer Facility (TTF) is a virtual trading point, since 2003, for natural gas in the Netherlands.

had no choice but to go fully for the energy transition as an effort to remain competitive globally while protecting the environment. In that equation, there was no space for geopolitics and the idea of a risk to the security of supply.

B. Market Value and Pricing

The discussion that follows uses the term "market value" for the price of gas, which can be defined as the price of gas to the end user equal to the end user's most economical alternative source of energy, adjusting for availability, quality, taxes, costs (opex and capex) and other contractual terms, e.g., contract duration, of competing energy sources. In the past, the market value price has been described as the "bearable" price; that is, the price that the market can bear. It should be noted there may be sensitivity in the marketplace to terms like "bearable price" and "bearability." As a side note, these same principles can also be applied to the pricing of hydrogen and the development of a hydrogen market. Thus the market value price is the price that equates to the price of the end user's best alternative energy mix at the point of consumption, e.g., burner tip, netted back to the delivery point. The market value price calculation should include all taxes and costs up to the delivery point, as well as any differences in capex and opex between gas and the alternative. It should also reflect the environmental advantages of gas as well as any premium, if obtainable, for gas due to its convenience.

The mix of competing fuels is an important factor in establishing the base price and for identifying subsequent changes in competition and market composition which may be taken into account during subsequent Price Reviews for long-term contracts.

C. Competing Fuels / Alternatives

The definition of the competing fuels and their relative weights requires careful study and may be different for each market and for each individual sales agreement.

- **Oil products** (primarily gas oil and low-sulfur fuel oil) compete with gas in most markets, especially where power plants are important consumers and where peak loading is an important element in overall demand.
- **Crude oil** has traditionally played an important role in gas sales in the Far East, where gas prices have been based on a premium over thermal parity with crude oil prices.

- **Coal** may be an alternative fuel for many electrical power producers. The market value gas price must in this case fully reflect the power producer's advantages of using gas as discussed in the paragraphs below. As a general rule in more mature Asian markets, customers have tended to use coal as a baseload fuel, reserving gas for intermediate and peak shaving requirements. Such differences also need to be factored into any price comparison. In the event coal is used, it would be desirable to take into account the cost of pollution control equipment since such costs are likely to represent a significant cost item for a coal consumer.
- **Electricity** may be a competing fuel in some markets and sectors such as residential, commercial, and industry**. It is recommended that electricity not be used to set the base price for a power producer or any other buyer,** as prices for electricity will ultimately follow the mix of the energy inputs used in power generation.
- **LNG/Gas** markets have evolved from three primary regions (North America, Europe, and Asia) to an interconnected global market that equilibrates through a shipping differential associated with LNG. For many buyers/users in these markets, natural gas is the most environmentally friendly baseload fuel.
- **Hydrogen** may be an alternative for buyers/users in selected markets. A base price reflecting gas competition to the extent that it is the best alternative for a buyer should be considered carefully. Such an assessment should be supported by detailed benchmarking of competing gas projects to better understand the pricing leverage of competitors. Such benchmarking analysis needs to consider the cost structure of other projects, and also anticipate probable pricing proposals, based on the historical track record of competitors and an assessment of their current marketing strategies and objectives.

D. Pricing Considerations and Factors

For sale to a gas distributor, the base price should consider the weighted average mix of the end users, e.g. residential, commercial or industrial sectors, served by the distributor. In addition, to the extent that new sales are displacing other fuels, e.g., LPG, pricing of such fuels should also be accounted for in determining market value price.

For sale to a power plant, the price should be based on the power producer's realistic alternative supply. For new power plant construction, a comparative analysis between gas and alternative fuels available to the power producer should include investment cost per unit of generating capacity, capital requirements, construction lead time vs. time period before power generation is needed, operating cost differences, costs for pollution control equipment, costs for disposal of ash and spent nuclear fuel, expected plant usage (base-load, swing, peaking), emissions caps, government restraints on alternative fuels, together with normal comparative generation cost economics.

For existing power plants, a buyer's alternative fuels may be more limited by its physical plant. In these cases, considerations should include capex and opex for alternative fuels available to a buyer, competitive gas pricing and a buyer's generation vs. shutdown (purchased power) economics.

For new power plants, in markets where alternative gas supply sources and alternative fuel options are limited, Seller should seek to set the gas price to generate the minimum acceptable rate of return on equity for the developer or minimum acceptable debt coverage ratio, assuming the resulting gas price is attractive versus other sales opportunities. The acceptable rate of return on equity for a buyer will vary between countries and developers and on the method of project financing used. Minimum debt coverage ratios are typically in the range of 1.2 to 1.5. Beyond these constraints, a buyer’s only alternatives are to cancel the project, defer the project, change the debt-to-equity ratio, and/or proceed with an alternative project if the initial price is not acceptable.

Other factors that may influence the base price include the following:

- Customers such as chemical feedstock users’ plants and fertilizer manufacturers may not be economically viable if their base gas price is based on an alternate fuel or feedstock. A case-by-case analysis will be required but if it appears they need a subsidized gas price to be viable, then we need to seriously consider not selling to them.
- Price controls on gas in certain markets may limit the obtainable base price, e.g., regulated gas tariffs in the domestic sector.
- Price flexibility may be limited by the need for equal treatment of similar customers who conceivably would be able to pay different prices, e.g., seasonal swing, residential vs. industrial etc..

Sales at prices not based on the net return of market value prices should be consummated only if the achievable price is a seller's best alternative, e.g., versus shutting-in gas or delaying the development of a resource, and if it provides an acceptable risk-weighted return to the seller. In the LNG market, the availability of gas from multiple sources means gas-to-gas competition may be the critical factor in determining what is an achievable market-based price.

When gas-to-gas competition occurs, an assessment of what price is achievable in the marketplace will require a detailed analysis of gas competitors, especially in those situations where buyers have established formal or quasi-formal tenders as the mechanism for selecting supply. Such an analysis should begin with a listing of potential competitors, identification of the gas supplies as surplus capacity, and expansion of trains or grassroots. A threshold cost analysis should be prepared for each competitor using publicly available cost data to assess its potential ability to compete. A range should be established for each competitor identifying its potential pricing positions, the lower limit being based on a minimum rate of return calculation, and the upper limit taking into account public information on competitor practices, including positions adopted in other contract negotiations, the status of existing contracts, stated positions on LNG marketing, pricing strategy, and other relevant factors.

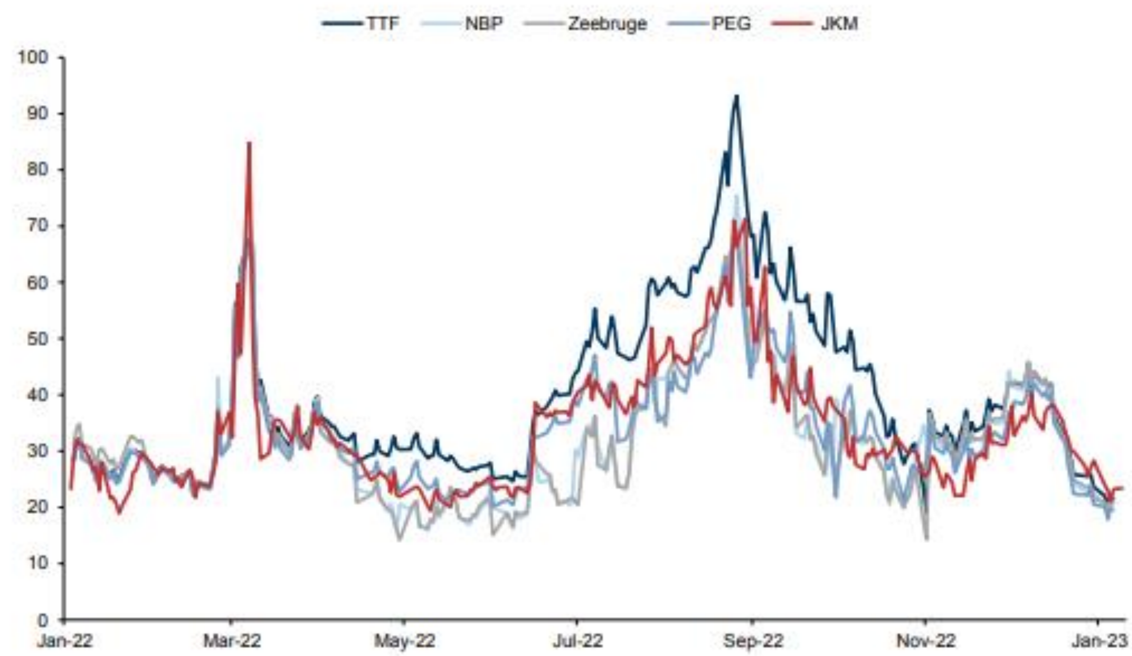
Though such a supply analysis may be subject to a certain amount of imprecision because it is based on public information sources, it will allow a fairly robust ranking of potential competitors and identify a target range for major competitors' probable pricing positions. Taken together with the assessment of market value price, Sellers will be able to work with a pricing band, the lower limit being set by alternative suppliers' minimum economic thresholds and the upper limit based on alternative fuel parity in the marketplace.

3. Current Status of Global Gas Markets

The gas market in Europe was already tightening in 2021, starting about 10 months before Russia’s invasion of Ukraine. Due to various independent events in the summer of 2021, European gas storage started the winter at an all-time low level, which was not immediately noticed by governments or the general public. In the Netherlands, the government was in an interim period, trying to form a new government, which took them approximately a year. Shell Global had just decided to reincorporate in London and was no longer considered the "big friend" of Hague politicians. Because it was the operator of the Groningen gas field, Shell's reputation was hurt by the earthquakes, and as a result, communication between Shell and consumers or other parties was hostile and unproductive. This said, Shell remains the single largest investor in renewable energy and energy transition projects in the Netherlands, a market highly integrated with strategic customers in Germany.

Following the Russian invasion of Ukraine, gas prices spiked. And given that electricity prices are set by the merit order and the marginal fuel (in this case, gas), all power producers, either from solar, wind, nuclear, coal, or gas, all received a price linked to the prevailing gas price of the next day (Figure 9).

Figure 9. Gas prices in Europe and Asia between January 2022 and 2023 in $/MMBtu.

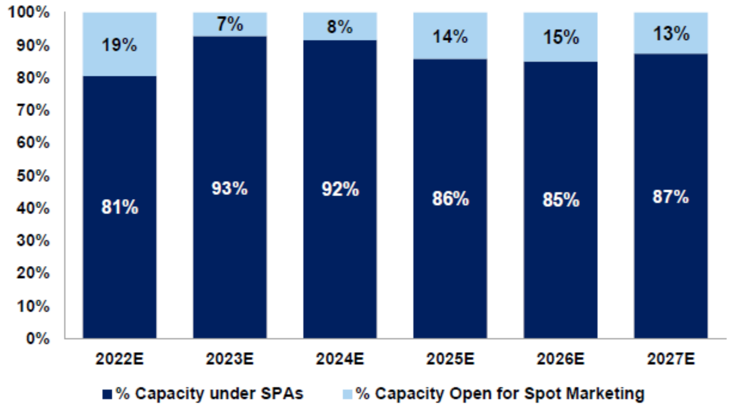


After the first spike in March 2022, prices normalized a bit, although on a much higher level than we were used to before 2021 – basically since the price collapse in 2014. However, by May, European governments saw the reduction in gas supplies from Russia and wanted to stop the purchases of Russian gas, not wanting to be accused of funding the Russian military.

This meant that alternative gas had to be found and be purchased in large quantities to fill up the empty gas storage facilities, notably in North Western Europe. Without new supplies available, Germany and the Netherlands have been outpricing everybody else, including southern European countries. Many Asian countries had ample supplies due to COVID-related economic slowdowns and were willing to sell their gas – notably American LNG – to sell to Europe.

Qatar was an equally important supplier and rerouted large volumes of LNG to Europe. However, when it became known that Europe had actually bought enough gas to fill up storage by up to 90%, prices dropped between September and November. Furthermore, mild weather, energy efficiency measures, i.e., demand destruction, and slowing economic development were contributors to an overall price drop, with only a temporary rise stemming from cold weather in early December. It is also interesting to note that Cheniere, the U.S.'s largest LNG exporter, will only have about 11% of its total volumes available for spot sales on average (Figure 10).

Figure 10. LNG Volumes Breakout: Contracts vs. Spot.



Source: Goldman Sachs, November 2022.

Despite a bigger deficit to be resolved year-on-year, incremental regasification capacity in Netherlands and Germany from this winter can potentially bring additional LNG at the margin. For instance, last summer, Dutch facilities were at maximum capacity while Germany was unable to import any volumes due to a lack of a regasification capacity. The 63 mcm/d of regasification capacity to be added in the Netherlands and Germany this winter will allow LNG to be allocated more efficiently. To be clear, this does not guarantee the added import capacity will be filled. Ultimately, European LNG imports are the result of their prices relative to the rest of the world, which can be particularly impacted by how much Asia is competing for resources. This year China's LNG imports decreased on a year-on-year basis due to slow industrial demand for gas. Going forward, however, economic activity in China will improve with the re-opening of the country, leading its LNG imports to increase year-on-year throughout 2023.

Ultimately, European gas prices will only sustainably move below industrial-demand-destruction levels once global LNG supply increases more significantly, from 2025, when several liquefaction projects already under construction from the U.S., Qatar, and Canada, among others, will start to come online.

Until then, Europe is left with a tight supply outlook. Specifically, UK production is in slow decline, the Netherlands has signaled that it is maintaining as scheduled 2023 shutdown of the Groningen field, and Norway's production flexibility from reallocating maintenance events is largely exhausted. With 2023 now embedding much more significant outages vs this year. Only Algeria is looking to increase gas exports though too small to resolve Europe's needs for 25 mcm/d by 2023/24. As a result, it is expected that European gas prices will continue to drive industrial demand destruction to help the region manage storage through 2024.[10] The unexpected price fall in the last months has changed the outcome and outlook of what was feared. Last summer, it was estimated that the increase in European energy bills implied by prevailing prices (vs. 2021) amounted to nearly €2 trillion, or approximately 15% of GDP. Yet, the approximate 75% fall in gas prices since, coupled with the regulatory measures introduced last year, suggests a much more modest increase in bills (less than €0.5 trillion). This implies that most consumers have already seen the bulk of energy bill increases.[11]

The improved outlook for energy security, coupled with much lower threats from energy affordability, suggest that Europe is through the most acute phase of the Energy Crisis. The reduction in energy bills, coupled with the fact that most countries have already introduced frameworks and measures to deal with the affordability issue, should ease the regulatory pressure seen throughout last year. Effective demand destruction, mild winter temperatures, and ongoing below-average Chinese LNG imports have led to abnormally high gas storage levels across Europe (currently approximately 90%, vs. a historical average of approximately 65% in mid-January). As a result, gas prices have declined steeply. The gas

---

[10] Goldman Sachs, "Natural Gas: The End of an Era", September 11, 2022.
[11] Goldman Sachs, "Electrify Europe: The Energy Crisis: We May Be Through the Worst," January 12, 2023.

supply/demand balance suggests that, for the coming nine months, gas energy security threats in Europe will be much more subdued. According to Goldman Sachs, summer gas prices could settle at current levels in a prolonged warm winter scenario; summer gas prices could exceed €100/MWh following a normalization in weather and could peak at c.€130/MWh if we assumed a cold winter, starting towards the end of January until late March.

A. Interventionist Policies by European Governments

To save end-consumers from high prices, European governments have been discussing and implementing a whole raft of new interventionist policies – each country in its own way, with an umbrella price cap policy on a pan-European scale - prioritizing prices over quantity. In aggregate, governments have introduced ad-hoc taxes, price caps, and fiscal aid totaling ca. €270 billion. This result is, at current gas prices, the affordability crisis has largely been contained. The improved outlook for energy security, coupled with much lower threats from energy affordability, suggest that Europe is through the most acute phase of the Energy Crisis. The reduction in energy bills, coupled with the fact that most countries have already introduced frameworks and measures to deal with the affordability issue, should ease the regulatory pressure seen throughout last year. Nevertheless, there is a growing consensus that TTF (and JKM[12]) gas price volatility, as we have been witnessing today, is here to stay, also recently predicted by Saad al-Kaabi, the Qatari minister of Energy. Moreover, he, as well as his colleague Suhail al-Mazrouei of the UEA, believe both oil and gas will be needed for a long time, with gas not just as a transition fuel but rather as a purpose-driven fuel within the energy transition, and therefore to stay and to further grow, together with hydrogen to become the overarching fuel for the future.

B. EU Balance of Short-Term Energy Needs with Long-Term Decarbonization Goals

[12] JKM is the Northeast Asian spot price index for LNG delivered ex-ship to Japan, Korea, Taiwan, and China.

The European Union (EU) has set ambitious goals for decarbonizing its economy and reducing greenhouse gas emissions in order to combat climate change. The EU has set a goal to achieve net-zero greenhouse gas emissions by 2050 and to increase the share of renewable energy in its energy mix. To balance its short-term energy needs with its long-term decarbonization goals, the EU has implemented a variety of policies and measures, including:

- Increasing energy efficiency: The EU has implemented measures to increase energy efficiency in buildings, industry, and transportation, which can help to reduce energy consumption and reduce greenhouse gas emissions.
- Promoting renewable energy: The EU has set targets for increasing the share of renewable energy in its energy mix, such as wind, solar, and hydro power, which can help to reduce dependence on fossil fuels and reduce greenhouse gas emissions.
- Carbon pricing: The EU has implemented a carbon pricing system, such as the EU Emissions Trading System (ETS), which puts a price on carbon emissions, which can provide an economic incentive for companies to reduce emissions and invest in clean energy.
- Investing in clean energy research and development: The EU has invested in clean energy research and development to support the development of new clean energy technologies, such as carbon capture and storage, hydrogen, and advanced nuclear.
- Encouraging energy storage: The EU has implemented measures to encourage energy storage, which can help to balance the intermittent nature of renewable energy and make it more reliable.
- Building a more interconnected energy system: The EU has been working on building a more interconnected energy system which can help to balance supply and demand for energy, and also helps to share renewable energy across countries.

Overall, balancing short-term energy needs with long-term decarbonization goals is complex and ongoing.

C. Asia’s Response to EU LNG demand

In response to increasing demand for liquefied natural gas (LNG) from the European Union (EU), Asian countries have become major exporters of LNG to the EU. Some of the ways Asian countries have responded to EU LNG demand include:

- Increasing LNG production: Many Asian countries, such as Australia, Malaysia, and Russia, have increased their LNG production to meet the growing demand from the EU.
- Building new LNG export terminals: Countries such as Australia and Russia have built new LNG export terminals to increase their export capacity and to better serve the EU market.
- Signing long-term supply contracts: Many Asian countries have signed long-term supply contracts with EU countries to ensure a steady and reliable supply of LNG.
- Investing in new technologies: Countries such as Japan and South Korea have invested in new technologies to improve the efficiency of LNG production and transportation, which can help to reduce costs and increase competitiveness.
- Increasing use of floating storage regasification units (FSRU) : Some Asian countries have increased the use of FSRU's as it allows them to import and regasify LNG at a lower cost as compared to land-based regasification terminals.

Asia has responded to EU LNG demand by increasing production, building new export terminals, signing long-term supply contracts, investing in new technologies, and increasing use of floating storage regasification units, which makes it more competitive in the global LNG market.

4. The Effect of Geopolitics on US Gas Markets

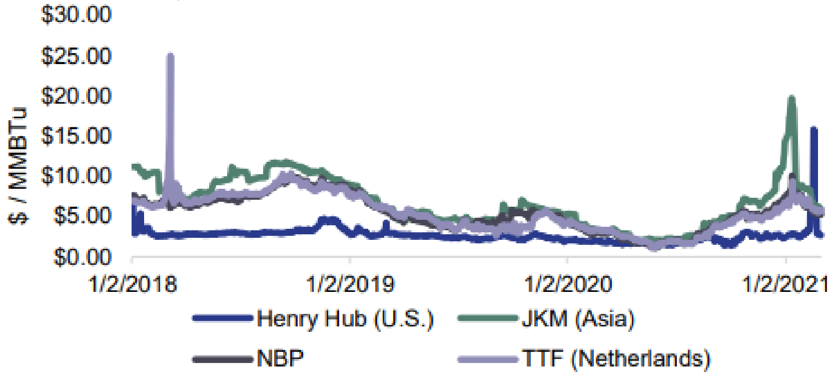
A. Geopolitical Factors that Affect U.S. LNG Exports and Pricing

Several geopolitical factors can affect U.S. liquefied natural gas (LNG) exports and pricing, including:

- Global demand: The level of global demand for LNG can affect the price of U.S. LNG exports. If global demand for LNG is high, it can lead to higher prices for U.S. LNG exports. Conversely, if global demand for LNG is low, it can lead to lower prices for U.S. LNG exports.
- Competition from other LNG exporters: The level of competition from other LNG exporters, such as Russia, Qatar, and Australia, can affect the price of U.S. LNG exports. If there is a lot of competition from other exporters, it can lead to lower prices for U.S. LNG exports.
- Geopolitical tensions: Geopolitical tensions can affect the ability of U.S. LNG exports to reach certain markets. For example, if tensions between the U.S. and a particular country are high, it may be difficult for U.S. LNG exports to reach that country's market, which can affect prices.
- Trade policies: Trade policies and tariffs can affect the price of U.S. LNG exports. For example, if a country imposes tariffs on U.S. LNG exports, it can make them less competitive and lead to lower prices.
- Infrastructure: The availability of infrastructure, such as ports and terminals, can affect the ability of U.S. LNG exports to reach certain markets, which can affect prices.
- Regulations: The regulations imposed by different countries on the import of LNG can affect the price of U.S. LNG exports. For example, if a country has strict regulations, it may be difficult for U.S. LNG exports to reach that country's market, which can affect prices.

U.S. LNG exports and pricing are affected by a combination of global market conditions, competition, geopolitical tensions, trade policies, infrastructure, and regulations. These factors are constantly evolving and can change rapidly, making it difficult to predict the future prices of U.S. LNG exports, although U.S. prices have been less volatile than prices in other regions (Figure 11).

Figure 11. Relative Volatility of Different Natural Gas Markets.



B. The Effect of the EU Price Cap on Global Gas Prices

The EU price cap on natural gas could have a mixed impact on global LNG prices. While it could lead to reduced demand for LNG imports and increased competition among LNG exporters, it could also lead to reduced bargaining power of major LNG suppliers and potentially increased demand for LNG in the long-term.

On one hand, the price cap could lead to reduced demand for LNG imports in the short-term, as domestic natural gas would become more competitive with imported LNG. This could put downward pressure on global LNG prices. Also, with the price cap, the EU will have more bargaining power over LNG exporters, which could lead to lower prices for LNG imports.

On the other hand, in the long-term, the price cap could lead to increased demand for LNG as the EU aims to reduce its carbon emissions and increase the share of natural gas in its energy mix. This could lead to increased competition among LNG exporters and potentially higher prices for LNG.

Additionally, the price cap could affect the bargaining power of major LNG suppliers, such as Russia, as they may have less influence over prices in the EU market. This could lead to increased competition among LNG exporters and potentially lower prices for LNG.

The impact of the EU price cap on natural gas on global LNG prices is complex and uncertain, as it depends on the specific implementation of the price cap and the broader economic and energy landscape.

C. The Effect of Instability Abroad on U.S. LNG Exports and Prices

Instability abroad, such as issues with LNG tankers and pipelines in the EU post-Ukraine, can potentially affect U.S. LNG exports and prices. The EU is a major importer of LNG, and disruptions to its supply lines can create uncertainty in the global LNG market and potentially lead to changes in demand and prices.

If there are disruptions to LNG supply in the EU, it could potentially increase demand for LNG from the United States, leading to higher prices for U.S. LNG exports. However, the U.S. LNG export facilities are relatively new and still have a limited capacity, especially when comparing the size of the domestic LNG market to the overall size of the domestic gas market.

Additionally, instability abroad can also affect the global price of natural gas, which in turn can affect the price of U.S. LNG exports. If global natural gas prices increase, it could make U.S. LNG exports less competitive, leading to lower prices for U.S. LNG exports. Conversely, if global natural gas prices decrease, it could make U.S. LNG exports more competitive and lead to higher prices.

It is also worth noting that instability abroad may also affect the shipping routes and logistics of LNG trade, which can also affect the price and availability of U.S. LNG exports.

Instability abroad, such as issues with LNG tankers and pipelines in the EU, can potentially affect U.S. LNG exports and prices, but the extent of the impact is difficult to predict and may depend on a variety of factors such as global natural gas prices, domestic production, and trade logistics.

D. Australia as a Case Study

The impact of LNG exports on natural gas prices can vary depending on the country, as different countries have different natural gas resources, production levels, and infrastructure.

In Australia, LNG exports have had a significant impact on domestic natural gas prices. Australia has large natural gas resources and has been increasing its LNG export capacity in recent years, which has led to a decrease in domestic natural gas prices. The country's LNG export facilities are well-developed and have a large capacity, meaning that a significant amount of natural gas is exported, reducing the amount available for domestic consumption. This has led to a decrease in domestic natural gas prices, making it more affordable for consumers.

In contrast, the impact of LNG exports on U.S. domestic natural gas prices has been relatively limited. The United States has a large and diverse supply of natural gas, with reserves and resources distributed across the country. The U.S. has been increasing its domestic natural gas production in recent years, primarily due to the development of unconventional resources, such as shale gas. This has led to lower domestic natural gas prices, making it more affordable for consumers. Additionally, the expansion of infrastructure, such as pipelines, has made it easier to transport natural gas to markets, further increasing accessibility. Additionally, U.S. LNG export facilities are relatively new and still have a limited capacity, meaning that even though the country has large natural gas resources, it is not yet a significant exporter of LNG.

Therefore, in Australia, LNG exports have had a significant impact on domestic natural gas prices, reducing the price, while in the United States, the impact of LNG exports on domestic natural gas prices has been relatively limited, largely because the U.S. has large domestic natural gas resources and increasing production, as well as limited LNG export capacity.

E. Effect of Other Policies or Levers on US LNG Prices

Several policies and other levers can influence domestic natural gas prices in the United States, including:

- Production levels: Policies that encourage or discourage natural gas production can affect domestic natural gas prices. For example, policies that provide tax incentives for natural gas production can lead to an increase in production, which can lower domestic natural gas prices. Conversely, policies that impose regulations or taxes on natural gas production can decrease production, leading to higher domestic natural gas prices.
- Transportation and infrastructure: Policies that affect the cost of transporting natural gas to markets can influence domestic natural gas prices. For example, policies that invest in pipelines and other infrastructure can make it cheaper to transport natural gas to markets, which can lead to lower domestic natural gas prices.
- Energy efficiency and conservation: Policies that encourage energy efficiency and conservation can reduce demand for natural gas, leading to lower domestic natural gas prices.
- Competition with other energy sources: Policies that support other energy sources, such as renewable energy, can make them more competitive with natural gas, which can lead to lower domestic natural gas prices.
- Deregulation: Deregulation of the natural gas market can also affect domestic natural gas prices. Deregulation can increase competition among natural gas producers, potentially leading to lower domestic natural gas prices.
- Export regulations: Policies that regulate LNG exports can influence domestic natural gas prices. Restrictions on LNG exports can reduce the amount of natural gas available for export, which can increase domestic natural gas prices.
- Storage regulations: Policies that regulate the amount of natural gas that can be stored can also affect domestic natural gas prices. If regulations limit the amount of natural gas that can be stored, it can lead to higher domestic natural gas prices during times of peak demand.

All of these policies and levers are interconnected and can have both short-term and long-term effects on domestic natural gas prices. The specific impact of each policy will depend on the specific implementation and the broader economic and energy landscape.