Dawn of a global commodity

LNG trading transformed

October 2017

LNG industry finally coming of age
Drivers and inhibitors of commoditization

Thriving in a commoditized LNG market
Shifting strategies in a new business landscape

Thoughts from the LNG industry
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LNG market analysis and forecasts
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Lead Author

Abache Abreu
LNG News & Analysis
S&P Global Platts

Editors

Ross McCracken
Energy Economist
S&P Global Platts

Stuart Elliot
Generating fuels news
S&P Global Platts

Mriganka Jaipuriyar
Associate Editorial Director
S&P Global Platts

Contributors

Marc Howson, Paul Bartholomew, Richard Langberg, Michael Ferguson, Rachel Adams-Heard, Chris Newkumet, Eriko Amaha, Kenneth Foo, Max Gostelow, Luke Stobbart, Desmond Wong, J Robinson, Ingrid Furtado, James O'Connell, Wyatt Wong, Edwin Loh and Michael Tsahalis

With analysis and forecasts from across the S&P Global group.

Design and Production
Amelie Yergeau and Martina Klančišar

Content Project Manager
Carrie Bharucha

S&P Global Platts
20 Canada Square, 9th Floor
London, E14 5LH, UK

President
Martin Fraenkel

Chief Financial Officer
Hywel Thomas

Chief Operating Officer
Sue Avinir

Global Head of News, Metals, Agriculture & Head of Asia Content
Sarah Cottle

Global forces of LNG commoditization

Introduction

Abache Abreu
Senior Editor, LNG News & Analysis, Asia-Pacific and Middle East
S&P Global Platts

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The LNG industry is well into its third and most significant expansionary phase, one in which supply is racing ahead of demand. But to turn an old adage on its head: there is nothing like low prices to cure low prices.

The industry's expansion is part and parcel of two overarching trends: the gradual spread of gas-on-gas competition that has emanated from both the US and North West Europe for more than a decade, and the global transition to lower emission energy sources, which is making LNG a key fuel of choice for many countries seeking to address chronic energy deficits.

LNG is well but ambiguously placed. It can bring the cleanest of fossil fuels to global markets and expansion has de-risked the supply chain. But when it arrives it must compete with local gas, other domestic sources of energy and alternative imported fuels.

Moreover, the supply of LNG is only as good as the weakest link in the chain. It requires heavy investment from both seller and buyer alike.

It needs gas production, liquefaction, transport, import facilities, storage and then distribution infrastructure before a single, chilly molecule can reach the end user. And it needs efficient markets at each and every point along the line. A market distortion in one element can have huge ramifications all the way back up to the supplier.

The high risk this entails has historically promoted inflexible supply agreements, necessary to provide investment certainty, but LNG is increasingly landing not in regulated but liberalized, competitive markets.

The juxtaposition of external inflexible supply and internal competition cannot help but create stresses and strains that are ultimately unsustainable.

It is not just a "buyers' market" in temporary supply and demand terms; it is a market that is structurally changing at both the point of production and the point of consumption.

This poses major challenges for the traditional LNG supply model, but within it also provides the seeds of resolution.

The industry's expansion is making LNG a global commodity in its own right, but to consolidate that trend new markets must be opened, and that means extending LNG supply chains into less credit-worthy, higher-risk markets and into industries relatively new to LNG, such as maritime and land transport.

It is a simple equation: in both these markets, and in existing, liberalizing markets, LNG must be at least as flexible as its competitors to succeed.

This inevitably shifts the focus of risk from buyers to sellers. The question then becomes how to mitigate this new risk, and the answer lies, as in other markets, in the development of improved financial architecture, greater market liquidity, and transparency, which allow risk to be shared by third parties, whether financial institutions, pension funds, traders or otherwise.

That transformation is taking place, and innovation and adaptation are required to transition from the inflexible, supply agreements of the past into a more versatile and nimble industry capable of opening the doors to new markets.

The growing pains are sometimes acute, but the LNG industry is finally coming of age.

Executive summary

Thriving in a commoditized LNG market

The reconfiguration of supply and demand in the LNG industry is on course to change the nature of global trading drastically and permanently.

The traditional ways of doing business, based on destination-restricted, oil-indexed long-term contracts, are disappearing, making room for enhanced flexibility and interconnectivity, promoting a more liquid, competitive and transparent marketplace.

Suppliers, challenged with high production costs or waiting to come on stream once the surplus erodes and prices recover, may see this as negative. But new opportunities are also up for grabs for those able to respond fast. Accepting that buyers' willingness to sign long-term deals largely depends on their ability to reduce risk through destination flexibility is a step towards securing new contracts and project FIDs into the 2020s. Continued investment in emerging markets should help producers diversify downstream portfolios and create outlets to absorb growing global supplies. Entering further into the value chain would boost their ability to optimize cargoes and capture spot value, while supporting the development of the **LNG derivatives market** could help limit future exposure to price volatility.

Legacy buyers in northeast Asia have seen the supply glut coincide with slowing consumption growth and deregulation in their domestic markets, a combination that is forcing them to prioritize profitability and risk management over security of supply in their LNG purchases. Japan, South Korea and Taiwan represent about half of global LNG consumption, an indication of their strong bargaining power in a buyers' market and the critical role they will continue to play in reshaping the way LNG is traded. Some have already entered the trading space in a bid to boost optimization capabilities, and are building hedging expertise to mitigate risk should the market tighten and prices rise.

In **emerging import markets**, particularly across South and Southeast Asia, the prospect of plentiful, cheap LNG for years to come is encouraging the development of a new wave of flexible regasification terminals, amid favorable policies that support a growing role for gas in the energy mix. Investment is pouring in as demand from Northeast Asia and the **Middle East** slows and international investors appear less constrained by conventional standards of creditworthiness. The level of success and participation of these markets in the future LNG sector will ultimately depend on the continuation of strong government policy initiatives to limit coal dependency, accelerate energy pricing reforms and pursue more flexible LNG contracts.

Nowhere have the disadvantages of rigid contracts become more apparent than in **India**, where downstream price sensitivity increases the risk of term deliveries becoming uncompetitive, or **China**, where the struggle of state-owned companies to absorb take-or-pay, oil-priced volumes is hindering the country's efforts to turn third-party access guidelines into law. More supply flexibility, greater infrastructure access and domestic prices that more closely reflect LNG fundamentals would help these Asian majors open immense opportunities for both domestic and international LNG stakeholders.

Traders have become key facilitators of LNG commoditization, having helped increase competition, cargo churn and the interconnected nature of the physical markets, while actively supporting growth in the derivatives space. Trading can only grow from here, fueled by a wave of flexible supplies, **shipping liquidity** and the emergence of new untapped markets, but its nature is also changing. Competition is growing, as buyers and suppliers are entering the trading space, while enhanced price transparency is eroding trading margins. Increasing **flexible supplies** from **North America**, Middle East and **Asia-Pacific** are reducing regional and seasonal price differentials, leading to fewer arbitrage opportunities. As competition sharpens and margins shrink, diversifying portfolios into new geographies should boost traders' ability to respond fast to short arbitrage windows, while expanding across the supply chain could ensure continued access to both strategic information and new buyers.

On the financial side, the ability of lenders to adjust to the new market environment will be crucial to ensuring a continuous flow of **finance** in the new marketplace, and avoid a supply shortage later into the 2020s once the current wave of projects reach completion. Lenders have been used to funding projects supported by rigid oil-linked contracts supplying regulated downstream monopolies. With that old world order ebbing, LNG sector finance will largely depend on acceptance of the increasingly pivotal role of spot markets, with improved operational efficiencies supporting LNG economics and stronger **pricing benchmarks** strengthening the market's hedging capabilities.

By the early 2020s, LNG industry stakeholders will be facing a very different market from the one we know today, and there are many reasons to be optimistic. A liquid, flexible and transparent spot market will be key to breaking price segmentation, improving fair competition, boosting energy accessibility for new markets, and facilitating the increasingly vital role gas is set to play in the future energy mix of a post-COP 21 world.

Highlights

Suppliers: Accepting that buyers' willingness to sign new deals depends on their ability to reduce risk through greater flexibility is a step towards securing new contracts and project FIDs

Legacy buyers: Building optimization and hedging capabilities should help mitigate the risk emanating from deregulation and slowing consumption growth in their domestic markets

Emerging buyers: Thriving in the new market will depend on strong policies aimed at limiting coal dependency, accelerating energy pricing reforms and pursuing more flexible LNG contracts

Traders: Diversifying portfolios across the supply chain and into new geographies should boost access to new demand centers and the ability to respond fast to short arbitrage windows

Lenders: Financing will depend on acceptance of the growing role of spot markets, with robust pricing benchmarks strengthening the market's hedging capabilities

Key takeaways

Interconnectivity

The emergence of US LNG and Australian coal seam gas-based LNG production have created significantly larger direct connections between the domestic gas markets and exports of LNG producing countries. At the same time, the expansion of LNG trade has formed bi-directional price transmission mechanisms between previously fragmented regional markets. Some countries are now both LNG exporters and importers.

Liberalization

On the demand side, legacy LNG markets are liberalizing, creating a much more diverse and competitive environment, in which LNG is just one competing energy source. More actors on the buy side sensitive to internal domestic market competition means sellers must build new relationships and change their value propositions to address the requirements of the new conditions emerging in these markets.

Risk allocation

The allocation of risk is shifting to different parts of the supply chain; buyers face new risks in their home markets, and are pushing that risk back up the supply chain to LNG suppliers, making the traditional LNG supply model – long-term, oil-indexed, take-or-pay contracts with destination restrictions – no longer fit for purpose.

Aggregation

Traders and portfolio LNG suppliers are grasping the opportunities these new conditions offer by finding innovative ways of mitigating the changing allocation of risk. Aggregating both demand and supply allows trading entities to break the direct link between a single LNG source and buyer, and at the same time enhance security of supply. Of equal, if not greater, importance, it allows them the flexibility to take maximum advantage of temporary periods of scarcity pricing in any of the growing number of LNG markets.

Flexibility

When taken together, the changes on the supply side and in these different import markets create a new and fast-evolving environment in which the point-to-point, bilateral trade model of the past no longer meets requirements. As a result, suppliers need to develop

flexible business models that can meet the needs of all market types in a non-discriminatory manner. This means shorter, less-restrictive contracts with new pricing mechanisms.

Financial architecture

In this more fluid, flexible and interconnected environment, both buyers and suppliers alike require more sophisticated financial instruments to mitigate the changing allocation of risk. Price transparency and liquidity are essential and it is incumbent upon Price Reporting Agencies, such as S&P Global Platts, trading platforms and exchanges, and market participants to engage in the construction of the financial architecture that can mitigate the challenges presented by the new world of LNG trade.

Market evolution

With these changes, LNG markets are evolving, albeit in different directions. Some are 'flux' markets subject to rapid change — for example in the Middle East, with the development of East Mediterranean gas, and in Latin America, with the development of Argentinean shale and Brazil's sub-salt oil and its associated gas. In these markets, LNG appears destined for an uncertain, and potentially temporary, often seasonal, balancing role.

Other markets are more clearly 'option' markets, where LNG provides a more significant balancing role and meets a variable proportion of baseload gas demand subject to price, for example in Europe and China. Pipeline gas supply and alternative energy sources provide a price ceiling, but these markets are also likely to deliver periods of scarcity pricing that require large supply volumes.

The third type of market – baseload — is the most dependable, although not without uncertainties. Here, LNG already occupies or promises to build a long-term position in baseload gas provision, for example in the populous nations of South Asia or in the legacy markets of North Asia. The expansion of gas use in key sectors, such as power, fertilizer production, petrochemicals, city gas or transport, is a major and well-articulated component of the country's energy policy, which promises long-term demand growth. In these markets, there are few alternatives: those that do exist carry significantly higher risk in terms of safety, cost, local air pollution or achieving national commitments to global climate change mitigation.

Foreword

Anne-Sophie Corbeau
Research Fellow II
King Abdullah Petroleum Studies and Research Center

When it comes to understanding how energy markets will evolve in the future, what we really need is a crystal ball. This is particularly true for LNG markets. The LNG industry – notably the supply side – was spoilt by years of high prices and Asia seemingly ready to absorb every drop of LNG at any price.

This drove US and Australia to build massive amounts of LNG export capacity that is currently coming online. This comfortable vision of the future, however, has collapsed amid growing uncertainties around future LNG demand and lower prices. Tremendous changes lie ahead that could bring about a complete reconfiguration of the LNG business.

This Global LNG Special Report investigates the future of various regional LNG markets, the potential commoditization of LNG trade and how key stakeholders are transforming their traditional business models.

This reconfiguration is not only a question of supply and demand. The very nature of LNG trade itself is changing as the industry reinvents itself.

The pre-2000 LNG "basket of kittens" that represented an industry consisting of a few buyers and sellers engaged in friendly rivalry has been replaced by a very competitive multiplayer environment. These days, when you attend an LNG conference, you are likely to come across new company names in every part of the LNG value chain. The number of countries looking at LNG imports is going through the roof. Within traditional importing countries, new entrants use LNG imports to gain market share through impending liberalization processes, while traders are eager to have a role and traditional players create their own trading entities. The LNG world is growing, and new players bring new business models and different requirements.

The old model of a metaphorical gas pipeline floating over the sea is gone. Flexibility is now the key: any cargo can go (almost) anywhere and change destination mid-journey depending on regional prices.

The traditional oil indexation model is under threat, restrictions on destination are being challenged by Japanese regulators, while buyers facing demand uncertainties increasingly opt for shorter - less than 10 years - contracts, smaller quantities and more destination flexibility.

Aggregators handling a portfolio of LNG supplies have become the norm.

These changes are daunting for companies investing billions of dollars in liquefaction projects that would operate for at least 20 years. Both new and existing buyers currently have little appetite for volumes above 1 million mt/year, which require suppliers to find more buyers to support any individual train. Beyond the question of finding a creditworthy buyer to commit for 20 years, uncertainties now surround the evolution of pricing and contractual frameworks. Buyers currently have the upper hand and their priorities have changed.

Building on this reconfiguration of the traditional LNG business model, there has been a growing debate about whether LNG would eventually become fully commoditized given the inevitable rise of spot LNG trading. This has been spurred on by the numerous attempts to create a gas/LNG trading hub in Asia as well as LNG futures markets, the rise of aggregators, a growing number of so-called portfolio contracts, traders entering the world of LNG and increasing amounts of flexible US LNG.

People often compare LNG to oil when the debate about commoditization comes up. The fact is global LNG markets have been changing and yearning to look like oil markets, but they are not quite there yet. Selling an oil cargo is considerably easier than an LNG cargo. Oil markets are liquid and a seller will always find a buyer at a given price; the cargo will probably change hands several times before it is unloaded. Sellers can also opt to store the oil cargo and sell it later. The LNG market is anything but liquid. There is little price transparency, or longer-term forward contracts. Few pure spot cargoes are traded daily despite the remarkable growth of spot and short-term LNG over the past few years. Unlike oil, the cost of transporting LNG is significant and arbitrages between destinations have to be made knowing that LNG cannot be stored forever because it loses volume due to boil off.

While LNG is not fully commoditized yet, how close can it go and will there be a tipping point whereby the industry enters a totally different paradigm? It is crucial for all stakeholders to understand the implications for global LNG trade, future LNG projects and long-term contracts in such an environment.

Thoughts from

Industry leaders discuss shifting trends and strategies in an increasingly

"We are now at the entrance of the door. For a long time, the door had been locked. But now, we have got the key and the plier to break the door chain. The key was brought by the Japan Fair Trade Commission; the plier, it depends on the case. But the bottom line is we need to enhance liquidity in the Asian LNG market."

Hiroki Sato
Senior Executive Vice President
Jera

"I am amazed by the pace of contractual change that we have seen in our industry recently. And I believe these changes will not be reversed; they are here to stay. Producers need to be competitive on price, but also offer sufficient flexibility which will allow our buyers to manage growing uncertainty in their downstream markets."

Andrew Seck
Vice President LNG Marketing and Shipping
Anadarko Petroleum Corporation

"Trading companies will need worldwide coverage in order to get a deep understanding of what is going on in different markets. They will definitely need to pay a much closer look at what is going on with other commodities, and adapt their internal process to reflect the more complex nature of the LNG market."

Javier Moret
Global Head of LNG
RWE Supply and Trading

the industry

commoditized LNG market

“This supply-demand gap that is foreseen for the next five to eight years is playing a major role in moving forward the commoditization process. The other side of that process is having a tradable standardized universal benchmark, as well as more participants, greater efficiencies and new technology on the regasification and liquefaction sides.“

M. Adnan Gilani
Chief Executive Officer
Pakistan LNG

”The direction is quite clear; as an industry we are heading towards a more commoditized, transparent, liquid and traded future. An understanding of how the industry is evolving is key in order to position yourself. Cost competitiveness and commercial innovations are essential, and so is the ability to make decisions quickly and provide solutions that fit customer requirements.”

Andrew Walker
Vice President Strategy and Communication
Cheniere Marketing

“It is very important for us to be customer-focused, whether it is in terms of more volume-flexible contracts, more destination flexibility, new pricing indexes or even new technical innovations. Some of the new customers also need us to bring capital and technical expertise to help them develop their markets.”

Jonty Shepard
Chief Operating Officer, LNG
BP

Risks evolve for new US LNG projects

The shift from long to short-term contracts in the LNG market alters new projects' ratings profiles, owing to increased market exposure. While LNG pricing risk formerly resided with off-takers, project developers now face new credit issues regarding resource and refinancing risk. Adapting will require innovation, perhaps in the form of smaller, modular LNG units, the first of which are unlikely to avoid a new set of concerns in the construction phase.

Richard Langberg
Director, North America, Energy Infrastructure
S&P Global Ratings

Michael Ferguson
Director, North America, Energy Infrastructure
S&P Global Ratings

Long-term contracts have been a critical support for LNG projects. They nearly eliminate market risk, and, at least post-construction, look like investment-grade credits, even with a considerable amount of leverage and some refinancing risk.

Since assigning initial ratings on Cheniere Energy's Sabine Pass LNG project in 2012, S&P Global Ratings has rated over $23 billion of debt at the Cameron, Freeport, Corpus Christi and Sabine Pass LNG projects.

The common credit thread that runs through all four of them is that cash flows to service each project's debt obligations are derived from 20-year, essentially take-or-pay contracts with investment grade counterparties.

However, almost no new US LNG projects have reached Final Investment Decision since 2015, and few new long-term LNG offtake agreements have been signed since 2014.

Commodity prices have fallen and the dynamics of international gas pricing have changed, weakening the rationale underpinning long-term LNG offtake agreements.

The dearth of credit worthy off-takers willing to enter into such contracts makes developing new projects increasingly difficult.

As a result, developers will in future need to be much more resourceful in arranging financing to fund the significant cost of developing and building large-scale liquefaction facilities.

This is not to say that liquefaction facilities will no longer be built in the US. However, the nature of these facilities may change. A greater number of smaller, more modular units is likely, based around shorter-term contracts. This changing model is likely to introduce a host of new credit issues.

Market risk

For the US LNG projects currently rated by S&P Global Ratings, market exposure has been greatly reduced because long-term contracts place the risk of LNG pricing with the off-taker.

However, LNG markets are much less well developed than global oil or regional power markets. The historical track record on which to base an assessment of market exposure is small, for either a base or downside case.

In addition, the issue of re-contracting is a complicating factor for project ratings. There is considerable uncertainty attached to projects' ability to re-contract its volumes after contract expiration and the rate at which that could be achieved, which could be much lower than the initial contract.

For certain US power projects, power pricing eroded to such a degree that re-contracting rates proved well below original assumptions. If re-contracting potential is assumed, a downside re-contracting price has to be taken into account, but again there is little in the way of historical precedent to guide such assessments in the LNG sector.

Under S&P Global Ratings' criteria, this market risk introduces a new question: how sharply would the profitability of a plant fall, if the market for LNG were to collapse? For a fully-contracted asset, the bottoming out of the market has few cash flow implications, but for a merchant plant, this market exposure — the change from base to downside case – can vary significantly. It might be classified as 'low' (15%-30%), 'moderate' (30%-50%), or 'high' (above 50%).

Moreover, the inclusion of market risk in an asset requires an assessment of its competitive position, which again is not an issue with fully-contracted plants. For LNG projects, key components of this score would be location and feedstock cost, each of which could improve cost competitiveness.

PRELIMINARY OPERATIONS PHASE SACP

OPBA	AA	A	BBB	BB	B
1-2	=> 1.75	1.75–1.20	1.20–1.10	<1.10§	<1.10§
3-4	N/A	=> 1.40	1.40–1.20	1.20–1.10	< 1.10
5-6	N/A	=> 2.00	2.00–1.40	1.40–1.20	< 1.20
7–8	N/A	=> 2.50	2.50–1.75	1.75–1.40	< 1.40
9–10	N/A	=> 5.00	5.00–2.50	2.50–1.50	< 1.50
11-12	N/A	N/A	N/A	=> 3.00x	< 3.00

Source: S&P Global Ratings

The consequence of shorter-term contracts, coupled with full merchant exposure, creates the possibility of a 'two-phase' project, with different business risks in each phase and therefore a different Stand Alone Credit Profile (SACP).

Resource risk

The next wave of US LNG plants could face heightened resource risk. In the existing rated financings, this has been largely absent. With long-term off-take contracts, it makes good economic sense to couple that exposure with similarly termed gas procurement operations.

In the case of Cameron LNG and Freeport LNG 2, the risk is outside the project structure, and resides with the project's revenue counterparties, not the project itself.

For LNG plants on the US Gulf Coast, the current risk of being unable to obtain gas is limited, amid an oversupply of natural gas that seems unlikely to abate in the near term.

However, even if the off-take contracts are shorter-term in nature, the asset life is not expected to be, and it is not yet clear how long-term resource risk would be mitigated to survive changes in gas supply, regulation, or natural gas infrastructure, all of which are critical elements of natural gas procurement risk.

For the moment, it might not be economic to fully hedge gas supply many years in advance.

As the next wave of LNG plants begins to sign short-term off-take contracts, it will be necessary to determine the validity of the various mechanisms used to offset this risk.

Moreover, as more LNG facilities are built, more gas sourcing could be a problem; Cheniere is already the single largest consumer of natural gas in the US.

Counterparty risk

Counterparty credit quality has loomed large over existing deals as investment-grade counterparties have supported investment grade operations at the plants rated to date.

"Developers will in future need to be much more resourceful in arranging financing to fund the significant cost of building large-scale liquefaction facilities."
— S&P Global Ratings

High credit quality counterparties are expected to be less available to the next wave of LNG plants, which are likely to be typified by shorter contracts, more pronounced market exposure, and/or lower-rated off-takers.

Under S&P Global Ratings' project finance criteria, material revenue counterparties could cap the rating of a project, if their credit quality is lower than the project's SACP.

Counterparties with 20-year contracts and a substantial portion of the off-take are considered material.

However, the same determination may not be made for a counterparty with a small portion of off-take and a shorter contract life.

Similarly, S&P Global Ratings' criteria requires an assessment of the operational ability of a project to meet standards set forth in its contracts.

This becomes less critical to a project that has no contracts, in which case the alternative is to assess only its ability to meet market norms for production.

Refinancing risk

Refinancing risk will also be more acute for LNG plants with only short-term contracts. For existing LNG plants with numerous debt tranches, S&P Global Ratings considers the Project Life Coverage Ratio (PLCR) at each point of refinancing.

When there is no market risk, the Operations Phase Business Assessment (OPBA) is lower (less risky), and consequently the standard for PLCR is lower. With market risk comes a need for better asset coverage to avoid a capped rating.

There are some lessons to be gleaned here from other asset classes that have significant market exposure, such as merchant power plants.

Utilization of a mechanism such as a cash flow sweep, which pays down debt with excess cash flows in periods of outperformance, could trim debt in later years and lead to higher Debt Service Coverage Ratios (DSCRs) in periods with greater market risk.

However, there is a caveat. For projects that rely very heavily on a cash flow sweep to reduce refinancing risk, ratings can be notched downwards.

This is because while the sweep can be effective in reducing the risk of a bullet maturity (when the entire principal value of a bond is paid at the maturity date), it will only do so when market conditions are favorable enough for such excess cash flow to be generated.

Construction risk

In addition to the impact of shorter-term revenue contracts on the operations phase, different contractual arrangements could also drive different construction needs.

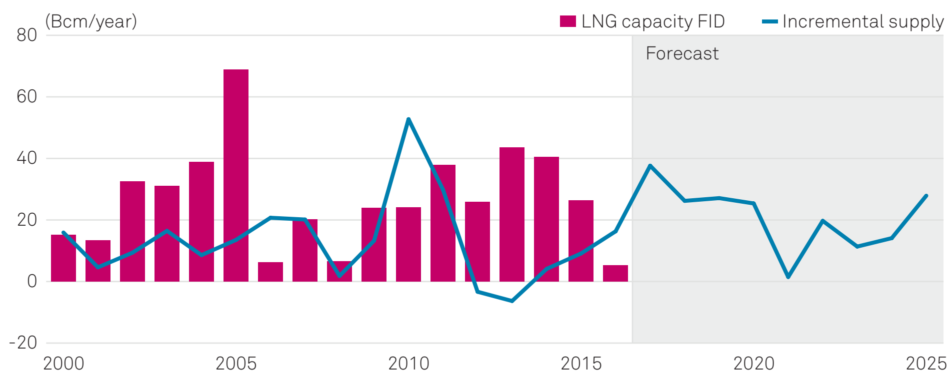
Shorter contracts for smaller volumes of LNG may require different technology to meet these specifications. Modular technology, in particular, could have several implications for an assessment of construction risk.

REFINANCE RISK RATINGS CAPS

	Stability of cash flows		
	High (OPBA 1-4)	**Medium (OPBA 5-8)**	**Low (OPBA 9-12)**
Asset coverage (PLCR)			
High (more than 3x)	None	None	None
Medium (1.5x-3.0x)	None	None	bb+ cap
Low (1.1x-1.5x)	None	bb+ cap	b+ cap
Very low (less than 1.1x)	bb+ cap	b+ cap	b- cap

Source: S&P Global Ratings

NEW FIDS NEEDED NOW TO BALANCE MARKET AFTER 2022



Source: S&P Global Platts Analytics

A greater quantity of funding could come from revenue during construction, if some units come online and begin exporting LNG prior to completion of total capacity.

However, the certainty of that revenue would depend on whether the output from early units is uncontracted or contracted with low credit quality counterparties.

In addition, some debt issuances, particularly bank lines, have stringent conditions for draws later in construction, which could result in a re-assessment of construction funding sources.

This effect could be amplified, if the creditors view the project as risky and seek to apply more onerous conditions.

Modularity can also potentially make construction shorter and less complex.

However, a supplier of modular technology may not be easily replaceable, while the technology they are providing, because it is bespoke, is not fungible. A supplier's financial woes could drive cost overruns or even prevent completion.

In addition, while modular construction may appear simpler, it may not be commercially proven in a particular configuration.

Moreover, if the arrangement is relatively new, EPC contractors might not be prepared to assume the same level of risk, leaving more of it with the project entity itself. Greater risk of scope exclusions could result in downward notches to ratings.

Flexibility at sea

Fleet transformation helping LNG evolve

New vessel capacity and technological improvements give LNG stakeholders the ability to direct cargoes towards higher prices while supporting the development of a spot market akin to oil and bulk commodities

Rachel Adams-Heard
Natural Gas Reporter
S&P Global Market Intelligence

The LNG shipping market used to be relatively simple, with fixed-voyage tankers shuttling back and forth between producers and their customers, as part of destination-restricted long-term supply contracts.

Thanks to an expanding and evolving LNG fleet, LNG stakeholders have been able to break away from that shipping rigidity and cater to an increasingly liquid and multidirectional LNG industry.

Shipping movements have since become less predictable. Charterers now have the ability to change destination mid-trip in response to new demand, or take longer routes in the expectation of higher bids.

The effect on the wider LNG sector has been apparent. Growing flexibility at sea has helped hasten LNG's shift towards a more efficient and commoditized market, akin to more mature commodities such as crude oil and refined products.

It has enabled spot liquidity growth, cargo churn, and the entry of new market participants looking for short-term vessel charters.

Expanding fleet

At the end of 2016, the global LNG tanker fleet consisted of 439 vessels, 31 of which were delivered that year, according to the International Gas Union.

Many tankers are now ordered on a speculative basis with a growing market in mind, rather than being tied to a specific project, according to the global association whose membership covers 97% of the gas market.

New tankers continue to be ordered in anticipation of a wave of LNG supply out of the US and Australia coming online by 2020 and growing demand from emerging economies looking to diversify away from coal and oil. More than twice as many countries now have the infrastructure in place to import LNG compared to a decade ago.

Also, similar to other commodity sectors, including oil and iron ore, there has been a move towards building larger vessels in a bid to lower the unit costs involved in transporting the resource. Order books show the average capacity of 100 tankers set to be delivered over 2017-2020 is 173,000 cu m, up from 153,600 cu m for vessels delivered in 2012, according to S&P Global Platts.

Evolving fleet

New vessels are also more technologically advanced than in the past. Better insulation and propulsion systems can help reduce the amount of gas that evaporates during the voyage, known as "boil-off."

LNG ship owner and operator GasLog predicts that just 0.085% of a cargo will boil off each day on newer vessels, down from 0.15% a decade ago. Tankers that can re-liquefy boil-off gas will see that rate fall even further, to 0.045% per day, the company has said.

Reduced boil-off gives market participants the ability to do what many in the industry refer to as "slow steaming" – sailing at slower speeds while waiting to see if a better offer comes along.

Falling rates

Plummeting charter rates, as new shipping capacity has outpaced demand for LNG tankers, have also helped improve accessibility to short term vessels at a time of thin LNG margins.

Those rates are made even lower by the market's shifting trade flows. Growing flexible cargoes from North America, Middle East and Asia-Pacific have reduced regional and seasonal price differentials, meaning vessels tend to stay intra-basin, resulting in lower shipping demand as charter lengths shorten.

Trading routes have also improved with the expansion of the Panama Canal providing a new and often cheaper route for US cargos into east Asia, supporting the Atlantic shipping market.

Average daily charter rates for 2017 have fallen to roughly $36,000, down from an average of about $117,000 five years ago, according to data compiled by S&P Global Platts. In August 2012, rates at times exceeded $140,000 per day.

Floating revolution

Floating storage and regasification units have also helped facilitate growth of the LNG market by reducing the cost and time of entry for new LNG importers.

They have added flexibility in comparison with onshore terminals, by reducing the need to commit to permanent onshore facilities, which importers have seen idled for months or years when market conditions change.

Some older, less efficient tankers have been repurposed as flexible

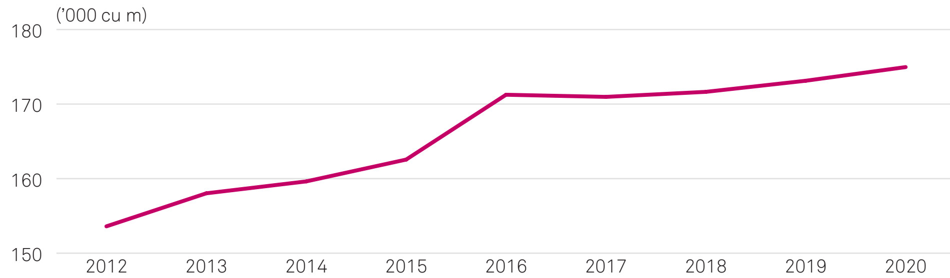
FSRUs — such as the Golar Arctic, which is now located off the Jamaican coast.

Though LNG is showing signs of following in the footsteps of oil and other global commodities, transporting the cryogenic fuel still provides challenges that could slow the path to commoditization.

Unlike oil, a certain quantity of the product will always evaporate, and while this is decreasing, there will always be pressure to get a cargo to the end user relatively quickly.

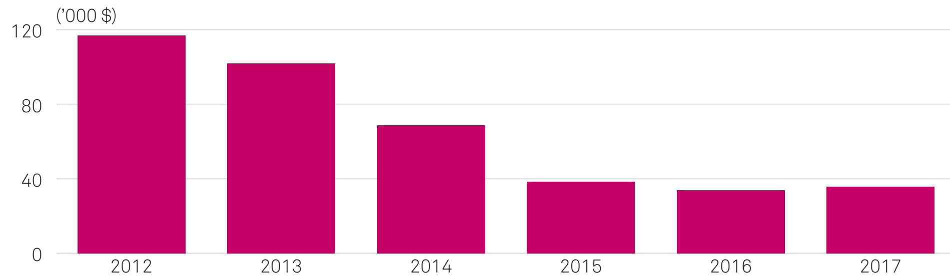
But there is little doubt the industry is heading towards greater commoditization and maturity as LNG's importance in the global energy profile increases – and shipping is playing a major role in this evolution.

AVERAGE LNG TANKER CAPACITY



Source: S&P Global Platts

AVERAGE LNG CHARTER RATE PER YEAR



Source: S&P Global Platts

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Moving regulatory targets in age of Trump

Though US policy pronouncements may flicker in and out of focus, LNG is gaining visibility in the White House and steps are being taken to enable US LNG exporters to grab market share. But before they do that, they need to overcome the challenges of overcapacity and low prices.

Chris Newkumet
Bureau Chief, Washington, DC
S&P Global Platts

With an oversupplied global market currently discouraging entry and forcing new US LNG exporters to think outside the box, a special challenge comes in the form of the somewhat erratic messaging and policy shifts of US President Donald Trump's administration.

Although the President's shifting trade policy pronouncements have left some scratching their heads, observers see access to financing and general pricing dynamics — rather than regulatory delays — as the key holdups for US projects looking for a piece of the growing pie.

For instance, after high-profile handshakes with China and South Korea, other signals have been less friendly, including a passing threat by Trump of a trade war with China or of tearing up South Korea's trade agreement.

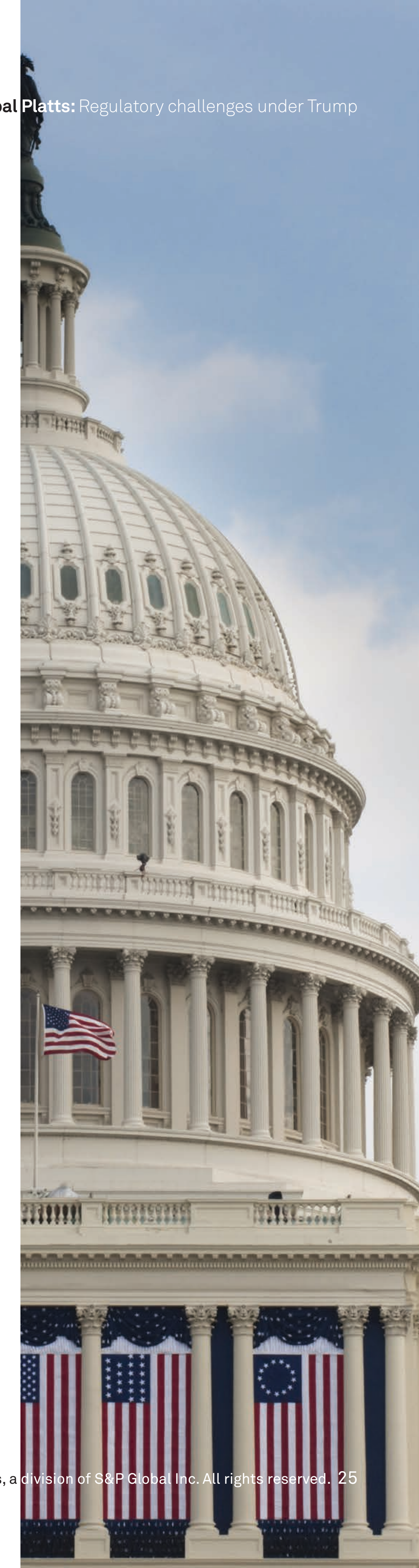
Nonetheless, industry advocates have welcomed the Trump administration's high-level cheerleading for LNG exports. In meetings with foreign leaders from Asia and Eastern Europe, Trump has touted LNG exports as a way to lower the US trade deficit while bolstering energy security abroad.

US Energy Secretary Rick Perry has signaled that he would move quickly to sign export orders. "Here are the rules — if you meet the rules, here is your permit," Perry said, summing up the current approach at a recent event. Any perceived foot-dragging is a thing of the past, he made clear.

To further support export approvals, the US Department of Energy, which Perry heads up, is expected to kick off a new study examining the economic effects of authorizing a higher level of exports. The 167 million mt/year in LNG exports authorized thus far by DOE tops the main scenario examined in the last major study the agency commissioned.

Tugging in the other direction, the Industrial Energy Consumers of America in August 2017 called for a moratorium of LNG export approvals, warning that the US might consume 58% to 71% of recoverable reserves by 2050. Environmentalists are also applying pressure, but so far the administration has offered little sign of slowing down.

DOE recently proposed a new rule to expedite review of small-scale natural gas exports. Cheniere Energy also has pushed for the Pipeline and Hazardous Materials Safety Administration to work more closely with FERC to eliminate overlapping jurisdiction and to update PHMSA's approach to LNG export terminals.



Along with DOE, FERC is part of the federal regulatory punch that US project developers face, and several sources expect the commission — which should soon have four new members and a Republican chairman — to starting picking up the pace of its project reviews.

Also looking to grease the skids for LNG exports are US Senator Bill Cassidy, Republican-Louisiana, and Representative Clay Higgins, Republican-Louisiana, who are pushing proposed legislation that would lift the requirement that DOE make a public interest determination for exports to countries without free trade agreements.

But it is unclear for now how much attention revamping LNG export reviews will get in the crowded political arena in Washington, as larger battles loom over taxes, the debt ceiling, US/Mexico border wall, health care and the budget.

In lieu of actual reform, LNG has gained increased visibility from the White House, DOE, the departments of State and Commerce, as well as the US Trade Representative, said Charles Riedl, executive director of the Center for Liquefied Natural Gas. “It is more optics at this point, but it is a noticeable effort and the value is not lost upon the industry,” he observed.

That may signal that LNG exports are aligned with broader energy policies that are friendly to adding production, and show buyers that US LNG is a reliable bet.

And US LNG will have to be a reliable bet if it wants to carve out a space for itself in markets that have swung over the last five years from a supply-constrained environment, which drove spot LNG prices above $20/MMBtu, to the well-supplied environment in place today.

Competition is fierce among pending US projects seeking to outlast the current glut, with six projects under construction, another three fully permitted but lacking a final investment decision, and more than a dozen representing 195 million mt/year of capacity in the queue at the US Federal Energy Regulatory Commission.

“The fundamental issue for US LNG is: do the economics still make sense,” offered Edward Chow, senior fellow for the Center for Strategic and International Studies. US LNG was well-positioned when international prices were above $8/MMBtu and domestic natural gas was at $3/MMBtu or less. “At global spot LNG prices of $5/MMBtu or even below, I do not see how US LNG is in the money,” he said.

For some new project developers, it still makes sense because by 2022 there will be sufficient demand and the spot LNG prices will not stay at the relatively low levels they are at today, he continued.

This longer-term optimism is being fueled by recent demand growth and estimates for the coming years.

Global demand growth is expected to remain robust for the foreseeable future, rising another 138 million mt/year by 2025, according to Platts Analytics, but for now it remains unclear how much more liquefaction can be added before prices sink to levels that force producers to shut in uneconomic capacity.

Legacy Asia

Time to flex buying power

Japan and South Korea are the world's biggest LNG buyers and with that status comes power. The two countries and Taiwan are at the forefront of efforts to negotiate improved LNG contract terms. With Japan's post-Fukushima market liberalization efforts beginning to bear fruit and destination clauses on the way out, improved market liquidity is set to follow.

Eriko Amaha
Associate Editor
S&P Global Platts

LNG heavyweights Japan, South Korea and Taiwan combined consume about half of the world's LNG supply, although this is a sharp drop from the near 60% of the market they accounted for in 2006. Japan alone in 2016 imported 31.3% of the world's LNG, South Korea 12.5% and Taiwan 5.6%.

Their huge market share explains why they have such strong bargaining power in the current LNG market, and why they will play such a critical role in shaping the way LNG is traded.

Market liquidity could be set to soar, owing to three key factors.

First, the Japan Fair Trade Commission (JFTC) ruled in June 2017 that destination restriction clauses in long-term LNG contracts were likely to be in violation of the country's antitrust laws. Although the ruling stopped short of proposing specific actions to be taken, it reinforces the ongoing trend observed in the LNG market, where contracts are already becoming shorter and more flexible.

This ruling could bring Japan closer to EU rules governing LNG imports and help create a level playing field for LNG buyers in Japan.

Second, Japanese and South Korean buyers appear to have overcommitted to LNG volumes under long-term contract.

They will want to sell unwanted cargoes and the JFTC ruling looks likely to give them the means to do so.

Third, several long-term contracts are due to expire without an extension agreement in place. This provides options in what is a buyers' market: non-renewal and recourse to the spot market, or new, more flexible contracts.

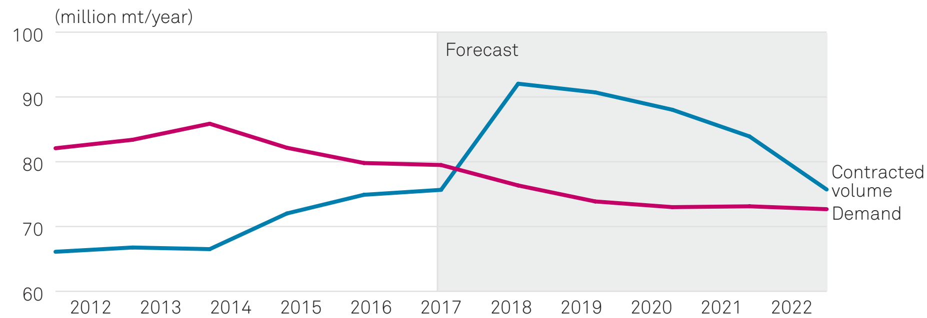
A continuation of the old contract model is unlikely. New contracts are expected to have at least some of the following features: shorter duration, smaller size, use of different pricing reference points, and no or less restrictive destination clauses. All will serve to increase market liquidity.

Change is gradual, but substantive, as legacy contracts and their newer more flexible incarnations overlap. In its Wholesale Gas Price Survey 2017, the International Gas Union noted that while the share of gas-on-gas competition for LNG imports globally rose from 13% in 2005 to 32% in 2015, it fell back in 2016 to 24%.

However, this reflects the domination of legacy contracts, and it is the terms of new contracts that count for the future.

According to the International Energy Agency's Global Gas Security Review 2016, 60.5% of long-term contracts signed in 2015 worldwide had flexible destination clauses, up from 49% of those signed in 2014.

JAPAN LNG DEMAND VERSUS CONTRACTED VOLUME



Source: S&P Global Platts Analytics

Changing mindsets

Increased flexibility is not the only driver of change. Rising supply of LNG on world markets provides an environment in which domestic market deregulation becomes more economically beneficial and easier to achieve.

"Japan's market liberalization is pushing incumbent players into new directions where managing price risk and ensuring profitability take priority over security of supply." — S&P Global Platts

Deregulation is enticing new market entrants, which will fuel competition and put additional pressure on traditional LNG importers to seek more flexible supply options and strengthen their trading capabilities.

Moves to fully liberalize Japan's downstream markets are a legacy of the 2011 Fukushima nuclear disaster.

Although Japan responded remarkably effectively in many ways to its entire nuclear fleet going off line in the wake of the accident, its ability to do so was hampered by the inefficiencies and poor interconnectivity of its gas and electricity transmission systems, organized on a regional basis and dominated by local monopolies.

Deregulation of the domestic energy market is now forcing incumbent utilities out of their comfort zones and into new trading activities. Japan opened up its domestic power and gas retail markets in April 2016 and April 2017, respectively. Further liberalization is on its way, with the division of former regional monopoly power-generation plants and transmission and distribution systems by 2020, and the unbundling of gas pipeline operations by 2022.

Several Japanese utilities have therefore decided to take advantage of flexible US LNG volumes to manage their portfolios more effectively and have also started to step into the realm of trading.

Kansai Electric and Tohoku Electric have announced plans to establish a trading unit, while Osaka Gas and Jera, a joint venture between Tokyo Electric Power Co. and Chubu Electric, have expressed interest in expanding their trading functions.

At the same time, Japan's Ministry of Economy, Trade and Industry (METI) is pushing for enhanced LNG price discovery and the development of an LNG trading hub in Japan.

This latest development is pushing incumbent players into new directions where managing price risk and ensuring profitability take priority over security of supply.

These moves dovetail with Tokyo's push to develop a fully-interconnected, national gas transmission system and improve third-party access to LNG terminals at home, which could in future boost regional liquidity, flexibility and efficiency.

In addition, Seoul's move to allow private companies to import LNG directly and resell in the domestic

market from 2025 coincides with the expiry of two large contracts held by state-owned gas importer Kogas – a 4.1 million mt/year contract with Oman and a 4.9 million mt/year contract with Qatar. Both contracts are due to expire by 2024.

Moreover, this year, SK E&S, a city gas company that has expanded into gas and renewables power generation, has been active in buying spot cargoes, after its own LNG receiving terminal in Boryeong started in January 2017.

The terminal, which SK E&S owns with GS Energy, is the second private terminal after Gwangyang and will start providing feedstock for the revamped Anyang power plant in 2018, which was sold as part of South Korea's privatization program in the power sector. More importers mean more competition for Kogas.

In Taiwan, utility Taipower is reportedly planning to build its own new LNG receiving terminal, bypassing the country's sole LNG buyer CPC Corp., and procure LNG on its own accord. Taiwan has also stepped up efforts to liberalize its power market and break up Taipower through new amendments to the country's electricity law.

CPC itself is planning to expand its LNG capacity up to 20 million mt/year by 2030, up 48% from 13.5 million mt/year in 2015, with its planned third terminal in Taoyuan adding up to 6 million mt/year of capacity.

The company could prioritize flexibility in its supply contracts looking forward, if domestic regulation raises competition at home.

Generation shift

LNG plays a pivotal role in Japan, South Korea and Taiwan's energy mixes, all three of which are chronically dependent on fossil fuel imports for power generation. When set against coal, LNG is cleaner; when set against oil, it is cheaper.

Moreover, all three are questioning the long-term future of nuclear power. The expectation is growing that it will be a combination of LNG and renewables that fills the void.

South Korea's new President Moon Jaei-in wants the reduce the country's reliance on nuclear power over the long term and shut down at least ten coal-fired plants that are 30 years or older before his five-year term ends in 2022.

South Korea runs 59 coal-fired power plants that supply about 39% of the country's total electricity, followed by nuclear, 31%, and gas, 19%. The government aims to boost the portion of gas in power generation to 37% by 2030.

S&P Global Platts Analytics forecasts this will increase South Korean LNG demand by an additional 5.5 million mt/year by 2022, bringing total annual consumption to 35 million mt.

Nuclear power is also falling out of favor in Taiwan. President Tsai Ing-Wen has promised by 2025 to phase out the energy source, which currently accounts for around 8.1% of Taiwan's energy consumption, and boost renewables and gas.

The island nation, which faces nuclear waste disposal issues and is also prone to earthquakes, has three nuclear power plants, which started up between 1977 and 1985. Only six reactors are currently operating, while completion of two reactors under construction since 1999 has been suspended.

Uncertainty over the extent of the restart of Japan's nuclear fleet remains a key variable in assessing the country's future LNG demand; gas consumption in the country has fallen from a peak of 118.9 Bcm in 2014 to 111.2 Bcm in 2016.

Of the 26 nuclear reactors that have applied for review under new safety standards set after the Fukushima disaster, only five had come online by August 2017, four were going through final checks, three required further reinforcement, and 14 remained under review.

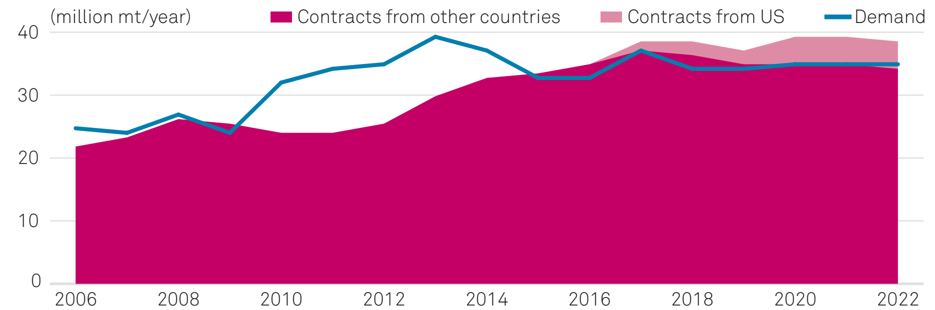
Very limited forecast electricity demand growth will put a brake on LNG use, as electricity generation accounts for up to 70% of the country's gas consumption. This creates a zero sum game in which gas, renewables, nuclear and coal compete for market share.

LNG and coal are forecast to account for 27% and 26%, respectively, of total electricity output in 2030, well down from the 2015 levels of 39.2% and 34%, according to METI. But the fall depends on nuclear output rising to 20-22% and renewables to 22-24% of total generation.

The timing and likelihood of reactor restarts remains unclear and will be determined as much by political as economic considerations.

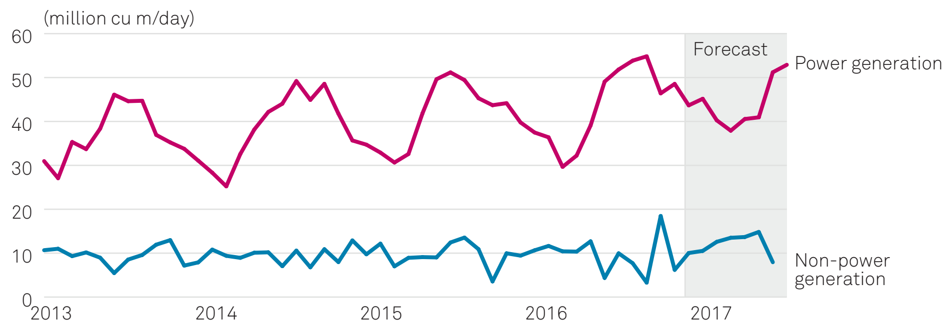
On past precedent, this suggests that nuclear output could fall well short of the 2030 target of 20-22%, or 213-234 TWh, implying the need for higher fossil fuel and especially LNG use.

SOUTH KOREA LNG DEMAND VERSUS CONTRACTED VOLUME



Source: S&P Global Platts Analytics 2017-2022 is forecast.

TAIWAN GAS USE



Source: S&P Global Platts Analytics

The renewables target, which is heavily dependent on solar, may also undershoot, owing to construction delays and resistance to the rising subsidy bill.

Transition markets

Although viewed as mature LNG markets, all three countries offer at least the potential for demand growth, largely depending on the fate of their nuclear industries.

But within that the structure of trade in the region is set to change dramatically.

As the global LNG market becomes flooded with new volumes, the line between buyers and sellers will become increasing blurred. Buyers from the legacy markets will have more flexibility in the procurement and resale of LNG volumes, and they are likely to play a more active role in LNG trade, potentially outside as well as within their own region.

It will not be a frictionless process. Managing sell and buy positions will be challenging for Northeast Asian buyers. But greater buyer power, growing competition and more flexible import infrastructure will help bring efficiency to the LNG market and drive a shift toward increased spot liquidity. Pushed by deregulation in their home markets, the opportunity offered by an increasingly diversified range of suppliers and the decline of nuclear power, Asia's traditional LNG markets are about to enter a new and exciting phase.

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Energy, a division of S&P
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Emerging Asia

Future market balancers?

Individually, they are relatively small markets, but combined they could represent the difference between an even more prolonged LNG supply glut and market balance. The weak price environment and increasing number of LNG sellers means emerging Asian LNG importers have the opportunity to mitigate risk by pursuing more flexible contracts and relying more on spot markets and players.

Abache Abreu
Senior Editor, LNG News & Analysis, Asia-Pacific and Middle East
S&P Global Platts

The expectation that LNG prices will remain depressed into the 2020s is creating an incentive for governments in emerging Asian markets to develop LNG infrastructure and accelerate energy reforms to support gas penetration in their downstream markets.

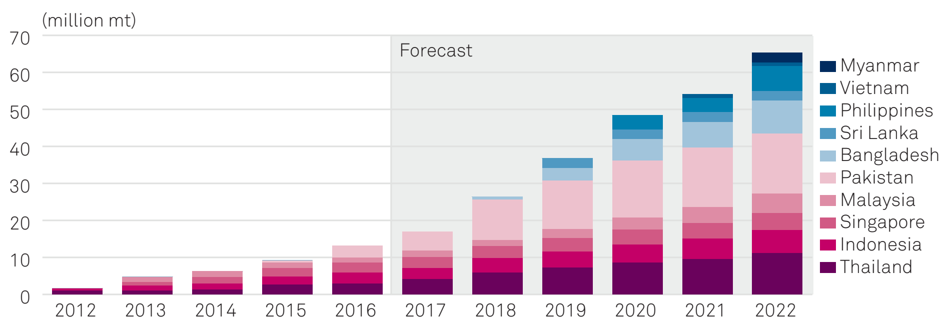
Some, such as Pakistan and Bangladesh, already face chronic gas shortages, while others, such as Thailand, the Philippines and Vietnam, face uncertain supply futures as a result of depleting domestic reserves and/or reduced pipeline imports.

Moreover, the proliferation of LNG suppliers and the increasing ability to agree short-term, flexible contracts is de-risking the LNG supply chain, while FSRU technology means projects can be delivered within a single electoral cycle.

From Pakistan to the Philippines, these 10 emerging markets of South and Southeast Asia are on track to become the world's biggest contributors to LNG demand growth, with a combined intake of more than 65 million mt/year, almost a fifth of global consumption by 2022, up from just 13 million mt/year in 2016.

In Pakistan, official forecasts suggest LNG demand could rise from 3.4 million mt in 2016 to as much as 30 million mt in 2022. In Bangladesh, the country's Power System Master Plan envisages LNG

LNG IMPORTS BY EMERGING ASIAN BUYERS



Source: S&P Global Platts

"The success and level of participation of these countries in a more liquid, commoditized LNG market will depend on their ability to negotiate better access to flexible LNG supplies." — S&P Global Platts

imports equivalent to almost 30 million mt from none today by 2041.

The region's growth potential is so significant that the end of the forecast period of LNG oversupply, which is expected to extend into the mid-2020s, is likely, in part, to be determined by how quickly these new demand centers absorb the excess volume.

In turn, sellers are looking to expand into these new markets, having seen demand growth stall over the last two years in the key legacy markets of Japan and South Korea.

From LNG terminals to gas pipelines and power plants, investment is pouring in, as bearish market forecasts continue to force LNG stakeholders to look beyond their comfort zone.

Lightweight wrestlers

Before now, governments in the region have prioritized supply security, given the escalating energy deficit across the region driven by strong consumption growth, limited upstream reserves, and poor cross-border pipeline connectivity.

The success and level of participation of these countries in a more liquid, commoditized LNG market will depend on their ability to negotiate better access to flexible LNG supplies.

However, the region's negotiating hand is weakened, even in a supply glut, by the fact that the individual markets are relatively small, despite the aggregate demand potentially being significant.

In addition, future importers, including Bangladesh, Myanmar, Vietnam, Sri Lanka and the Philippines, are faced with the additional challenge of higher investment risk, linked to their lower credit ratings, limited gas-to-power infrastructure and heavily-regulated downstream markets.

As a result, sellers face a number of concerns with regard to contract fulfillment: the timely completion of import facilities, the construction of the pipeline distribution network, and the competiveness of LNG versus domestic gas and competing fuels in regulated and subsidized markets, which are often subject to unexpected regulatory intervention.

Moreover, in Pakistan and Bangladesh, gas shortages have increased the pressure on governments to find solutions, further strengthening the negotiating position of suppliers, giving them a unique opportunity to lock in volumes via restrictive long-term contracts.

This, in effect, transfers the risk of import facilities, distribution infrastructure and demand not arriving in time to the buyers.

While sellers now appear less constrained by traditional credit-worthiness standards, the balance of power in these

Petronas and the supply transformation

While the region's biggest transformation is taking place on the demand side, there are important supply developments shaping the global process of LNG commoditization.

Regional supply volumes will remain relatively stable, with only marginal increases forecast through 2022, but a growing share of that supply will become flexible, as long-term contracts near expiry, and legacy suppliers become more confident in spot trading.

Nearly 30 million mt in long-term contracts are due to expire over the period 2018-2025. That's more than half of total production from the region's three exporters: Malaysia, Indonesia and Brunei.

While Indonesia's Pertamina has taken a more inward approach, aimed at diverting domestic gas supplies towards its expanding native market, Petronas has been more progressive, opening its receiving infrastructure to international imports, increasing its exposure to spot trading, and exploring new ways of expanding its customer base in emerging markets through joint venture investments.

"We want to become a solutions provider," Petronas' vice president for LNG trading and marketing, Ahmad Adly Alias, said in an interview with S&P Global Platts. "The market has now changed because the US model has taken a different approach, adding more liquidity and flexibility, so Petronas is also becoming more progressive, willing to change the way it operates."

Petronas has also been expanding its presence in spot markets, where it sold around 3 million mt of LNG, or close to 40 cargoes, in 2016, out of a total output of 29 million mt, up from 1 or 2 spot cargoes sold in 2013, Alias said.

"Nowadays, we are becoming more comfortable with the fact that there is an opportunity to play in the spot market and create liquidity," Alias said, highlighting the importance to fully understanding the inherent risks of seasonal demand variations and price volatility. "It is important that we are able to manage those [seasonal] cycles and that we are able to be flexible with our buyer, so we can offer spot, short-term and long-term contracts."

Petronas has also diversified its supply contracts, selling more volumes under short-term deals, and pricing against a variety of benchmarks, including Henry Hub, NBP and the Platts JKM.

> *"The market has now changed because the US model has taken a different approach, adding more liquidity and flexibility, so Petronas is also becoming more progressive, willing to change the way it operates."* — Petronas

emerging markets is less in favor of the buyer than in the more mature legacy markets of North Asia or those in Europe.

> *"These countries are making significant downstream Investments to meet baseload requirements, so the appetite for being completely reliant on spot LNG is relatively weak. Depressed oil prices are also making it harder to challenge oil indexation, particularly as sellers are accepting lower slopes and offering more flexibility."*
> *— PIRA Energy, a division of S&P Global Platts*

Uncertain steps

However, these emerging markets are already using the weak pricing environment to their advantage. In Bangladesh, state oil and gas company Petrobangla has decided to take less gas than initially planned from its maiden LNG contract with Qatar's Rasgas, highlighting the trend towards allocating a bigger share of their baseload demand to short-term and spot purchases.

"Only if we find that by 2018 or 2019 everything is going fine, then we will go for another long-term or mid-term contract. We do not want to get bled by [take-or-pay] clauses," Petrobangla's manager of the LNG Division, Kazi Md. Anwarul Azim, said in an interview with S&P Global Platts.

In the meantime, the state-owned buyer is planning to supplement its oil-linked Qatari contract with flexible volumes and diversify its pricing exposure to alternative indexations.

Elsewhere, much of the existing demand from Pakistan, Thailand, Singapore and Malaysia is being met by a growing population of LNG aggregators with flexible portfolios and spot trading expertise, which is helping boost cargo churn, transparency and global interconnectivity.

Moreover, the growing number of potential partners on the sell side appears likely to be matched on the buy side.

While open access to gas infrastructure is still rare in Asia, the governments of Thailand, Pakistan and especially Singapore are taking steps to allow third-party access to terminals and pipelines in a bid to boost capacity utilization and competition.

Singapore and Thailand have also led efforts to set up LNG trading and marketing companies, with the establishment of Pavilion Energy by Singapore's sovereign wealth fund Temasek in 2012, and more recently PTT Global LNG, a venture created in 2017 between Thailand's PTT and its subsidiary PTT Exploration and Production (PTTEP).

Singapore, a unique case

The greatest push towards regional flexibility and price transparency has so far come from Singapore which, strategically located in one of the world's busiest shipping waterways and home of a growing LNG trading community, is determined to claim the title of LNG trading hub.

Singapore is an exception among the region's emerging buyers. It has taken bold steps to develop a competitive, liberalized gas market, has access to pipeline connections to Malaysia and Indonesia, and already allows third-party access to its gas and LNG infrastructure.

It has the support of its regulatory authorities and first-mover advantage relative to similar efforts by Japan and Shanghai to build their own LNG hubs.

The country's move to expand its LNG capacity to 11 million mt/year by 2018 and enable storage and reloading services to international players demonstrates its commitment to making Singapore a facilitator of regional flexibility.

Parallel efforts to create a Singapore-based pricing point for spot cargoes have also been made in a bid to boost regional pricing transparency, although so far the initiative's success has been limited, partly because of thin liquidity.

And liquidity will continue to be the biggest challenge to Singapore's hub ambitions, as the limited size of its domestic gas market relative to Asian LNG trade would make it very difficult for the country to replicate the unique characteristics of the European markets, with their fully functional trading hubs and interconnected national markets.

Nonetheless, while the long-term prospects of Singapore's hub ambitions are still uncertain, the country is well on track to becoming Southeast Asia's reference for LNG trading, especially amid ample growth potential of small-scale LNG in Indonesia and the Philippines.

China

An uneven playing field

China has long been seen as key to continued global LNG demand growth, but policies at home are hampering efforts by non-state companies to join the party. Its long desire to create a gas trading hub in Shanghai is also being held back by continued government intervention in price setting.

Kenneth Foo
Team Leader
Asia LNG Assessments
S&P Global Platts

China's efforts to liberalize further its LNG sector have long promised significant opportunities to domestic and international stakeholders.

Beijing has carried out market reforms affecting LNG on three key fronts: boosting third-party access to LNG terminals, liberalizing domestic gas pricing, and promoting a trading hub.

However, turning guidelines into policy at home and pushing for greater flexibility in international supply agreements abroad will be crucial if China is to succeed in an increasingly commoditized marketplace.

Unlike Asia's main LNG importers – Japan, South Korea and Taiwan – which are largely dependent on LNG to meet their gas demand, China has relatively diverse supply options. It can source gas from its own domestic resources or import gas either as LNG or through pipelines.

Demand is growing fast and policy directives encouraging coal-to-gas switching to combat air pollution mean that imports are increasingly needed to feed China's enormous energy appetite. China's gas demand has outstripped domestic production since 2006, with LNG imports emerging as a demand-supply buffer.

As part of its 13th Five-Year Plan, the Chinese government intends to raise the proportion of gas in the country's energy consumption to around 10% by 2020 from 5.9% in 2015. Beijing also aims to cut annual coal consumption by 160 million mt by 2020.

As a result, LNG imports will play an increasingly important role in the country's energy mix, especially in the highly populated coastal regions, which have limited access to pipeline supplies or production from domestic gas fields.

> *"Turning guidelines into policy at home and pushing for greater flexibility in international supply agreements abroad will be crucial if China is to succeed in an increasingly commoditized marketplace."*
> — *S&P Global Platts*

Partial access not enough

A major move toward LNG market liberalization will be increased third-party access to import terminals, which should lead to growing gas demand and trade through the addition of new consumers. This will help China absorb the major ramp-up in contracted volumes of LNG over the next decade, mostly from Australia in the medium term, and potentially from the US following the US-China trade deal signed in May 2017 that has opened the door for a contracted wave of US LNG to hit the country.

China – predominantly through its National Oil Companies (NOCs) PetroChina, Sinopec and CNOOC – has signed up for more LNG than it needs. It was over-contracted by 8.65 million mt in 2016, despite increased demand, and while those levels are set to fall China will still be over-contracted by 3.08 million mt in 2017 and 1.79 million mt in 2018, according to Platts Analytics.

For third parties and independent players, being able to access greater volumes of LNG at import terminals operated by state companies gives them the opportunity to arbitrage between low LNG spot prices and high regulated prices in the domestic Chinese market.

This arbitrage has led to a growing number of new market entrants. They include gas distribution companies and city gas companies ENN, Guanghui, Jovo and Beijing Gas Group, as well as power utilities like Huadian, Huaneng and Guangdong Development.

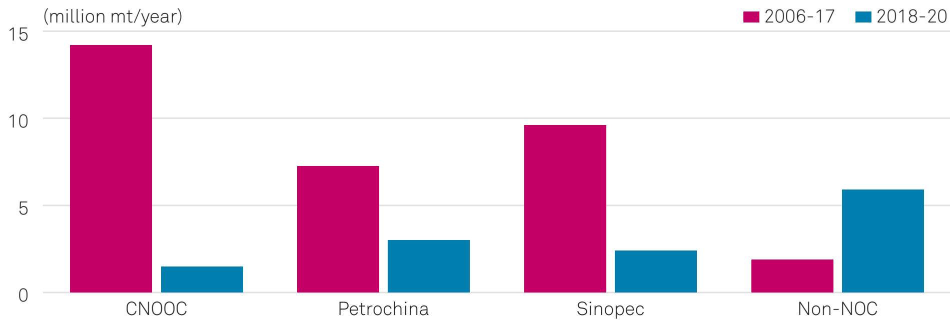
As well as eyeing spot cargoes, a slew of term contracts have also been signed by these independent players. By 2018,

TERM CONTRACTS SIGNED BY INDEPENDENT PLAYERS SINCE 2015

Buyer	Seller	Contract Type	Signing Year	Contract Start	Duration (years)	Volume (million mt/year)
ENN	Chevron	SPA	2016	2018	10	0.65
ENN	Total	HOA	2016	2018	10	0.5
ENN	Origin	SPA	2016	2018	5	0.28
Guangzhou Gas	Woodfibre LNG	HOA	2016	2020	25	1
Huadian	BP	SPA	2015	2020	20	1
Huadian	Chevron	HOA	2015	2020	10	1
JOVO	Petronas	SPA	2016	2017	6	0.7
JOVO	Chevron	Key Terms Agreement	2016	2018	10	0.5

Source: S&P Global Platts, Company reports

CHINA CONTRACTED VOLUMES BY BUYER



Source: S&P Global Platts Analytics

long-term contracts by non-NOCs will account for 3.21 million mt, or 8% of contracted volumes into China. This will rise to 6.99 million mt, or more than 14% of contracted LNG in 2020.

However, the state incumbents are not taking the rise of the independents lightly. Fear of losing market share has prompted capacity hoarding with the state importers not adhering to new guidelines issued by the National Development and Reform Commission (NDRC) in 2014 for third-party access to LNG terminals operated by state companies.

Currently, only PetroChina allows companies to use its receiving terminals at Rudong and Dalian, but even here the third-party access contracts are awarded in the form of master sales agreements and are not legally binding.

An additional barrier to entry is the fact that third-party access to the pipeline system is restricted and there is limited impetus to spin off pipeline assets from CNPC and Sinopec.

To get round these problems, some companies have sought to construct their own LNG import facilities, despite being hampered by high taxes on such investments and an onerous approval process. Both Jovo and Guanghui Energy have built import facilities in Dongguan and Jiangsu, respectively, while ENN's Zhoushan terminal is scheduled for commissioning in 2018.

However, the future could be brighter for the non-NOC importers. By turning third-party access guidelines into law, and setting achievable targets for state companies to allocate capacity, China could further boost terminal capacity utilization from the current rate of around 60%, improve end-user cost efficiency, and increase downstream gas consumption to absorb growing term supplies.

More flexible LNG term contracts would also be needed to improve state companies' ability to maneuver in a more competitive domestic gas market, and trade contracted surpluses on the spot markets, which would ultimately boost liquidity and efficiency in the wider LNG industry.

International efforts to abolish destination clauses, spearheaded by Japan, are already accelerating the erosion of destination-restricted long-term contracts based on oil-indexation, in favor of more short-term, spot or LNG index-linked deals.

Shanghai trading hub: lacking key elements

China, like both Japan and Singapore, is pushing to establish a regional market hub, able to reflect the interaction of prices and volumes between China's pipeline gas and LNG imports.

But, Beijing's grand ambition to establish a regional trading hub will likely fail unless it is backed by concerted efforts to drive deregulation, and state control is pulled back in favor of market forces.

Shanghai, with its well-developed interconnecting regional pipelines, as well as access to several LNG terminals along the east-coast, has been identified as an obvious candidate.

The Shanghai International Energy Trading Center and the Shanghai Free Trade Zone were set up in 2013 to facilitate the international trading of oil and gas. The Shanghai Petroleum and Natural Gas Exchange (SHPGX) was launched in July 2015 to provide a market-driven trading platform primarily for gas and LNG.

However, little progress has been achieved since. The Shanghai hub initiative has failed to fulfill the two initial stages of market hub development as outlined by the US Energy Information Administration (EIA): gas price de-regulation and sales unbundling, and third-party access to terminals.

Gas price de-regulation and sales unbundling – the first stage – has been held back by the government's strict involvement with gas price setting and market control.

And the second stage – access to pipeline and LNG import capacity, a primary ingredient for functioning trading hubs – has been restricted by the lack of third-party access adoption in China.

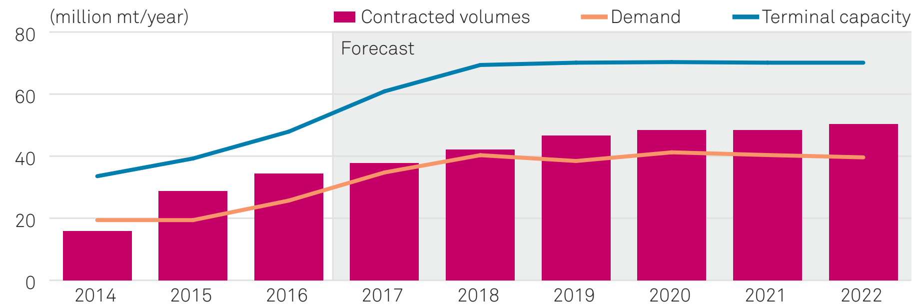
But there has been some progress on the third and fourth stage of hub formation: prevalent bilateral trading and transparency in volumes and pricing traded.

The NOCs and a few independent players engage in active spot, short-term and long-term trading, although much of these are with a narrow group of suppliers and traders with pre-existing long-term relationships.

Price reporting agencies like S&P Global Platts and Argus, as well as the SHPGX exchange now contribute to market transparency.

But trading on the SHPGX lacks depth. There were only 1,116 LNG trades in 2016, amounting to about 0.58 million mt, on the SHPGX from Ningbo LNG import terminal, according to the exchange.

CHINA IMPORTS PROJECTIONS VERSUS CAPACITY



Source: S&P Global Platts Analytics

Domestic gas price liberalization

Since 2011, the Chinese government has sought to reform domestic gas pricing by linking city gate prices to a basket of competing fuels like fuel oil and LPG, in order to ensure gas price competitiveness.

But the prices often contain an extensive time-lag that can span several months for both LNG and pipeline gas relative to oil prices.

Furthermore, the formula for the city-gate prices can be complex and subjective. The state government sets the baseline prices, while the transportation prices beyond the city gate are determined by provincial governments that favor subsidizing residential consumption over that of industrial usage.

But there have been progressive steps to inject market-representative domestic pricing. A major change took place in November 2016 in which suppliers and buyers negotiate the city-gate price within a 20% range of the baseline price for each trade.

In terms of LNG imports, new entrants not tied to long-term oil-indexed or gas-indexed contracts may undercut incumbents by trading spot cargoes on a fixed-price or an Asian gas index.

Many contracts signed before 2010 were linked on high slopes to oil prices. New buyers could arbitrage the disconnect between spot LNG and oil-linked term prices and use the cost savings to grab market share from the majors in downstream markets.

That explains why the NOCs continue to be fiercely against granting third-party access. But the tide is turning, with state-owned utilities with reasonable government support like Huadian and Huaneng trying to muscle onto the scene.

As a result, the NOCs have a couple of choices in front of them: relent and offer third-party access, but lose market share in the process. They could import more LNG on a spot basis but risk buying at higher prices during the winter.

Another option is to renegotiate term contracts with no destination clauses and set up experienced trading teams to resell these volumes. This might also require a derivatives trading strategy to hedge the market risk.

All these options are possible, even in conjunction with one another.

But simply put, the perfect market reform policy for China would be one that drives at third-party access promotion twinned with gas price liberalization.

India

Feeding the tiger; the search for market-priced LNG

The fall in global LNG prices has been particularly timely for India given the country's desire to make gas a cornerstone of its energy policy. With abundant LNG supplies globally, India is looking to LNG imports to supply a huge expansion of its domestic gas grid. But to compete internally, India's importers need greater third-party access to infrastructure and the ability to source LNG on a flexible basis at market prices.

Max Gostelow
Senior LNG Pricing Analyst
S&P Global Platts

India has made it a strategic priority to increase the share of gas in its energy mix from 6.5% currently to 15% by 2021. LNG demand is expected to reach 30 million mt/year by 2022, according to Platts Analytics, almost double current throughput as terminal logistics are resolved and new import infrastructure completed.

The gas transmission network is expected to double in size in the next three years to 29,000 kilometers, bringing access to gas – primarily imported LNG – to the country's east and south, which currently account for only 20% of national use. With an existing structural deficit, which its domestic gas resources cannot meet, fertilizer production, city gas, transport, and the refining and petrochemicals sectors all represent key areas of demand growth, driven by both local air pollution and national emissions targets.

Power sector prospects are less certain, but could still add some demand. India has embarked on a massive renewables program that envisages 175 GW of renewables capacity by 2022. The impact of this buildout is expected to reduce the country's dependence on coal-fired

INDIA LNG IMPORT CONTRACTS

Importer	Exporter	Country	Volume (million mt)	Delivery Terms	Start	End
Petronet	RasGas	Qatar	5.0	FOB	01/01/2004	01/12/2028
Petronet	RasGas	Qatar	2.5	FOB	01/01/2010	01/12/2028
Petronet	RasGas	Qatar	1.0	DES	01/01/2016	01/12/2028
Petronet	ExxonMobil	Australia	1.5	FOB	01/11/2016	01/10/2036
Gail	Cheniere	US	3.5	FOB	01/01/2018	01/03/2036
Gail	Cove Point LNG	US	2.3	FOB	01/01/2018	01/12/2037
Gail*	Gazprom	Russia	3.5	DES	01/01/2019	01/12/2043
GSPC**	BG	Portfolio	2.5	DES	01/01/2015	01/12/2034

*To be sourced from now-cancelled Shtokman LNG export plant. Gazprom now aims to source supply from its global portfolio.

**Contract starts with 1.2 million mt/year, ramp up to 2.5 million mt/year after 2 years

Source: S&P Global Platts

"Over the long-term, buyers and sellers require flexibility in an increasingly liquid market, which in turn promotes regional market supply and demand as the dominant forces driving rational pricing."

— S&P Global Platts

power, and current power supply tenders are seeing renewables undercut coal. This combination implies a highly-competitive scenario for LNG in the generation sector.

Indian opportunities

India is expected to have uncontracted LNG demand of as much as 8.5 million mt/year by 2022, even with a ramp-up in new long-term supplies. The emergence of new importers unrestricted by long-term contracts and increased third-party access to import terminals are encouraging more competition downstream, forcing traditional buyers to prioritize price competitiveness and risk management over long-term supply security.

The larger Indian importers are already buying more LNG on a shorter-term basis, mainly via spot purchases or through prompt tenders where a cargo is delivered within three months of the tender's issue date. Heavyweights GAIL, Indian Oil Corporation (IOC) and Gujarat State Petroleum Corporation (GSPC) sought an average of five cargoes per month through spot tenders over the first half of 2017, while new LNG entrant Torrent Power has also looked to procure volumes through short-term tenders.

With growing exposure to the spot market, Indian buyers have also become more aware of the need for robust market-based LNG pricing, and have been supportive of the development of hedging instruments, like the JKM derivatives, to mitigate market risk.

Nonetheless, however bright the outlook, significant risks remain, not least the timely delivery of gas distribution infrastructure and the government's willingness and ability to pursue further liberalization of the domestic gas market, as well as ensure third-party access to all parts of the gas supply chain. This process is likely to be enhanced if Indian importers are better able to source LNG on a flexible basis with prices that reflect LNG market supply and demand fundamentals.

The search for a market price

Gas demand in India is acutely price sensitive in part because of regulated domestic prices and in part because of the financial weakness of its power distribution companies.

The risk of committing to long-term LNG import contracts indexed to oil is thus high. If demand is highly responsive to price, then inflexible pricing will retard demand, market growth and the incentive to invest further in the country's growing distribution network.

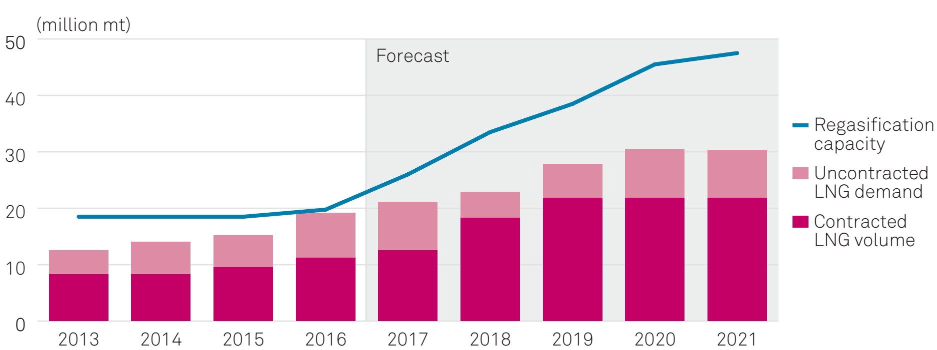
Oil-linked contracts for LNG imports from Qatar and Australia's Gorgon project have already proved problematic for India's Petronet, while GAIL's more recent Henry Hub-indexed US LNG term deals are also at risk of becoming uncompetitive once supplies begin in 2018.

However, recognizing a buyers' market, India importers have been renegotiating these contracts. In 2015, following the rapid fall in oil prices, Petronet imported significantly less than the contractually agreed volume from its 7.5 million mt/year contract with Qatar's RasGas.

This was in part due to the inability of the downstream market to absorb this high-priced contracted gas, imported at a 60-day moving average oil-linked floor price.

Consequently, the contract had to be renegotiated outside of the contractually-specified renegotiation period, with the eventual removal in 2016 of the 60-day moving average ceiling and floor price and waiver of $1.5 billion in penalties under the take-or-pay clause for volumes that Petronet had not imported. As a concession, Petronet agreed to buy an additional 1 million mt/year and import

INDIA CONTRACTED AND UNCONTRACTED LNG DEMAND



Source: S&P Global Platts

all of the volumes not taken during that time over the remainder of the contract, which runs until 2028.

Petronet has also been reportedly looking to revise down the price of its 1.5 million mt/year contract for supplies from Gorgon in Australia. In 2009, the price was agreed with a high oil-linked slope, which has become an issue for the buyer in the current low-price LNG spot market.

> *"The challenges for India becoming a global hub are that of lack of storage, limited downstream access – owing to infrastructure constraints – and the absence of a strong clear policy directive in the power sector, amid cheap coal and declining costs of renewables."*
> *— PIRA Energy, a division of S&P Global Platts*

Most recently, the US Sabine Pass contract terms have also come into focus, with GAIL heard attempting to renegotiate the terms of its 3.5 million mt/year deal with Cheniere Energy.

The contract was signed on a FOB basis in 2011, with the price formula set at 115% of the Henry Hub gas price plus a fixed $3/MMBtu terminal usage charge. This was an attempt by GAIL to break away from the problems of oil-indexation and take advantage of the US' more flexible delivery terms. However, given surplus LNG availability in Asia Pacific, this has resulted in prices for US volumes being well above spot market prices for cargoes delivered into India.

GAIL also signed in 2013 a contract with Dominion Energy for 2.3 million mt/year of LNG from the planned Cove Point project in the US, bringing total US volumes on a FOB basis to 5.8 million mt/year. GAIL may look to renegotiate this contract as well.

The need to renegotiate Henry-Hub-based formulas demonstrates that different forms of price indexation bring different forms of risk. HH prices protect US LNG exporters from fluctuations in the price of their domestic feedstock. But, while they free importers from oil market volatility, they replace that risk with exposure to the US gas market, which is reflective of neither LNG supply and demand in Asia-Pacific nor their own domestic market.

Yet sellers need to lock in export volumes to raise finance and ensure sufficient utilization to justify the capital investment in liquefaction capacity. It is hard to square the circle in the interests of both parties. Over the long-term, both sides require flexibility in an increasingly liquid market, which in turn promotes regional market supply and demand as the dominant forces driving rational pricing.

Wider infrastructure access

One of the key obstacles to further demand growth in India is the number of bottlenecks across the country's pipeline and terminal infrastructure, but steps are being taken to improve connectivity and to allow for greater access to regasification facilities.

A recent expansion at the Petronet-operated Dahej terminal – from 10 million mt/year to 15 million mt/year – has created more availability for other Indian buyers to gain access to import capacity. GSPC and Torrent Power have leased long-term capacity at Dahej for 2.25 million mt/year and 1 million mt/year, respectively.

Greater access to Dahej, initially aimed at catering for Petronet's long-term contract with Qatar, will lead to increased competition in the downstream and a greater desire on the part of importers to source cargoes at market-based spot prices.

The country has over 16,100 km of existing gas pipelines and nearly 14,000 km more domestic pipelines are under construction or proposed, including pipelines aiming to connect the east and west coasts, which should link the gas grid to more industrial end users.

However, even though there is increased opportunity to gain access to LNG import capacity, a lack of third-party access to the gas transmission network, which is largely operated by GAIL, has meant that there are limited prospects for other large gas users, reliant on these pipelines, to increase LNG imports. Further regulatory reform to increase third-party access to pipeline infrastructure would encourage new importers' forays into the LNG spot market and in the current market reduce India's average LNG import costs.

Supporting gas usage

India also needs to overcome the challenge of its complex tax, pricing and subsidy regimes, but steps are being taken to facilitate LNG affordability and gas penetration. In 2017, India halved the import duty on LNG to 2.5% from 5%, encouraging more demand across all downstream sectors.

In the power sector, the Indian government had been providing subsidies for the sale of imported LNG to revive more than 14 GW of stranded gas-fired power generation capacity hit by domestic gas shortages. Under the scheme, around 8 GW of gas-based capacity was brought back into operation in the first phase. However, the subsidy scheme was discontinued in March 2017.

In the fertilizer sector, the government has announced a policy to pool domestic gas and imported LNG for urea production where gas is the most important cost component. Under the new pooling scheme, all fertilizer plants using the gas grid pay the same average pooled price, blending the domestic and imported gas costs.

This measure saw several fertilizer units resume production and has had a clear impact on reducing India's reliance on imported urea in line with the government's goal of being self-sufficient in urea production by 2021.

Finally, the government has extensive plans to expand city gas distribution networks downstream, which, if realized, represent a major source of long-term demand growth. City gas supply has been prioritized, but it is the planned expansion of city gas networks that really promises to deliver new demand. The government is looking to an internationally competitive bidding process, allowing for marketing exclusivity of the gas for a period of up to five years.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Australia

A pivot toward flexibility

The early successes of the Australian LNG sector have been tarnished in recent years by cost blow-outs, LNG price declines and the threat of domestic gas shortages despite the country's vast gas resources. LNG operators are now having to adopt increasingly innovative approaches to capitalize on its huge, and still growing, LNG export capacity.

Marc Howson
Director, LNG Market Development
S&P Global Platts

Cost overruns at home and depressed prices abroad are suppressing optimism in a country that is set to become the world's largest LNG exporter by 2019. The increasingly buyer-friendly characteristics of global LNG trading is adding further challenges to an exporter that has structured its business model around primarily destination-restricted, oil-indexed long-term contracts, increasingly opposed by LNG buyers.

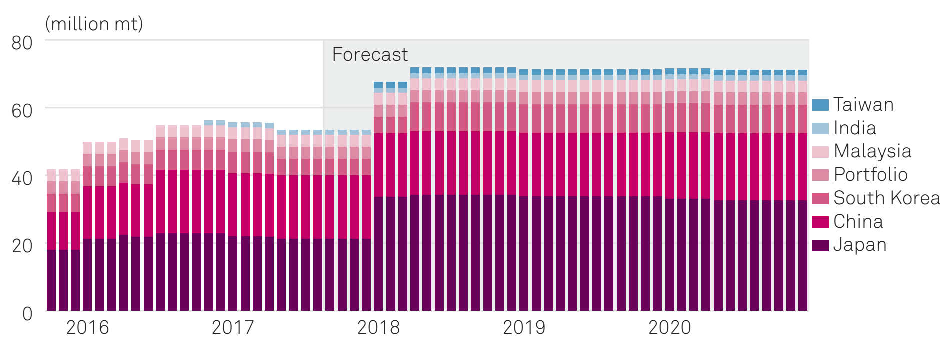
But Australia's LNG stakeholders are anything but bystanders in this changing market, and are gradually adjusting their business model to an increasingly liquid, flexible and commoditized trading space. Their level of success will largely depend on their ability to improve cost competitiveness at home, and further expand their customer base, particularly into the growing emerging markets, through more innovative marketing strategies.

Flexible supply

While Australian LNG is largely sold via destination-restricted contracts, the country is set to become an increasingly important supplier of flexible volumes.

This liquidity will initially come in the form of commissioning cargoes as new export facilities ramp up production. Five new trains are due to start up in Western Australia by mid-2018, adding a

CONTRACTED AUSTRALIAN LNG BY DESTINATION



Source: S&P Global Platts Analytics

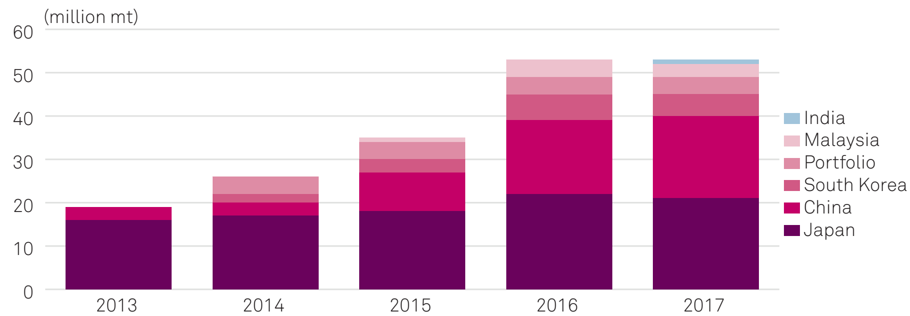
combined 21 million mt/year of capacity, according to Platts Analytics. The country's total LNG exports are forecast to rise to 69 million mt in 2018, before overtaking Qatar in 2019.

More than 10% — over 8 million mt — of Australia's projected LNG exports of 81 million mt/year by 2019 remains uncontracted, which could add a substantial amount of flexible liquidity to global spot markets.

More flexible supply could also emerge as a result of existing long-term volumes being resold in the spot markets, as customers flex down their purchases under long-term contracts.

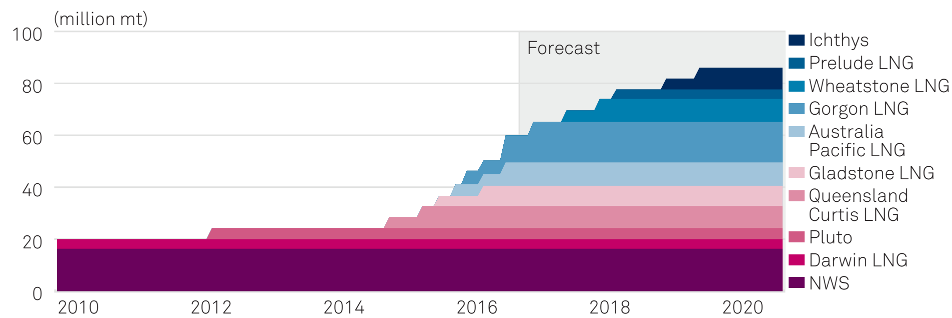
In addition, around 10 million mt in medium/long-term supply contracts between Asian buyers and Australia's LNG exporters are due to expire by 2026. Japan's determination to eliminate destination restrictions is likely to define the terms of any future agreements, potentially unleashing large locked-in contractual volumes onto the spot market.

AUSTRALIAN LNG CONTRACTS BY TYPE



Source: S&P Global Platts Analytics

AUSTRALIAN LNG SUPPLY CAPACITY BY LIQUEFACTION PROJECT



Source: S&P Global Platts Analytics

Innovative approaches needed

Of the 73 million mt/year of Australian LNG that is contracted in 2019, most of it has been sold into Northeast Asia on an oil-indexed basis with limited flexibility to divert into alternative markets. In fact, in recent years only around 4 million mt/year of Australian LNG has been contracted on a portfolio, or destination-flexible basis, according to Platts Analytics.

The limitations of these relatively inflexible contracts have become apparent in recent years, as buyers have found themselves over-contracted. Greenfield pre-FID Australian LNG projects marketing volumes will find it hard to compete with other growing supply centers in the US, which have contracted sizable LNG volumes on a FOB and non-oil index basis, or with Qatar, which enjoys some of the world's lowest production costs.

For Australian suppliers, remaining competitive may partly depend on their ability to lower production costs, especially in Queensland, where the relatively high marginal cost of large-scale drilling of coal-seam gas wells is already providing an incentive for developers to shut in production when the market is weak and netback prices cannot cover marginal costs.

But Australian LNG suppliers' business success, or even survival, may also depend on their ability to expand their customer portfolios by offering more attractive terms, including shorter, more flexible and diversified supply contracts.

Targeting growing markets across the Middle East, South Asia and Southeast Asia would also guarantee an additional customer base and outlet to absorb growing global supplies, while further immersion along the value chain would increase Australian suppliers' ability to optimize cargoes and capture spot value.

The latter is already a reality. Growing uncontracted volumes are encouraging Australian suppliers to venture into the spot trading space, which is adding to rising spot cargo liquidity, market interconnectivity and trading competition.

Queensland LNG producers will also need to manage their LNG exports in light of the domestic market's gas demand. Strong Australian domestic gas prices, combined with the sharp decline in LNG spot prices have given suppliers economic incentives to channel their gas into the domestic market. This economic incentive has been compounded by political pressure, following Australia's decision to introduce means to restrict LNG exports when it believes there is not a secure gas supply to domestic users.

Platts Analytics expects that a combination of economic and political pressures will lead to an increasing prioritization of the domestic market, resulting in the three Gladstone-based LNG export projects producing a combined 23 million mt of LNG until at least end-2019, 10% below their 25.4 million mt nameplate capacity. This underutilization is expected to initially reduce the availability of uncontracted LNG supply that could potentially be sold on a spot and/or flexible basis.

The domestic gas shortage is likely to turn Australia into a potential seasonal buyer of short-term LNG cargoes. AGL Energy's proposed LNG import project in southeastern Australia would likely rely on seasonal, short-term deliveries to alleviate the region's gas shortages, potentially further boosting spot market liquidity.

AGL is planning to develop an Australian floating LNG import jetty and pipeline, with Crib Point, Victoria, the preferred location. In August 2017, AGL announced plans to invest approximately A$250 million in the project and, following the completion of feasibility studies, start construction in 2019 with the aim of beginning Australian LNG imports in 2020/2021.

The project's LNG would likely be sourced from the global market, aimed at meeting seasonal gas demand peaks over the winter months. If the project materializes, Australia could join the relatively small group of countries with both LNG import and export infrastructure, including Malaysia, Indonesia and the US.

AUSTRALIA'S LNG EXPORT PROJECTS

Source: S&P Global Platts Analytics

"Cost cutting will be an essential part of future LNG projects throughout the world, as delivered LNG prices must drop to levels that will compete with coal and carbon pricing. For Australia, brownfield development is the road forward."

—PIRA Energy, a division of S&P Global Platts

Middle East

Shifting sands, changing strategies

Gas market fundamentals in the Middle East have changed dramatically in recent years. Amid fast rising regional demand, traditional LNG exporting countries have become importers. Now growing regional pipeline supplies threaten some of these new markets. But for Qatar, the world's largest LNG exporter, it is market developments outside of the Middle East that are creating the most pressure for change.

Luke Stobbart
Senior Pricing Specialist - LNG
S&P Global Platts

Fast rising regional gas demand in the Middle East has made it a major emerging market for LNG, but one which is now threatened by rising regional pipeline supplies as offshore gas fields in the East Mediterranean come on-stream.

By 2016, five Middle Eastern and North African countries — Egypt, a former LNG exporter, Israel, Jordan, Kuwait and the United Arab Emirates, itself an LNG exporter — were all importing LNG.

Egypt and Jordan have been challenging traditional buying formats since they entered the market in 2015, kicking off a trend for other emerging buyers and providing traders with new opportunities in the LNG space. Egypt has ignored the concept of single-supplier long-term contracts in favor of short-term tenders, while Jordan has been supplementing contracts of five years or less with occasional spot purchases.

On the supply side, increased competition and innovative contracting strategies will continue to put pressure on Qatar to drop its formerly rigid selling parameters, especially as the world's largest LNG producer seems determined to protect its global market share through capacity expansions.

Buy like an Egyptian

Egypt, currently the biggest LNG importer in the Middle East, is the best example of how buying patterns have changed in the region.

Cairo entered the LNG market in April 2015 to address the country's major domestic gas shortages, but it did so in an unconventional manner. Instead of signing up for traditional long-term contracts, typically ranging between 15 and 20 years, the country has relied entirely on short-term tenders to fulfill demand requirements.

The largest of these was issued in October 2016, and sought 108 cargoes for delivery over 2017 and 2018. Only half of the cargoes were awarded, mostly for delivery in 2017, and only six cargoes for delivery in 2018, demonstrating Egypt's confidence in its ability to secure

Sanctions against Qatar have limited impact on LNG industry

Political attempts by some of its neighbors to isolate Qatar may have failed to shake the country's crucial LNG exports, but they have dealt a strong hand to its legacy customers, especially Japan, as they fight for greater flexibility and a more openly traded marketplace.

On June 5, 2017, Saudi Arabia, the UAE, Egypt and Bahrain severed diplomatic ties and transport links with Qatar, citing the country's alleged links to terrorism. The most palpable impact of the sanctions was felt in the shipping segment, with Qatari LNG vessels being banned from the UAE port of Fujairah, the main bunkering port in the region. Qatar responded by setting up its own temporary bunkering facility. Initially, vessels headed to and coming from Qatar were also banned from entering Fujairah, although this restriction was subsequently relaxed.

Outside of the restrictions at Fujairah, there has been limited impact on Qatar's LNG operations. Qatari-flagged and Qatari-owned vessels have been transiting the Suez Canal unimpeded since the June 5 announcement. Furthermore, gas flow continues through the Dolphin pipeline, which delivers around 2 Bcf/day of Qatari gas to the UAE.

Qatari-sourced LNG cargoes have also continued to arrive in Egypt. However, according to some market sources, Qatar will no longer be supplying cargoes to traders for the purpose of filling short positions into Egypt, in order to mitigate potential complications.

volumes on a prompt basis amid rising domestic gas production, which is reducing the country's overall need for imported gas.

Moreover, most of Egypt's supply tenders have been awarded to traders such as Glencore, Trafigura and Vitol – companies with no LNG production capacity of their own. Because these traders need to source cargoes from the market, spot trade and cargo churn rate have increased significantly.

The flexibility that has been afforded to Egypt under its supply contracts has been robust.

The country managed to renegotiate the delivery of 12 cargoes scheduled for 2017 delivery into 2018 as gas production at the BP-operated West Nile Delta gas development increased.

The revival of Egypt's upstream highlights the advantages of avoiding long-term commitments. The country's gas production is expected to double between 2016 and 2020.

In combination with a reduced rate of demand growth, Egypt is expected to return to gas surplus and end LNG imports around 2020/2021 except for some seasonal requirements.

Nearby Jordan has taken a more conservative approach, but has also incorporated a more short-term ethos into its buying strategy.

The majority of the country's gas demand has been covered by two-year and five-year contracts with portfolio seller Shell, with the remainder secured via tenders seeking one or two cargoes, and usually awarded to traders.

Jordan's bigger tenders have also been split into small tranches, allowing multiple awardees, and opening up opportunities for smaller trading houses that would otherwise struggle to supply larger volumes.

However, in Jordan too, LNG demand is threatened, not by domestic gas production, but by regional pipeline supplies. Jordan is already in talks to import gas from Israel and may benefit from Egypt's return to gas surplus via the Arab Gas Pipeline.

Despite declining requirements from these recent market entrants, overall demand in the region will see support from the entry of Bahrain as an LNG importing nation and increasing demand from Kuwait.

Together, the two countries are expected to account for a total 10 million mt/year of demand by 2022, up from the 3.6 million imported by Kuwait in 2016.

While the buying strategy of these customers is not clear, growing international supplies and changing buying patterns are likely to give them more leverage when negotiating new term contracts, if they choose to employ term contracts at all.

“Because these traders need to source cargoes from the market, spot trade and cargo churn rate have increased significantly.” — S&P Global Platts

Locally-sourced cargoes will have a clear transport cost advantage, which would benefit Qatar. However, this may well be affected by the partial trade embargo imposed on Qatar by Saudi Arabia, Egypt, the UAE and Bahrain in June 2017. The option of inserting a third-party between buyer and seller in this scenario may give added impetus to LNG trade in the region.

Qatar: the nimble giant?

Faced with growing competition from a more diverse set of LNG suppliers, lower prices and fewer guaranteed markets, Qatar has opted to compensate by increasing its sales volumes – a clear-cut market share strategy.

In April 2017, Doha lifted its self-imposed ban on further development of the offshore North Field, the world's largest conventional non-associated gas field with recoverable reserves of around 900 Tcf (25.5 Tcm) or around 13% of global proven gas reserves.

The country plans to develop the southern section of the field over a period of five to seven years and once completed the project is expected to yield additional capacity of 4 Bcf/day, equivalent to about 20% of the field's current output.

Most of this gas is to be directed towards new LNG, with the country's export capacity rising from 77 million mt/year to 100 million mt/year.

Qatar is well positioned to make a market share play, as it has one of the lowest costs of production for its LNG globally, owing to the scale of its operations, low production costs from the giant North Field and the co-production of Natural Gas Liquids along with LNG.

However, at the same time, the decision is likely to extend the period of LNG over-supply into the 2020s, which will further boost the bargaining power of customers, put more pressure on spot prices and accelerate the transformation of the business landscape into a shorter, more flexible market, which Qatar and other legacy suppliers have long resisted.

With fewer and fewer opportunities to sell on an oil-linked long-term basis, the producer will need to choose between adjusting its business model to capture value in a changing market, or being relegated to the role of low-cost supplier to a growing community of aggregators.

Signs of change are already evident. Faced with limited growth and expiring contracts in Northeast Asia, Qatar has increased its cooperation with trading houses and portfolio aggregators to place excess volumes into short-term tenders issued by emerging, less credit-worthy customers.

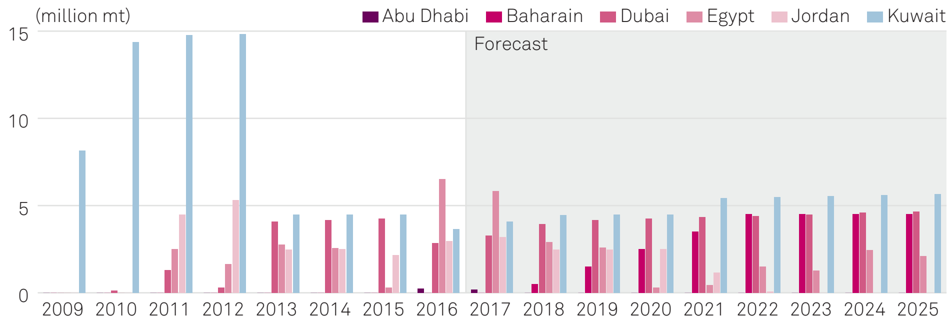
More recently, the exporter has taken a more direct approach to marketing its LNG in emerging markets across the Middle East, South Asia and Southeast Asia. In July 2017, Qatar's state LNG shipping company Nakilat signed an agreement with Norwegian shipping company Hoegh LNG to stimulate fresh demand in emerging markets for Qatar to sell its LNG via floating import terminals.

Qatar's long-term marketing strategy has also been impacted, with RasGas having renegotiated the pricing formula of its sizeable contract with Petronet in favor of the Indian buyer amid low spot prices in Asia-Pacific. The Indian government has actively encouraged its domestic importers to seek better contractual terms.

Japanese buyers will also be encouraged by a recent ruling from the Japan Fair Trade Commission that destination clauses may be anticompetitive, a development which could have lasting implications on the wider market.

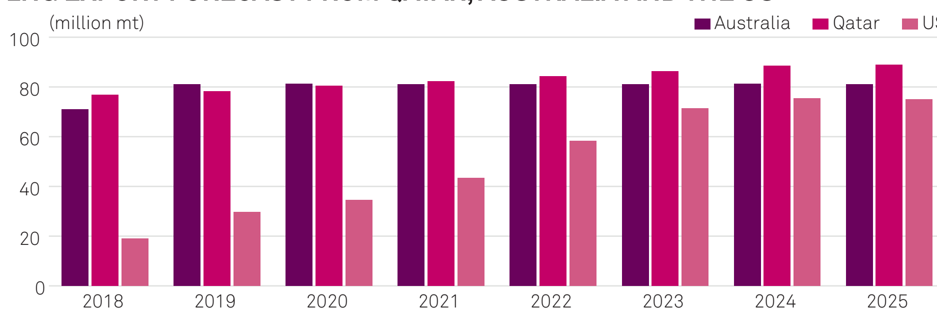
The pressure is only likely to increase as Qatar's biggest customers appear determined to push for improved terms ahead of the expiry of sizeable, oil-indexed, long-term contracts with restrictive destinations clauses.

MIDDLE EAST LNG IMPORTS



Source: S&P Global Platts Analytics

LNG EXPORT FORECAST FROM QATAR, AUSTRALIA AND THE US*



*Forecast made prior to Qatar's LNG capacity expansion plan announcement in July 2017
Source: S&P Global Platts Analytics

> *"Qatar's potential loss of 33% of its long-term customer base starting in 2022 is central to spot market development. Not all of this volume will be re-signed, which will significantly increase liquidity in the spot market in the decade to come."* — *PIRA Energy, a division of S&P Global Platts*

Africa

FLNG: a pathway to Africa's LNG renaissance

Floating LNG (FLNG) is opening up new offshore gas basins for LNG development in Africa, producers are striking off-take agreements with portfolio players and traders, and sizeable long-term contracts are due to expire from 2020. This, the ownership structure of Africa's new LNG production, and the willingness of International Oil Companies (IOCs) to deploy new technologies, will drive the commoditization of LNG and help cement its growing role as a global energy commodity.

Ross McCracken
Managing Editor, Energy Economist
S&P Global Platts

Africa has been at the heart of LNG trade since its inception. The first LNG supply agreement was signed between Algeria and the UK as far back as 1962. Libya soon joined the industry and, by the early 1980s, Algeria was the world's largest LNG producer. By 2017, Africa had six countries with liquefaction capacity – Algeria, Libya and Egypt in North Africa; Nigeria, Equatorial Guinea and Angola in Sub-Saharan Africa.

However, LNG volumes have been falling. In 2016, Africa exported 33.46 million mt, 12.7% of the global market, but down from 38.48 million mt in 2012. The fall reflected a multiplicity of problems: conflict in Libya; a dearth of gas in Egypt; technical problems in Angola; and persistent social unrest in the Niger Delta, the source of Nigerian LNG plants' feedstock.

The tide now appears to be turning. Africa is forecast to see volumes rise above 50 million mt/year by 2021, reflecting both the recovery of legacy producers and the emergence of new African LNG. It is the particular nature of the new capacity coming on-stream that will drive the commoditization of LNG.

FLNG – a new technological driver

Uniquely, FLNG vessels will provide the first liquefaction plants in both Mozambique and Cameroon, while the technology is also expected to lead an expansion of LNG capacity in Equatorial Guinea.

Italy's Eni and its partners took a Financial Investment Decision (FID) on the 3.4 million mt/year Coral FLNG project offshore Mozambique in June 2017. It will be the first FLNG project to have as much as 60% of its cost funded on a project finance basis, backed by 15 international banks and guaranteed by five export credit agencies. Eni has signed an agreement with BP for the sale of all the LNG produced at Coral South for more than 20 years.

Equatorial Guinea's Ministry of Mines and Hydrocarbons (MMH), Ophir Energy and La Compania Nacional De Petroleos De Guinea Ecuatorial in August 2017 nominated trading house Gunvor as its preferred LNG off-taker for the 2.2 million mt/year Fortuna FLNG project. The deal takes the project an important step forward towards FID. Gunvor is committed

"The new West and East African trading hubs, starting small with FLNG, could expand hugely from 2025 with larger-scale onshore developments, providing a rich new dimension to global LNG trade."

— S&P Global Platts

to take the full contract capacity, which will be purchased on a Brent-linked, FOB basis for a 10-year term.

BP and Kosmos' Tortue FLNG project offshore Mauritania and Senegal is progressing on the back of positive drilling results. KBR was awarded in August 2017 pre-FEED and project support services contracts for development of the 15 Tcf Tortue/ Ahmeyim field. A string of large offshore gas discoveries in the region are sufficient to underpin multiple LNG projects and deliver BP's stated ambition of developing a new West African LNG hub.

However, Africa's first FLNG deployment is likely to be in Cameroon. The 2.4 million mt/year Hilli Episeyo has been contracted by France's Perenco Cameroon SA and Cameroon's Societe Nationale Des Hydrocarbures for LNG production on the offshore Kribi fields. The vessel is expected to leave Singapore in October 2017.

The project has some unique elements. It is the first conversion of a ship to an FLNG vessel and was undertaken by Golar on a speculative basis. Ship conversions potentially offer a cheaper and quicker route to FLNG deployment than newbuilds. LNG from the project will be sold to Russia's Gazprom.

Two-speed development

There are also major onshore projects planned in Sub-Saharan Africa, but they are progressing more slowly than FLNG.

Mozambique LNG signed a sales and purchase agreement in September to supply Thailand's national oil and gas company, PTT, with 2.6 million mt/ year of LNG. Project operator Anadarko has also secured agreements with Maputo allowing it to design, build and operate the marine facilities for its 12 million mt/year LNG project. However, Anadarko and its partners need to secure further off-take agreements before progressing to FID.

Tanzania also has substantial proved gas reserves ear-marked for LNG development. However, the government is proving less hospitable than in Mozambique. Tanzania's gas ambitions received a blow in early July when the government decided to force all existing upstream investors to renegotiate the terms of their contracts and concessions. The Natural Wealth and Resources and the Natural Wealth and Resources Contracts bills affect all parts of the oil, gas and mining sectors.

Portfolio players

FLNG, in contrast, is racing ahead as these projects' smaller scale means securing off-take agreements is easier – often requiring a single buyer. Of particular note is the sale of FLNG-produced LNG to portfolio players and traders rather than end-users: Coral to BP; Fortuna to Gunvor; and Kribi to Gazprom.

Moreover, operating companies are keen to get early experience of a new technology that offers not only the ability to exploit large, formerly-stranded offshore gas assets, but to do so in a way that reduces the risk of civil instability that can affect onshore developments.

There is even the prospect of emerging intra-African trade. Ghana is expected to become Sub-Saharan Africa's first LNG importer. The FSRU Hoegh Giant is slated to start a 20-year contract with Quantum Power from mid-2018. This reflects in part the unreliability of gas supplies via the West African Gas Pipeline, which originates in Nigeria's Niger Delta region, again a reminder of the enhanced security offered by offshore production in the Sub-Saharan African context.

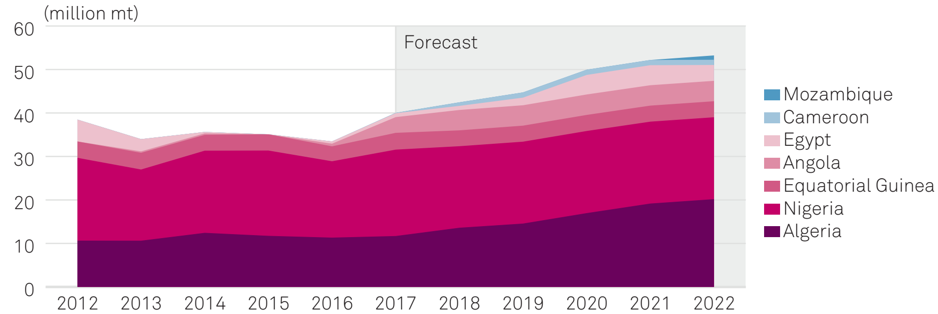
Contract expiries

FLNG developers' willingness to sell to trading houses and portfolio players is reflected elsewhere in Africa. Angola LNG, having overcome its technical difficulties, signed an agreement with France's EDF Trading in March 2016. This was followed in September 2017 by separate deals with traders Vitol, Glencore and Germany's RWE Supply and Trading.

Angola LNG may prove a model for contract renewal as long-term contracts move towards expiry for Africa's legacy LNG producers. Contracted volumes from Nigeria's LNG plants fall sharply in coming years from 20.75 million mt in 2017 to 9.61 million mt in 2026. This frees up significant volumes to be re-contracted on new terms, sold to new buyers or traded spot.

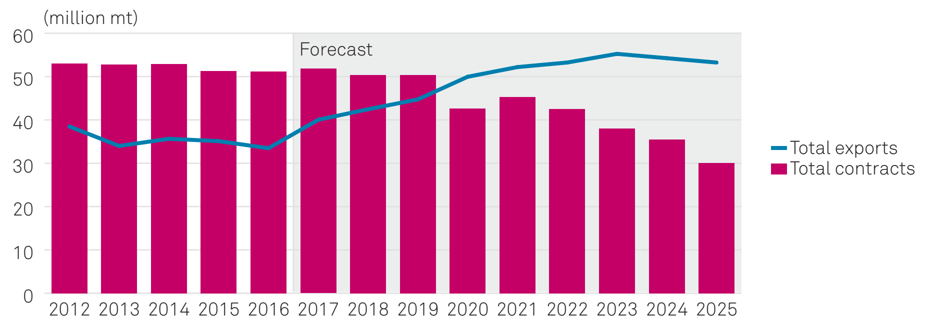
There is already a clear shift in balance between Nigerian contracts signed for delivery into a specific national market and those with portfolio players. The proportion currently in percentage terms is 63% to specific end-use markets versus 37% to portfolio players. Based on existing contracts, this, by 2025, is reversed to a 36% to 64% ratio. Contracts direct with end-user markets may be renewed, but currently portfolio players appear more willing to contract forward.

LNG EXPORTS BY COUNTRY



Source: S&P Global Platts Analytics

AFRICA'S CONTRACTED VOLUME VERSUS TOTAL SUPPLY



Source: S&P Global Platts Analytics

Equity structure

The upstream involvement of IOCs in Nigeria's LNG projects lends itself to contractual arrangements with portfolio players and trading houses, as oppose to Africa's other main producer, Algeria, where sales and production are controlled by state company Sonatrach. Notably all of Sonatrach's current contracted volumes are with specific end-use markets, all of which are in Europe, including Turkey.

However, Algeria, too, will see contracts expire, with contracted volumes falling from 15.36 million mt in 2017 to just 5.63 million mt in 2020 and 2.67 million mt in 2024. Sonatrach, which has already said it will consider shorter-term contracts, needs to secure both its pipeline and LNG supplies to its principal markets. However, it faces increasing competition in the Atlantic basin not just from the US and Qatar, but also the traders to which the new West African producers are contracted.

The new FLNG projects mean that the West and East African LNG hubs are emerging on a model similar to Nigeria, but with fewer onshore risks. Joint-ventures of IOCs develop the upstream project, carrying minority shares held by less-technically able National Hydrocarbons Companies. The new West and East African trading hubs, starting small with FLNG, could expand hugely from 2025 with larger-scale onshore developments, providing a rich new dimension to global LNG trade.

Europe

Through the European looking glass

The price of gas at European hubs continues to drive LNG price formation globally, but competition is increasing between the National Balancing Point and the Title Transfer Facility hubs to be at the center of LNG pricing dynamics. Meanwhile, Europe's LNG import infrastructure remains severely underused, bringing its traditional role as market of last resort into sharp focus.

Desmond Wong
Managing Editor,
European and Atlantic Basin LNG
S&P Global Platts

With no liquid onshore gas markets in the Asia Pacific region, the well-developed onshore gas hubs in Europe are expected to continue growing in importance as a global pricing floor and destination of last resort in an oversupplied LNG market.

European hubs have often laid the foundation above which other prices form, with market participants often citing shifts in European pricing as reasons to move bids or offers into Asia Pacific and elsewhere.

The depth of the European gas market also allows it to absorb a loose cargo with little difficulty, particularly given the underutilized import infrastructure available throughout the continent.

Given the challenges faced by numerous gas trading hub initiatives in Asia, this trend is set to continue, with European markets and their gas hub prices expected to remain integral to the formation of a more liquid, flexible and transparent global LNG market.

The depth of European LNG demand

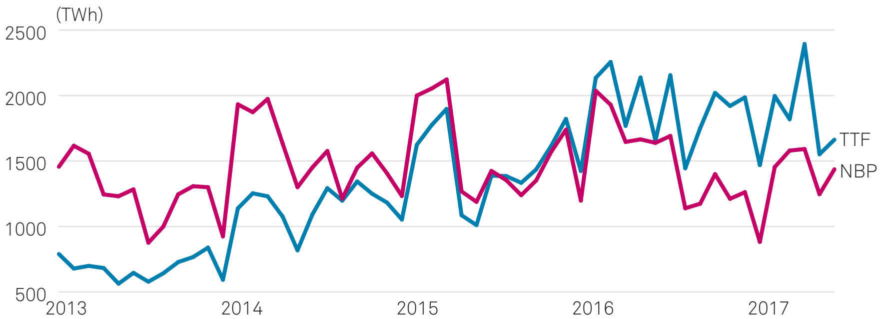
Europe is often portrayed as an LNG destination of last resort, but it is important to note that European buyers are unlikely to go out of their way to purchase spot volumes. LNG infrastructure in Europe remains largely underutilized, with terminals across Western Europe, including Spain, seeing an average of less than one third utilization over the past few years.

However, this is the result of ample pipeline gas supply from Russia and Norway in the north, as well as domestic European production – albeit falling – from the North Sea and the Netherlands.

At the same time, a growing renewables sector throughout Europe has provided stiff competition for gas in power generation in key markets like Germany and Spain, the latter of which also benefits from pipeline connections with Algeria.

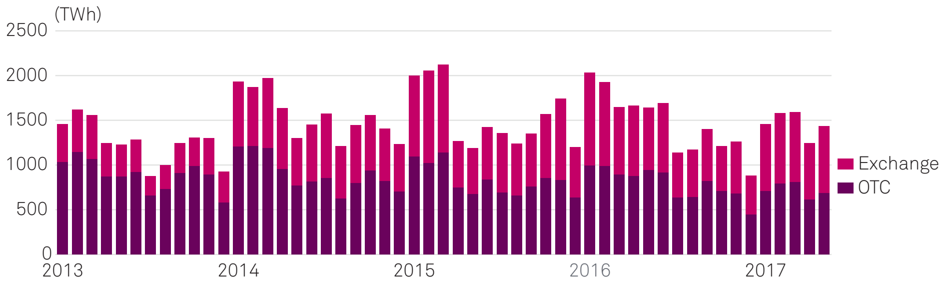
Moreover, more pipeline gas is on the way via the Trans-Anatolian Pipeline (TANAP) across Turkey and the Trans-Adriatic pipeline to Italy.

TRADED VOLUME NBP VERSUS TTF



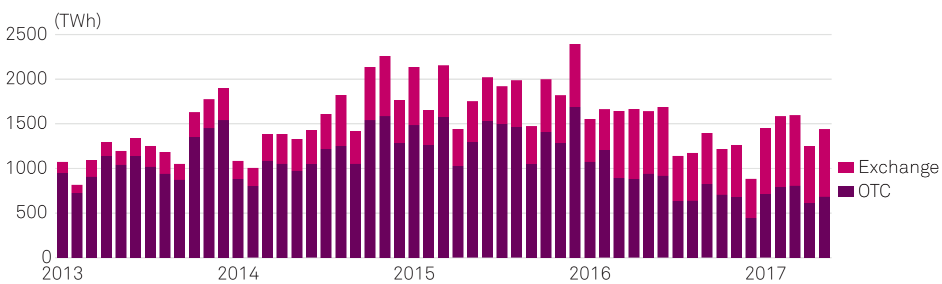
Source: S&P Global Platts

NBP TRADED VOLUME - OTC VERSUS EXCHANGE



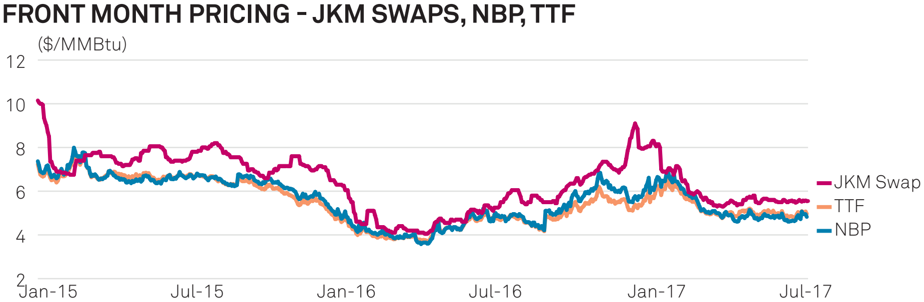
Source: S&P Global Platts

TTF TRADED VOLUME - OTC VERSUS EXCHANGE



Source: S&P Global Platts

FRONT MONTH PRICING - JKM SWAPS, NBP, TTF



Source: S&P Global Platts

Russia's Gazprom also continues its moves to reshape its delivery infrastructure through its pursuit of an expanded northern corridor with the proposed Nord Stream 2 pipeline and, in the south, with the Turk Stream pipeline project across the Black Sea to Turkey, which will compete with TANAP.

As a result, while Europe is the destination of last resort for LNG, LNG is also the fuel of last resort on the continent, raising questions about the real depth of European LNG demand.

However, there is an upside for LNG in this scenario – the underutilized capacity is attractive to the LNG spot market because it allows the global LNG industry to access something that the Asia-Pacific markets do not currently provide: a transparent and liquid forward curve of prices for gas that can be used as a baseline position against other spot LNG destinations.

The price is right: but which is the right price?

The UK's NBP has been a key reference point for LNG pricing in the Atlantic for a long time, and for good reason.

But liquidity trends suggest market participants should start paying greater attention to the Dutch TTF hub as the main Northwest European pricing point.

While NBP is often still referenced when it comes to spot LNG trade or the purchase of cargo tranches, TTF has also begun to see its fair share of reference, most publicly in the contracts agreed between US LNG supplier Cheniere Energy and France's EDF for cargoes into the new Dunkirk LNG facility in northern France.

In terms of liquidity, NBP has historically been the more liquid gas hub, hitting a peak of 2,122 TWh traded in March 2015. However, since then, TTF trading has surged in volume, passing the NBP's peak to hit 2,394 TWh in March 2017.

At the same time, NBP has seen a slowdown in trade, averaging 1,473 TWh over 2016, compared with 1,550 TWh in 2014 and 1,543 TWh in 2015. This suggests that while NBP liquidity remains largely stable, it is the TTF that is attracting the additional growth in Northwest Europe.

S&P Global Platts has already seen TTF taking a greater role in wider Atlantic Basin LNG pricing, with tender prices in the region for deliveries into the Mediterranean and the Americas being quoted in reference to the Dutch hub rather than NBP.

NBP resilience?

Nonetheless, a closer look at where liquidity comes from sheds some light on why NBP has remained a reference point for many within the LNG market.

Almost half of NBP trade is conducted through exchanges — almost all on the Intercontinental Exchange (ICE) — a factor that increases transparency and accessibility to new market entrants, especially those that are not incumbents in European markets.

PUT OPTIONS INTO CONTINENTAL NORTHWEST EUROPE

Export/p lant/ Organization	Buyer	Delivery terms	Exporter country	Import point	Start	End	Volume (Bcm/year)
RasGas 2 Train 3	EDF Trading	DES	Qatar	Zeebrugge	Jan-07	Dec-27	4.7
Angola LNG	EDF Trading	DES	Angola	Portfolio (assumed Dunkirk or Zeebrugge)	2016	2018	Unknown
Qatargas 4 Train 7	E.ON	FOB	Qatar	Gate	Jan-14	Dec-18	2.1
Qatargas 3	RWE Supply & Trading	DES	Qatar	Portfolio (assumed Gate)	Jul-16	Dec-23	1.5
RasGas	EDF Trading	Unknown	Qatar	Dunkirk	Jan-17	Unknown	2.8
Cheniere	EDF Trading	DES	US	Dunkirk	Jan-18	Dec-18	2.6
Cheniere	EDF Trading	DES	Portfolio	Dunkirk (assumed)	Jan-17	Dec-18	2.4
Cheniere	Engie	DES	US	Montoir	Jan-18	Dec-22	1.2

Source: S&P Global Platts Analytics

> *"Europe's underutilized capacity allows the global LNG industry to access something that the Asia-Pacific markets do not currently provide: a transparent and liquid forward curve of prices for gas that can be used as a baseline position against other spot LNG destinations."* — *S&P Global Platts*

By contrast, most TTF trade is conducted on an over-the-counter (OTC) basis.

TTF trading that does take place on exchanges is conducted across two locations – Pegas (the European Energy Exchange platform for gas) and ICE – and while the proportion of exchange traded activity for NBP has remained stable, there is clear growth in the same segment for TTF.

Over 2014, the exchange-traded TTF activity comprised only about 13.7% of total transactions, with OTC making up the rest. However, by 2016, TTF exchange-traded activity had risen to 27%, and, for 2017 up until the end of May, that proportion hit 30%.

Trading gas in Europe on the TTF hub also eliminates the foreign exchange risk associated with NBP. All major gas hubs are traded in Euros per megawatt hour (Eur/Mwh), while only the NBP and Zeebrugge hubs are denominated in pence per therm (p/th).

As a result, it appears likely that the TTF will continue to be the most liquid gas hub in Europe, and that it will see further exchange-led growth as well, assisting the entry of new market participants.

While there is no denying the size and relevance of NBP, the TTF looks likely to emerge as a key reference price for both European gas and LNG markets more broadly.

> *"Europe's liquid and transparent gas hubs provide not only a reference point for the prompt spot LNG market, but also support for the only like-for-like LNG hedge, namely the JKM Swap."* — S&P Global Platts

Financial architecture

The deals signed with Cheniere and European utilities for deliveries of US LNG are significant, but also a continuation of Europe's long-standing role as destination of last resort as a result of put-option arrangements.

While the specifics vary, these essentially provide a seller with the option to deliver into a destination, without the commitment of regular volumes arriving.

This gives cargoes a "safe harbor" of sorts, giving volumes a discernible price and home destination of last resort when a cargo needs placing.

In short, put options offer the flexibility to deliver into a market, providing a price that can be hedged. As a result, while cargoes may not necessarily arrive on European shores, the flexibility to place cargoes if needed has a value all on its own, which the market has recognized.

Europe's liquid and transparent gas hubs provide not only a reference point for the prompt spot LNG market, but support for the only like-for-like LNG hedge, namely the JKM Swap. While hedging through a related product like European gas, crude oil or coal can be imprecise, the growth of the JKM derivatives has provided a direct analogue to the physical LNG market.

Physical LNG has yet to develop a robust forward curve, but the transparency of the NBP and TTF hubs have allowed paper traders to take positions further out on the JKM derivatives, knowing that the European price has formed the floor of the market.

NBP or TTF price movements have become a leading indicator of value for parties participating in the paper market, and this correlation has grown closer as liquidity on the JKM derivatives market has grown.

The European gas hubs have also allowed physical LNG traders to manage their positions further down the curve with the like-for-like hedge of JKM derivatives, which reference the NBP or TTF curve for pricing.

This has rapidly driven the growth of JKM derivatives to see almost 43 cargoes worth of volume being cleared on ICE over 2016. By end-June 2017, the JKM derivatives market had already exceeded 2016's volume.

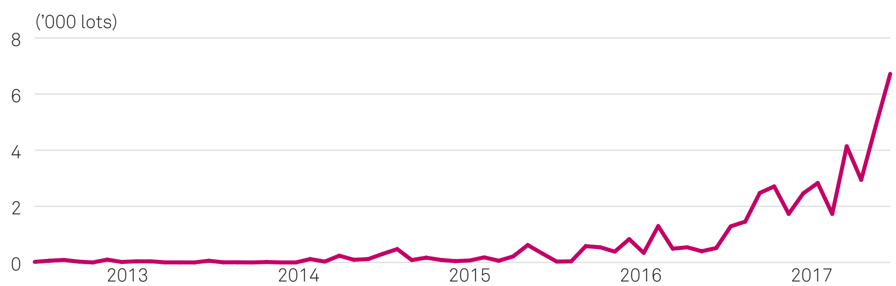
Moreover, in the same way that the forward European gas markets have supported the growth of the JKM derivatives curve, so should growth in JKM derivatives support the development of physical spot LNG.

A longer and more liquid like-for-like hedge in the JKM paper markets will encourage spot trade as market participants feel more comfortable with taking physical positions further out that are not just hedged against an associated commodity but LNG itself.

As confidence grows in the physical market, both transparency and liquidity are likely to increase, driven by support from the JKM derivatives.

Participation in benchmark physical pricing, such as JKM, should also increase as market participants seek to participate in the price formation of both the paper and the physical sides of the spot LNG market.

JKM SWAPS CLEARED THROUGH AN EXCHANGE



Source: S&P Global Platts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United States

A revolution in the making

The startup in February 2016 of LNG exports from the US Gulf Coast has already begun transforming global markets, with a new approach to contracting, pricing and marketing, building on a wave of liberalization in international LNG trade.

J Robinson
Senior Writer
S&P Global Platts

As excess LNG supply continues to weigh on the global market through the early 2020s, that length itself is likely to drive adoption of the US export model. With contract terms that offer destination flexibility and a diversity of pricing and hedging options, Gulf Coast exporters are likely to be among the most competitive globally.

Both new and seasoned LNG buyers alike are now armed to with the bargaining power to dictate the terms of trade. For these buyers, especially those faced with growing downstream deregulation and competition, destination flexibility is paramount, as it allows them to resell, divert or swap an unneeded cargo with minimal transaction costs.

And in a market where contracts are still largely dominated by oil indexation, the diversity of pricing options offered by US exporters — some still in development — offer an attractive means of reducing risk exposure through portfolio diversification.

Destination flexibility

The single, most defining characteristic of US LNG contracts is destination flexibility. Traditionally, global exporters have fiercely defended their export markets by enforcing contract terms that require cargo deliveries to specified regasification ports.

US project developers including Cheniere Energy, Dominion Cove Point, Cameron LNG and Freeport LNG have all discarded these traditional restrictions.

Since the startup of exports from Cheniere's Sabine Pass, numerous cargoes have been diverted mid-journey from their original destinations, as key attributes such as price, size and quality determine where a cargo is delivered.

This is already resulting in greater market flexibility and interconnectivity, increased cost optimization, and the progressive erosion of global LNG price segmentation and the so-called "Asian premium."

Price linkage diversity

With Cheniere pioneering the start-up of US LNG exports, many industry observers and analysts have come to consider the "115% Henry Hub plus liquefaction" pricing formula as the US standard for FOB Gulf Coast exports.

That, however, is just one of the LNG pricing models offered by US LNG developers.

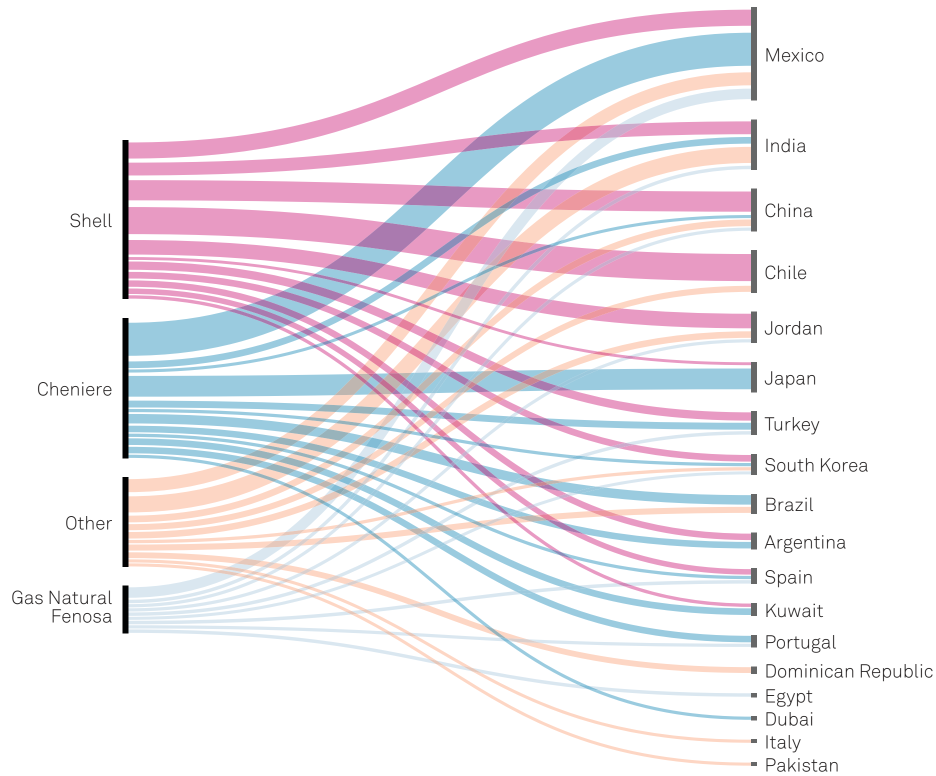
Under the Cheniere price model, off-takers commit to sunk-cost liquefaction fees ranging from $2.25-$3.50/MMBtu that must be paid regardless of whether the service is used.

The cost of feedstock gas and its transport to the terminal is covered by the "115%-Henry Hub" component. If an off-taker decides not to use the pre-paid liquefaction service, this latter charge can be temporarily or indefinitely suspended.

Elsewhere, the liquefaction-tolling model used by Dominion's Cove Point, Cameron LNG and Freeport LNG offers buyers additional portfolio diversity with a slightly different take on pricing.

Under this contract structure, buyers also commit to a sunk-cost liquefaction fee, but they have the option to source their own gas and hedge price risk further upstream.

SABINE PASS EXPORTS BY CHARTERER TO DESTINATION COUNTRY



Source: S&P Global Platts Analytics

The rise of alternative benchmarks in the US market, most notably Dominion South Point — which rivals Henry Hub in terms of liquidity — offers tolling-model buyers the opportunity to link export costs to markets that more closely reflect producer prices in Appalachia, a region where dry gas production is expected to grow at the fastest pace of any US region.

Yet another pricing model has been proposed by Tellurian Investments for its proposed Driftwood LNG project.

The company is proposing smaller contracts, totaling about 7 million mt/year, under five-year agreements at a fixed delivered ex-ship price of $8/MMBtu, starting from 2023.

Tellurian Chairman Charif Souki said this proposed model would "take the volatility out of the market."

However, it remains unclear how much destination flexibility these contracts would offer, or whether buyers would be inclined to lock themselves into a price that seems high in the current market.

LNG priced against Henry Hub was seen as attractive by many Asian buyers looking to reduce costs in the face of high oil prices. But following a steep decline in the price of spot LNG, Henry Hub has lost much of that appeal. Platts Analytics' Bentek Energy forecasts Henry Hub prices will rise above $3.50/MMBtu by 2021, which could present challenges for those trying to sell US LNG into Asia, if current depressed spot LNG prices persist.

Reported attempts by India's GAIL to renegotiate its 3.5 million mt/year contract with Cheniere in 2017 reflect the risks associated with this system.

The contract was signed on a FOB basis in 2011, with a pricing formula at 115% of Henry Hub plus a fixed $3/MMBtu terminal fee, in a move by GAIL to break away from the oil price-linkage.

However, given the surplus LNG availability in the Asia Pacific region, Henry Hub-linked prices are likely to remain uncompetitive in India by the time the contract kicks off in late 2017.

The US-Asia LNG arbitrage

Back in November 2013, when the US started out on its large-scale construction of LNG liquefaction capacity, the difference between Henry Hub prices in the US, at around $3.80/MMBtu, and spot LNG sales in Asia Pacific, at $17/MMBtu, was huge. Taking into account liquefaction/tolling costs and freight, US LNG could be landed in Japan at about $7.00/MMBtu, providing a whopping $10/MMBtu margin. Potential exports from the US west coast looked even better, owing to lower freight costs.

However, both the low price of US gas and the relatively high price of gas in Asia, whether spot or oil indexed, were relatively new phenomena, the latter in large part a reflection of the post-Fukushima rise in LNG demand from Japan, which was accompanied by an increase in imports to South Korea, which was suffering its own problems with its nuclear fleet.

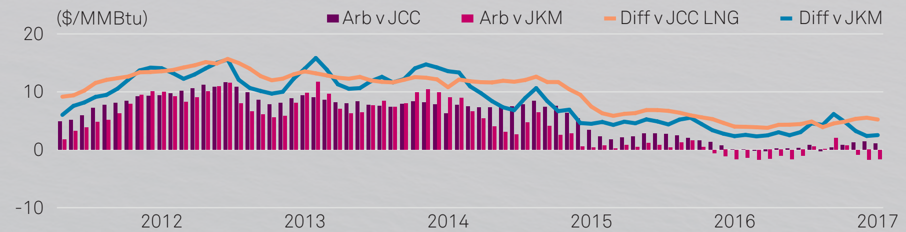
Today, US gas remains relatively cheap, with Henry Hub around $3/MMBtu. However, the arbitrage for US LNG into Asia-Pacific is now thin when set against oil-indexed LNG, and was negative from March to August 2017, in comparison with spot sales of LNG in the Asia Pacific market represented by the Japan-Korea Marker price, which was about $6/MMBtu as of August 31, 2017.

The general rule of thumb — based on contracts struck by Cheniere's Sabine Pass LNG plant — is 115% of Henry Hub plus about $2.65/MMBtu liquefaction and $1/MMBtu shipping, putting the breakeven point for US LNG sales into Asia-Pacific at around $7/MMBtu.

Tying an LNG contract to Henry Hub thus provides an alternative to oil-indexation, but brings with it a new set of risks centered around the US gas market, which in turn determines only one half of the US-Asia LNG arbitrage. Moreover, US gas prices are not wholly disconnected from oil, as higher oil prices tend to drive US gas production as a result of the growing predominance of shale wells, which produce both oil and gas.

How the US-Asia LNG arbitrage evolves will have a major bearing on the supply of US LNG. According to S&P Global Eclipse Energy data, US LNG exports will rise from an annualized rate of 12 million tons a year, based on August 2017 production volumes, to 57.6 million tons a year in September 2019. Much of this is 'must-run' LNG, as opposed to price-sensitive production. Eclipse estimates must-run US LNG volumes will peak in May 2019 at 247 million cu m/d, but decline thereafter as the balance starts to shift towards greater price sensitivity.

ARBITRAGE HENRY HUB VERSUS JCC, JKM



Source: S&P Global Platts

Innovative marketing

A variety of options for procuring US LNG or investing in the LNG industry itself is also helping eliminate risk for emerging and traditional buyers.

By adding liquidity to the spot market and offering buyers unconventional opportunities for hedging risk, US LNG developers and the upstream gas industry are facilitating market entry for nascent buyers and allowing traditional ones to assume larger offtake positions.

At Cheniere, the creation of a marketing arm dedicated to spot, tender and short-term sales has added additional liquidity to the global LNG market by deconcentrating sales.

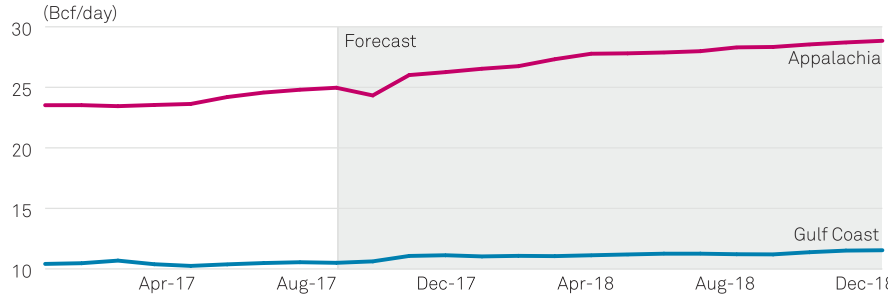
Contracted Sabine Pass off-takers Shell and Gas Natural Fenosa have already begun taking the equivalent of 3.5 million mt/year, while the remaining volumes from Trains 1-2, and more recent commissioning volumes from Train 3, have been sold by Cheniere Marketing.

With each liquefaction train capable of liquefying up to 4.5 million mt/year, this has left a significant volume available for export by Cheniere.

From January through May 2017, a total of 25 cargoes or nearly 32% of the total lifted from Sabine Pass, were exported on a spot basis, according to data from the US Energy Information Administration.

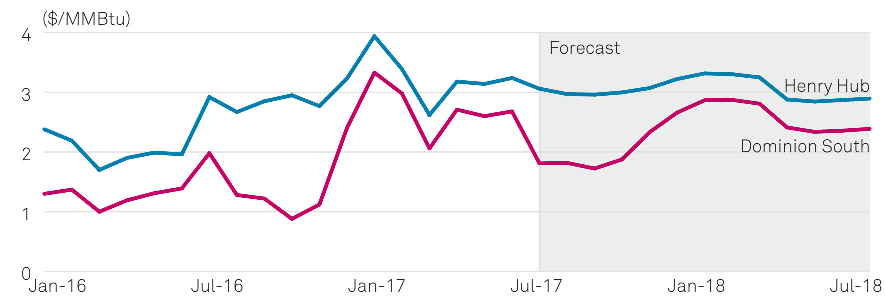
In addition to building market liquidity, US LNG developers have also allowed off-takers to take equity stakes in the industry itself, with upstream investments offering an unconventional means of hedging price risk.

US NATURAL GAS PRODUCTION BY REGION: APPALACHIA VERSUS GULF COAST



Gulf Coast data excludes production from East Texas
Source: S&P Global Platts Analytics

HENRY HUB VERSUS DOMINION SOUTH MONTHLY AVERAGE AND FORWARD CURVE



Source: S&P Global Platts

South Korea's Kogas, the world's second largest LNG importer, has signed a memorandum of understanding with Shell and Dallas-based Energy Transfer to study the feasibility of an investment in their Lake Charles LNG project in Louisiana. That MOU was just one of several signed by Kogas, which has also expressed investment interest in the Port Arthur LNG and Alaska LNG projects.

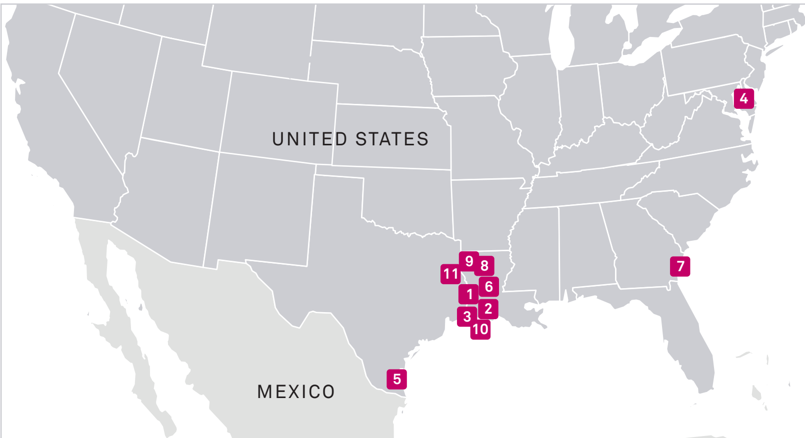
Fellow South Korean importer SK Group also signed an MOU seeking to expand its interest in a joint venture with Continental Resources that would bring additional investment to the companies' upstream assets in the Woodford Shale play of Oklahoma — part of a deal originally signed in 2014.

Japan's Tokyo Gas, which has similar investments in US upstream and midstream assets in the East Texas/Louisiana region, is also betting on the US upstream.

By giving gas buyers a stake in E&P assets, the US industry allows large stakeholders to "ride the wave" of higher gas prices. While conventional price hedges offer some protection from price volatility, these upstream investments give buyers a meaningful stake in the potential benefits of higher prices.

All in all, the pace of activity in the US LNG sector – accompanied by continued spending in the US upstream – shows no sign of slowing.

US LNG EXPORT PLANTS APPROVED



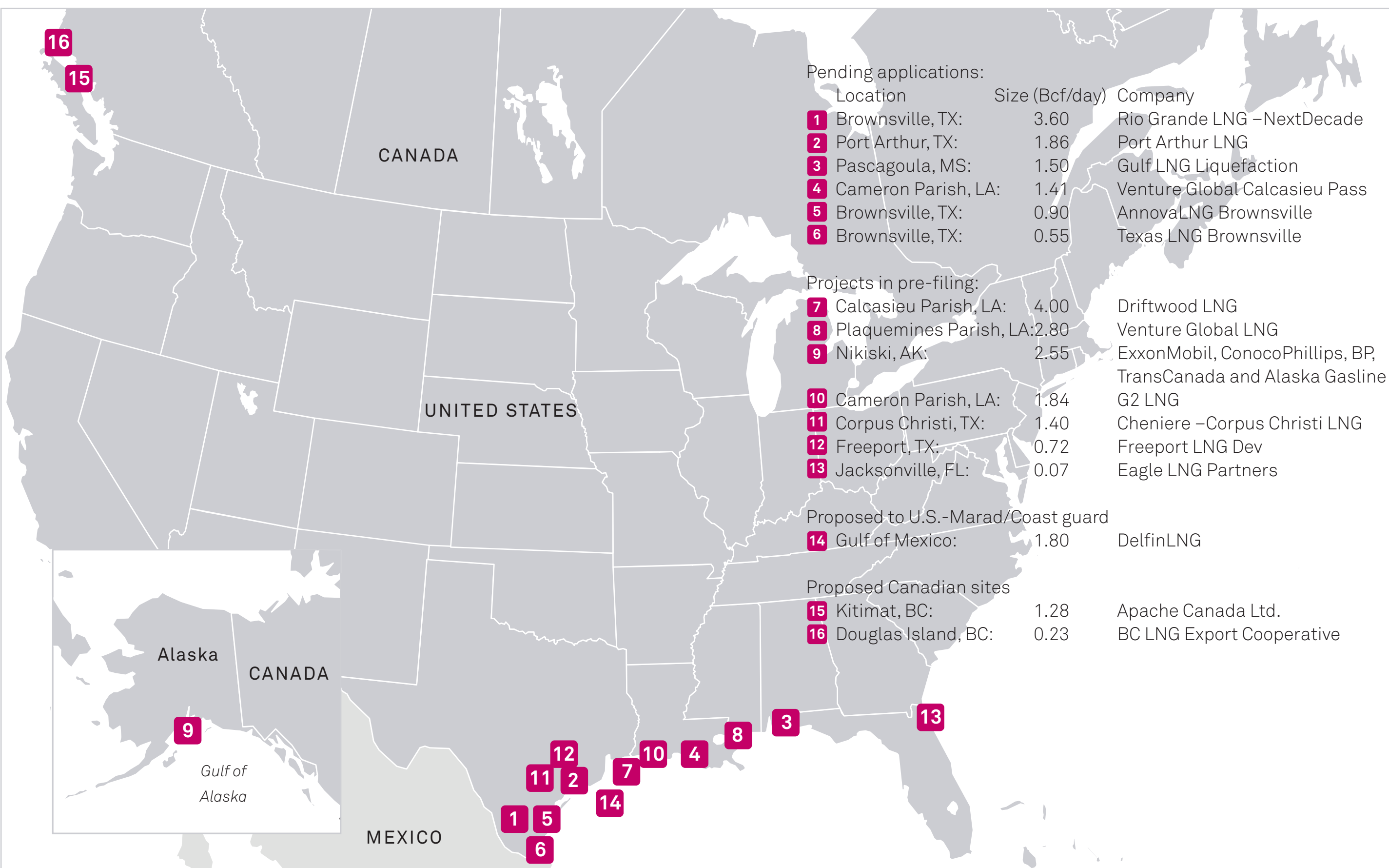
Approved - under construction:

	Location	Size (Bcf/day)	Company
1	Sabine, LA:	0.70	Cheniere/Sabine Pass LNG
2	Hackberry, LA:	2.10	Sempra-Cameron LNG
3	Freeport, TX:	2.14	Freeport LNG Dev/Freeport LNG Expansion/FLNG Liquefaction
4	Cove Point, MD:	0.82	Dominion Cove Point LNG
5	Corpus Christi, TX:	2.14	Cheniere-Corpus Christi LNG
6	Sabine Pass, LA:	1.40	Sabine Pass Liquefaction
7	Elba Island, GA	0.35	Southern LNG Company

Approved - not under contruction:

	Location	Size (Bcf/day)	Company
8	Lake Charles, LA:	2.20	Southern Union-Lake Charles LNG
9	Lake Charles, LA:	1.08	Magnolia LNG
10	Hackberry, LA:	1.41	Sempra-Cameron LNG
11	Sabine Pass, LA:	2.10	ExxonMobil-Golden Pass

NORTH AMERICAN PROPOSED LNG EXPORT PLANTS



Pending applications:

	Location	Size (Bcf/day)	Company
1	Brownsville, TX:	3.60	Rio Grande LNG –NextDecade
2	Port Arthur, TX:	1.86	Port Arthur LNG
3	Pascagoula, MS:	1.50	Gulf LNG Liquefaction
4	Cameron Parish, LA:	1.41	Venture Global Calcasieu Pass
5	Brownsville, TX:	0.90	AnnovaLNG Brownsville
6	Brownsville, TX:	0.55	Texas LNG Brownsville

Projects in pre-filing:

	Location	Size (Bcf/day)	Company
7	Calcasieu Parish, LA:	4.00	Driftwood LNG
8	Plaquemines Parish, LA:	2.80	Venture Global LNG
9	Nikiski, AK:	2.55	ExxonMobil, ConocoPhillips, BP, TransCanada and Alaska Gasline
10	Cameron Parish, LA:	1.84	G2 LNG
11	Corpus Christi, TX:	1.40	Cheniere –Corpus Christi LNG
12	Freeport, TX:	0.72	Freeport LNG Dev
13	Jacksonville, FL:	0.07	Eagle LNG Partners

Proposed to U.S.-Marad/Coast guard

	Location	Size (Bcf/day)	Company
14	Gulf of Mexico:	1.80	DelfinLNG

Proposed Canadian sites

	Location	Size (Bcf/day)	Company
15	Kitimat, BC:	1.28	Apache Canada Ltd.
16	Douglas Island, BC:	0.23	BC LNG Export Cooperative

Source: Federal Energy Regulatory Commission

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Latin America

Small-scale efforts driving commoditization

LNG in Latin America faces increasing competition from renewables, from US pipeline imports to Mexico, and from the revival of domestic gas production in Brazil and Argentina. However, its role in LNG trade will remain significant, owing to the expansion of the Panama Canal, its variable, spot-traded demand and the adoption of new technologies that promise to extend LNG's reach into smaller markets.

J Robinson
Senior Writer
S&P Global Platts

Ingrid Furtado
Pricing and Assessment Analyst - LNG
S&P Global Platts

Latin American countries received just over 5% of global LNG export volumes in 2016. Yet despite the relatively small size of individual markets, importers across Latin America are helping to build price transparency and market liquidity in significant ways.

Tenders and spot market purchases from two of the region's largest flexible importers, Mexico and Argentina, often provide valuable price signals to both buyers and sellers in the Atlantic Basin and beyond.

These pricing cues have been particularly meaningful during the northern hemisphere's summer months when demand from traditional buyers in East Asia often wanes.

Even much smaller Latin American countries in the Caribbean and Central America are contributing to global market growth by embracing new technologies that are helping LNG to trade with greater liquidity.

Innovative infrastructure solutions, including floating import terminals and ISO containers, have allowed LNG to reach latent demand in markets that until recently remained largely inaccessible.

The recent expansion of the Panama Canal has also helped strengthen the global and interconnected nature of LNG.

Although linked to broader growth in the global trade of manufactured goods and commodities, the expansion has slashed voyage distances for LNG vessels allowing inter-basin supply and demand to balance more quickly.

Even recent efforts by the Canal Authority itself to lower emissions along the waterway could have far-reaching implications for the market growth of LNG as a bunkering fuel.

Signaling prices in the northern summer

By avoiding long-term contract commitments, Argentina, Mexico and Brazil have all benefited in recent years not only from greater flexibility on import volumes, but also from lower spot prices when compared with oil-linked contracts.

During the southern hemisphere's winter from June to August, Argentina routinely issues multi-cargo purchase tenders for LNG delivered ex-ship to the country's Escobar and Bahia Blanca import terminals.

Typically, in periods of illiquidity in the Atlantic Basin, buyers and sellers from Europe, the US and beyond often await the results of these tenders before agreeing separate — but concurrent — spot market purchases or sales.

In Mexico, the seasonal ramp in gas demand to service cooling load from July to August has often provided similar price signals in the Atlantic Basin.

And prior to Brazil's recent economic slowdown, which has seen domestic gas demand fizzle, the onset of the dry season and low hydropower had typically boosted LNG demand from June to October.

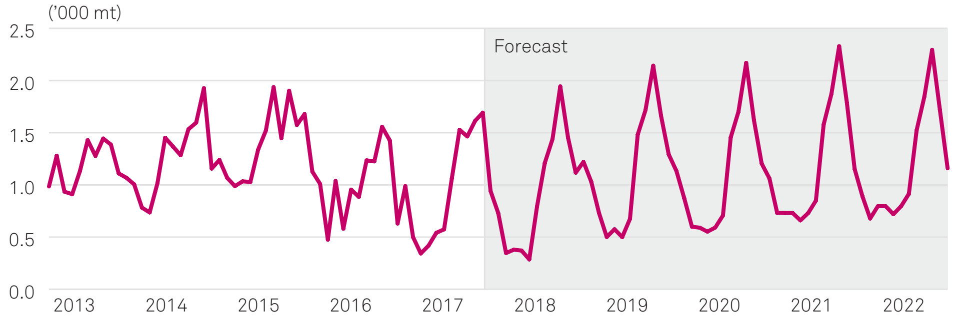
While the volume imported by each of these countries is typically small, the price signal it generates has often become a starting point for trade negotiations, not only in the Atlantic Basin, but as far afield as East Asia.

FSRUs – Enabling flexible imports

In 2008, South America pioneered the adoption of the Floating Storage and Regasification Unit (FSRU). Early adoption of the technology, now commonplace globally, has helped facilitate growth of the LNG market by reducing the cost and time of market entry.

It has also increased flexibility in comparison with onshore terminals,

SOUTH AMERICA DEMAND FORECAST



Source: S&P Global Platts Analytics

which many importers have seen idled for months or years when market conditions change.

While larger-scale onshore LNG import terminals built in Mexico took years to construct, the FSRU technology allowed Argentina and Brazil to begin importing gas from global suppliers within a much shorter time frame. They did so at a fraction of the cost required to build traditional import terminals.

Excelerate Energy, among the pioneers of FSRU technology, has estimated the cost of vessel conversion at $300 million, which pales in comparison with the cost of an onshore facility, which typically carries a price tag exceeding $1 billon.

The use of FSRU technology in Latin America has also allowed for greater flexibility, by reducing the need to commit to permanent onshore import infrastructure.

In Brazil, the recent economic slowdown prompted state oil and gas company Petrobras to initiate an early termination—14 months ahead of schedule—of its charter contract for the Golar Spirit. This kind of flexibility offered by FSRU technology has made Brazil, Argentina and many other countries more willing to enter the global LNG market.

ISO containers – Facilitating small-scale LNG

Over the next decade, Central America and the Caribbean look set to provide a small but important element of Latin American LNG demand, as small nations across the region look to transition toward cleaner burning and cheaper generation fuels.

However, the significance of these developments lies not in market size, but the use of new technology that could be replicated elsewhere, driving forward the penetration of LNG into new markets.

Until recently, the relatively small size of these markets posed serious logistical challenges for potential importers.

Standard LNG vessels, which deliver the vast majority of globally exported LNG, range in size from 60,000 to 80,000 MT. They would overwhelm not only the ports of these small nations, but also their market demand.

LNG TERMINALS IN LATIN AMERICA

Source: California Energy Commission, S&P Global Platts

> *"It is as a counter seasonal buyer that this market will be critical to the US in maintaining a steady stream of exports when global LNG demand is at its seasonal lull, but there is no upside to the amount of LNG buying that Latin America is expected to engage in and plenty of downside risk."* — PIRA Energy, a division of S&P Global Platts

But the emerging use of ISO containers has already begun reaching some of these elusive small-scale markets. Barbados has been one of the earliest adopters of this technology.

This year alone, the island nation has imported 26 LNG-loaded ISO containers from the US through June, according to data compiled by the US Department of Energy.

AES Dominicana, an LNG importer and power generator in the Dominican Republic, sees ISO containers as a potential solution for nations across the entire region.

The company's existing Andres Energy Complex in the Dominican Republic and its planned Colón Complex in Panama will be capable not only of importing standard-size LNG cargoes, but more importantly of reloading to small bulk carriers and ISO containers for shipment to small-scale markets across Central America and the Caribbean.

The anticipated adoption of these technologies, which would provide cleaner burning and lower cost feedstock fuel for power generation, should expand LNG's reach in coming years.

Panama Canal - Connecting the global markets

The recent expansion of the Panama Canal also represents a significant infrastructure investment that has already begun transforming the global LNG market.

Prior to installation of the new locks, the canal was able to accommodate just over 5% of the global LNG fleet and not a single standard-size LNG vessel. Since its completion in mid-2016, the canal now accommodates nearly 90% of the global fleet.

For exporters from the US Gulf Coast, the implications have been dramatic. For a Gulf Coast-laden cargo transiting the canal, the journey to Japan has been reduced to around 9,725 nautical miles, compared with 14,450 nautical miles through the Suez Canal.

Within the Americas, the change has been even more dramatic. For a US cargo delivered to the Manzanillo import terminal on Mexico's Pacific Coast, the journey has been shortened to 3,195 nautical miles, compared with 12,185 nautical miles through the Strait of Magellan.

Cutting travel distances to import terminals in the Pacific Basin has allowed US exporters to compete more effectively with suppliers like Australia and Qatar. More importantly, it is allowing markets to become more competitive and interconnected, while helping prices to more accurately reflect global supply-demand fundamentals.

The recent introduction of the Environmental Premium Ranking initiative by the Panama Canal Authority could also have a global impact on the LNG market. The optional program offers cargo shippers that reach certain environmental or energy efficiency standards a higher status in the waterway's Customer Ranking System.

LNG-fueled ships, which dramatically cut sulfur oxide and nitrogen oxide emissions, receive the largest increase in ranking status, making them more likely to receive priority in transiting the canal.

With plans by AES to offer an LNG bunkering service near the waterway's Caribbean entrance, vessels with LNG-bunkering capability could soon begin ramping up demand for the fuel.

This capability will become increasingly important as the industry begins preparing for tighter emissions regulations from the International Maritime Organization which take effect on January 1, 2020.

LNG as back-up

Net LNG imports into Latin America reached a peak of 22.3 million mt in 2014, but had fallen by more than a third to 14.21 million mt by 2016, despite the addition of Colombia as a new market. Caribbean island imports have remained steady around 2 million mt a year; the fall in import volumes has come largely in Brazil, Mexico and Argentina.

Brazil, Colombia, Argentina and Chile are all effectively gas/hydro duopolies when it comes to energy.

Brazil sourced 66% of its electricity from hydropower in 2016, Argentina 26%, Chile 25%, while Colombia's hydro share was 61%. Hydropower suffers from seasonal and annual variability, which in South America is heavily influenced by the El Niño effect. On top of this, changing weather patterns as a result of climate change threaten further variability, increasing water flows in some parts of South America and reducing them in others.

Natural gas has been the primary back-up, providing additional baseload generation and mitigating the often large variations in hydro output.

However, growth in LNG volumes from 2008, when Argentina completed its first regasification facility, also reflected the failure of domestic gas production to keep pace with demand.

This had knock-on effects for Chile, which was reliant on Argentinean gas exports, forcing it too to become an LNG importer and seek alternative forms of energy generation.

Brazil similarly was unable to increase domestic gas production sufficiently quickly to meet growing domestic gas demand.

The result was that while natural gas was the back-up to hydro, LNG became the secondary back-up to domestic natural gas. South American LNG demand is a function of hydro output on the one hand and the availability of domestic gas, or imported pipeline gas, on the other.

Future hydro generation remains hard to predict, but Brazil added 9.526 GW of new hydro capacity in 2016 and has substantial unexploited reserves. Colombia added 830 MW in 2015.

Both countries plan to increase hydro capacity, while hydro capacity in Chile is also expected to rise incrementally.

However, the real threat to South American LNG imports lies in the development of new renewables, mostly wind, solar and, in northern Chile, geothermal power, alongside potential increases in domestic gas production as a result of shale gas from Argentina's giant Vaca Muerta and from associated gas produced by Brazil's exploitation of its huge sub-salt oil reserves.

Argentina expects to return to gas self-sufficiency by the early 2020s, which will impact the import of LNG directly and via Chile. Argentina could also, potentially at least, resume exports of domestically-produced gas to Chile.

This will back-up Bolivian pipeline gas exports. Bolivia's current export contract with Brazil expires in 2019 and it is not expected to be extended on the same terms or for the same volumes.

At the same time, South American countries are embracing renewables, for which costs have fallen rapidly over recent years, making them competitive when set against gas-fired projects dependent on imported LNG. Brazil already has over 10 GW of wind installed, but in fact generates more electricity from burning bagasse, the left over plant material from sugar cane harvesting.

Renewables now dominate power generation tenders in Brazil, Chile and Argentina, while electricity demand growth has slowed across the region.

There are major plans for extensions of the gas grid, particularly to supply city-gas, in southern Chile for example, and in Peru and Bolivia, but in the latter two additional gas demand will be met by domestic supply.

Uruguay's LNG import plans, on which it has blown hot and cold for years, are a case in point. The installation of 1.21 GW of wind capacity, in what is a very small system, have reduced the need for LNG to meet domestic gas demand, meaning that should the project go forward it would be dependent on securing a long-term off-take deal to supply neighboring countries, where the gas balance is also uncertain.

The dual challenge presented by the build out of renewables and the increase in regional domestic gas supplies does not bode well for the future trajectory of LNG imports, which are likely to retain only a small but important seasonal role.

Although plans abound, there is only one new regasification terminal under construction in South America, in Brazil, scheduled for 2020. As it is an FSRU, it could well be deployed elsewhere.

Mexico

Mexico too appears an uncertain market for LNG imports. The country has embarked on a major renewables program, but is also increasingly well connected to the US gas system.

"South American LNG demand is a function of hydropower output on the one hand and the availability of domestic gas, or imported pipeline gas, on the other."

— S&P Global Platts

Despite plans to expand the use of gas, Mexico's LNG imports are suffering from competition from US pipeline supplies and from renewables in the power generation sector. Coal and fuel oil are expected to be the main losers, but that does not mean LNG will benefit.

With 3,527 MW of wind capacity installed up to 2016, Mexico now has 5,313 MW under construction or soon to begin construction. In addition, a further 5,457 MW capacity has been awarded, authorized, or is in the process of acquiring permits.

Solar is expected to expand even more rapidly, although from a small base of around 300 MW. There is 5,044 MW of solar capacity under construction or soon to begin construction, while a further 2,488 MW has been awarded.

Meanwhile, Mexican imports of pipeline gas and LNG were both on the rise from 2007-2014, LNG imports reaching a peak of 6.87 million mt in 2014. However, increases in US-Mexico pipeline capacity have already produced a sharp drop off for LNG. Mexican LNG imports fell to 5.13 million mt in 2015 and 4.14 million mt in 2016.

In contrast, US pipeline exports to Mexico jumped 45.9% and 28.4% in these years respectively, rising from 20.5 Bcm (1.98 Bcf/day) in 2014 to 38.4 Bcm (3.72 Bcf/day) last year.

Notes

www.platts.com | support@platts.com

For more information, please contact the Platts office nearest you:

NORTH AMERICA

New York
2 Penn Plaza, 25th Floor
New York, NY 10121-2298, USA
P: +1-800-PLATTS8 (toll-free)
P: +1-212-904-3070 (direct)

Boston
225 Franklin Street, 14th Floor
Boston, MA 02110, USA
P: +1-800-752-8878
P: +1-617-530-8300

Denver
1800 Larimer Street, Suite 2000
Denver, CO 80202, USA
P: +1-720-264-6600

Hightstown
148 Princeton-Hightstown Road
Hightstown, NJ 80021, USA
P: +1-800-PLATTS8 (toll-free)

Houston
Heritage Plaza
1111 Bagby Street, Suite 2200
Houston, TX 77002, USA
P: +1-800-PLATTS8 (toll-free)

Pittsburgh
424 South 27th Street, Suite 306
Pittsburgh, PA 15203, USA
P: +1-412-431-4370

Washington, D.C.
1200 G Street NW, Suite 1000
Washington, DC 20005, USA
P: +1-212-904-3070

LATIN AMERICA

Buenos Aires
Tte. Gral. Juan D. Perón 346,
6th Floor
(C1038AAH) Buenos Aires, Argentina
P: +54-11-4121-4810

São Paulo
Av Brigadeiro Faria Lima
201 21st Floor
São Paulo – SP Brasil – 05626-100
– Brazil
P: +55-11-3818-4100

EUROPE, MIDDLE EAST AND AFRICA

London
20 Canada Square
9th Floor, Canary Wharf
London E14 5LH, UK
P: +44-20-7176-6111

Dubai
DIFC, The Gate Precinct
Building 1, Level 05
P.O. Box 506650
Dubai, UAE
P: +971-4-372-7100

Moscow
Business Center
Mokhovaya
4/7 Vozdvizhenka Street
Building 2, 7th Floor, 125009
Moscow, Russia
P: +7-495-783-4141

Stavanger
Øvre Holmegate 1
4006 Stavanger
Norway
P: +47-51-89-06-66

ASIA-PACIFIC

Singapore
12 Marina Boulevard
#23-01 Marina Bay
Financial Centre Tower 3
Singapore 018982
P: +65-6532-2800

Beijing
Suite 1601, 16/F Tower D
Beijing CITC
A6 Jianguo Menwai Avenue
Chaoyang District
Beijing 100022, China
P: +86-10-6569-2929

Hong Kong
Unit 6901, Level 69
International Commerce Centre
1 Austin Road West
Kowloon, Hong Kong
P: +852-2841-1035

Shanghai
33/F Shanghai Plaza
138 Huaihai Road (M)
Shanghai 200021, China
P: +86-21-5110-5488

Tokyo
Marunouchi Kitaguchi
Building, 28th Floor
1-6-5 Marunouchi
Tokyo 100-0005, Japan
P: +81-3-4550-8300

Melbourne
Level 45, 120 Collins Street
Melbourne
VIC 3000, Australia
P: +61-3-9631-2000

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