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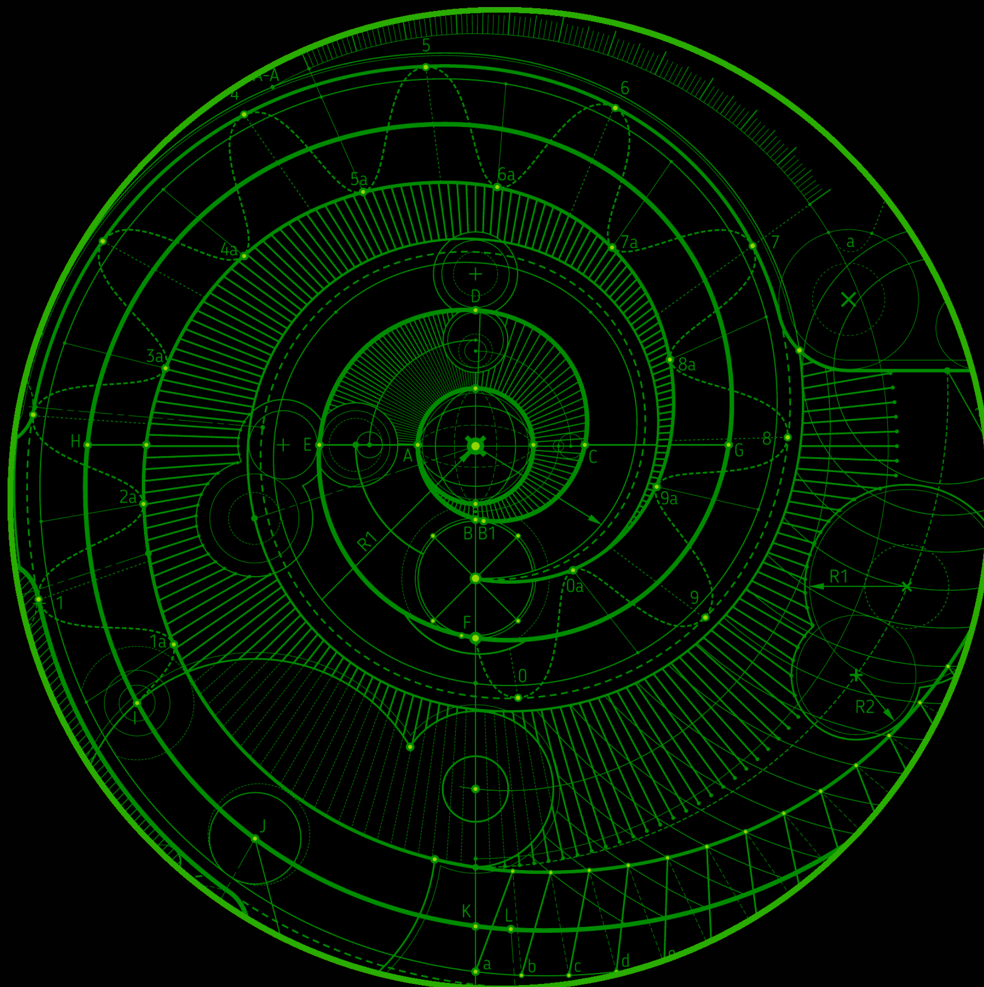

Work in progress: How can business models adapt to evolving LNG markets?

Deloitte Center *for* Energy Solutions

Table of contents

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Executive summary

Over the past 40 years, the global liquefied natural gas (LNG) industry appears to have evolved into six principal business models that carry out the bulk of manufacturing, buying, selling, and trading of LNG. These business models have successfully linked distant sources of supply with growth markets and have been enabled by contracting structures that managed the critical financial risks involved. However, as outlined in an earlier publication, *LNG at the crossroads: Identifying key drivers and questions for an industry in flux*, the global LNG market seems to be undergoing a number of specific structural changes that raise questions about how the business models may need to adapt.

As the industry both expands and fragments, introducing greater liquidity and optionality, it would probably be too simplistic to assume that the sector can evolve on exactly the same lines as the oil industry. Its key differences include the sheer scale of current industry participation, the degradation rate of LNG in transit, shipping factors, and limitations in customer infrastructure. Unlike oil, these factors mean that liquefaction, shipping, and regasification costs can make up significant portions of the delivered price. Instead, we anticipate the LNG business models will adapt to target the significant opportunities that are emerging. Some of these adaptations are global in nature, while others are narrowly focused on optimizing trade within regions or specific business models, including:

- A pronounced "move to the middle" as buyers become traders and liquefiers become capacity marketers.
- Rising activity levels may favor those models with the most developed trading and marketing capability, most likely the trading and portfolio players.
- Trading hubs may gain favor as a more efficient means to achieve price discovery, clear markets, and optimize physical shipping.
- Market hubs can provide valuable physical services, not yet available but useful, for fragmented markets and to manage demand risk.
- New business models may develop to support creative financing of key enabling technologies, like floating storage and regasification units (FSRU), floating LNG (FLNG), micro-LNG, and bunkering.
- Contracting may evolve to allow more flexible shipping, shorter terms, and creative pricing, giving rise to new financing models.

Effective understanding of the existing landscape and business models, the forces of change, and the actions by competitors will be critically important as the marketplace adapts for the future. The value at stake in the industry, in addition to LNG's promise as a cleaner future fuel, presents an exciting opportunity for many more companies than just the current incumbents.

This fourth paper in Deloitte's series on the evolution of LNG markets establishes a framework for thinking about these developments. It describes the opportunities and risks, due to the rise of new business models and industry expansion.

Existing LNG business models face new challenges

Historically, LNG was imported by major utilities to fuel power plants across Europe and Asia. However, with concerns over carbon emissions and non-dispatchable renewable energy, natural gas in the form of LNG could become an even more important global fuel, provided that it can be delivered efficiently and affordably to end users.

To date, the industry has been comprised of mainly six business models spanning the full spectrum of buying and selling activities:

- Large upstream companies that invest in liquefaction capacity to monetize large gas discoveries not adjacent to sufficiently large markets
- Manufacturers who procure gas from the broader market and then liquefy and export it as LNG
- Portfolio companies that manage a broad number of LNG assets, generating value by combining liquefaction capacity with sales and marketing functions to access global markets more effectively
- Independent trade and finance organizations that support and facilitate LNG trade
- Large utilities, or consortiums of utilities, that purchase large quantities of LNG with long-term and frequently oil-indexed contracts
- Smaller buyers, including regional gas and power utilities, that currently have insufficient need or scale to sign long-term, indexed contracts and, therefore, limited access to the global gas market

The global gas market is undergoing a structural shift—challenging businesses to adapt. The large number of new projects planned to come on stream in the next few years has led to excess liquefaction capacity. This capacity, along with low oil prices passing through to indexed contracts, will likely have impacts on the industry not just in the short-term, but in the mid- to long-term as well. These changes will likely have both positive and negative impacts on existing business models. As business models adapt, there is opportunity for a more inclusive LNG market that provides natural gas to a broad number of people at an affordable cost. Navigating that new world profitably could be a challenge.

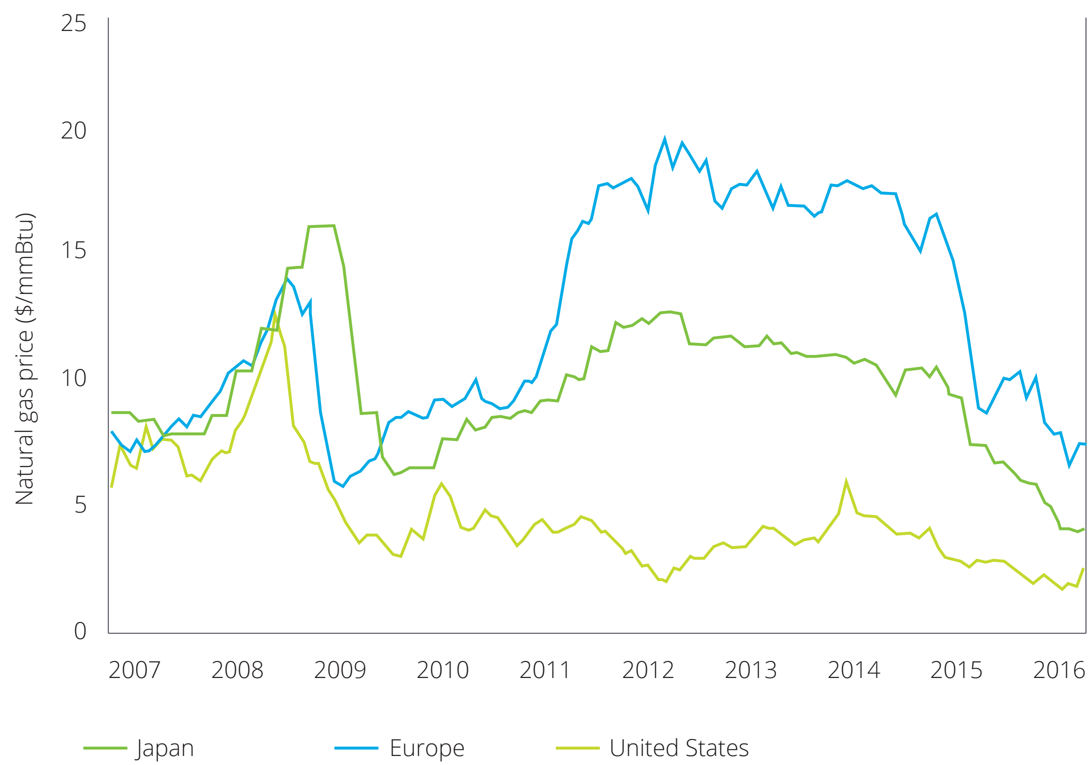
The LNG market continues to diversify as it matures

Global LNG exports reached 247 million tonnes per annum (mtpa), quadrupling over the last 20 years,[1] and are projected to more than double again over the next 20.[2] Today almost 20 countries export LNG, including the United States and Australia, which are both currently ramping-up capacity.[3] Over 30 countries import LNG, with a number of new types of buyers and end users expected to enter the market,[4] contributing to this ten-fold growth over the 40-year period.[5] This growth will likely strain traditional buyer-seller relationships. Financing new projects in the LNG industry was historically backed by long duration contracts with oil-indexed prices and destination restrictions to reduce revenue risk. With the dramatic increase in cargoes, routes, and market participants, the trade has become more truly globalized, which may create opportunities for a more flexible and liquid world gas market.

LNG, as an industry, appears to remain unique. Its trade crosses continents, but the contractual limitations mean most shipments only connect point A to point B, rather than facilitate a flexible, traded market. That limitation, along with the high cost of liquefying and shipping natural gas, has led to persistent gas price differentials between three distinct regional markets: the Americas, Europe, and Asia.

That has begun to change. With excess supply, moderation of demand, and increased availability of spot and short-term LNG, differentials are shrinking. Following the Fukushima incident, both Japanese and European prices spiked, averaging more than US$17 and US$11 per million British thermal units (Btu), respectively, from 2011 to 2015[6] (figure 1). Since then, indexed prices have declined substantially[7] as oil prices have declined and trade volumes have risen,[8] with excess liquefaction weighing on the market. The latter is mainly due to the surge in exports[9] from Australia, including the 2015 and 2016 start-ups of Australia-Pacific, Gladstone, and Gorgon LNG projects,[10] and from the Sabine Pass in the United States.[11]

Figure 1. Slack demand and excess supply have led to a decline in global natural gas prices



Source: International Monetary Fund[12]

One upshot of the recent market shifts is that long-standing agreements could be amended to allow for increased buyer flexibility. For example, Petronet revised its 25-year contract with RasGas, waiving a potential penalty and halving the prices of recent cargoes.[13] Even more ominous from a seller's perspective is that the Japanese Fair Trade Commission has begun investigating whether destination restrictions violate anti-competition laws.[14] With imports tied to specific ports and regasification facilities, utilities are looking to re-direct natural gas from oversupplied regions to those where it is still in high demand.

There is precedent for governmental involvement. In 2009, the European Union approved the Third Energy Package (TEP)[15] to unbundle supply and transport networks with the intent of maintaining lower energy prices. The construction of European pipeline interconnections[16] combined with certain portions of the TEP, are likely affecting Russian gas imports by increasing competition of supply and liquidity. The ongoing structural changes in LNG may have potentially similar impacts on the global gas market.* Unbundling suppliers, pipelines, and end users in the piped gas and electricity businesses may pose many challenges, but it can lead to opportunities for divergent business models. The same will likely be true of shipped gas.

That opportunity set will likely be defined by not just the ebbs and flow of the markets, but also where players stand today and will stand over the next five to 10 years. Many of today's buyers include large-scale utilities, like Korea's Kogas or Spain's Gas Natural Fenosa, and consortiums, like JERA (50 percent TEPCO and 50 percent Chubu Electric) in Japan that boost buyers' clout. Historically, sellers have been heavily represented by upstream national oil companies (NOCs), like Sonatrach in Algeria or PERTAMINA in Indonesia, as well as large integrated oil companies (IOCs), like Shell and Total. The growth in LNG capacity and its heavy capital intensity, across a number of geographies, has led to significantly higher investment.[17]

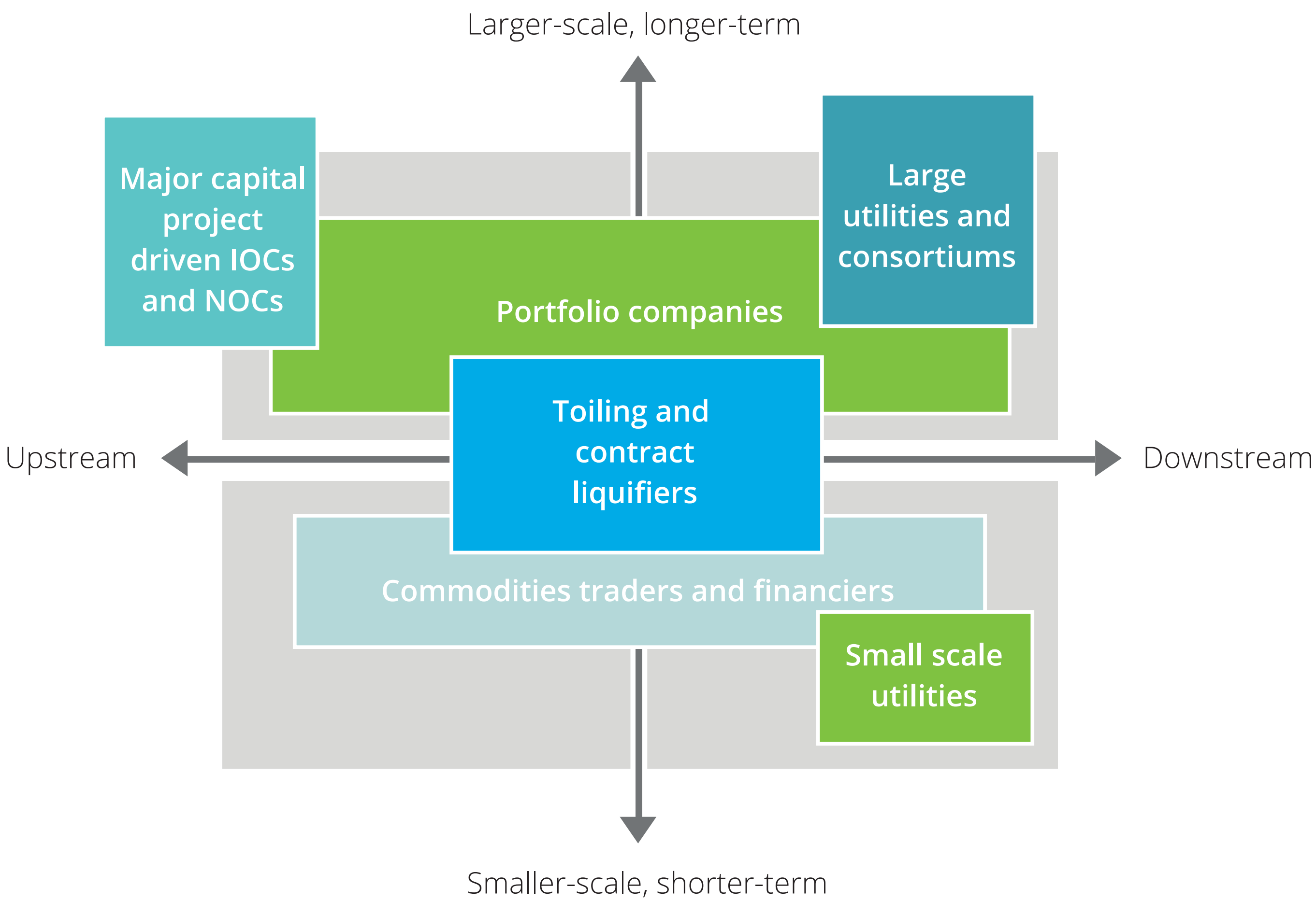
For much of LNG's history, trade has been unidirectional with dedicated shipping fleets and well-defined delivery schedules and volumes. More recently, trading houses and financiers have entered the markets to facilitate trade. To better adapt to shifting supply and demand across the Atlantic and Pacific Basins, some companies, like BG[18] (acquired by Shell in 2015), became large producers and intermediaries of LNG, acting as "portfolio companies" that can deliver gas from a range of gas assets in its portfolio to fulfill diverse supply obligations.

All of these business models may need to exist for the industry to continue to develop, but portfolio and trading companies hold the potential to dramatically open up the sector. There is strikingly little overlap between major suppliers and buyers, connected more or less by dedicated shipping routes (figure 2). There are no major exporters in the small-scale upstream space yet, and there is substantial unrealized demand from small regional buyers like national utilities in smaller markets, utilities facing seasonally intermittent demand,** and city gas companies. Portfolio companies moving down the value chain and traders branching from oil and refined products into gas could serve these markets. Widespread, dedicated intermediaries and niche buyers for excess cargoes could optimize trading and routes to boost incremental value through the supply chain, leading to a larger and more transparent LNG market, including regional hubs as seen in oil or piped gas.

*Like LNG, Russian natural gas exports to Europe are both typically oil-indexed, and facing increased competition (particularly from LNG).

** Seasonal demand in small markets can fluctuate due to multiple factors, including weather. For example, hydroelectric power is dependent on rainfall, and output from non-dispatchable sources, like solar and wind, can vary substantially, requiring back-up capacity, such as natural gas generation.

Figure 2. Current business models across the LNG value chain have little overlap



Source: Deloitte Center for Energy Solutions

Of course, the strategic evolution of the major, minor, and new players will not unfold in a vacuum. LNG has changed dramatically over the last 20 years, and even in the last five. It would be prudent to expect that rate of change to continue, if not possibly accelerate. In a prior publication, *LNG at the crossroads: Identifying key drivers and questions for an industry in flux*, the Deloitte Center for Energy Solutions highlighted seven trends impacting the market both today and over the medium-term. Increased uncertainty and sluggish global economic growth, together with continued improvements in energy efficiency, slows demand growth. This is partially offset by untapped opportunities in smaller markets and in emerging sectors like transportation. Supply factors, including excess liquefaction and shipping capacity, means buyers would gain some flexibility, but liquefiers' margins would be strained. Factoring in both supply and demand factors, in combination with more effective intermediaries, can also lead to improved liquidity. A larger, more liquid market will likely incentivize active trading strategies, leading to a deeper, broader short-term market potentially creating a positive feedback loop—enabling and begetting more trade.

Bearing that in mind, how will companies adapt their business models to today's upheavals? What about tomorrow's? More importantly, what does the equilibrium look like, and is it (relatively) stable? Answering these questions requires consideration of the global natural gas value chain as a holistic ecosystem rather than a sum of parts or a variation on the more mature oil market.

Adapting old business models for a new and increasingly complex market

Like the oil industry, LNG trade is separated into a number of related verticals representing different parts of the markets. There is potential for vertical integration, but currently the industry is quite segmented. Upstream producers generate the source gas for large-scale export projects. Typically, these producers also own and operate liquefaction plants, though the United States is an outlier with independent LNG manufacturers.

Unlike the oil industry, the current midstream and financial intermediaries remain small in both scale and scope. In that vacuum, large upstream companies and portfolio players that straddle upstream and midstream coordinate sales of cargoes to customers. Alternatively, the large buyers can pursue long-term contracts and manage the logistics of transporting gas themselves, buying LNG via free on board contracts.

These business models vary by industry positioning, size, and flexibility, but they all interact to move natural gas from rock pore to burner tip (figure 3). For example, while larger players have historically anchored the business by signing long-term contracts between financially stable counterparties, recent shifts in the industry have both enabled and necessitated the development of smaller, more flexible companies and contractual arrangements. Adapting these older business models may be key to support continuing volume growth.

Figure 3. LNG business models face varying opportunities and risks

Company type	Upstream IOC/NOC	Tolling and liquefiers	Commodity trading and finance	Portfolio	Large-scale utilities and aggregated buyers	Small-scale utilities
Examples	Chevron, ENI, PERTAMINA	Cheniere, Texas LNG	Gunvor, Vitol, Trafigura	BP, Shell, Total	Kogas, JERA, Petronet, ENGIE	JOVO, Polskie LNG.
Current business model	Operate or own equity interest in oil and gas fields supplying owned liquefaction facilities, usually anchored with long-term contracts with large scale buyers.	Own and operate liquefaction capacity but do not invest upstream or downstream capabilities. Potential for partnering with logistics, trading or marketing organizations to purchase and sell gas.	Either negotiate the purchase and delivery of LNG cargoes on behalf of clients, or purchase gas via long-term contracts which is then marketed on the spot market or shorter-duration contracts.	Integrate upstream, liquefaction, trading and marketing functions in a single company.	Operate large numbers of electric power plants and national natural gas networks or are a part of consortiums representing similar interests.	Typically smaller power plant or regional gas networks operators. These buyers focus on diversification of supply, with small and likely intermittent demand.
Opportunities	Gives companies to access to a wide variety of exploration opportunities and producing assets provides long-term supply for liquefaction projects.	Provides greater flexibility to buyers, with take-or-pay value only of tolling costs rather than delivered cargo price. Many tolling companies currently buy gas from the broader US market at low prices, with large amount of room to scale.	Generate value by intermediating needs of suppliers and buyers of LNG. May be able to sell LNG at a premium by purchasing gas through long-term contracts and selling to those with intermittent or small needs and lower creditworthiness.	Combines the opportunities of the other three seller types allowing portfolio companies to optimize assets as demand shifts across the world.	Large buyers with strong credit are critical to anchoring liquefaction investments and can negotiate favorable terms for future contracts due to high availability of unsanctioned supply.	Historically these companies have had limited access to the LNG markets and trade financing. Excess capacity and a larger number of market participants will likely accommodate these smaller buyers.
Risks	Reliance on single (or few) sources for gas, as well as a handful of larger buyers reduces flexibility and increases the likelihood of negative impacts from cost overruns and commodity price swings.	Currently only the US and Canada have a sufficiently broad and deep natural gas market to facilitate this time of business model. Viability in other markets is uncertain, limiting growth potential.	Lack equity interest in gas supply and therefore may face price volatility on either side of the transaction. Volatility risk might be amplified by limited liquidity in a currently immature market.	Material equity in the entire chain requires substantial capital investment limiting opportunity to only the largest oil and gas companies.	Companies secured supply through long-term contracts, frequently exceeding 20 years. Changes in economic growth or energy efficiency may lead to excess natural gas in domestic markets with limited re-export opportunities.	Market tightening could lead to difficulties renewing short term contracts. These players are also price takers which could lead to sudden price spikes either causing financial stress at the utility or passed through to rate payers.

Source: Deloitte Center for Energy Solutions

Similar to other commodity businesses, companies can be split between buyers, sellers, and intermediaries. What stands out in LNG is the sheer size of the companies, which is a function of the high, upfront capital intensity of the business. Sufficient economies of scale are needed to justify such large upfront investment. Typically, a facility needs to be able to produce at least four mtpa, or one billion cubic feet per day (bcfd) equivalent, of LNG to reach sanction, and even then projects usually include potential for expansion. One of the largest, Qatar's RasGas, exports 36 mtpa gas via seven LNG trains, which is 20 percent more than the total consumption of the state of Louisiana[19] or the entire country of France.[20]

While a small private-equity backed company might drill gas wells in the US Marcellus Shale, only large NOCs or IOCs (and frequently both in a joint venture) can develop an upstream project that generates enough natural gas to anchor a liquefaction project. And, the same is true of the LNG projects themselves. Liquefaction plants built over the last five years have cost anywhere from $200-1,800 per tonne per annum of capacity, on the order of $5-30 billion.[21] This wide range reflects diverse geographies and execution challenges. Highly prospective gas discoveries are frequently far from prospective demand centers.

Moving down the value chain, liquefying large quantities of natural gas requires large ports with a sizeable fleet of transport vessels. These are typically owned or leased by the seller (older contracts) or the buyer (newer US-style contracts). Cargoes need to be matched to ships and ports, used for loading at the source and unloading at the destination (if known). The weather, voyage length, and canal limitations may need to be factored in as well. Beyond these considerations, costs can escalate quickly for longer journeys due to boil-off of the LNG as it warms, as well as charters in the tens of thousands per day. This makes shipping both logistically challenging and expensive, with both substantial capital investment and ongoing operating costs.[22]

Financing the future

With so much capital deployed to bring gas to market, smaller or infrequent buyers may face challenges buying gas. The current level of excess capacity may provide access to the spot market and short-term cargoes that have historically been the exception, not the norm. However, to finance purchasing via mid- and long-term contracts spanning multiple years, creditworthiness and liquidity are often key.

Currently, there is a deep and broad futures market for oil, with both physical and paper trading. Buying a West Texas Intermediate contract for Cushing, Oklahoma can provide producers with volatility hedges and a means to secure future financing. In the most basic terms, a hedge plus a well can generate some level of predictable cash flows. This is not true for natural gas in the global markets. While there is Henry Hub in the United States and National Balancing Point in the United Kingdom, international hubs for LNG remain nascent.

The barriers to further financialization of the industry are likely due to both the structure of the market and the nature of the product. Building physical trading hubs requires both access to cryogenic storage and shipping access, as well as electronic trading support. Developing a hub by leveraging infrastructure in places like the US Gulf Coast or Japan might make sense in the medium-term. Building a fit-for-purpose physical hub in a convenient port city, like Singapore, also might have potential, but the lack of demand and upfront costs will likely limit interest. But, developing a hub could promote price transparency and provide a means to balance risk across the system.

Balancing risk would not just dampen large buyers' and sellers' price volatility, but it could also be basis for trade financing, allowing intermediaries to provide transaction services, e.g. brokering sales, as well as funding to buy cargoes, allowing new buyers access to global markets. Furthermore, generating a long tail of smaller prospective buyers and broader spot and short-term contracts could partially de-risk revenue for large-scale liquefaction projects lowering the threshold for the number of long-term contracts needed to anchor a development. That would be a particular boon for operators of smaller modular or floating projects; combining flexible technology with tractable financing could be an avenue to a more inclusive LNG trade.

Just as the vessel must be matched to the cargo size, it must also be matched to the receiving jetty and the accompanying storage. Unlike oil, which is stored at more or less atmospheric conditions above ground, importers of LNG will need to store it at cryogenic temperatures, or regasify it and inject it into either underground storage, e.g. salt caverns, or the regional pipeline network. This entails substantial infrastructure as well as solid supply and demand balancing. It is more viable with regular and predictable LNG shipments combined with storage to meet the needs of a relatively stable demand outlook, conditions which may be lacking in many potential markets. This means beyond financing trade, there is a role for intermediaries to manage optimization of vessel fleets, receiving ports, and regasification facilities, and ultimately connecting floating and piped gas transportation networks.

While all of these factors combined seemingly lead to a global market tying together large (and creditworthy) players via long-term contracts, latent unmet demand should provide sufficient impetus for evolution. Specifically, traditional contracting models excluded traders who lacked financial incentive to enter into destination-limited contracts. The same is true for portfolio players. By excluding companies that focus on distribution from the greater LNG market, smaller buyers who could not enter into long-term contracts found themselves without willing sellers. With the glut of Australian and US LNG entering the market, both traders and smaller or infrequent buyers have begun playing a role in the trade. That role is almost certain to grow.

External factors will continue to drive strategy

So, what will the LNG industry look like in 2020? Or 2025? Volumes traded will almost certainly be larger, maybe even by 50 percent. And, the total number of cargoes may increase even more since smaller vessels may be better suited to a more diversified market. It is important to understand how macro factors will evolve and how that could affect these players. In our prior report[23] we highlighted seven trends that we expect to shape how the market will unfold, namely:

1. Global economics growth might be slowing, thus reducing energy demand, and is pivoting toward Asia and the developing world.
2. Energy efficiency may be leading to lower consumption even as economies grow, though not across all sectors to the same degree.
3. New LNG plants from Australia and the United States are entering an already saturated market, opening-up spare spot capacity.
4. New ship delivery is outpacing demand, with both likely increasing availability and lowering charter rates for the foreseeable future.
5. Potential for profitably selling to smaller end users may lead to new markets outside of the traditionally big buyers, e.g. Japan and Korea
6. New end users have entered the scene as improved technology and tighter emissions standards improve LNG's relative economics including in the transport sector.
7. New sellers, buyers, and intermediaries entering the market will likely improve market liquidity.

Additionally, broader environmental trends will likely play out. Following the 2015 Paris Climate Conference (COP21), renewed interest in reducing carbon intensity will likely lead to scrutiny of many countries' progress in meeting their targets. This may affect how energy efficiency policies are designed, the adoption of alternative fuels for transport, and how developing economies might determine their future power generation needs.

How do these trends affect the existing business models? With utilities holding contracts in excess of demand, some have begun re-marketing future cargoes.[24] And, many liquefiers* also market volumes outside of longer contracts. So, in a sense there is, at least in part, a rush to the middle, with liquefiers selling spare capacity and buyers selling excess cargoes on the spot market, with portfolio players pursuing short- and medium-term contracts with third-parties. That may not be sustainable since it requires expanding investment outside of a company's core focus. However, building out a more robust and mature LNG ecosystem will likely require someone to fulfill this role on a larger scale than currently exists.

Looking further into the future, this need for more extensive marketing will likely only increase. Consumption growth of large scale buyers is uncertain and likely less than expected even a few years ago. Even if prices and take-away volumes are not renegotiated downward, there may be substantial headwinds for major capital projects in the LNG space in the next five years. Future demand growth may very well come from end users that were too small for companies to have directly sold to in the past—or perhaps to customers not even on the radar. With excess cargoes, active trading is appealing in the short-term, but that may not be the best route across all the business models in the longer-term.

As mentioned previously, this fragmentation could provide large opportunities. For example, instead of a single buyer, seller, and destination, a consortium of smaller utilities would be able to better negotiate purchases, as aggregation would minimize the intermittency issues. Moreover, optimizing delivery via "milk runs" could support some economy of scale while meeting customers' needs. That, however, will unlikely materialize without the renegotiation of existing destination clauses, as well as organizations providing credit and the construction of smaller LNG vessels. Pursuing tail-end opportunities is likely better suited for trading and portfolio companies rather than utilities companies.

*Examples include Cheniere (http://www.cheniere.com/marketing/marketing-overview/) and Total (http://www.total.com/en/energy-expertise/ship-market/trading-shipping/oil-gas-worldwide-supply-demand) among others.

The same is true for liquefiers—the real value of trading and financing comes from geographical and geological diversity. Producing gas from both large offshore fields in the Pacific and shales in the United States allows a company to arbitrage prices across basins and across time, as well as optimize trading routes and balance supply and demand on both macro and micro scales. Very large portfolio companies can pursue this strategy following a large upfront investment. Alternatively, a physical trading shop could achieve a similar structure by buying contracts of varying duration, size, and location and then selling on short-term and spot markets—more or less the exact opposite of traditional banking's maturity transformation. For both business models, sizeable financing and contract flexibility will likely be key.

These kinds of shifts are probably needed to improve the liquidity in the market. In many ways the LNG industry of prior decades has faced a sort of "chicken and egg problem" where liquefactions projects could not be financed without long-term contracts. Of course, they involved buyers who may or may not already have the infrastructure for large-scale natural gas consumption and certainly would not construct new power plants without a guarantee of supply at an affordable price. Resolution typically involved large sums of money invested by all parties well ahead of the first cargoes.

New technologies enable new markets

Increasing contracts destination and volume flexibility change the equation slightly. But, better yet, technology has long-term potential to shift the risk-reward relationship. Three technologies may potentially drive the changing face of LNG: floating liquefaction and regasification, micro-LNG, and LNG as a fuel.

FLNG plants and FSRU simplify the process of monetizing smaller projects. For example, Petronas's *PFLNG Satu* has capacity to produce only 1.2 mtpa. This is much smaller than its nearby onshore LNG projects in Sarawak, which allows the company to produce from fields too small to tie-back to onshore infrastructure.[25] Similarly, for countries with limited or intermittent natural gas demand, using a FSRU facility provides flexibility with lower upfront costs and a shorter construction timeline.

One alternative to floating projects is LNG plants built from prefabricated, modular developments. This model can be volume-flexible for both liquefaction and regasification. Using smaller liquefaction trains in parallel, adding incremental capacity if there is sufficient demand (and financing), would limit risk. Shrinking the footprint can further allow for the development of niche options, like powering micro-grids in remote areas and the use of natural gas-powered truck and municipal bus fleets.

The latter may become more prominent, not just onshore, but also in shipping with LNG bunkering of ocean-going vessels. Using LNG instead of traditional bunkering fuel produces less emissions, including carbon dioxide and fine particulate matter.[26] Expanding the number and geographic dispersion of smaller LNG liquefaction, storage, and regasification facilities could be the impetus for broader adoption if global emissions standards are tightened.

Considering all possible futures

Based on the current industry structure, LNG can be an expensive energy source with high upfront investment in upstream and liquefaction capacity along with specialized storage facilities and vessels. Broad adoption of imported gas will remain challenged under traditional commercial structures and business models, due to limited destination flexibility and the potential for delivered prices to exceed $10 per mcf.*

Delivered cost of LNG typically consists of roughly one-third upstream production and transportation, one-third liquefaction, and one-third shipping and regasification.[27] Considering that the industry is expected to grow to over 368 mtpa, or roughly close to 48 bcfd by 2020,[28] there is likely sizeable need and opportunity for optimization through the value chain to generate profits while remaining affordable to a larger customer base.

What could optimization look like? Shipping LNG from the US Gulf Coast to Tokyo could take close to 40 days, whereas exporting from Pilbara, Australia would take less than ten, costing one third as much after accounting for chartering and fuel costs.[29] While that route is an outlier, there were 4,057 voyages in 2015, with an average length of 7,640 nautical miles.[30] That is roughly 18 days at 18 knots, and even with recent low charter rates, that "average" route could cost at least $800,000.[31] After factoring in the return trip, a 20 percent reduction in miles travelled would reduce costs by close to a billion dollars per year. And, the savings could be substantially more considering current spot charter rates are one-quarter of where they were in 2011 and remain less than a third of long-term contracted rates.[32]

Reducing shipping costs likely requires companies to become more nimble, adapting existing business models to a world less tethered to the same geographic locations—where point-to-point contracts could be supplemented with intermittent demand across different basins and customer types. Portfolio players have, in many ways, moved toward this paradigm of liquefaction plus—as in liquefaction plus shipping, or liquefaction plus trading, and maybe, in the future, liquefaction plus financing. However, the changes to the industry are broad and some of the other business models may prove too narrow. While "moving to the middle" is one approach, vertical integration may only make sense for a few, since the cost of vertical integration can be prohibitive and there are opportunities outside of crossing the entire value chain.

The industry may need trading hubs for price transparency, independent marketing and financing, and large investments in supporting infrastructure. Current business models will likely need to evolve to meet this. For example, large utility-type buyers operate or have access to regasification facilities across a number of ports, existing relationships with both liquefiers and portfolio companies. They might be better positioned to invest downstream in natural gas-fired power plants and pipelines to connect the system together. Similarly, large liquefiers could use the more flexible financing tied together with FLNG as means to connect smaller gas fields to regional buyers that cannot anchor long-term contracts.

The future also will likely move beyond the current focus on large buyers and large sellers. Arguably, LNG in 2025 will not be portfolio companies directly interfacing with major consumers, selling excess volumes to the smaller regional buyers. The ability to contract excess liquefaction capacity, something that had been in short in supply until recently, could allow trading organizations and banks to make markets whole, trading both physical and financial contracts to manage both risk and demand. This flexible, interactive model could pull from the strengths of each business model to provide services currently not affordable and available. Reserve capacity, combined with a strong marketing organization, provides multiple business models in a way that mimics the portfolio model, generating additional value by exploiting the long tail of supply and demand and monetizing fields, LNG plants, and ships and ports that otherwise might not be tapped to meet future energy needs across the world.

Looking toward the future, the stable and predictable business models of LNG's past will not likely survive intact with such vigorous change impacting the industry. While incumbents in the sector have robust advantages in light of the changes, incumbency alone is likely not sufficient to assure success. New businesses may well find fertile ground for innovation in LNG in the short- to medium-term. Adaptability and nimbleness, not size, will likely dictate success in a more complex global gas market.

*LNG contracts have historically been linked to oil prices at different rates, typically ranging between 12-15 percent with potential additional costs related to transport, storage and regasification.

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Let's talk

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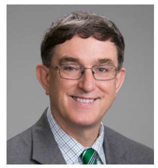

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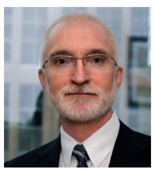

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