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They Might Be Giants:
How New and Emerging LNG Importers Are Reshaping the Waterborne Gas Market

By Teddy Kott and Akos Losz

NOVEMBER 2017

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How New And Emerging Lng Importers Are Reshaping The Waterborne Gas Market

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EXECUTIVE SUMMARY

For several years, many liquefied natural gas (LNG) market observers have been anticipating looser waterborne markets and lower prices. Primarily due to surging exports from Australia and the United States, new supply has been entering the market at an unprecedented pace since mid-2014, and this expansion is set to continue through the end of the decade. However, the physical LNG market does not appear to have loosened substantially, even though spot LNG prices are down from the lofty levels of 2011–14, following Japan's Fukushima crisis.

The purpose of this paper is to demonstrate that physical LNG markets have remained quite tight in the face of growing supply and to examine an underappreciated driver of this tightness: enormous demand growth by a group of new and emerging LNG importers since 2014. Facilitated by an expanding fleet of floating storage and regasification units (FSRUs), these emerging importers have quickly upended the conventional wisdom that the LNG market has entered a period of structural oversupply. The paper's key takeaways are the following:

- Global LNG supply has surged since 2014, and spot natural gas prices across Asia and Europe are well below their heights during 2011–14 in the wake of Japan's Fukushima crisis.

- However, a more nuanced look at LNG flows suggests that physical markets still have not loosened substantially three years into this supply boom. European LNG imports represent a crucial barometer for understanding the state of physical LNG balances. Europe's liquidly traded hubs feature a market flexibility that allows the continent to act as a sink for flexible LNG once the rest of the world has balanced. LNG flows to Europe have not increased significantly during this period of LNG supply growth, suggesting that the market has actually remained physically tight despite growing supply.

- The main driver of lower prices in the world's LNG importing markets since 2015 does not lie in a loosening physical market. Instead, the impetus for lower prices has come from outside the LNG market; the lower oil price environment has dragged down the soft ceiling for LNG prices. When assessed as a percentage of oil prices, LNG prices have been only slightly weaker than during the three years of very high prices in 2011–14.

- The most important factor that has absorbed the looming LNG surplus since 2014 has been a largely underappreciated feature of the market: a collection of small and emerging LNG importers. Chinese demand has been booming for the past year, capturing industry headlines, but this group of 12 disparate importers has absorbed a remarkable amount of LNG during the past three years. These emerging importers represented just 3.3 percent of global LNG demand in mid-2014 but have accounted for nearly 60 percent of net global demand growth since then.

- The expansion of FSRU capacity has been the most important dynamic underpinning this source of new demand growth. FSRUs reduce the initial investment necessary to access the waterborne market, making them attractive options for new importers. The shorter lead times for FSRU-based facilities have allowed importers to commence or expand LNG purchases much faster than traditional land-based facilities would. FSRUs are a mature technology, but the fleet's capacity has expanded considerably in recent years, and the fleet will continue to grow going forward.

- Apart from absorbing much of the expected LNG surplus, the rapid expansion of the LNG buyers' club carries other implications for the market and for governments. The entry of some countries introduces significant credit and governance risks to the market and to specific projects. The participation of multilateral organizations can help to overcome some of the key financial constraints that would otherwise prevent a country from becoming an LNG importer. Meanwhile, the introduction of new buyers should influence market flexibility on the demand side. These importers likely introduce greater medium-term flexibility (demand elasticity over a one- to three-year time frame) while actually reducing shorter-term market flexibility over a one-year time horizon as they lock in demand. Finally, the rapid move by some governments to access the LNG market will impact millions of lives as these countries begin to access waterborne gas supplies to address severe fuel shortages and electricity reliability issues.

INTRODUCTION

Perhaps it is the waterborne nature of the LNG market that encourages metaphors of inundation. Since as early as 2014, many market observers have anticipated that an impending flood of new LNG exports would soon wash over markets as a wave of new liquefaction projects begins to crest. This supply growth would drag down prices in the world's importing markets and send substantially greater LNG volumes to the market's destination of last resort: the liquidly traded gas hubs of Northwest Europe.

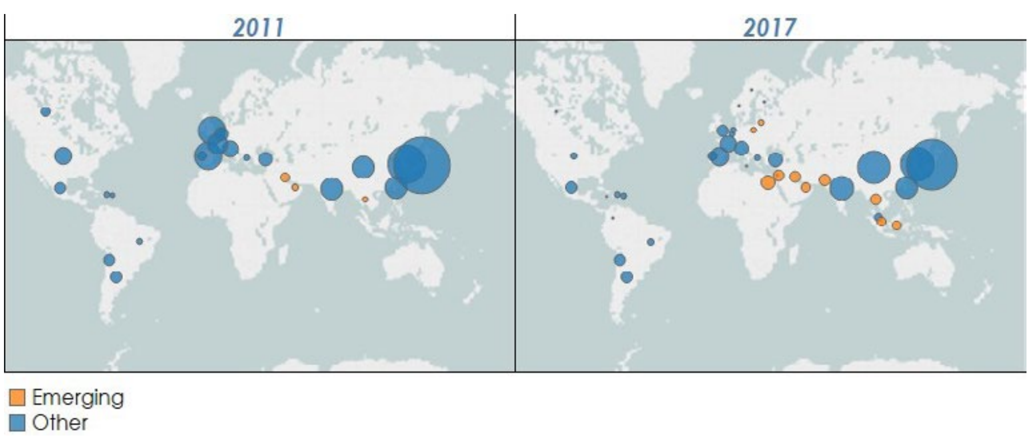
As expected, global LNG exports have been surging since mid-2014, and gas prices in the world's importing markets are considerably lower than their heights of 2011–14 in the immediate wake of Japan's Fukushima crisis. The higher supply and lower prices have lent support to the idea that the era of loose global gas markets has already begun. But so far, this wave of new supply has barely touched Europe's shores, an important signal that the market has not yet loosened as many had expected.

Why not?

Most of the major drivers of LNG markets are obvious and dramatic: Japan's Fukushima crisis and ensuing nuclear shutdown, China's surging gas consumption amid economic growth and local air pollution crises, massive investments in new liquefaction capacity from Australasia to the United States, and Qatar's decision to lift its production moratorium. But this paper explores an often-overlooked new dynamic: the rapid rise of new and emerging LNG importers. Largely flying under the radar, the aggregate impact of these emerging importers has been the most important factor keeping the physical LNG market tighter than expected since 2014, absorbing an extraordinary amount of global supply growth and keeping the long-awaited global LNG surplus at bay.

This paper focuses on the impact of a collection of one dozen importing countries that individually appeared to be marginal or non-players in the LNG market in 2014 but that have demonstrated a capacity to grow imports (table 1). These countries accounted for just 3.3 percent of global imports in mid-2014 but were then responsible for 57 percent of net global growth through September 2017 (using one-year moving average imports). Demand growth from these new and niche markets has been greater than the growth from China, India, and Taiwan combined over that period. When taken as a group, the demand shock from these emerging importers has been more pronounced than even Japan's post-Fukushima burst of LNG demand.

Figure 1. LNG imports by country 2011 (full year) and 2017 (through September)



Source: Kpler, CGEP.

Table 1. Emerging importers' LNG imports in 2013 vs. the 365-day moving average through September 2017

Country	First LNG arrival	Population (million)	2013 imports (mtpa)	Past 365 days (mtpa)	Growth
Kuwait	Jul-09	4	1.6	3.6	**2.0**
UAE	Sep-10	9.3	1.4	2.8	**1.4**
Thailand	May-11	69	1.4	3.8	**2.4**
Indonesia	Apr-12	261	1.3	2.9	**1.6**
Singapore	Apr-13	5.6	0.9	2.6	**1.7**
Lithuania	Oct-14	2.9	0.0	0.9	**0.9**
Pakistan	Mar-15	193	0.0	4.0	**4.0**
Egypt	Apr-15	96	0.0	6.7	**6.7**
Poland	May-15	38	0.0	1.2	**1.2**
Jordan	May-15	9.5	0.0	3.5	**3.5**
Jamaica	Sep-16	2.9	0.0	0.3	**0.3**
Malta	Jan-17	0.4	0.0	0.2	**0.2**
Bangladesh	*Expected '18*	*163*			
TOTAL			**6.7**	**32.5**	**25.8**

Source: Kpler, CGEP.

A key feature of the market that has allowed for this demand growth has been the expansion of the fleet of floating storage and regasification units (FSRUs), LNG tankers with regasification capacity on board. Although not a new technology, the growth of global FSRU capacity has started to unlock an infrastructural bottleneck, compressing lead times and initial capital expenditures involved in developing import facilities. Growing FSRU capacity has facilitated import project development in many countries that could not have supported traditional onshore regasification projects, effectively democratizing access to LNG imports.

Relying on granular tanker-tracking data, the authors tease out the importance of this new dynamic, even if it receives far less attention than developments in the world's major LNG importers. With LNG supply expected to surge through the end of the decade, whether this democratization of LNG markets will continue is a question that ranks among the most important uncertainties facing the market.

Apart from the first-order effects on LNG fundamentals and prices, this paper also discusses a number of other consequences of the collective rise of small importers. This dynamic is likely to impact market flexibility and challenge long-term market forecasting while some countries' rapid move into the market could amplify credit and governance risks that linger beneath the surface of many commodity markets. And as access to LNG imports spreads over the coming years, it will improve millions of lives as the waterborne gas market begins to supply fuel to populations struggling with fuel shortages and power reliability.

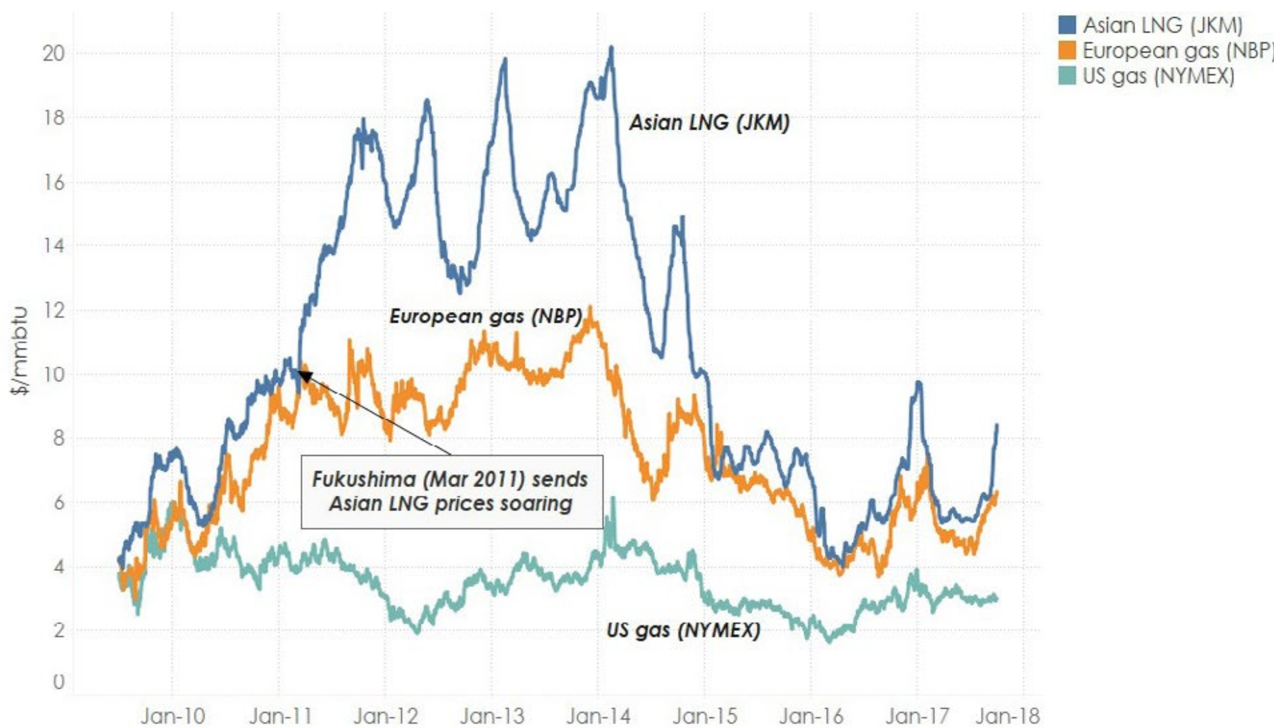
To understand the significance of this change, it is crucial to put the rise of emerging importers in a broader context to understand the importance of this new dynamic—and why it has gone underappreciated by many market observers. This paper is broken into five sections that discuss (1) rising global LNG supply, (2) Europe's role as a swing LNG importer and how it reveals a story of tight markets despite lower prices, (3) the democratization of LNG imports and its impact on the market, (4) how floating storage and regasification units can quickly unlock new demand, and (5) the implications of this source of rapid demand growth.

A SUPPLY SURGE AND THE APPARENT GLOBALIZATION OF GAS PRICES

Prior to the current boom, the last time that the LNG market experienced a substantial burst of new supply was during 2009–11. Largely owing to a new generation of Qatari megaprojects, global LNG supply jumped by 39 percent—68.3 million tons per annum (mtpa)—holding the promise of a more globalized natural gas market. Instead, the world's traded gas markets soon fractured into three distinct regions. For much of 2011–14, natural gas in Europe was roughly *three times* as costly as in the United States. And gas in Asia was often nearly *twice* as expensive as gas in Europe.

From 2009 into 2010, the world economy was on the mend, and most commodity prices were rebounding from their lows during the financial crisis. Booming shale gas production and a lack of export capacity kept a lid on US natural gas prices, but prices in Europe and Asia followed the rest of the commodity complex upward. The Great East Japan Earthquake in March 2011 and Japan's ensuing nuclear shutdown catapulted Asian LNG prices even higher as Japan leaned heavily on gas-fired power generation to offset its lost nuclear capacity (figure 2). But another wave of new LNG supply was already in the works, once again dangling the prospect of a truly global market.

Figure 2. Daily spot gas prices in the United States, Europe, and Asia since mid-2009

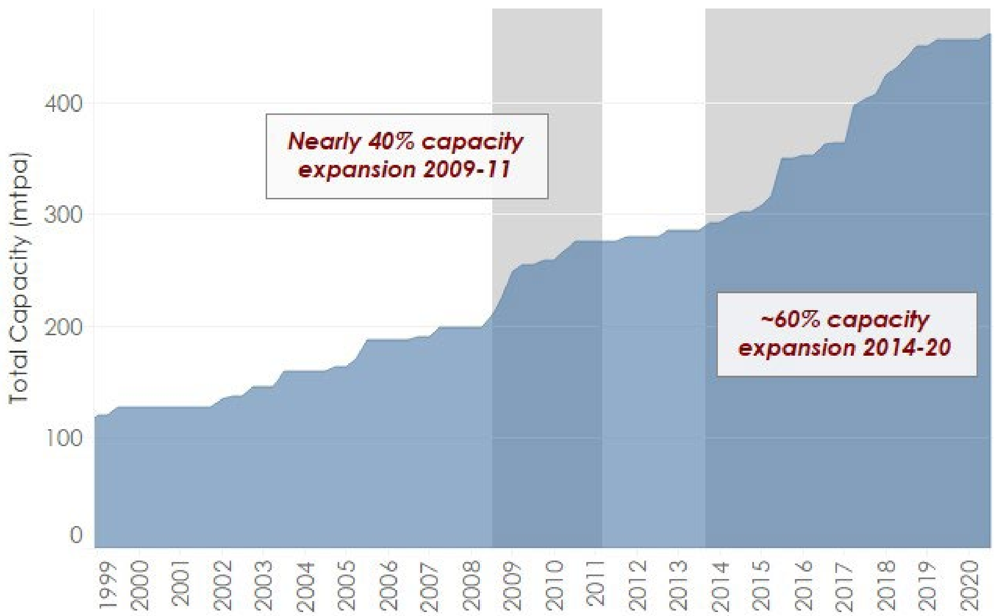


Source: Platts, Bloomberg, CGEP.

The next generation of Australian liquefaction capacity was under construction, and with Asian LNG prices surging past $15/mmbtu by mid-2011, a race was on in the United States to transform underutilized LNG import facilities into export capacity to sell $2–4/mmbtu domestic gas into the premium waterborne market. Once the US government began to authorize liquefaction projects, it became clear that Australia would pass the baton to the United States as a driver of global export growth in the second half of the decade. Three years into this supply expansion, prices have indeed converged—to a degree—suggesting on the surface that gas markets have finally taken steps toward globalizing.

Because liquefaction projects take several years and many billions of dollars to develop, the market can anticipate production growth with reasonable confidence. With global liquefaction capacity in the midst of an approximately 60 percent growth spurt through the end of the decade (figure 3), many market participants—quite reasonably—have been anticipating price convergence across traded gas markets.

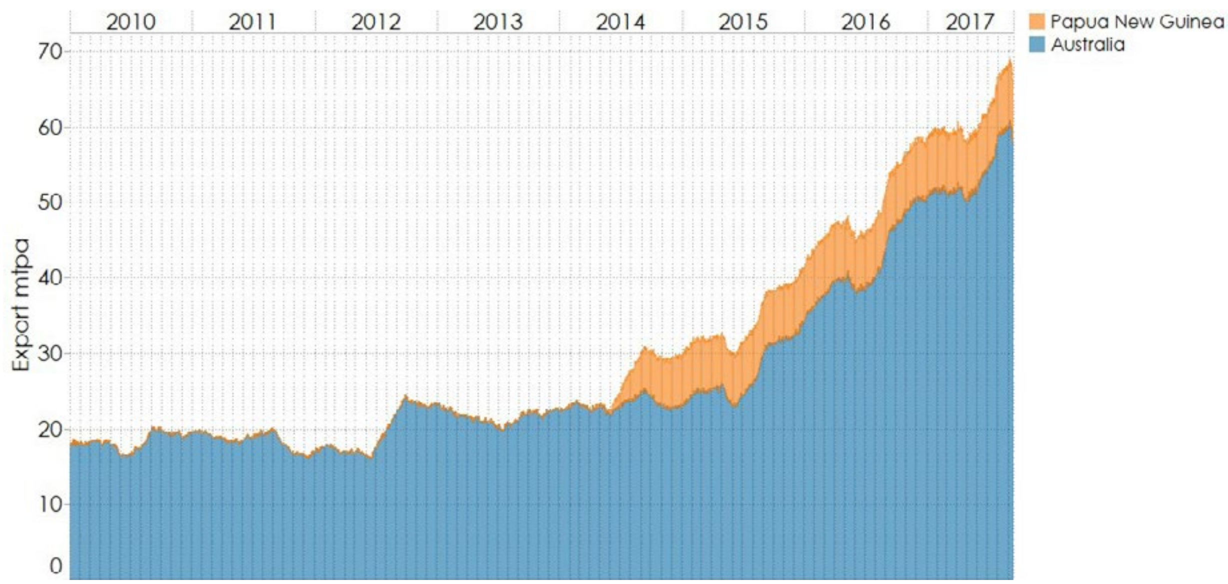
Figure 3. Actual and expected global liquefaction capacity, 1999–2020



Source: Wood Mackenzie.

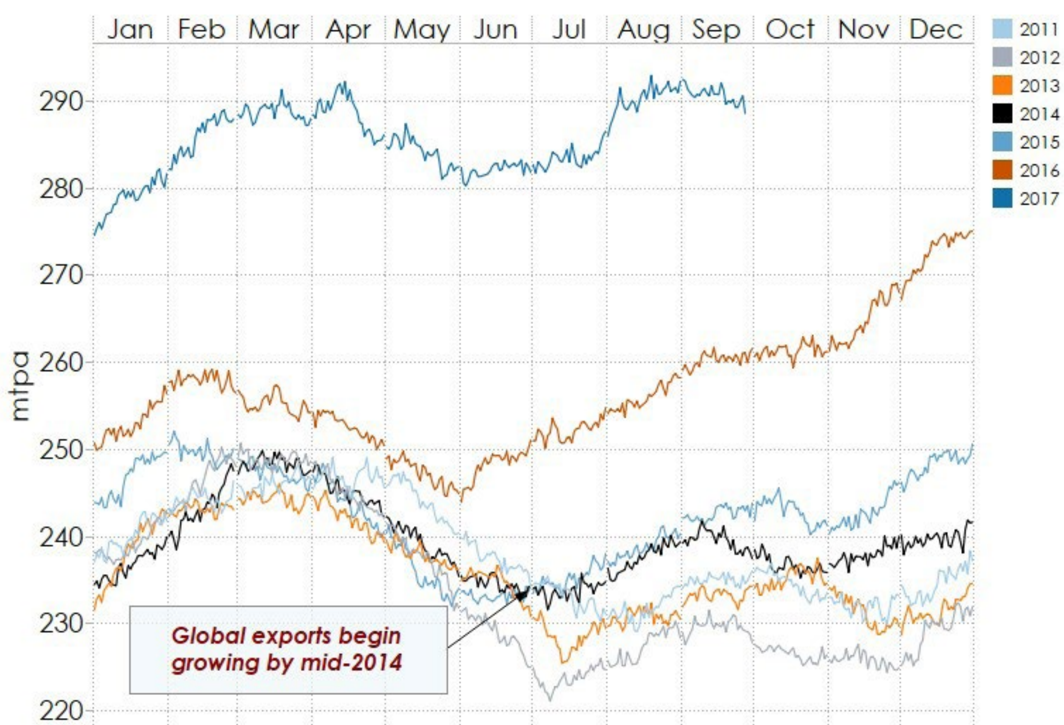
Global LNG exports declined slightly from 2011 into 2012–13, but the surge in global LNG supply started to materialize by mid-2014, with Australasian exports having already jumped by 165 percent since then (100-day moving average, figure 4).[1] Despite significant production declines and outages spread across Egypt, Yemen, and Trinidad and Tobago, the new volumes pushing into the Pacific Basin managed to tip global supply into a growth phase; during the fourth quarter of 2014, global LNG exports were up 4 percent year on year. After some wobbles in the first half of 2015, supply continued to grow, and the contiguous United States began contributing to the expansion, with Cheniere Energy's Sabine Pass terminal launching exports in February 2016. By the end of 2016, global supply was 17 percent higher than at the end of 2013 (figure 5).

Figure 4. Australasian LNG exports (100-day moving average)



Source: Kpler, CGEP.

Figure 5. Global LNG exports since 2011 (100-day moving average)



Source: Kpler, CGEP.

As these new supplies pushed into the system, prices in key importing markets tumbled. Asian LNG prices had touched a high of over $20/mmbtu in early 2014 and then plummeted by two-thirds over the following year. European hub prices retreated from the collapsing Asian market, dropping by one-third over the same period. But by early 2015, Asian LNG prices had fallen to parity with European gas hubs; by the summer of 2016, these importing markets approached the cheap US market, creating narrow price spreads that would challenge even the short-run economics of exporting LNG from the United States after accounting for the variable costs of liquefaction fuel, shipping, and regasification (and treating tolling fees as a sunk cost).[2] The heralded global price convergence seemed underway. But reality was more complicated.

EUROPEAN IMPORTS: SIGNALING A TIGHT LNG MARKET DESPITE LOWER GAS PRICES

While the fact that prices were falling and LNG supply was growing by 2014 may have indicated that a period of looser global gas markets was underway, looking at the LNG market from a European perspective reveals a different story. The volume of LNG flowing to Europe is a particularly important barometer for the global LNG market, with the continent acting in many ways as the world's swing LNG buyer. *And the number of cargoes arriving in Europe suggests that this vast new supply did not loosen the physical markets by nearly as much as most observers had expected.*

The drivers behind LNG imports into Europe can be quite different from those that dictate imports in the rest of the world. Outside of Europe, demand for LNG is driven more by structural issues than by price competitiveness. There are a handful of key dynamics that influence imports into these markets:

1) In several markets, LNG is *the only source of natural gas imports*. So if a country's gas demand rises or falls due to macroeconomic factors, nuclear plant outages, or renewable energy growth, buyers often flex LNG imports up or down as the marginal fuel source. Japan, South Korea, and Taiwan are the clearest examples of this dynamic.

2) In growth markets—China is by far the largest—*infrastructural development* can unlock dormant gas demand. New regasification terminals can connect energy-hungry regions to the waterborne market for the first time. Midstream and downstream developments can grow the market for gas; pipeline and distribution investments increase the population connected to the gas grid while new industrial or power projects can provide large sources of new demand at a time.

3) Long-term *take-or-pay supply contracts* can lock in LNG demand from a specific buyer, limiting the flexibility to curtail imports even when fundamental circumstances or spot market price signals might suggest that lower imports would be appropriate.

4) As in practically every gas market, *the weather* can push demand up or down. A particularly cold winter can trigger additional heating demand in Asia, for example. Or low precipitation in Brazil can drag down hydroelectric output and force increased reliance on natural gas for power generation. Mother Nature leaves her mark on gas markets every year.

With the United States no longer a major LNG importer, Europe—specifically the traded market hubs stretching from Italy in the south to the United Kingdom in the northwest—has become the only major LNG importer flexible enough to bend to the whims of the waterborne market. Europe absorbs additional LNG when the rest of the market loosens and can adjust accordingly when markets elsewhere require more LNG. In a bit of an oversimplification, Europe is often the buyer of last resort for LNG; once the rest of the world has sated its demand, the leftovers of global supply drift to Europe.

Several features make the European market more flexible than other importing regions:

1) Europe has *abundant physical flexibility* in its natural gas system, with substantial spare regasification capacity, ample storage capacity, and pipeline interconnections to move gas between markets.

2) The European markets benefit from *multiple supply sources* as alternatives to LNG in the form of pipeline imports from Russia, Norway, and North Africa; LNG accounted for just 7.4 percent of total gas supply in the liquidly traded gas markets last year.[3]

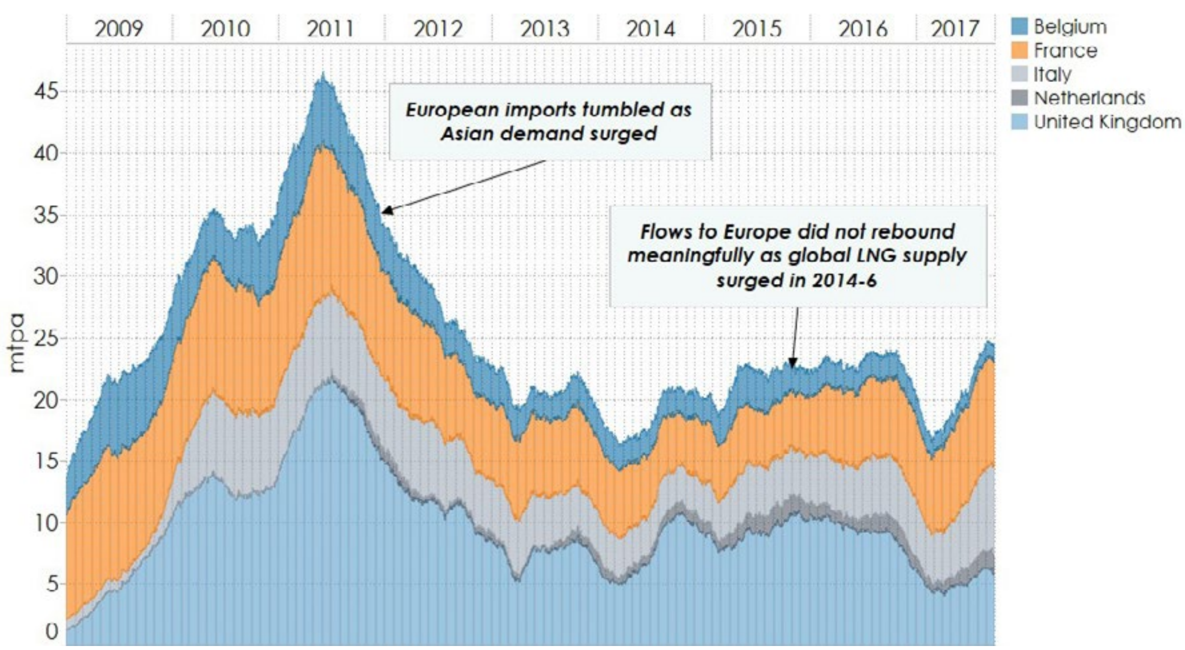
3) The demand side provides additional flexibility as *gas competes with coal in the electricity sector*, increasing gas demand when gas prices are relatively low (versus coal) and decreasing gas demand when prices are high. This demand elasticity results from the system as a whole dispatching more or less gas-fired power over time rather than individual power plants switching between fuels.

4) Though European hubs are not nearly as liquid as those in North America, *financial markets* in Europe do allow participants to hedge LNG flows, sell additional supply on short notice, or replace lost supply if LNG is diverted at the last minute. Financial derivatives in the Asian LNG market are in their very early stages of development, and market liquidity remains scant.

The interplay between European imports and demand in the rest of the world has played out clearly in recent years. At the beginning of this decade, LNG markets were loosening rapidly as new Qatari-led supply growth well outpaced demand outside of Europe, particularly with expected US imports never materializing in the face of booming shale production. New regasification capacity opened in the United Kingdom, France, Italy, and the Netherlands, allowing LNG imports to jump by 240 percent from the beginning of 2009 to mid-2011 (figure 6).

But Japan's Fukushima crisis in March 2011 and its subsequent nuclear fleet shutdown boosted LNG purchases by the world's largest importer by 25 percent within two years (+17 mtpa using a 365-day moving average to smooth out seasonality). Meanwhile, Korean demand was growing (due to its own nuclear fleet problems and some cold weather), and China emerged as a major importer by adding regasification capacity and nearly doubling its imports. In the three years following the Fukushima crisis, combined Korean and Chinese import growth almost matched Japan's. As demand surged from these core importers, global LNG exports barely grew during 2011–14. Europe, the world's swing import market, saw its LNG supplies evaporate while cargoes chased premium markets elsewhere.[4]

Figure 6. LNG flows to key European markets since 2009 (200-day moving average)



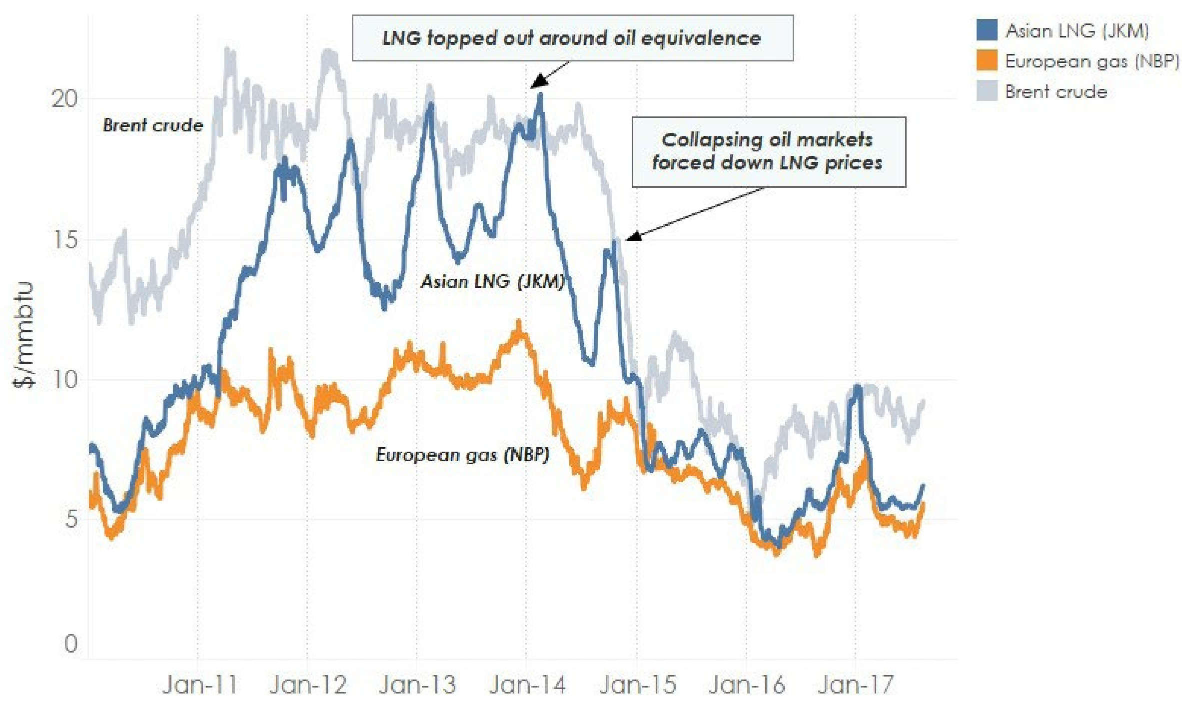
Source: Kpler, CGEP.

But a curious thing happened once global supply started taking off in 2014: European imports did not recover—even as prices dropped around the world. *The long-awaited LNG wave to Europe did not materialize, despite LNG imports into Japan, Korea, and China actually falling by 10 mtpa from early 2014 through the end of 2016*, giving up one-third of their post-Fukushima demand surge just as global supply was expanding. Even flexible US LNG exports, which many had thought would head to Europe, have found buyers elsewhere. Since Sabine Pass began liquefaction, less than 5 percent of these volumes have landed in Europe (excluding Iberia and Turkey, which represent another 10 percent).

What happened? Clearly, the LNG market was not as loose as many observers had expected. Much of the explanation lies in places that few people were watching: countries that represented less than 4 percent of global demand during the year leading up to mid-2014. But before detailing the ascension of these new and emerging importers, it is important to account for how Asian and European prices collapsed and converged if physical markets were not actually loose. The primary driver of falling gas prices came from outside of the LNG market, as plummeting oil prices triggered a period of premature convergence between Asian and European prices.

From June 2014 to January 2015, Brent crude prices dropped by nearly 60 percent. Halfway through this collapse, crude prices fell to energy-equivalent parity with spot Asian LNG prices. Figure 7 illustrates the path of Asian and European spot gas prices alongside crude prices expressed in $/mmbtu. Even during the LNG market's tightest periods in 2011–14, Asian prices struggled to climb beyond oil equivalence. And as oil prices tumbled, LNG's soft price ceiling crashed with them, pushing Asian spot LNG prices down toward European hub levels.

Figure 7. Asian and European gas prices vs. Brent crude oil in $/mmbtu since 2010



Source: Bloomberg, Platts, CGEP.

There are two main reasons why oil prices help to create a soft ceiling for LNG prices. First, the vast majority of long-term LNG supply contracts are still indexed to the price of oil, even as oil indexation has become less of a factor in European contracts in recent years. Many short- and medium-term LNG contracts and tenders are also priced as a percentage of oil.

The long-term contracts usually contain a measure of flexibility for the buyer to increase or decrease volumes within a certain range according to short-term needs (often around 10 percent of the contract volume). When LNG importers see spot LNG prices rise above the cost of their oil-indexed supply, they can flex up their long-term supply volumes while pulling back from the spot market. This behavior can also reduce spot supply as some LNG cargoes that would have been sold on the spot market are used instead to satisfy higher contract demand. But this flexibility serves to kink the supply curve for long-term importers and to help provide a soft cap for the spot market. Importers can also use a combination of LNG storage and increased oil-indexed purchases over several months to smooth demand shocks over a longer time, making it difficult for LNG prices to break well above oil equivalence for an extended period.

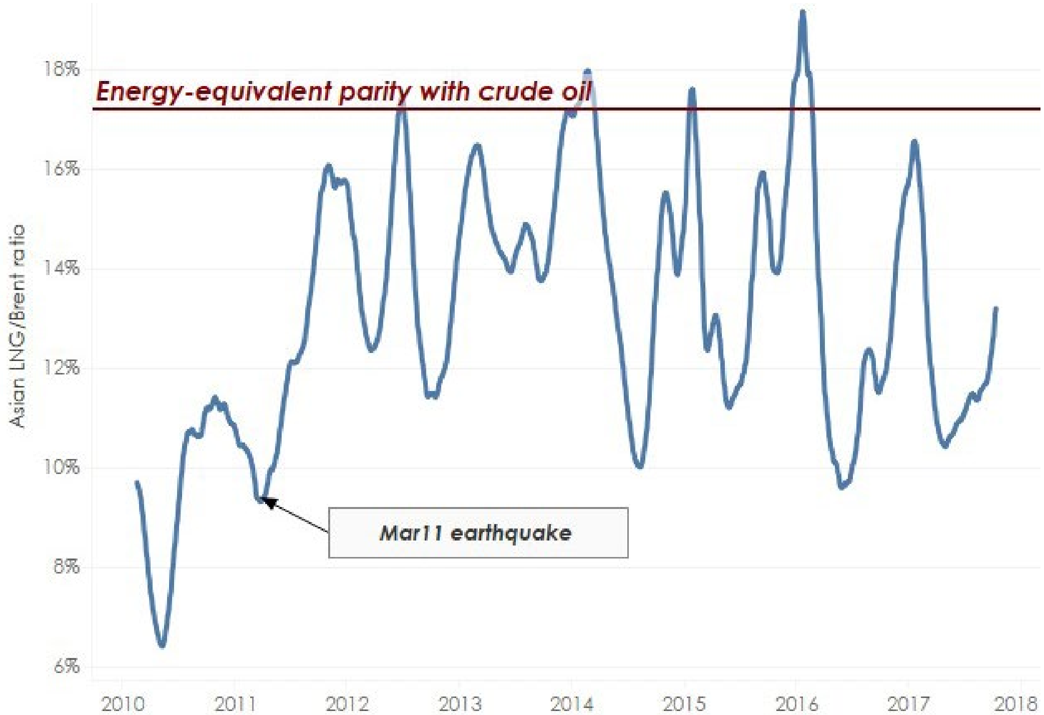
Second, there is some capacity for demand to switch between gas and oil in the short term. Some Japanese utilities, for example, have shown that they will dispatch oil-fired power plants ahead of gas-fired power plants during times when LNG prices are especially high. Elsewhere, some refineries and other industrial plants that typically consume natural gas can instead turn to oil-based fuels on a limited basis. In the grand scheme of things, this demand response is of a smaller scale than most of the fundamental dynamics that we discuss, but it does help to enforce a loose oil-based cap on spot LNG prices. LNG prices can indeed move above oil equivalence, but those moves are rare, usually short lived, and struggle to break far above the oil parity level.

So while global supply was ramping up after mid-2014, the Pacific-Atlantic price convergence turned out to be a bit of misdirection for observers primed to expect a looser market. When looking at Asian spot LNG prices as a percentage of crude oil, as prices are often discussed in the market, the continued tightness in the physical market becomes more apparent. Figure 8 illustrates a simple LNG-to-Brent ratio using the front-month prices. After Fukushima, Asian prices rallied relative to oil, with prices briefly breaching crude-oil parity during periods of acute tightness. The period after mid-2014, when global LNG supply started growing, has not been markedly less tight by this measure.[5] If the physical LNG market started loosening dramatically after mid-2014, this shift was not clearly reflected in LNG prices.

Indeed, gas prices in the world's importing markets began to rebound soon after oil markets recovered from their low point in 2016. In April 2016, front-month UK gas (NBP) fell to as low as \$3.70/mmbtu, and the Japan Korea Marker (JKM), an indicator of the spot Asian LNG market, touched a low of \$4/mmbtu. Prices were pushed lower both by the oil (and coal) market plunge into the beginning of the year—and an exceedingly warm 2015–16 European winter that left European gas inventories very high heading into summer. During the 2016–17 winter, JKM touched a high of \$9.75/mmbtu, and Q1 2018 financial swaps are pricing over \$9/mmbtu at the time of writing.

Although we have portrayed the market as tighter than conventional wisdom among market observers has suggested, we must acknowledge that there is at least some evidence that global gas markets have been loosening on the margins. There are a number of reasons why gas prices in the importing markets have strengthened since touching their lows. Among the most important factors has been the rising price of coal. Figure 9 shows the energy-equivalent ratio of UK gas versus coal prices (unadjusted for typical power plant efficiencies) in forward markets. Although absolute gas prices have climbed in the United Kingdom and the rest of Europe, gas prices have generally fallen relative to even stronger coal prices. This has allowed gas to displace some coal in in the European power-generation system. So while oil has lowered the soft ceiling for LNG prices, higher coal prices have supported gas markets, at least in Europe. Nonetheless, this erosion of gas prices relative to coal has more to do with European fundamentals and cannot explain the tightness in the waterborne market that has kept LNG supply out of Europe.

Figure 8. Ratio of Asian spot LNG (JKM) vs. front-month Brent (30-day moving average since 2010)



Source: Bloomberg, Platts, CGEP.

Figure 9. Energy-equivalent ratio of UK gas (NBP) vs. API2 coal for the 2018 calendar-year contracts

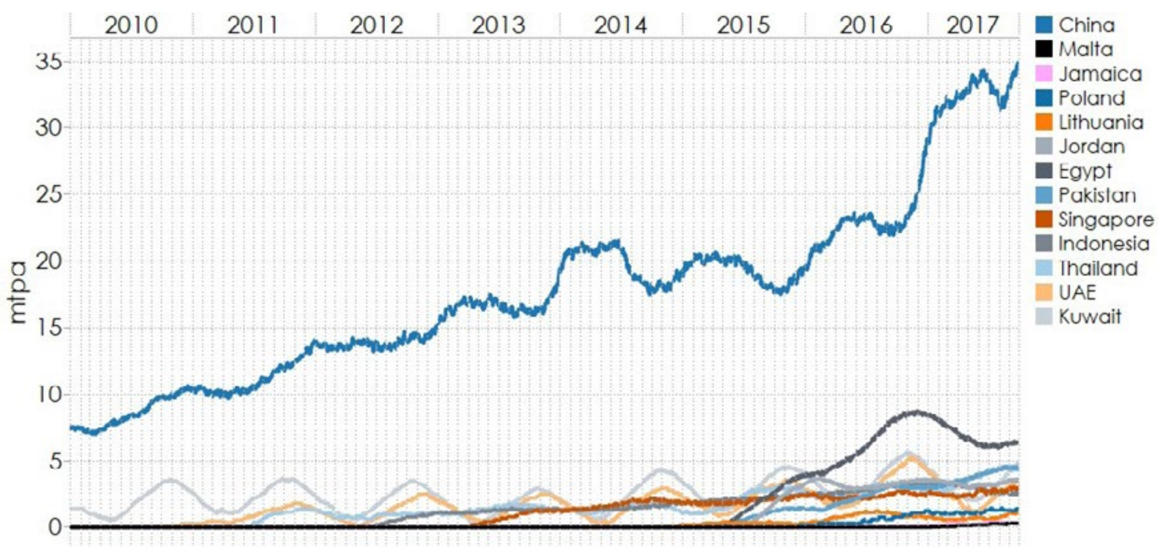
Source: Bloomberg, CGEP.

THE DEMOCRATIZATION OF LNG IMPORTS

In the first half of 2014, a total of 31 countries imported LNG, but the demand side of the market was extraordinarily top heavy; Japan, Korea, and China alone accounted for 60 percent of global LNG imports. Generally speaking, as go these three, so goes global demand. At the time, most LNG analysts might reasonably have assumed that they could get most of the way to forecasting waterborne demand if they could accurately predict imports into the big three. But this rule of thumb was about to change.

Through September 2017, the club of LNG importers has grown to 40 countries, but it remains a top-heavy group. Figure 10 illustrates imports since 2010 to China and 12 smaller LNG importers that the authors have grouped into a collection of emerging importers—countries that may seem to be marginal players in the LNG market but have demonstrated a capacity for import growth. As the world's third-largest importer, China's demand dwarfs that of these smaller markets, and China's 68 percent growth since mid-2014 (200-day moving average) has been remarkable.

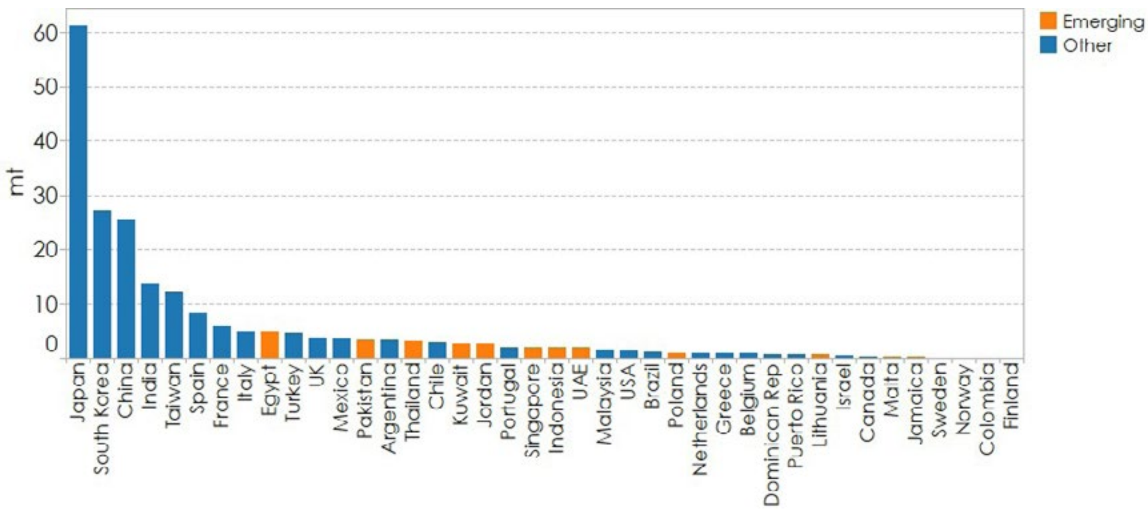
Figure 10. LNG imports by China and 12 noncore countries since 2010 (200-day moving average)



Source: Kpler, CGEP.

The scale of these 12 smaller importers is further illustrated in figure 11; among the group of emerging importers, only Egypt has managed to crack the world's top 10. Even as the largest of these emerging importers, Egypt accounted for a mere 2.3 percent of global imports.

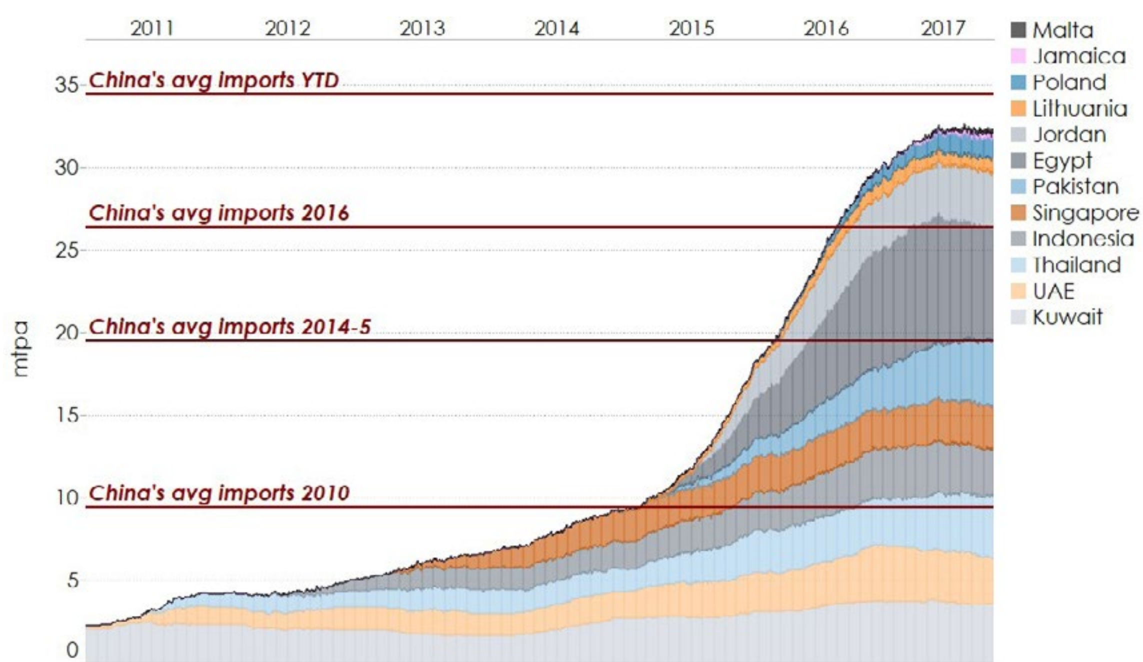
Figure 11. LNG imports by country in 2017 (through September 2017)



Source: Kpler, CGEP.

However, when these disparate countries are viewed in aggregate rather than individually, we can see that they have become an astonishing new force in the global LNG market. Figure 12 once again illustrates LNG flows into these small and new LNG importers. At the middle of 2014, these 12 countries accounted for just 3.3 percent of global LNG imports (365-day moving average), with several of them yet to import a single cargo. I*n slightly more than three years since then, these importers have accounted for a staggering 57 percent of net global import growth*, with imports leaping by 24.2 mtpa. As a group, the emerging importers now import almost as much LNG as China does, and they have contributed two-thirds more to global import growth than China has since mid-2014—even with Chinese imports surging over the past year.

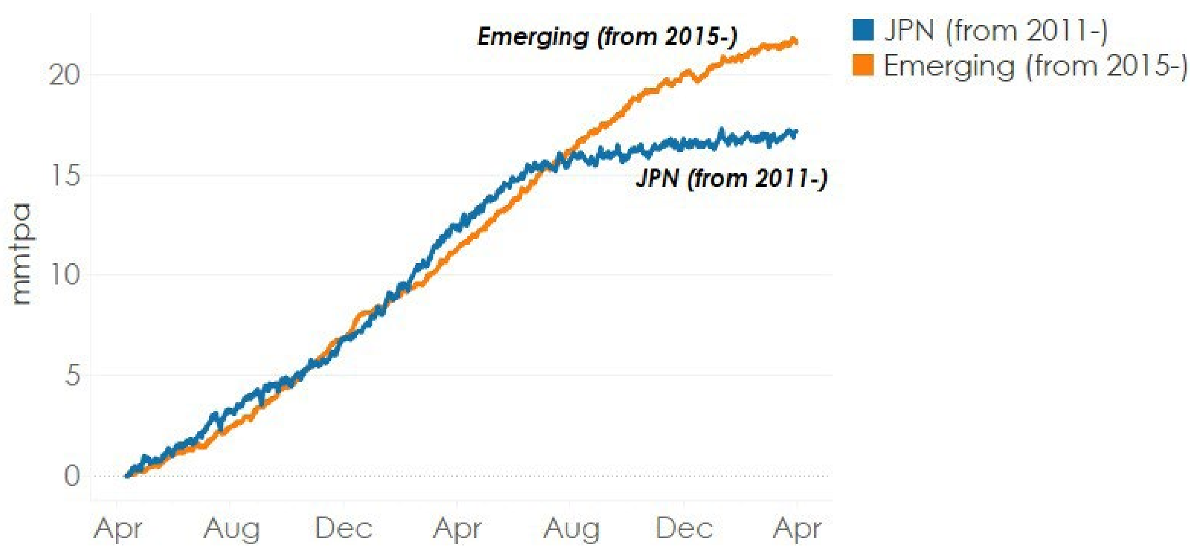
Figure 12. LNG imports by 12 non-core countries since 2011 (365-day moving average)



Source: Kpler, CGEP.

There are many other ways to illustrate the scale of this phenomenon. But perhaps the most striking comparison we can make is to place the emerging importers next to the most dramatic shock ever to hit the LNG market. In the two years after April 2015, *the demand shock from these dozen countries surpassed Japan's demand boom in the wake of its Fukushima disaster and nuclear shutdown*. Two years after the 2011 earthquake and tsunami, LNG imports into Japan, the world's largest importer, had jumped by 17.2 mtpa from a base of 68.2 mtpa (figure 13). In the two years following April 2015, the emerging importers registered 21.7 mtpa of growth—off of a base of just 10.2 mtpa. If market observers had known in 2014 that another Fukushima-scale demand shock was rumbling beneath the surface, most of them likely would have tempered their forecasts for a rapidly loosening market.

Figure 13. Two years of import growth in Japan from April 2011 vs. a group of 12 emerging importers from in April 2015 (365-day moving average)



Source: Kpler, CGEP.

Some observers may point to surging demand by these importers as a symptom of a loose LNG market rather than evidence of a structurally tighter market than expected. Booming demand from these countries, the argument would suggest, is simply a response to the lower prices that have prevailed since 2015. It is indeed possible that these importers took in more LNG than they otherwise would have at higher prices. But attributing this new demand purely to price sensitivity overlooks some of the intricacies of the LNG market.

Among the emerging importers, the largest portion of demand growth came from Egypt, Pakistan, and Jordan (see discussion below), all of which opened new terminals in early 2015—reflecting investment decisions taken in 2013–14 while spot LNG prices were still very high, averaging more than $16/mmbtu. This timing suggests that many of these investment decisions were not made in response to low absolute LNG prices but rather to attract baseload energy supply to address energy shortages or to displace oil in power generation.

Moreover, this burst of demand does not seem to be a response specifically to declining LNG prices relative to competing fuels. Many of the emerging importers have turned to the LNG market to displace more expensive petroleum as a fuel for power generation or to alleviate energy shortages. But as we have seen above, LNG prices as a percentage of oil have fluctuated in a similar (and high) range since 2011, including during this burst of LNG demand in 2014–16. Within the lower absolute-price environment seen since early 2015, a similar gas/oil ratio means that the total fuel cost savings of switching from oil to gas in power generation actually declined from the 2011–14 period to the period of substantial import growth during 2015–17.

The story of growing demand from emerging importers is as much about infrastructure availability as it is about price response. So how did this growth catch the market by surprise when LNG infrastructure projects typically take years and hundreds of millions of dollars to develop? Moreover, growth from emerging importers has tapered off this year. Was 2014–17 just an anomaly, or can emerging importers continue to demonstrate substantial growth going forward? The answers to these questions lie in an examination of FSRUs, a type of offshore regasification facility that has allowed for the rapid opening of new markets.

SNEAKING UP ON THE MARKET: INFRASTRUCTURE UNLEASHES PENT-UP DEMAND

Not all of the new demand from the group of emerging importers should have caught the market by surprise, as the development of regasification projects in Poland, Lithuania, and Indonesia had been years in the making. But the largest sources of growth seemed to sneak up on the market. The surprise is primarily due to the rapid deployment of FSRUs, which allowed countries to begin importing LNG faster than most observers had expected.

The first FSRU entered service in 2005 at Excelerate's Gulf Gateway facility off the coast of Louisiana, and today FSRUs are considered a mature technology.[6] An FSRU is effectively an LNG tanker with regasification capacity on board, giving the vessel the capability to send gas into a pipeline rather than offloading LNG to a separate regasification facility. FSRUs are either purpose-built vessels or converted LNG carriers. They can be moored at sea, docked at a jetty, or even shuttled between ports, filling up with LNG at one and regasifying it at another.[7]

Leading up to 2014, conventional wisdom among market observers suggested that becoming a new LNG importer required three to five years and a capital outlay of up to $1 billion for a land-based regasification facility and at least 18 months of lead time to deploy an FSRU for an offshore option.[8] An onshore facility is typically less expensive per unit of energy imported over multiple decades because of economies of scale and the potential to build substantial LNG storage capacity. Indeed, the main disadvantage of FSRUs is their limited storage and send-out capacity compared to onshore terminals, which makes them less flexible to respond to major short-term fluctuations of gas demand—an important feature in a market in which demand can be very sensitive to weather.

But floating units have several advantages that can make them quite attractive to importers seeking to access the waterborne market for the first time, such as

1) a smaller capital outlay to build or convert an FSRU than for an onshore facility;

2) the ability to lease FSRUs from third-party owners, allowing even smaller initial investments and an ability to use the facility for periods shorter than the full lifetime of the asset; and

3) much shorter lead times in developing the project due to shorter permitting periods and construction timelines.

Funding the construction of a newbuild FSRU costs between $250 million and $350 million, depending on the vessel specifications.[9] Converting a conventional LNG tanker into an FSRU costs between $80 million and $160 million, depending on vessel type and size.[10] Though these are reasonably large investments, they pale in comparison to larger onshore facilities that often exceed $1 billion.

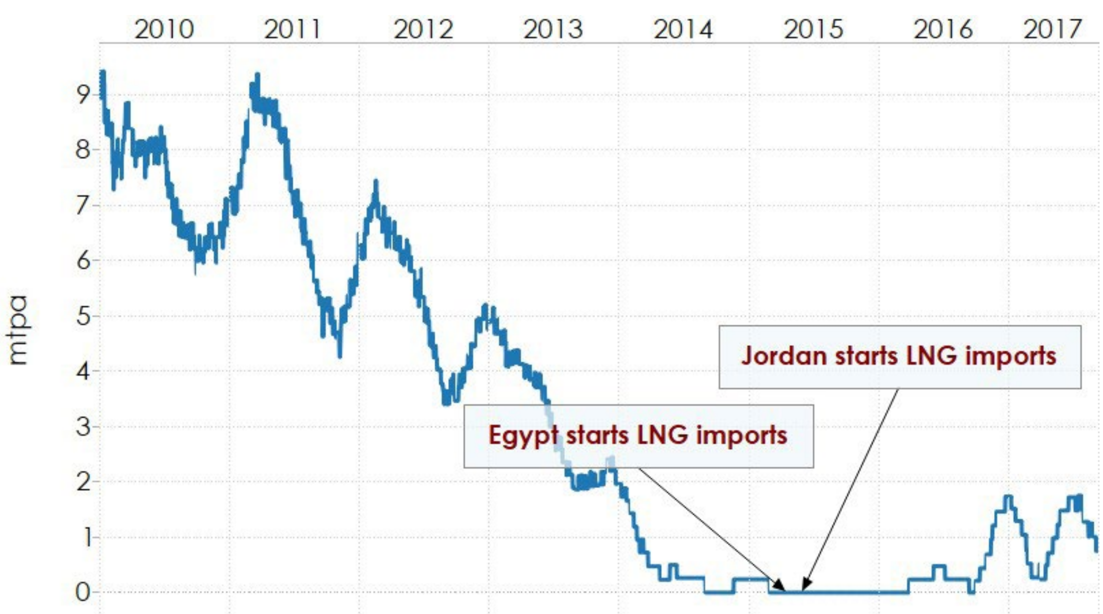
Although FSRUs can be constructed with the express purpose of servicing a specific import facility, the lower capital cost allows companies to order vessels speculatively as well. Companies such as BW Gas, Golar, and Hoegh have ordered FSRUs without specific commitments from importers to charter the vessels, hoping to place the units before the ship is delivered. Capable of reaping dayrates of $100,000 to 135,000 for a regasification project, one FSRU can earn $35 to $50 million of revenue in a given year. And if there is a gap between commitments at regasification terminals, many FSRUs can operate as standard LNG carriers as well, continuing to generate revenue via the shipping market.

This ability to lease, rather than develop and own, an FSRU presents an attractive entry point to the LNG market for many aspiring importers. Although chartering a vessel can create a multiyear financial commitment, it spreads the cost over time and drives down the initial investment even further. With the importer not having to finance the vessel itself, its primary capex goes to building an underwater pipeline or a jetty connecting the FSRU to the onshore gas transmission grid. The typical cost of the infrastructure required to support an FSRU terminal is in the range of $100 million to $200 million, although this can vary significantly. Part of the reason why the costs of an FSRU are lower than those of an onshore facility is that the footprint on land is substantially smaller. Not only does this require less preparation work, but it also means that projects often face fewer regulatory hurdles in the permitting process.

Between the more limited physical work, the shorter permitting window, and the ability to charter a vessel already in the market (or under construction), the time between making an investment decision and beginning LNG imports has shrunk dramatically. Early in the decade, the rule of thumb was that launching an FSRU-based import facility would take at least 18 to 24 months—considerably faster than a land-based facility but still with plenty of advance notice for the market. But by 2015, the lead time had shrunk to 12 months or less, even in places that many observers deemed unlikely to deliver projects on time.

Of the 24.2 mtpa of import growth in the emerging LNG importers since mid-2014, approximately 60 percent has come from three countries that have aggressively deployed FSRU: Egypt, Jordan, and Pakistan. Egypt, which was one of the world's first LNG *exporters*, saw its gas production decline rapidly following the Arab Spring and the toppling of the Mubarak regime. With rising domestic demand and energy shortages, Egypt began to divert natural gas into the domestic market while Qatar helped to support the Morsi government by backfilling some of Egypt's LNG volume commitments to its offtakers.[11] Overall, Egypt's LNG exports dropped from 9.4 mtpa in early 2011 to zero by early 2015 (figure 14).

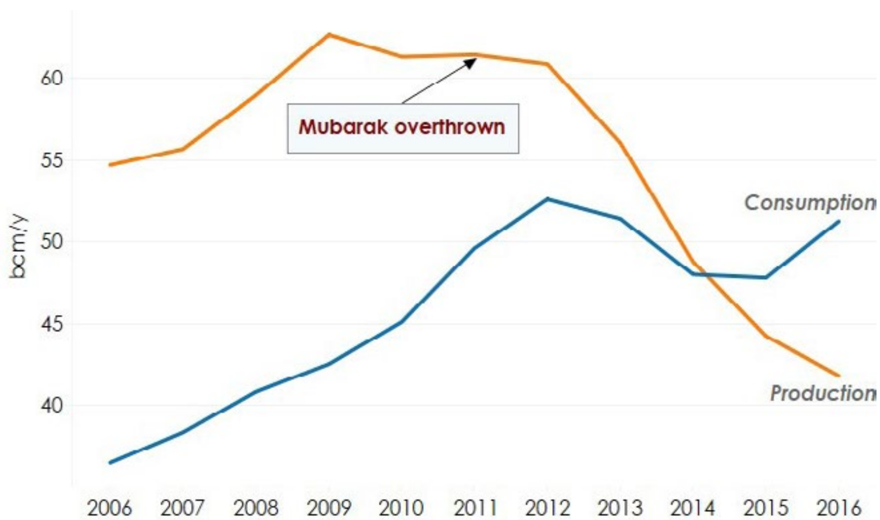
Figure 14. Egypt's LNG exports since 2010 (100-day moving average)



Source: Kpler, CGEP.

The gas supply situation in Egypt was even worse than the tumbling LNG export volumes suggest. Natural gas accounts for more than half of Egypt's primary energy consumption, and domestic demand grew by 44 percent from 2006 through 2012, just as production began a steep decline (figure 15). By 2014, widespread blackouts had become commonplace, and state-owned EGAS started curtailing gas deliveries to major industrial buyers in an effort to keep the lights on.[12] EGAS signed a letter of intent with Hoegh to charter an FSRU in May 2014 and imported its first cargo 11 months later.[13] The second FSRU was developed even faster, with just five months passing between EGAS's invitation to tender in May 2015 and sending out first gas via the BW Singapore at the beginning of November.[14]

Figure 15. Egypt's natural gas production and consumption since 2006



Source: BP 2017 Statistical Review of World Energy.

Egypt had also been exporting gas via the Arab Gas Pipeline to Jordan and Israel, but attacks on that pipeline caused multiple disruptions after 2011. With Egypt needing to divert gas into its domestic market anyway, exports via pipeline dried up. Jordan's pipeline imports dropped by 80 percent from 2010 to 2012 and halted completely by mid-2013. Having relied on gas to fuel 80 percent of its power generation, Jordan turned to more expensive oil-fired power generation to make up for the gas shortfall.[15]

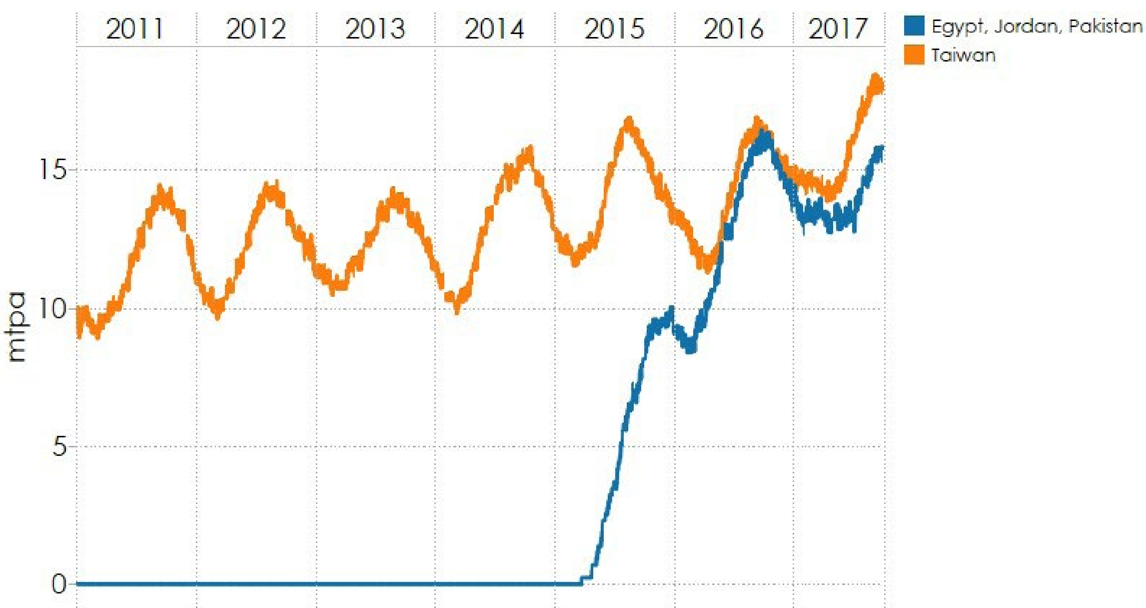
Jordan quickly decided to turn to the LNG market, with the Ministry of Energy and Mineral Resources chartering the Golar Eskimo in July 2013 with National Electricity and Power Company holding the capacity and importing LNG.[16] The Aqaba Development Corporation awarded a turnkey development contract in November 2013, and the FSRU delivered its first gas 18 months later in May 2015.[17] Since commencing LNG imports, Jordan has even occasionally sent some regasified LNG over to Egypt via pipeline.

Pakistan, meanwhile, also decided to jump into the LNG market. The country of 193 million people faces persistent energy shortages, with the IEA estimating that a quarter of the population lacks access to electricity.[18] From 2010 to 2015, Pakistan's population and energy demand expanded by 9 to 10 percent, but its gas consumption has grown by just 2.8 percent, with fuel shortages forcing the electricity fleet to rely heavily on oil-fired generation. Over the previous five years, Pakistan's gas-fired electricity generation actually shrank by 6 percent, while the country's oil-fired generation increased by 30 percent, according to the country's electric power authority.[19]

Despite some early controversy about the tendering process for construction of the terminal, the Engro Elengy facility was developed within 11 months of breaking ground in April 2014, with the first gas arriving in March 2015.[20] Competition with pipeline gas imports is far from imminent. Although Pakistan has recently broken ground on its section of the planned TAPI (Turkmenistan-Afghanistan-Pakistan-India) pipeline, that project has experienced persistent delays and seems destined to recede into the horizon with seemingly insurmountable geopolitical risks, financing difficulties, and cost escalations.

As Egypt, Jordan, and Pakistan have demonstrated, when infrastructure unlocks access to countries with a combined population of 300 million, the potential to unleash latent gas demand is substantial, particularly with preexisting natural gas infrastructure to distribute and consume the gas internally, allowing a rapid uptake of LNG in these markets. The three countries each imported their first LNG cargoes via FSRUs within a two-month period in the spring of 2015. Eighteen months later, the three countries were importing a combined 16.5 mtpa, on par with peak summer demand in Taiwan, the world's fifth-largest LNG importer (figure 16).

Figure 16. LNG imports into Egypt, Jordan, and Pakistan vs. Taiwan since 2015 (100-day moving average)



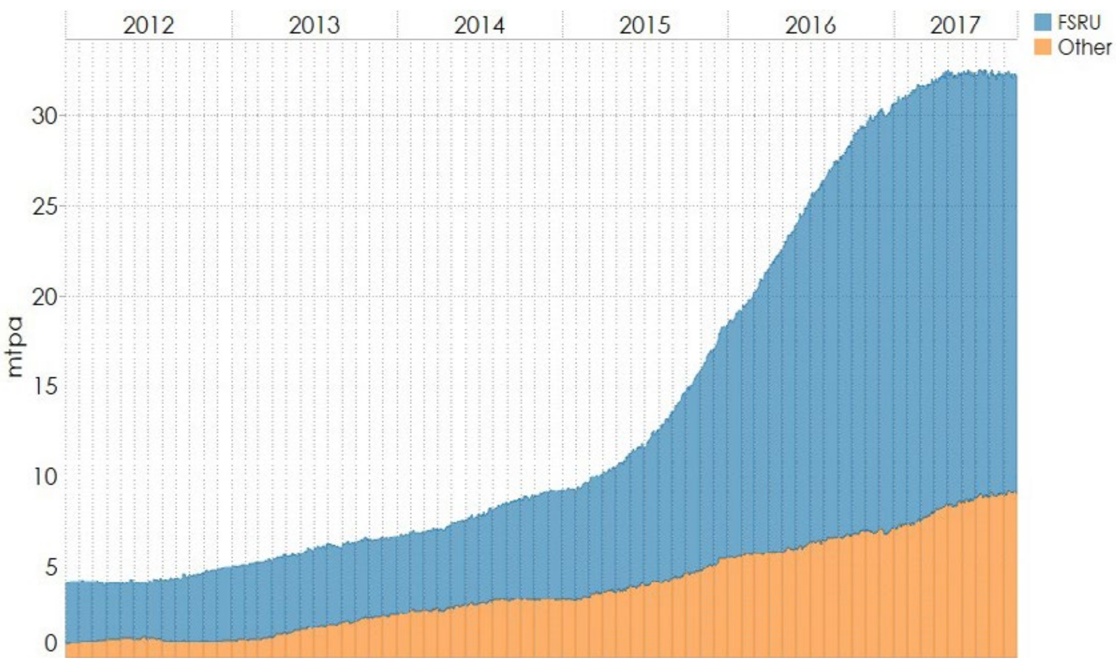
Source: Kpler, CGEP.

It is worth noting that growth from the broader group of 12 emerging importers has slowed from its breakneck pace in 2017. A major reason for this slowdown has been a slate of promising upstream projects in Egypt (with the largest one, Zohr, likely starting production within months), which have started to revitalize the country's upstream and reduced Egypt's need to import LNG. At the end of September 2017, Egyptian LNG imports were down by 2 mtpa year over year while Jordan's imports have been steady and Pakistan's have continued to climb.

But even if Egypt's LNG imports dwindle toward zero as domestic production ramps back up, its two FSRUs are not stranded assets. They can depart from Egypt and redeploy elsewhere in the world, chasing new markets and highlighting the capability of these assets to continue to unleash demand even if consumption in a given market evaporates or the unit is replaced by a larger onshore facility, as occurred at Tianjin in China and as is planned in Kuwait.

Detailing the drivers of LNG demand growth from all 12 of our selected emerging importers is beyond the scope of this paper, and we have highlighted just three of them here. Not all of the demand growth from emerging importers has come via FSRUs, but it is clear that access to FSRU capacity has played an enormous role in driving this new dynamic, with 18.1 mtpa (75 percent) of the group's new demand since mid-2014 coming via FSRUs (figure 17). The share of global LNG imports that have discharged at FSRUs has climbed from 6.2 percent at the middle of 2014 to 11.3 percent over the past year.

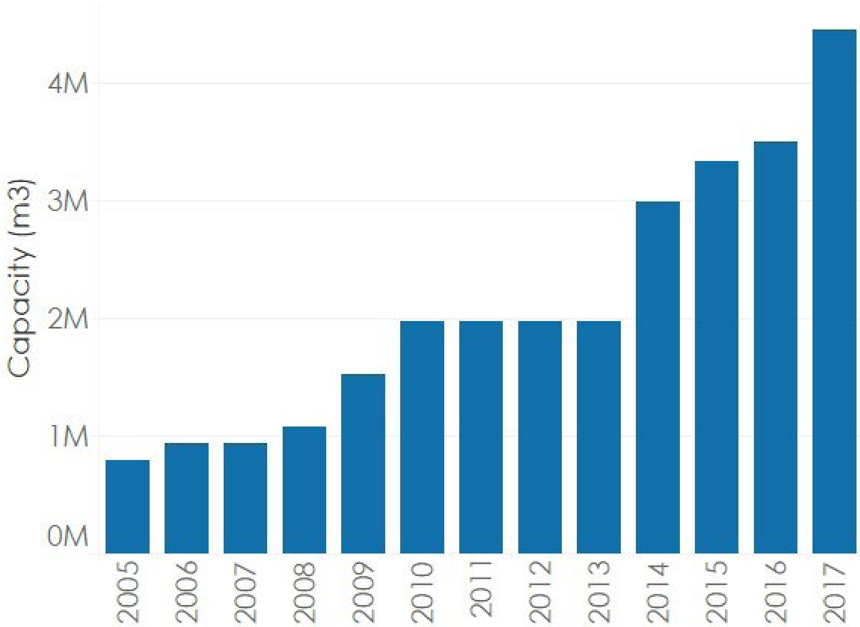
Figure 17. LNG imports to 12 emerging importers by facility type since 2012 (365-day moving average)



Source: Kpler, CGEP.

As recently as 2013, only 14 FSRUs were in service. By the beginning of 2017, the global FSRU fleet consisted of 24 vessels (20 actively deployed at regasification terminals) with another 11 vessels on order. Seven of the FSRUs on the order book had already been assigned to various regasification projects, while the other four remained speculative orders for the time being. From the end of 2013 through the end of this year, total FSRU tanker capacity will have climbed by nearly 125 percent (figure 18).

Figure 18. FSRU fleet capacity in cubic meters since 2005



Source: Wood Mackenzie.

Although FSRUs represent just 6 percent of a global LNG tanker fleet that has been growing alongside liquefaction capacity, they have played a major role in expanding import capacity around the world. FSRUs have accounted for 13 of 44 (31 percent) new regasification projects since the beginning of 2013 compared to just 3 of 21 new facilities during the preceding three years.

As global LNG supply continues to grow through the end of this decade, a key question is whether there will be sufficient FSRU capacity to continue making LNG imports accessible to myriad locations, unlocking pockets of demand and absorbing much of the looming supply overhang. Given the number of FSRUs currently under construction, uncommitted to regasification, or potentially available to be redeployed, *it is unlikely that FSRU capacity will be a substantial bottleneck limiting demand growth in the next few years*. We expect that more than one dozen such FSRUs will be available for new regasification projects through the end of the decade. Moreover, if demand for FSRUs strengthens further, companies can construct a newbuild FSRU within 30 to 36 months or potentially convert a conventional tanker in just 20 months. Shipping companies such as Hoegh, Excelerate, and GasLog have taken steps to expedite the process of expanding their FSRU fleets by taking out options for slots at various shipyards or preordering essential equipment necessary to proceed with anticipated conversions.[21]

The potential for pent-up demand to continue mopping up more of the expected LNG surplus remains substantial. In just the next few years, Bangladesh, Ghana, the Philippines, and South Africa may connect to the waterborne market, adding countries with a combined population of more than 350 million to the LNG importer club. Meanwhile, Pakistan has plans to continue expanding its import capacity. Even Australia, while becoming an LNG export powerhouse, is considering import terminals for regions where gas supply is tight (Indonesia, Malaysia, Egypt, and the United States already simultaneously import and export LNG).

Bangladesh, in particular, has announced ambitious plans to leap into the LNG market. Three substantial floating facilities are in the works with a total nameplate capacity of 11.25 mtpa, including two FSRUs slated for operation next year. Midstream projects to deliver the gas to market have already made considerable progress, and the country has further plans for a handful of smaller floating facilities and more distant hopes for land-based facilities within a decade.[22]

Clearly, the capacity for emerging importers to continue reshaping the LNG market should be a crucial theme for the industry through the end of the decade. It is a dynamic that should be watched as closely as the demand trajectories of LNG giants like Japan, Korea, and China, as well as the progress of massive liquefaction projects under construction and an expansion of Qatari exports. But this new source of demand growth holds a number of potential consequences beyond supply and demand metrics.

IMPLICATIONS FOR LNG MARKETS

There are a number of broader implications for market participants and for governments as more countries access the LNG market for the first time. Addressing specific issues country by country is beyond the scope of this paper. But at a high level, we can group several of these issues into four categories: commercial, financial, governance, and market implications.

Commercial Considerations

Any time that a country wades into a capital-intensive industry for the first time, there are many commercial issues to untangle. The LNG market is no different. One example of a commercial challenge lies in how governments and companies with little experience in the market select their LNG suppliers. In general, when faced with these circumstances, *new importers have leaned toward familiar faces*, turning toward their established petroleum suppliers or underpinning the new gas supply with government-to-government agreements. International and national oil companies have been able to place significant volumes into the new markets. Trading houses, in particular, have demonstrated outsized success in opening up new markets quickly to grow their own share of the LNG trade. Egypt's rapid move into the LNG market is an excellent example, with EGAS awarding a large portion of its purchases to Glencore, Trafigura, Vitol, and Gunvor.[23]

Familiarity cuts both ways. Even with LNG prices down from their 2011–14 heights, a single LNG tanker can carry $15 to $25 million worth of fuel. Counterparties in some of these emerging importers often have poor credit ratings, and payment periods can stretch to three months or even longer, depending on the market.[24] If a seller agrees to place just two cargoes per month into a market, it could wind up with more than $100 million in receivables outstanding to a questionable counterparty at any given time, enough to make many executives blanch.[25] Along with their prior relationships as suppliers to these countries in other fuel markets, *large trading houses have a history of actively participating in insurance and reinsurance markets to manage such risks*, which helps to mitigate any hesitancy to jump into a new LNG market.

Finally, the establishment of LNG imports often creates a supportive environment for international-local partnerships when developing infrastructure. International companies bring deep pockets and expertise in accessing financial, commodity, and shipping markets, along with project development skills. But they rarely have the ability to market natural gas further downstream within a new country. So even if large LNG players can identify attractive opportunities in new markets, they often need to find local partners to help execute projects. Meanwhile, multilateral institutions, such as the World Bank, have become involved as well, stepping in to provide financing to support some of these projects (see below).

As FSRUs help open new markets, the lowest-hanging fruit may soon dry up. Generally speaking, the countries that can most quickly benefit from new regasification capacity are those that have previously developed midstream and downstream natural gas infrastructure. It is no surprise that countries like Egypt, Pakistan, and Bangladesh have been among the most aggressive in snapping up FSRUs. Natural gas accounted for about half of primary energy consumption in Egypt and Pakistan last year—and three-quarters in Bangladesh—making them excellent candidates to connect to another source of gas supply via the waterborne market.[26]

Smaller markets or countries lacking widespread gas infrastructure face an additional set of challenges in developing an internal market to utilize the fuel. LNG-to-power projects hold the promise of alleviating power shortages or weaning smaller countries off of more expensive petroleum-fired power generation. However, *aligning the financial and operational incentives and risks across stakeholders in both the regasification project and the power project is not always straightforward*. Nonetheless, creative approaches to project structuring can mitigate these problems, and, as LNG-to-power projects become more widespread, such solutions may become commonplace.[27]

Financing Issues

Even though an FSRU-based import facility requires far less capex than a land-based facility does, the preparation work can still exceed $100 million. Accessing the funds to undergird these investments can be a challenge for many new project developers. This is especially the case when cash-strapped governments or their state-owned energy companies are juggling multiple priorities or external debt problems.

Support from multilateral development banks can help overcome some of the challenges related to credit quality. Pakistan's first FSRU project, for example, received loans from both the World Bank and the Asia Development Bank, as well as a 20 percent equity investment from the World Bank's International Finance Corporation (IFC).[28] The IFC also committed to provide up to $136 million in equity and debt financing to support the Moheshkhali Island FSRU project in Bangladesh.[29] Overall, the past three years have demonstrated that capex concerns have not been a binding constraint for companies and governments seeking to enter the market.

However, once the facility is operational, working capital can become a persistent battle. Some importers can develop unwieldy backlogs of receivables for their sales further downstream, making it more difficult to fund LNG procurement on an ongoing basis, especially when regulated retail prices fail to cover wholesale fuel costs. Even with firm contracts, the default risk is real.

Egypt provided an illustration of these risks just eight months after it began importing LNG, when EGAS reportedly had trouble paying for its LNG supplies. A BP cargo arrived offshore Egypt in late December 2015 but lingered for two weeks without offloading its LNG before it was eventually diverted to Brazil.[30] EGAS wound up extending its payment terms from 15 days to 90 days, with some estimates suggesting that the company had accumulated an outstanding bill of up to $1 billion for delivered LNG. When EGAS eventually made a payment for LNG in March 2016, the state-owned company made headlines across the industry as suppliers breathed a sigh of relief.[31]

Working capital struggles are not unique to this group of emerging importers, nor are they universal to this group. But they are often more acute in emerging economies, amplifying the credit risks associated with opening new LNG markets and forcing some importers to pay a slight premium to secure supply. The fact that LNG exporters and trading houses have been willing to take on substantial credit risk to place LNG volumes in new markets provides some evidence that the market has been loosening on the margins.

Governance Challenges

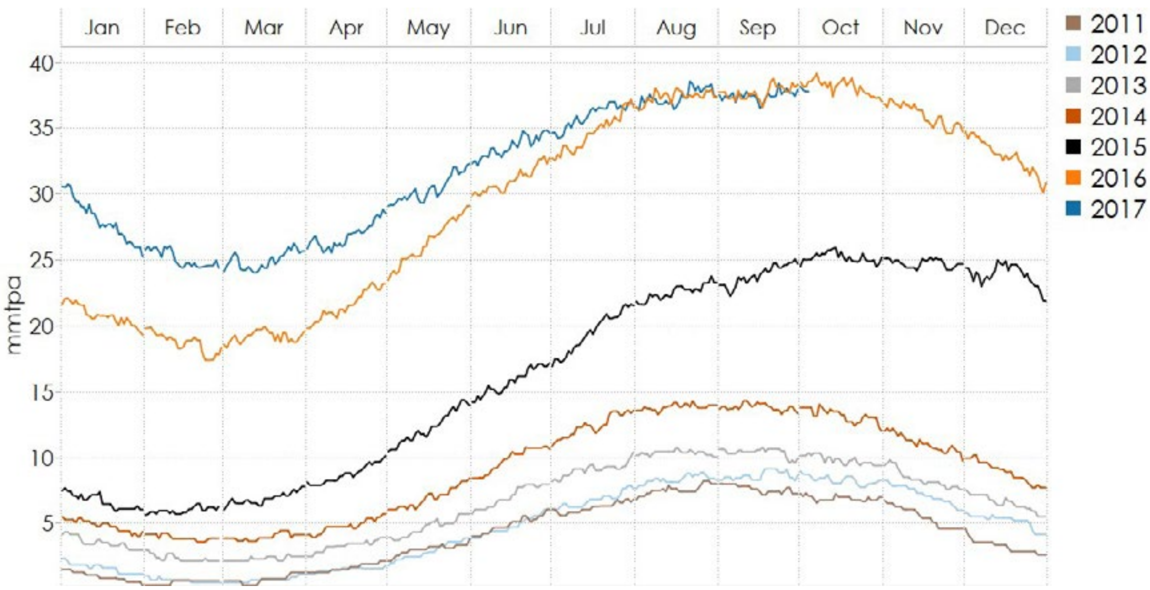
A number of the countries in our emerging importers group face significant governance challenges, sometimes exacerbated by corruption. In Transparency International's 2016 Corruption Perceptions Index, countries such as Bangladesh, Pakistan, Egypt, the Philippines, and Thailand received scores of 35 out of 100 or worse.[32] Most of these countries also fare poorly in the World Bank's ease of doing business index, highlighting issues related to excessive bureaucracy and opportunities for corruption. These issues present challenges both to the importing country eager to meet its energy needs and to the companies seeking to capture market opportunities.

Again, these challenges are not universal to this group of emerging LNG importers, which also includes Singapore, UAE, Poland, and Lithuania (ranked among the 38 best countries by Transparency International). But even for countries not facing widespread governance challenges, there is often a knowledge gap among government and industry about the workings of the LNG market. This does not prevent countries from entering the market, but it can make for a steep learning curve, causing delays to project development or mismanaged tenders for supply.

Market Implications

There are a number of broader consequences for the LNG market as well. First, these importers do not pull on the LNG market at the same rate throughout the year. Much of the impetus for these countries to begin or increase LNG imports is to alleviate energy shortages or to displace petroleum in power generation. Electricity demand spikes during the Northern Hemisphere's summer across the Middle East and much of Asia. This results in a seasonal shape to the LNG purchases by emerging importers, with a clear peak in the third quarter (figure 19).

Figure 19. LNG imports by emerging importers since 2013 (100-day moving average)



Source: Kpler, CGEP.

Imports to this group rise by ~15 mtpa from the winter trough to the summer peak (100-day moving average). Demand from the LNG market's big three importers of Japan, Korea, and China exhibits a countervailing pattern, typically dropping by 45 to 50 mtpa from a winter peak to an early-summer trough. The emerging importers, therefore, may provide contraseasonal demand that could smooth out the global market's annual fluctuations. However, the seasonal patterns are not perfect mirror images, perhaps moving the market's seasonal shape toward more of a double peak for global demand as emerging importers continue to grow as a group.

The ascension of this group of importers is also likely to impact flexibility in a waterborne market that has been developing more liquidity with shorter supply contracts, fewer destination restrictions, and a growing number of flexible free-on-board (FOB) cargoes coming out of the United States. It is difficult to pinpoint exactly how this group of buyers will impact flexibility except to say that it will be complicated.

The heart of this paper suggests that increasing FSRU capacity has introduced greater flexibility for buyers to commence and grow LNG imports on relatively short notice. In this respect, FSRUs have opened the door for new and growing markets to absorb a significant amount of the anticipated LNG surplus in the latter half of this decade. However, once an importer makes the decision to develop an FSRU-based facility, the consequences for market flexibility become more nuanced.

The drivers of LNG demand growth in emerging importers are diverse, but the most important dynamics tend to be alleviation of energy shortages (e.g., Egypt, Pakistan, Bangladesh), displacement of oil in power generation (Pakistan, Kuwait, UAE, Jordan, Jamaica, Malta), fueling economic growth (Thailand, Singapore, Pakistan), offsetting domestic production declines (Indonesia, Egypt, Pakistan), and diversifying the natural gas supply mix (Poland, Lithuania, Jordan).

So when we contemplate whether these countries will be price sensitive, the cost of LNG supply must be weighed against the alternatives. Even if LNG prices jump, the demand response will depend on the context of that price move, such as the relative value of LNG versus oil and the scale of increasing fuel costs relative to working capital constraints in countries facing energy shortages. The economic and political cost of blackouts are typically far greater than the costs of fuel purchases, so governments have a strong incentive to keep the lights on.

Moreover, *these countries' LNG purchases do not lend themselves to short-term price sensitivity*. Although some purchases are indeed small and relatively short term, most purchases by emerging importers come via bilateral multiyear contracts or tenders for supply that can stretch for a year or more. And the majority of these purchases are indexed to the price of oil, pushing much of these countries' short- and medium-term price risks into oil markets rather than spot LNG markets.

By and large, the entities responsible for securing LNG volumes are not structured to be commercially nimble. Most of these institutions are set up for fuel procurement rather than flexible trading or optimization. For many of these state-controlled energy companies, even establishing the capacity to hedge financially requires an act of government. As a consequence, they tend to leave their oil price exposure unhedged in paper markets. Although larger or more sophisticated LNG purchasers sometimes sell volumes back into the market, emerging importers are unlikely to resell volumes that have already been contracted for delivery, even if prices do jump. Overall, we think it is fair to say that expanding FSRU capacity likely boosts the market's demand elasticity in the medium term (adjustments over a two- to five-year period), but the emergence of these new importers probably locks in new demand and reduces market flexibility in the short term (within one year).

Finally, the democratization of LNG imports might serve to maintain linkages between gas and oil prices in the waterborne market. In the more liquidly traded gas markets, oil indexation is now largely a historical relic. After the discovery of natural gas resources in North America and Europe, producers worked to establish markets for their product. To do so, they priced gas relative to oil, the fuel they sought to displace, with a slight discount. After years of infrastructure development and growing market liquidity, oil indexation has become obsolete in markets where oil has retreated from the power and heating sectors. In these parts of the world, the two fuels no longer compete for market share, as there is no substitution in meaningful volumes.

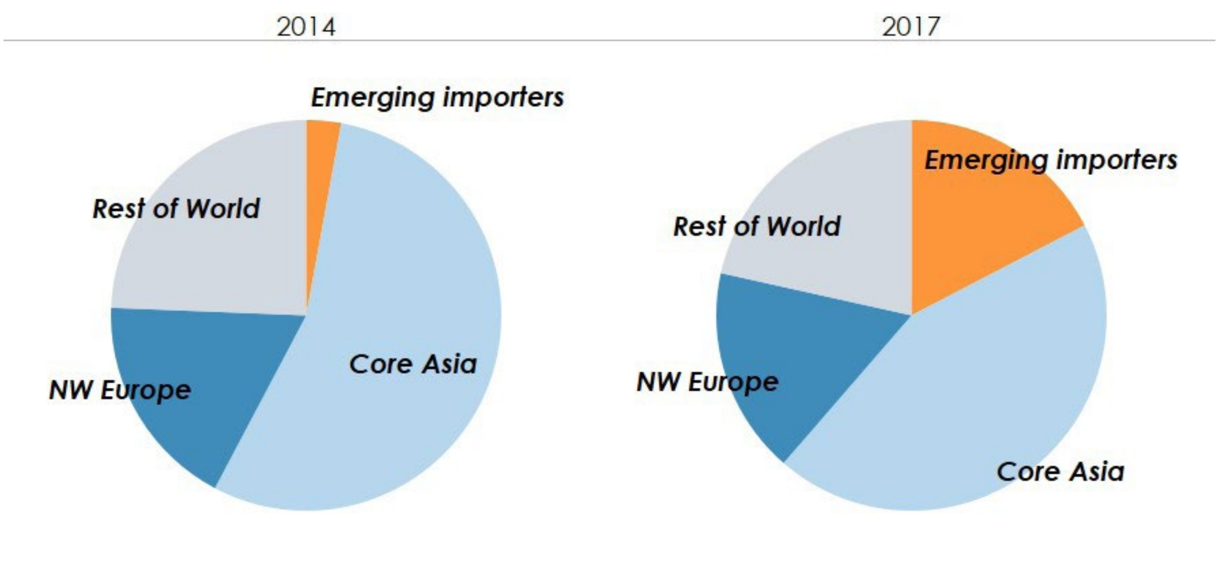
The United States did away with formal oil-gas price linkages in the 1990s, and oil indexation has become a less prominent pricing mechanism in long-term European supply contracts in recent years. Oil indexation covered just 30 percent of Europe's gas consumption in 2016 but remains a widespread feature of LNG contracts (see appendix), operating as the price mechanism for 76 percent of volumes.[33] As new markets from the Middle East to Asia and the Caribbean seek to displace oil-fired power generation with gas, the rise of emerging importers may help maintain price linkages between oil and gas in the waterborne market, even as growing FOB liquidity due to US LNG exports holds the promise of disconnecting the two commodities.

CONCLUSION

Perhaps one of the most promising signs that the democratization of LNG will continue is that some of the largest LNG exporters are taking notice. One decade ago, Qatar Petroleum was looking ahead to its liquefaction expansion and the challenge of placing an unprecedented volume of LNG around the world, so it invested in large-scale regasification plants in Europe and the United States with an aggregate regasification capacity of 36.6 mtpa.

But Qatar is now turning its attention to smaller markets that hold the promise of collectively absorbing substantial volumes of LNG. Earlier this year, Qatar Petroleum joined a consortium to develop Pakistan's first privately owned (and third overall) FSRU project, which is slated to start operation next year.[34] Qatar Gas Transport Company has also formed a partnership with Norway's Hoegh LNG (another member of the Pakistani FSRU consortium) to explore ways to boost LNG demand by expanding LNG access in new markets.[35] Perhaps this is a reflection of emerging importers accounting for 17 percent of Qatari exports, up from just 3 percent as recently as 2014 (figure 20). Malaysia's Petronas is looking to open new markets to its LNG exports as well, announcing plans to build Bangladesh's third import terminal.[36]

Figure 20. Breakdown of Qatari LNG exports by destination: 2014 vs. 2017 through September



Source: Kpler, CGEP.

As emerging importers have established themselves as a major driver of global LNG balances, they have also made it more difficult to forecast market trends with confidence. Projecting demand from the largest importers, such as Japan, Korea, and China, is by no means easy. But analysts are usually working within the confines of reasonably well-established relationships between gas demand and the variables that influence them: the weather, economic growth, competing sources of power generation, and policy initiatives. Analysts might not always be precise in their forecasts, but they can at least think through the probabilities in a rigorous way.

Emerging importers present a different problem altogether, especially now that they can enter the market with little advance warning. The challenge here lies not in econometric forecasting but in handicapping whether a potential importer will take an investment decision, be able to manage the project to completion, and obtain LNG supply to meet demand. How does an outside observer assess whether conversations in government offices and boardrooms in South Africa, Morocco, Vietnam, or Myanmar will lead to actual regasification projects? And even when a project moves forward, trying to predict seasonal patterns and utilization rates is difficult when assessing markets that lack data transparency.

Beyond reshaping global LNG flows, when countries do connect to the waterborne market, those decisions impact millions of lives. Like Pakistan, Bangladesh faces a number of severe energy challenges, including fuel shortages and widespread blackouts that the World Bank has estimated cost the country 2 to 3 percent of its GDP.[37] Accessing the LNG market allows countries like Bangladesh and Pakistan to alleviate their energy shortages—and to do so in a way that does not exacerbate air pollution crises in countries[38] that already face some of the worst local air quality problems in the world.[39]

Some of the lessons that we have drawn from this group of emerging importers also apply to established importers with growing economies and their own environmental challenges. If governments in China or India pivot to aggressively incentivize natural gas consumption, an infrastructure-driven demand response could materialize very quickly. China has experienced a burst of demand growth this year as the government has moved to help clean up the air in northern cities by replacing coal-fired boilers with gas-fired ones. China Gas estimates that such conversions can eventually add upward of 40 million new customers to the gas grid in northern China.[40]

If called on to help facilitate demand growth, the global FSRU fleet has demonstrated its ability to expand regasification capacity faster than observers would have thought just three years ago. And as the LNG market continues to look ahead to expanding supply and years of potential surplus, the story of these emerging markets warns market observers against resting too comfortably on easy assumptions.

APPENDIX: OVERVIEW OF PRICE MECHANISMS IN LNG SUPPLY CONTRACTS

Historically, most LNG has been bought and sold under long-term (i.e., 20 years or longer) take-or-pay contracts with oil-indexed pricing formulas and very limited destination and volumetric flexibility. These features were adopted from pipeline gas contracts in the early days of LNG trade.

LNG export projects are highly capital-intensive undertakings with long lead times and payback periods. The developers of multibillion-dollar LNG export schemes have traditionally required relatively inflexible long-term commitments from their buyers to mitigate project risk and to be able to finance their project.[41] The buyers—predominantly Asian utilities—also accepted long-term contracts because their primary concern was to secure a reliable baseload energy supply (and their domestic commitments were often similarly long term in nature).

Destination restrictions—limitations to the right to resell contracted LNG volumes to third parties—have also been a common feature of long-term LNG contracts, especially in Asia. Some LNG contracts allow the buyer to divert contracted cargoes but require it to share the profit of such sales with the seller.[42] Destination restrictions have traditionally protected the seller from having to compete against its "own" LNG on the spot market, while also allowing it to apply price discrimination and capture the arbitrage between regional markets. The European Commission banned these destination clauses in natural gas contracts in the early 2000s,[43] but such restrictions have largely survived in Asian LNG contracts, in part because utility buyers had little incentive to trade contracted LNG cargoes on the spot market until recently.

Oil indexation gained near-universal acceptance in long-term LNG contracts during the 1970s and 1980s mainly at the insistence of LNG exporters, who were also major oil producers at the time.[44] Linking the price of LNG to crude oil initially had sound logic from the buyers' perspective as well, since natural gas was a direct competitor to oil and oil products in stationary applications, including power generation. Moreover, the utility buyers of the time were able to pass through any potential cost increases to their domestic customers with no difficulty.[45] European buyers later amended the model and replaced crude oil with a combination of oil products (mainly fuel oil and heating oil) in their pricing formulas.[46] But the practice of indexing LNG prices to crude oil—typically using 3 to 9-month moving averages—lives on in the majority of long-term LNG contracts in Asia as well as in some Southern European contracts.

As a result of these characteristics, LNG trade, for most of its history, was a relatively rigid point-to-point business. But in recent years, each of the main tenets of LNG contracts and pricing mechanisms has come under pressure.

Given the potential for lower spot LNG prices over the next several years and the uncertainties around the gas demand outlook in many key LNG importing countries, buyers are less willing to commit to new long-term LNG contracts today than they were a few years ago. This is reflected in the substantial decline of the average length and size of LNG contracts over the last three years compared to the 2011–13 period.[47]

There are also signs that buyers are opting for greater volumetric flexibility both within and outside the traditional take-or-pay structures—by seeking lower minimum purchase obligations in existing contracts or by ruling that take-or-pay requirements are potentially illegal once the export project achieved sufficient return on its investment, for example.[48] However, the lack of new investments over the past two years indicates that the industry is not yet ready to completely abandon long-term take-or-pay contracts as one of the cornerstones of LNG project finance.

The future of destination restrictions appears less ambiguous. Following in the European Commission's footsteps, Japan's Fair Trade Commission recently found these restrictions illegal,[49] while South Korea is currently examining the legality of destination clauses in LNG contracts.[50] Other Asian LNG importers could soon follow suit and eventually completely outlaw the use of destination restrictions in LNG contracts.

Oil indexation has given way to some other indices in long-term LNG contracts in recent years. US LNG, for example, is linked to the US Henry Hub benchmark. Other contracts use hybrid pricing, linking the price of LNG to a mixture of crude oil and/or various hub prices, such as the NBP in the UK or the TTF in the Netherlands. However, oil indexation remains dominant in LNG trade for now—even as it is being constantly squeezed in European pipeline gas contracts—and it is unlikely to disappear completely in the foreseeable future.

NOTES

1 Throughout this paper, the authors rely on shipping data that track discrete journeys by LNG tankers around the world. Several vendors collect and disseminate data from tanker automatic identification system (AIS) signals using a combination of satellite- and land-based transponders. Kpler, a developer of ship-tracking software, has provided data that allows us to analyze global LNG tanker journeys. Analyzing tanker traffic focuses on import and export flows rather than nameplate import and export capacity. Put simply, the authors are counting ships. Tanker journeys offer extraordinarily noisy data, so the paper uses various moving averages to more clearly illustrate fundamental flows. Generally speaking, the authors try to use moving averages that are sufficient to smooth out the data but brief enough to identify inflection points or seasonal trends. The data are presented in million tons per annum (mtpa) and annualized to normalize flow rates across different periods. Mtpa is a common unit of measure in the LNG market, rather than bcf/d or mcm/d, which are more common units of measure in the pipeline markets of North America and Europe, respectively. Travel times between LNG export and import locations can last anywhere from two days to several weeks. The authors track LNG exports using the day of departure and LNG imports via the date of arrival, using data through September 2017 in an effort to be current. These moving average calculations may sometimes look different from other sources that present discrete monthly or quarterly data points, such as customs data or financial reports. Furthermore, estimates of the specific quantity of gas in an individual tanker can sometimes vary slightly due to different methodologies and conversion factors that we rely on as outside observers. But overall, the assertions in this paper should align well with other sources, particularly those that rely on shipping data, even if figures are not identical.

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3 These are the authors' own estimates of gas supply in the interconnected and liquidly traded gas markets of United Kingdom, Belgium, France, the Netherlands, Germany, Switzerland, Italy, and Austria, calculated using publicly available daily flow data published by the transmission system operators (TSOs) in each of these countries. For example, data from the United Kingdom is available via National Grid at http://www2.nationalgrid.com/uk/industry-information/gas-transmission-operational-data/.

4 Here, we define European LNG imports as flows into Belgium, France, Italy, the Netherlands, and the United Kingdom. We have chosen this definition because the regasification facilities and pipeline networks in these countries are well connected to traded European gas hubs. Though Spain and Portugal import significant LNG volumes, Iberia has only limited connections with more liquid physical markets via France. We have grouped Poland and Lithuania within the new and emerging markets. Despite a substantial pipeline connection with Germany, this is primarily a transit corridor for Russian gas via Poland, though commercial linkages between Poland and the rest of Europe are growing with reverse-flow capacity at the border. Lithuania lacks connections with the traded European markets altogether, with its new LNG imports competing with the country's Russian supply.

5 In reality, oil-indexed gas supply is benchmarked against an assortment of formulas and trailing moving averages. This simple ratio of spot prices represents more of a shorthand for the relative value of prices that is often used within the industry. The authors use the Platts Japan Korea Marker (JKM) as an indicator of Asian spot prices. From the start of the Fukushima crisis in March 2011 through mid-2014, the JKM-to-Brent ratio averaged 14.2 percent. During the period from mid-2014 through September 2017, that ratio averaged 13.1 percent—down slightly but well above the 9.6 percent ratio that prevailed for 15 months before Fukushima. At the time of writing at the end of September 2017, the ratio stands at 15.6 percent. For a more detailed overview of price mechanisms in LNG contracts, please see the appendix.

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