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Asian LNG market changes under low oil prices: prospects for trading hubs and a new price index

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ABSTRACT

Presented is an analysis of the changes in the North-East Asian energy landscape as a result of the decline in global oil prices. The end of February 2016 saw the first exports of liquefied natural gas (LNG) from the U.S. mainland when major shale gas company Cheniere Energy's first LNG cargo left the Sabine Pass terminal in Texas. There are expectations that the beginning of U.S. LNG exports may trigger flexible trading. To the year 2020, U.S. LNG exports to North-East Asia will be increased. North-East Asia needs to continue its effort to promote regional cooperation and co-prosperity by building a North-East Asian gas trading hub. Russia will seek to keep U.S. LNG in check through price negotiations. The evolution of an Asian gas hub will be to a great extent influenced by how Russia and China will reconsider their energy strategies.

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Liquefied natural gas (LNG) markets in Asia are undergoing profound and permanent structural (pricing and contractual) changes amid an ongoing global supply glut in the low oil price environment over the last two years. When oil prices began to decline in mid-2014, many observers initially expected that this trend could prolong dependency on Middle Eastern oil and gas by diversifying with Russia and the United States. The low oil price environment over the last two years has been both a blessing and a curse for Asian LNG players. The growth of gas in the power sector was suppressed by cheap coal and growth in renewables (RES). There is an oversupply of massive quantities of LNG exports. But there have been ongoing pricing and contractual renegotiations between Qatar and Asian LNG buyers. Qatar is the world's top LNG supplier and swing producer.

Long-term contracts have formed the foundation for the growth of the LNG market in Asia. Asian LNG buyers pay a so-called 'Asian premium' since the traditional pricing mechanism link to Japan Crude Cocktail (JCC). In addition, Asian customers are subject to rigid requirements on supply quantities, and restrictions on where LNG can be delivered. In January 2016, India's Petronet successfully renegotiated a long-term gas deal with Qatar, with prices almost halved. Qatar no longer being able to dictate deals. There has already been less Qatari LNG going to Asia, and they were really affected by increased production from Papua New Guinea, Australia, and Indonesia in 2015. New LNG export projects are coming on stream in the next few years in Australia, North America, Russia, and East Africa. From the Asian side even if some of the LNG exports from the U.S. or Australia are more expensive, they need security and diversification. Asian LNG buyers do not want to rely exclusively on Qatar and the Middle East.

LNG's correlation to oil is weakening, meaning opportunities to buy LNG at low prices are growing. LNG customers view the current market as a buyers' market, and are seeking to take advantage of their market power to challenge the existing long-term contract structure. The logical endpoint of these pricing and contractual changes is the creation of trading hubs in Asia.

Much has been written about the impact of low oil prices. This article provides an analysis of the impact of low oil prices on the LNG market in Asia. The goal of this article is to examine whether the Asian LNG market, which has been characterized by long-term LNG contracts, will experience a structural shift toward a more liquid spot market, and whether, as a result, an LNG trading hub will develop in Asia. In so doing, some lessons will be drawn from the gas market integration and the emergence of trading hubs in Continental Europe. The main argument of the article is that even if some of the 'first steps' toward the development of a gas trading hub in Asia have already been taken, there is considerable work to be done.

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The first section of the article provides an analysis of the impact of low oil prices on the global LNG supply and demand. The second section offers an overview of the LNG market in Asia and North-East Asia in particular and some of the pricing and contractual changes in 2009–2013. Third section examines the supply and demand rebalancing in the wake of the oil price collapse in 2014. The final section documents some of the recent moves toward gas trading hubs and a new price index in Asia in 2015–2016.

Global energy market rebalancing post 2014

There has been an extensive academic literature on the impact of the recent drop in oil prices (Claes, Goldthau, & Livingston, 2015; Baffes, 2015; Export-Import Bank of Korea, 2014; Kim, 2015). More recent studies examine the causes for, and the impact of, low gas prices, comparing oil and natural gas (Boersma, Ebinger, & Greenley, 2015; Bordoff & Houser, 2015; Colombo et al., 2016; Fattouh, Rogers, & Stewart, 2015; Kim, 2016). The literature on the drop in natural gas prices suggests that the global LNG market is currently oversupplied and stricken with low demand and prices. LNG glut is known to be worse than oil. Global gas demand growth has weakened considerably. The fall in gas prices has been the most dramatic in Asia. Spot prices in the key Asian markets have tumbled 75% from US$20 million British thermal units (MMBtu) in early 2014 to below US$5 MMBtu currently.

In June 2016, the International Energy Agency (IEA) released its 2016 Medium-Term Gas Market Report (IEA, 2016). The report claimed that energy policies have largely failed to deliver the promised Golden Age of natural gas. Noel Tomnay, head of global gas research at WoodMac, described the continuing slide of LNG prices as a 'train wreck happening in slow motion' (requoted from De Vriend, 2016). According to Nick Cunningham, there is a major difference between oil and LNG: the market for LNG is much smaller and less liquid. Therefore, a handful of new LNG export terminals, he argues, can significantly alter the supply/demand balance (Cunningham, 2015).

In terms of the causes for weak gas demand, the slowdown in Asian gas demand has particularly intensified, prompting a rare decline in the region's LNG imports. Economies in Asia are slowing, leaving a shortfall in demand. Japan, the largest LNG importer, is seeing its economy stagnate. China's growth has slowed significantly. China's plans to replace coal with natural gas to clean up its air may be scaled back. Another factor blamed for China's reduced appetite for gas and LNG is its move away from manufacturing. Should the implementation of environmental policies be slower than expected, the expansion in Chinese gas demand would be much slower. Demand in Japan and South Korea is forecast to stagnate or even to decline sharply depending on the scale of nuclear comeback in both countries. European gas demand peaked around 2010 at 543 billion cubic meters (BCM) (IEA, 2014). Demand in Europe fell around 390 BCM last year. Gas demand is projected to increase very modestly, with small increases in the power sector offsetting small declines for residential and commercial. While gas imports are expected to rise over the next decade as European domestic production in the North Sea rapidly declines, overall consumed volumes could stagnate or even fall in the next five years. In the U.S., increases in gas-fired generation from 2015 levels will be limited to the need to replace some of the coal capacity that retires. U.S. gas prices are unlikely to fall much further from the very low level of 2015, and coal-to-gas switching potential has largely been exhausted. The use of coal for power generation in the U.S. reduced from 49 to 37% from 2008 to 2012. Conversely, the use of natural gas increased from 21 to 30%. According to the announcement by the U.S. Government in July of 2015, the amount of gas used in power generation in the U.S. (31%) surpassed that of coal (30%) for the first time (Krane & Egerton, 2015). The number of thermal power plants reduced from 593 in 2009 to 518 in 2013.

It was believed that gas was heading for a golden age of high demand and solid prices to support the massive investments being made globally. LNG was believed to be at the center of this natural gas revolution. As the carbon emissions target set by the international agreement was uncertain before the signing of the climate change agreements in Paris in December 2015, the demand for gas – an eco-friendly fossil fuel compared to others – was increasing rather than introducing new and renewable forms of energy. Natural gas accounted for 23.7% of the five major energy sources in 2007, ranking third behind oil and coal, which accounted for 35.8–28.4%, respectively. New and renewable energy accounted for 7% of the energy mix (mostly hydro power), while nuclear energy accounted for just 6%. As of 2012, the energy ratio shifted, with oil accounting for 33.1%, coal accounting for 29.9%, and gas constituting 23.9% of energy usage. According to World Energy Outlook, published by the IEA, the global gas demand was expected to increase by 88% from 2750 to 5160 BCM by 2030 (Nyquist, 2015).

As the IEA warned in the Medium-Term Gas Market Report 2015, it is difficult for gas to compete in a world of very cheap coal, falling costs, and continued policy support of RES. Global gas demand is caught between cheap coal and continued policy support for RES. In the Medium-Term Gas Market Report 2016, the Executive Director of IEA, Faith Birol, said, 'We see massive quantities of LNG exports coming online while, despite lower gas prices, demand continues to soften in traditional markets.' Birol went on to say that the growth of gas in the power

sector was being suppressed by cheap coal and growth in RES (IEA, 2016).

The production of new and renewable energy in the U.S. is continuously increasing. According to the U.S. Department of Energy, a third of new power generation will come from new and renewable energy within 3 years and, including solar, wind, and geothermal energy will reach 17,000 MW. Solar energy production itself increased a whopping 418% from 2012 to 2014 to 12,000 MW (Blackwill & O'Sullivan, 2014). The EU's push for a low carbon future, as epitomized in its 20-20-20 goals, the 2030 Energy Strategy and the 2050 Roadmap, puts a policy priority on the transition toward a sustainable energy system, by way of supporting RES, energy efficiency measures, and reducing the share of fossil fuels in the energy mix (Goldthau, 2016, p. 10). Grid parity for solar and wind power becoming a reality in various Europe countries, which is a function of pro-RES regulation, subsidy policies, and rapidly faltering installation costs (Ibid).

Countries in Asia (North-East Asia (except Japan), Southeast Asia, and South Asia) are turning to coal. Power companies in India and elsewhere in Asia are turning back to coal because it is cheap and domestically sourced. Asian power companies are building more than 500 coal-fired power plants this year alone. And more than a thousand are on the drawing board (De Vriend, 2016).

Slowing primary energy demand growth means that the share of gas in the world's energy mix will still increase marginally over the next five years, despite slower global gas demand growth (IEA, 2016). The IEA expects that the oil market will be close to balance in the second half of 2016, and in 2017 it will be in balance (Ibid). This should help gas production growth resume, as gradually recovering oil prices improve the economics of associated/wet gas (Ibid). The process of market rebalancing is likely to take longer for gas than for oil (Cunningham, 2015). IEA does not foresee oversupply in traded gas markets improving meaningfully before the end of the decade.

Taking stock of gas market integration in Asia

The trajectory of global gas markets – and how fast they rebalance – will depend on the scale of reform for a more transparent and efficient market, including gas trading hubs in Asia. Much has been written about the benefits of gas market integration in different regions and countries. The commercial status quo of energy and gas markets established many decades ago has been in the process of change. In many parts of the world, the pricing mechanism based on oil indexation still predominated. The issue was not only the long-term contracts themselves, but the terms of these contracts such as destination and Take-or-Pay (TOP) clauses.

In North America, a liberalized gas market emerged and Henry Hub as the main North American gas trading hub was adopted in the late 1980s (Rogers & Stern, 2014, p. 1). The United Kingdom established the National Balancing Point (NBP) as a reference price in the late 1990s. The European experience demonstrates the potentially far-reaching implications of the development of gas trading hubs. In Continental Europe, the price of gas sold through a *take or pay* contracts was generally oil-pegged, reflecting a long-established policy by EU countries aimed at securing long-term natural gas contracts. Most pipeline gas and LNG was imported into Continental Europe under long-term import contracts with oil indexed price formulae and 85% of TOP contracts.

As noted, the British NBP was the first European gas hub, which started trading in 1996 although significant activity commenced in the spring of 1997 (Heather, 2015, p. 18). During the 2000s, several natural gas trading hubs emerged in Continental Europe. The Dutch TTF started in 2003 but for several years did not trade very much. Progress was firm from 2009 to 2011. The TTF today is about two-thirds the size of NBP in total traded volumes (Ibid, 19). As with the NBP, the TTF has very good data transparency and accessibility, good liquidity and is attracting an ever greater number of participants (Ibid). Germany has two Market Areas and two hubs: the NCG and the Gaspool both of which started trading in 2009. France now has two Market Areas and two hubs: PEG Nord and TRS.

Based on the North American and British markets' transition experience, the process can take 10–15 years and this is now proving to be the case in Continental Europe. Despite nearly 20 years passing since the British gas market liberalized and some 15 years since the EU published its first Gas Directives, there is still confusion in some parts of Europe as to what a 'gas hub' actually is (Heather, 2015, p. 5). The first prerequisite for the development of a liberalized wholesale market and a successful traded hub is to ensure that the industrial, commercial, and residential sectors are fully liberalized; this creates competition between suppliers and encourages the end-user to demand more competitive pricing (Ibid). Patrick Heather further defines the trading hubs:

> The contracts used in the traded gas market tend to be standardized, meaning that terms and conditions are harmonized apart from the delivery period, quantity and of course price. They can be traded bilaterally or on exchanges but they are all essentially of the same format. This is important because standardization concentrates liquidity, liquidity attracts volume, volume attracts traders and together they help create a successful hub.

Continental Europe's liberalization of the energy markets was driven by the EU's political ambitions to create a

fair market for all consumers and this it instigated through Directives which were part of 'Energy Packages' that also included reforms to the electricity markets. The process usually starts with a move to Third-Party Access (TPA) to the network infrastructure, often requiring legislative changes to force incumbents to release infrastructure capacity and gas supply volumes thus incentivizing independents to enter the market. Three regulatory 'packages' fundamentally reshaped the European energy sector. The 1998 package fostered limited and gradual market opening (Goldthau, 2016, p. 10). The second 'package' in 2003 went further and introduced independent energy regulators, made EU countries adopt a regulated access tariff and stipulated the goal of non-discriminatory TPA to energy infrastructure (Ibid). The Third Energy Package of 2009, then, fully enforced TPA provisions through ownership unbundling (Ibid).

As a result of the shift from oil-indexation to gas-on-gas (hub) pricing from 2007–2014, Northwest Europe is now 88% gas-on-gas, Central Europe over 50% (Rogers, 2015, p. 31). Most of oil indexation is now in South-East Europe. Gazprom has strongly defended the principle of oil-indexation (Ibid).

The main type of barrier to integration of the gas market in Europe has been the political and geopolitical barrier. Russia has consistently fought against EU-sponsored reforms promoting market integration, and Gazprom is actively trying to prevent the emergence of traded markets in continental Europe (Ruszel, 2015). A more coherent and united foreign policy would help Europe develop a single competitive gas market. On balance, it is unlikely that EU member states will soon converge politically on a truly shared gas vision. European countries have different gas contracts with Russia. Some states pay more for natural gas and other pay less for the same gas from the same supplier (Ruszel, 2015, p. 3). It can be seen in Hungary, where the discount on Russian gas is more important than the common interest of the EU. The situation is similar in Germany, where the business lobby would protect the relation with Russian companies regardless of the Europeanization of energy security (Ibid).

European gas companies have profited from 20 years of experience with trading hubs, dating from 1994, when the British virtual trading point, the NBP, was established (IEA, 2014, p. 112). Other hubs were established in Northwestern Europe starting in the late 1990s. Dutch TTF, set up in 2003, has now emerged as the most liquid trading hub. Unlike the Henry Hub, the NBP is a virtual trading point. These trading hubs are supported by exchanges and clearing houses (Ibid). These trading hubs enabled introduction of a price indexation that truly reflects the dynamics of supply and demand. The situation in Asia is close to what the situation was in Europe in the very early stages of liberalization (IEA, 2014, p. 115).

Asia is a region where long-term contracts on an oil indexation formula are still predominant. Korea, Japan, and China will need to sign new LNG contracts for delivery in the early 2020s. Are these Asian LNG buyers going to seek a move away from an oil indexation to new price and contractual conditions? There are already several Asian spot indices such as Platts JKM, ICIS' East Asia Index, and Argus' NEA (Rogers & Stern, 2014, p. 34). These indices are based on a subset of Asian spot cargoes. Such spot indices lack depth and exhibit too much volatility and could be influenced by individual players. They are unlikely to be adopted as the basis for price indexation in long-term LNG contracts. Setting up a trading hub in Asia would enable introduction of a standardized pricing mechanism that truly reflects Asia's dynamics, not that of another region or another fuel.

However, a number of challenges still need to be overcome in the development of an Asian LNG hub and a standardized pricing mechanism. Trading hubs so far have developed on the basis of imported pipeline gas or gas produced domestically. In Asia most natural gas is imported as LNG, and the price is indexed to crude oil on a long-term, contractual basis (Energy Information Administration [EIA], 2015). An interconnected gas pipeline has not taken shape in Asia as it is not a single landmass. The biggest consumer of natural gas is the North-East Asian region – comprising Japan, South Korea, and Taiwan (and increasingly China). There is, therefore, a reliance on LNG tankers to ship gas to these destinations in Asia. Oil price linkage was introduced in the 1970s when oil was the main competing fuel to natural gas in Japanese power generation. The supply of LNG, in the case of Korea, Japan, China, and Taiwan, was dominated by 20–25 year long-term TOP contracts that link the price of gas to that of oil. The share of oil indexed gas (both LNG and pipeline) in Asia was 88%, much higher than the global average of 65% (Shi & Variam, 2016, p. 587). The disadvantage of this system was that it had kept Asian gas prices much higher than in other parts of the world. Over the past several years, high crude oil prices resulted in increases in LNG import prices. One notable side effect of this increase was the emergence of what became known as the 'Asian premium' (Hughes & Muthmann, 2015, p. 2). In particular, this premium became increasingly pronounced as a result of the shale gas revolution in North America.

How will trading hubs work with LNG cargoes? The potential hubs in Asia will mainly serve spot-trading LNG trade rather than the whole natural gas trade (IEA, 2014, p. 117). Many potential candidates for Asia's first natural gas hub, with the exception of China, rely solely on LNG

imports. LNG cargoes do not provide a constant flow and differ from each other in quality and quantity (Ibid).

In 2013, the IEA published a report examining the obstacles and opportunities for developing a natural gas trading hub in Asia. The key conclusions were that a competitive national/regional market would need to be developed in order to set a reliable gas price for the region (IEA, 2013; IEA, 2014, p. 38). One notable feature of the gas markets of Asia, especially when compared with the markets of North America and Europe, is the almost total absence of competition as a market organizing principle (Hughes & Muthmann, 2015, p. 1). The European Commission (EC) has taken a leading role in the liberalization of the energy market. There is no equivalent in Asia. There is no overarching body which could establish the necessary rules in Asia, even though several bodies of cooperation and coordination on energy issues exist such as ASEAN Ministers on Energy Meeting, APEC, and East Asia Summit (Herberg, Kamphausen, Toichi, & Cutler, 2014). Regulatory changes are happening in many Asian countries, notably China and Japan. Singapore is already well on track in meeting the conditions necessary to create a liquid and transparent trading hub. However, there is still considerable work to be done in the other countries in terms of wholesale price deregulation and TPA to pipelines and LNG import infrastructure (IEA, 2014, p. 107).

In 2008–2010, Europe was especially attractive because of the process of gas market liberalization and creation of a single European gas market, allowing new entrants to offer gas on rapidly developing wholesale markets, and gas-to-gas competition (Luciani, 2016, p. 106–107). However, conditions suddenly changed following the Fukushima accident. The disabling of the entire Japanese nuclear power generation fleet led to a sudden surge in Japanese gas demand, while Chinese demand also continued to grow strongly. This led to a widening price gap and to a surge of re-exports of LNG out of Europe. In 2011–2014, these developments gave rise to a situation, where prices for gas delivered into Asia were consistently at a 50–100% premium to European prices, not to mention a multiple of four to five times the wholesale price of gas in North America (Hughes & Muthmann, 2015, p. 3). There were concerns that the current pricing system could harm the competitiveness of the region's economies. It also threatened to limit the expansion of natural gas in the energy mix (Kim, 2013). There emerged a chorus of complaints by Asian LNG buyers, strongly encouraged by the Japanese Government, to seek better pricing conditions for their supplies. Asian LNG buyers began to submit that more flexible TOP or destination clauses would go a long way toward increasing the trade volume of LNG. Through buyers' collaboration, they sought to take the recent changes in the LNG market as a chance to do away with destination clauses and create a fairer and sounder LNG trade relationship for both producers and consumers (Moon, 2016).

An extensive literature has developed along two avenues of research: price benchmark changes, on one hand, and contract flexibility such as destination clauses. The impact of potential North American and Australian LNG exports was highlighted in particular. Some strand of the literature addressed the security dimension of energy constraints. Most Asian energy consumption depends on the Middle East and certain marine transport routes linking Asia with that region. Such existing marine routes have traditional security problems such as naval build-up among countries as well as non-traditional security issues like pirates and traffic congestion. About 80% of China's energy imports come from the Middle East and Africa. Energy transport ships pass through the Strait of Malacca, a narrow marine route between Malaysia and Indonesia. The future of China's energy security depends on whether or not it can make such concentrated energy transport routes more diversified. China creates conflicts with Vietnam and the Philippines over naval build-up and territorial issues in the South and East China Seas in order to address the problem (Herberg et al., 2014).

At the center of the commercial debate was the question of whether or not the 'Asian Premium' was caused by destination restriction. The logical endpoint was the question of whether or not this price and contractual changes would lead to the creation of a trading hub in Asia along the lines of North America and Europe (Stern, 2016a). Destination flexibility was taken to be much more important than hub indexation in East Asia except China (Shi & Variam, 2016, p. 588). Hub indexation is as important as destination flexibility in China due to pipeline imports (Ibid).

Post-Fukushima, Japanese utilities began to suffer losses, due to the divergence between JCC (the 'Japan Crude Cocktail')-linked prices and physical LNG cargo prices. LNG consumers in Asia felt the need to diversify LNG import routes and take advantage of various supply measures, such as tapping into pipeline natural gas (PNG). Together with a stable supply of natural gas, LNG consumers in Asia aimed at laying the foundation for a more efficient market and diversification. Asia's dependency on the Middle East was expected to diversify into Russia and the U.S. as a result of the shale gas revolution.

In the past, long-term contracts would typically not permit cargo deliveries to be diverted. However, more 'flexible' term contracts have become more prevalent in recent years. Flexible-contract cargoes may be re-traded, and some partial cargoes have become available for trading. This has a positive impact on the price discovery process, and is behind the rapid growth of Spot LNG, which now accounts for 30% of the traded market. The Henry

Hub natural gas index is increasingly being used for term LNG contracts in Japan and South Korea. With Cheniere Energy pushing to link LNG to gas prices globally, Henry Hub is likely to become an important pricing benchmark for LNG term contracts in Asia.

Since 2013, more LNG cash contracts have started to be priced off spot indexes. The number of LNG contracts traded on spot, or short-term, basis in Japan rose from less than 15% in 2013 to over 30% in 2015.

An estimated 40% of the spot and short-term contracts are currently priced off the Platts JKM index. Efforts are underway to develop alternative benchmarks to complement the Platts JKM. This includes current efforts in Singapore and China to develop regional spot LNG indexes. In September 2014, the Japanese Ministry of Economy, Trade and Industry (METI) developed a LNG NDF contract on its Japan Over-the-Counter Exchange (JOE), which is settled against the RIM Index.

Many East Asian importers have started to create its own regional gas pricing benchmark through the establishment of gas trading hubs. Currently, Singapore, Japan, and China are leading hub initiatives in East Asia. In 2013, the IEA published a report examining the obstacles and opportunities for developing a natural gas trading hub in Asia and identified Singapore as the most likely candidate to establish a successful gas trading hub in Asia (IEA, 2013; Rogers & Stern, 2014, p. 38). Singapore has its advantages of liberalized electricity and gas markets, good reputation of legal, fiscal, and financial regimes, and experience in developing an oil trading hub (Shi & Variam, 2016, p. 588). The country also has pipeline connections with Malaysia and Indonesia and Asia's first open-access LNG terminal which started operating in 2013. However, the Singapore gas market is less than 10 BCM, and its expansion potential in terms of LNG receiving terminal and storage capacity is uncertain (Rogers & Stern, 2014, p. 41). While Singapore may be well placed to develop a pricing point for the South-East Asian gas market, the North Asian market arguably has its own unique characteristics (e.g., summer/winter seasonal fluctuations in gas demand) and may be better served by a trading hub and pricing point located in a North Asian country (MacLaren, Lingard, & Kirkness, 2016). What is lacking for the formation of an energy futures trading system in Japan is a hands-off government approach and effective unbundling of transport activities. TPA to LNG import terminals remains limited. The initiative of the METI to set up a gas futures market is an encouraging sign, but this would require liberalization of the wholesale gas market, specifically TPA to LNG terminals and pipelines (Rogers & Stern, 2014, p. 40).

China has domestic production, pipeline imports from both Turkmenistan and Myanmar (and potentially from Russia by the end of this decade) and LNG. The IEA sees formidable obstacles to establishing a liquid spot market, despite the fact that small quantities of LNG are already being traded in Shanghai. There is no TPA to pipeline or LNG infrastructure and the gas industry is dominated by three NOCs.

North-East Asian LNG market under low oil prices

When oil prices began to decline in mid-2014, many observers initially expected that this trend could negatively affect Asian efforts to reduce dependency on Middle Eastern oil and gas by diversifying with Russia and the United States. However, in today's prolonged period of lower oil prices, the reality has been much more nuanced and in some cases has contradicted our previous assumptions.

As both a major producer and consumer of energy supplies, China is a particularly instructive example of the nuanced impact of declining oil prices. The country has aggressively worked to enhance its energy security by forming an alliance with Russia and diversifying its PNG suppliers, for instance, by introducing gas from Turkmenistan in 2010 and Myanmar in 2014. Oil imports from Saudi Arabia fell from more than 19% of the Chinese energy mix in 2013 to almost 15% in 2015, largely due to increased supplies from Russia (Rava, 2016). By 2020, an estimated 68 BCM of Russian gas will be supplied through pipelines based on PNG contracts signed in May and November 2014.

In contrast, Russian efforts to advance into the South Korean and Japanese energy markets have been less successful. In Asia, Russia was expected to compete with the Middle East, North Africa, and Latin America as the provider of same-grade crude oil. In addition to offering the security benefits of diversification, Russian oil takes only five days to ship from the Kozmino port in the North Pacific to the North-East Asian markets of China, South Korea, and Japan, compared with more than the two weeks of shipping time required for oil imported from the Middle East. Today, the Middle East still exports a considerable amount of gas (46.8 BCM) to North-East Asia, while Russia only exports 16 BCM to the region. Russia's attempt to economically engage with South Korea and Japan through increased energy exports is being further delayed, and Japan has instead looked to satisfy energy demand through its alliance with the United States. In addition, Japan and South Korea are both striving to procure LNG competitively from other suppliers because of the expected sharp increase in LNG supply for the Asia-Pacific by 2020.

For the region at large, lower oil prices have had a sizable impact on natural gas markets. Although lower oil prices have made oil-indexed contracts desirable in

Table 1. Spot LNG prices in 2013–2016 ($/MMBtu).

	Dec. 2013	Sep. 2014	June 2015	Nov. 2015	May 2016
US Henry Hub	4.5	3.8	2.7	2.0	1.9
UK National Balancing Point	10.6	8.2	6.7	6.0	4.2
Platts JKM™	17.6	12.8	7.5	7.5	4.4

Source: Compilation of data from https://www.eia.gov/dnav/ng/hist/rngwhhdd.htm, https://ycharts.com/indicators/uk_heren_nbp_index_natural_gas_prices

the short term, both companies and governments want to encourage gas-on-gas competition to create a more stable LNG market in the future. Lower oil prices may have diminished Asian gas buyers' urgency to diversify from oil indexation, but they have not removed the fundamental need to establish an alternative pricing mechanism that better reflects gas market fundamentals. Although the demand for LNG is in a downturn, it is likely to increase in the future as the international community responds to climate change by emphasizing energy sources that allow for greater reductions in greenhouse gas emissions. Therefore, efforts should be made to improve the fairness and efficiency of the LNG market, and now is the perfect time to address the structural problems that are holding the market back.

North-East Asian LNG market in 2015

The global LNG market has been a seller's market ever since the Fukushima disaster. The market, however, went through a big change in 2014. Due to a decrease in demand starting in the summer of 2014, the spot prices of LNG dropped and were priced at roughly $10/MMBtu as of November 2014 (Timera Energy, 2015). As the global oil prices have dropped since June 2014, Asian LNG prices linked to the global oil prices fell accordingly. Asian market analyst Yingying Zhou, at Wood McKenzie, stated that Platts JKM LNG (Japan-Korea Market price for LNG) was $20.00/MMBtu in the beginning of 2014 but it dropped to less than $7/MMBtu in the first quarter of 2015. It is expected to be at about $8.5/MMBtu in the third quarter (Wood Mackenzie, 2015).

Recent reports suggest that the reduction in LNG demand from China, Japan, and Korea is pulling down the North-East Asian prices of LNG altogether (Table 1). The operation rate of the LNG import terminal in China was below 55% in 2014 compared to 67% in 2013. A reason for this figure may be found in China's recent economic growth slowdown. However, the main cause points to the fact that cheaper oil is replacing expensive gas as oil prices continue to drop (Interfax Natural Gas Daily, 2015).

China's LNG demand is extremely important. China is the only country in North-East Asia that imports LNG while having its own pipeline connection and domestic gas production. China's gas production and demand in 2014 was 123.5 and 183 BCM, respectively. Imported gas accounted for 58.3 BCM. 31.3 BCM of the gas was imported through pipelines and 27 BCM was LNG. China has an aggressive plan to diversify PNG suppliers and thus started to introduce gas from Turkmenistan in 2010 and Myanmar in 2014. As of 2020, 68 BCM of Russian gas will be supplied through pipelines based on the PNG contracts signed in May and November 2014.

The most influential factor to China's LNG demand is the development of domestic shale gas. According to China's 12th five year plan, the country produced 176 BCM of natural gas in 2015, which is expected to be consisted of 138.5 BCM of traditional gas, 15~18 BCM of coal-to-gas, 16 BCM of Coal-bed Methane, and 6.5 BCM of shale gas.

Traditional gas production targets are expected to be achieved but non-traditional gas production is only tentatively expected to be reached. China's production of natural gas has increased since 2000 and likewise, production of non-traditional gas started to gain traction. According to The National Oil and Gas Resource Trend Evaluation (2010), China's traditional gas reserves amount to 52 trillion cubic meters (TCM) (recoverable resources, 32 TCM), non-traditional gas reserves account for 36.8 TCM (recoverable, 10.8 TCM), and shale reserves make up 25 TCM.

Korea's LNG imports also decreased by 26% in February 2015 and the spot price of LNG dropped 20% to $13.48/MMBtu. This decrease is attributed to three nuclear plants that have been put back into service and consequently replaced LNG demand.

In February 2015, the LNG spot price in Japan was $10.7/MMBtu, which had dropped from $13.9/MMBtu in January. Whenever a single nuclear plant restarts in Japan, the LNG demand is reduced by 1 million tons. If the Fukushima nuclear plant were to recover its operation rate to the rate prior to the accident, 17% of global LNG demand decreases the global LNG demand decreases by 17%. Before the massive earthquake hit Japan, the Japanese power generation mix in 2005 consisted of nuclear energy (31%), coal (26%), and water power (8%). Together, these power sources accounted for more than 60% of the total power generation. Thermal power using LNG and oil made up for the remaining 40%. Evidently, after the earthquake the power generation mix changed as nuclear power generation came to a halt in 2011. Consequently, nuclear power (1%), coal (30%), and water power (9%) now accounts for only 40% of the total generation, and the remaining part comes from oil and LNG. As a

result, electricity bills increased approximately 20% for households, and 30% for businesses. The Japanese METI announced that it would reduce the electricity bills by means of securing more than 60% of power from nuclear, coal–thermal, and water power plants, and reducing the ratio of expensive LNG and oil power generation in the long term.

U.S. LNG exports

Skeptics are questioning whether the era of new LNG liquefaction capacity in the U.S. is over. Since the start of 2015, over 50 U.S. shale producers have filed for bankruptcy. But shale oil and gas have continued to flow, in part because even when drillers go bankrupt, their existing wells are usually left in production by their creditors. Despite the large supplies of natural gas coming from the U.S., Australia, Russia, East Africa, and the Middle East, many industry analysts and executives expect LNG demand to pick up at some point after 2020 as countries reduce their reliance on coal, in part from international accords on climate change. The global LNG market is set to increase by 50% between 2015 and 2020, nearly 20 Bcf/day (billion cubic feet per day). By 2020, the United States is set to become the world's third-largest LNG producer after Australia and Qatar. Through 2020, the U.S. and Australia are expected to account for 90% or more new LNG exports (Clemente, 2016). The U.S. could be exporting 12 Bcf/day by 2020, more than current global leader Qatar. More than 4.0 Bcf/day of U.S. liquefaction capacity has long-term (20 years) contracts with markets in Asia, of which 3.2 Bcf/day is contracted to Japan, South Korea, and Indonesia (Ibid).

The U.S. is currently a net importer of natural gas, but with imports only representing 10% of the total natural gas supply in 2015. The EIA predicts that the U.S. will be a net exporter of natural gas by early 2017, and could occur even earlier given the sustained low commodity price environment (EIA, 2016b). In 2015 the United States imported natural gas mainly from Canada by pipeline, totaling 7.5 Bcf/day while they exported the majority of what was produced to Mexico by pipeline, totaling 4.8 Bcf/day (EIA, 2016b). After years of preparation, Cheniere Energy Partners completed loading its first tanker with LNG for export at a Louisiana terminal on 24 February 2016 (Otani, 2016). The closely watched first shipment of LNG departed for Brazil. Landing prices in Brazil were above $7/MMBtu. Cheniere's interim CEO, Neal Shear said, 'While demand for natural gas is "a little bit slack," the company is continuing construction of LNG terminals along the Gulf Coast, and will likely see positive free cash flows within the next few years' (Ibid). Cheniere plans to ship as many as eight cargoes of LNG from its Sabine Pass project by May 2016 (Ibid). Gail India Ltd. bought the second shipment of LNG from Cheniere Energy. The second cargo, bought on spot basis, at the Dabhol import terminal on India's west coast in 1 April 2016 (Chakraborty, 2016). The delivered price of the cargo was about $5/MMBtu, higher than the $4.30/MMBtu, paid by customers in North-East Asia for spot cargoes. The sixth Sabine Pass commissioning cargo arrived in Portugal on 15 April 2016 (LNG World News, 2016a). Most notably, gas-rich United Arab Emirates and Kuwait purchased U.S. LNG. While both are among the top 20 nations in the world by proven gas reserves, a lack of investment and surging demand has forced an unprecedented need for the Middle East to turn to the United States for gas.

In addition to the Sabine Pass terminal that was the source of the first-ever February 2016 LNG shipment, four other LNG export terminals are currently under construction. The first stands alone on the East coast in Cove Point Maryland. This Cove Point LNG facility, being built by Dominion Energy, will add 0.82 Bcf/day of export potential. The remaining three projects all lie on the Gulf Coast, from Corpus Christi, TX to Freeport, TX and Hackberry, Louisiana. These are being developed by Cheniere, Freeport LNG, and Sempra Energy, respectively. All three projects will add 5.64 Bcf/day of LNG export potential (EIA, 2016b).

Australia, already a major LNG exporter, plans to expand its LNG export capacity in the coming years. In late 2015, two terminals began service in Australia, Gladstone LNG and Australia Pacific LNG, both located on Australia's East Coast. Australia could add six new LNG export terminals by 2020, tripling its liquefaction capacity to over 13 Bcf/day (Clemente, 2016).

Australia is physically closer to Asian customers, lowering shipping costs. Japan has typically taken in over 70% of Australia's LNG exports, but Japan's power consumption is now at its lowest since at least 1998, with LNG facing the headwinds of more coal plants, solar capacity, and a nuclear restart (Clemente, 2016). The U.S. has lower production costs and lower capital costs for new infrastructure, namely liquefaction facilities. About 90% of the capacity of new Australian LNG is already under contract to Asian customers, Australia's only LNG outlet. Now at 5–10%, the share of shorter term pricing for Australia is not expected to extend significantly. Australia's producers need firmer, long-term contracts to recover the higher costs associated with developing 'greenfield' projects, as opposed to less costly 'brownfield' re-configurations in the U.S. (Ibid).

The expansion of the Panama Canal in July 2016 will up competition in the U.S. to ship LNG to Asia. Exports of U.S. LNG stand to benefit substantially from the $5.4 billion expansion of the Panama Canal, which will lead

to much shorter travel time and much lower costs for shipments from the Gulf Coast to big markets in Asia (Loveless, 2016). EIA estimates that U.S. LNG traffic through the canal could exceed 550 vessels annually, or one to two vessels per day, by 2021 (EIA, 2016a). A transit from the U.S. Gulf Coast through the Panama Canal to Japan, Korea, China, and Taiwan will reduce voyage time to 20 days, compared to 34 days for voyages around the southern tip of Africa or 31 days if transiting through the Suez Canal (Ibid). The wider Panama Canal will also considerably reduce travel time from the U.S. Gulf Coast to South America, declining from 20 to 8–9 days to Chilean regasification terminals, and from 25 to 5 days to prospective terminals in Colombia and Ecuador. For markets west of northern Asia, including India and Pakistan, transiting the Panama Canal will take longer than either transiting the Suez Canal or going around the southern tip of Africa (Ibid).

In 10 May 2016, the Panama Canal Authority has introduced new toll structures for LNG vessels designed to encourage additional LNG traffic through the Canal, especially for round trips. Transit costs through the Panama Canal for an average 3.5 Bcf LNG carrier are estimated at $0.20/MMBtu for a round-trip voyage, representing about 9–12% of the round-trip voyage cost to countries in North-East Asia (Ibid).

There is no clear timeline for when Canada might start to export LNG of its own. Canada has 20 proposed projects, a few of which have permits in place, but none of which have received a final investment decision from their corporate sponsors (Johnson, 2016). Petronas, which is behind the Pacific Northwest plant, is still making its final investment decision. The huge LNG Canada export project proposed for Kitimat appears to have suffered a setback with Royal Dutch Shell announcing it will postpone its final investment decision. Shell owns a 50% stake in LNG Canada. PetroChina, Korea Gas Corp, and Mitsubishi Corp are also stakeholders in the joint venture. LNG Canada cleared an important hurdle when it was granted the first permit to build a LNG export facility in northern British Columbia (Karin, 2016). The project could cost up to US$40 billion and would initially consist of two processing units called trains, each able to produce 6.5 million tons of LNG annually. The facility could be expanded to four trains in the future (Ibid).

Changes in Russia's export strategy in North-East Asia

As of 2014, Russia is one of the largest producers of both oil and gas in the world. It produces 10 million barrels of crude oil and about 600 BCM of natural gas annually. It exports about 200 BCM of the gas. As the export of crude oil and gas continues to be a main source of national income, it is a very important task for Russia to develop a domestic production system more efficiently in order to properly respond to the changes in the global market (Henderson, 2013).

Russia put in a great deal of effort to advance into the Korean, Chinese, and Japanese energy markets, which were heavily dependent on imports from the Middle East in the mid-1990s. Russia's Asian energy strategy, known as the Eastern Gas Program, brought about the first tangible result from 2009 to 2012. This strategy made it possible for Russia to export 600,000 barrels of oil to Asian countries via Pacific ports by opening the Eastern Siberia–Pacific Ocean pipeline (ESPO) and to export LNG for the first time through LNG export facilities in the southern part of Sakhalin. In Asia, ESPO was expected to function in place of the Middle East as the provider of same-grade crude oil from Russia and act as competition to the Middle East, North Africa, and Latin America. It takes five days to ship Russian oil from the Kozmino port in the North Pacific to the North-East Asian markets of China, Korea, and Japan, which is greatly advantageous compared to more than the 2 weeks of shipping time required to get it from the Middle East. Now the Middle East exports a considerable amount of gas (46.8 BCM) to Asia, while Russia only exports 16 BCM to North-East Asia.

Russia's oil and gas export to Asia entered the expansion phase in 2013 and 2014. On 24 December 2012, the 2nd section of ESPO was completed a year earlier than scheduled and on 22 March 2013 China's president Xi Jinping chose Russia as the first country to visit since his inauguration. The most notable part in the agreement between Xi Jinping and Putin is that China will import 1 million barrels of oil per day from Russia by 2018 and will become the largest importer of Russian oil, surpassing Germany. At present, Russia's oil export to Asia reaches 1.2 million barrels, as Russia and China signed contracts on supplying 28 and 30 BCM of gas through pipelines in May and November 2014, respectively. Therefore, it is expected that in total, 82 BCM of gas, including 14 BCM of LNG, will be supplied by 2020 (Henderson, 2014).

Because of the Russian-Chinese natural gas pipeline deals, U.S. LNG exports seemed no longer competitive in Asia. Russian supply would force the price of LNG delivered to Asia down to between $10 and $11, too low for American LNG exports to be profitable. The spot LNG prices to Asia in 2014 were $10.10/MMBtu for China, $10.50 for Korea, and $10.50 for Japan.

In 2015–2016, the outlook for Russia's plan to supply natural gas to China through two routes is now murky (Kaneko, 2016). China does not have a strong interest in importing Russian gas through the western route. In September 2014, Putin told Chinese Vice Premier Zhang

Gaoli that China would be offered a stake in the Vankor oilfield complex. Initially, Russia expected that businesses with China would completely offset the losses caused by the sanctions, but Moscow is now realizing that it was being too optimistic. Bilateral trade had plunged by 30% in 2015 from the previous year (Dettoni, 2016).

In March 2016, Rosneft agreed to sell 50% of its Vankorneft unit to India's state-run Oil and Natural Gas Corp. to raise its existing stake in Vankorneft to 26%. It will also sell a 23.9% stake in the unit to a group of three state-owned Indian oil companies – Indian Oil, Oil India, and Bharat PetroResources. Vankorneft develops Vankor, Russia's second-largest oil field cluster, which is located in east Siberia and accounts for 4% of the country's oil production (Dettoni, 2016).

Prospects for trading hubs and a new price index in Asia

Under low oil prices, despite low gas demand, multiple hubs are developing in Asia, some with physical, some with financial, but the idea is to have a reliable pricing index. Now that the supply–demand balance for LNG is loosening under low oil prices, LNG's correlation to oil is weakening, meaning opportunities to buy LNG at low prices are growing. But for that to become reality, highly transparent prices that can serve as a benchmark will be necessary (Nikkei Asian Review, 2016).

Japan seems to take lead in the race for an Asian gas hub. IEA Executive Director Fatih Birol said, 'For LNG to achieve its potential, we need well-functioning markets. These do not emerge automatically. Progress will be required – less government intervention, less regulated gas prices and more access to networks' (Platts, 2015). Calls for increased contract flexibility dominated discussions at the fourth annual LNG Producer-Consumer Conference in Tokyo in September 2015. Buyers' sentiment was that the removal of destination clauses, TOP terms, and the use of more upward and downward quantity tolerance in contracts would aid the development of the LNG market because it would draw more players and increase liquidity and spot trades (Platts, 2015). Jae-do Moon, South Korea's vice minister for trade, industry and energy, said,

> LNG producers must improve on the contract practices of the past. Simply put, producers need to help increase the flexibility of the trade. Buyers face difficulties in managing supply as the demand decreases. In this regard, I am sure more flexible take-or-pay or destination clauses will go a long way to increasing the trade. We need to take recent changes in the market as a chance to do away with the destination clause once and for all. The result will be a fairer and sounder LNG trading relationship for all parties. (Ibid)

In September 2014, Japan launched the JOE – its first LNG trading hub-through a Japanese-Singaporean joint venture between Tokyo Commodity Exchange and Ginga Energy, with the full backing of the Japanese Government (Gas Strategies, 2014). The Japan over-the-counter (OTC) Exchange is an OTC LNG platform. Trades can be OTC, which is off-exchange and conducted directly between two parties, or via an exchange, such as the New York Mercantile Exchange or the Intercontinental Exchange (Gas Strategies, 2014). There were significant regulatory changes in Japan in 2015. Legislation passed in 2015 would create TPA to regasification terminals in 2017 and separation of network assets from supply businesses of the three major gas companies by 2022. Liberalization of the electricity industry also started in April 2016 (Ibid).

The ministers of Canada, France, Germany, Italy, Japan, the United Kingdom, the United States, and the European Commissioner for Climate Action and Energy, met in Kitakyushu on 1–2 May 2016 to discuss developments against the background of volatile energy prices and the COP21 Paris Agreement.

> The expanding role and globalization of natural gas markets, for both pipeline and liquefied natural gas (LNG), bring new opportunities and challenges. We welcome Japan's Strategy for LNG Market Development, the EU Strategy for LNG and gas storage, and LNG exports from North America and other sources, the ministers said in a joint statement. (LNG World News, 2016b)

In 1 May 2016, the Japanese METI released the Strategy for LNG Market Development. James Stern assessed that the main goals of the strategy are the development of a flexible and liquid LNG market and the creation of an LNG trading hub (Stern, 2016b). 'Now is our chance, and we have a window of three or four years to act,' before the balance of supply and demand might change, said Ken Koyama, a managing director and senior economist at Japan's Institute of Energy Economics, which advises the Japanese Government on energy policy (Negishi, 2016).

JERA Co., a joint venture between Tokyo Electric Power Co. and Chubu Electric Power Co. now the world's single biggest buyer of LNG, clinched what is thought to be the first resale deal for a Japanese buyer. It agreed to sell as much as 1.5 million metric tons of LNG to a unit of France's Electricite de France SA between June 2018 and December 2020, at a price linked to Europe's cheaper prices (Ibid). The deal is judged to catapult Japan as a seller that could undercut its suppliers.

In June 2015, Singapore Exchange launched SLInG, a weekly LNG price index based on anonymous price assessments given by market participants in order to establish a reliable LNG spot price index in the region. The index is already beginning to be used: in January 2016, Trafigura and Pavillon Gas traded 10,000 MMBtu of FOB

LNG swap in the March 2016 contract month in a deal worth about US$50,000. JERA, the Japanese joint venture between TEPCO and Chubu Electric Power may also use the index in its terms contracts. Singapore Exchange listed futures and swaps in January 2016. It has 22 companies cooperating in benchmark price calculation, and has recorded trades equal to 500 tons of LNG so far.

JOE is still at a very early stage, having just launched, and questions remain as to whether it will accurately reflect regional supply and demand (Gas Strategies, 2014, p. 8). The Japan OTC Exchange got a boost in March when the Chicago-based CME Group began providing clearing services, a development made possible after Japanese prime minister Shinzo Abe lobbied Leo Melamed, CME chairman emeritus. Having the CME Group as a service provider lessens credit risk (Nikkei Asian Review, 2016). The Japan OTC Exchange currently has 26 trade participants.

Conclusion

The growth in Asian LNG demand in 2016 will be mainly from South-East Asia and India, offsetting the region's weaker demand in Japan and Korea. In aggregate, Asia is unlikely to require more than 5 million tons of the additional 22 million tons per year of production in 2016, leaving 17 million tons available for markets elsewhere in the world. Despite the current slowdown of Asian LNG demand, Asia is likely to continue to drive the development of the global LNG market.

Because countries in Asia have yet to establish a unified market and price for natural gas, and efforts to transition to new and renewable energy have been relatively slow, Asia's dependency on nuclear power will remain high. Due to both international pressure to reduce greenhouse gas emissions and the poor commercialization of new and renewable energy, for Asian countries other than Japan, nuclear power is becoming the only alternative as they look to secure energy sources to support economic growth and maintain energy security. It is expected that nuclear power generation will continue to grow, especially in China, South Korea, and India. The Association of South-East Asian Nations countries are also expected to develop nuclear energy as a main energy source to improve energy security and respond to climate change.

Going forward, for LNG to expand its demand, we need well-functioning markets. Trading hubs enable introduction of a price indexation that truly reflects the dynamics of supply and demand. The current state of the development of gas trading hubs in Asia is close to what the situation was in Europe in the 1990s. The establishment of an Asian gas trading hub will take many years. The creation of hubs such as the Henry Hub in the U.S. in 1988 and the UK's NBP in 1996 occurred after deregulation of their natural gas markets, including TPA, competition among suppliers, and deregulation of gas prices.

The term 'hub' has various definitions. Hubs might take different forms. In Asia, are we going to see the emergence of a natural gas trading hub or an LNG trading hub? If there is a likelihood of an Asian natural gas hub in its true sense of the term, it will be in China. China has many of the attributes of a physical hub, if not a virtual hub. The problem is that China is not an open market. Currently, China is challenging the Japan-dominated LNG market. China has multiple gas supply sources, both PNG and LNG. Both Japan and China has been waging a battle over who is the dominant one in terms of setting the natural gas price in the region. Singapore does not have the volume of demand to support an independent index. A Singapore index must be geared toward one of the large demand centers, either China or Japan.

China and Japan have diverging energy security and LNG goals. Japan is looking to exports from the U.S. The United States could be one of the three biggest suppliers of LNG by 2020. Many expected U.S. oil output would collapse under the weight of a lengthy price war with Saudi Arabia. While Saudi Arabia's strategy of oversupply may have made some high-cost U.S. operators economically unviable, U.S. shale extractors have proven highly adept at cutting costs. The key issue is price. China puts first priority on pipeline import diversification with Russia and Central Asia. This is how China and Russia see where and how natural gas prices are determined. Natural gas prices are reflective of both continental pipeline trade and seaborne LNG trade. An LNG trading hub, led by Japan, is to open up the Asian gas market to unprecedented levels of transparency and competition.

The end of February 2016 saw the first exports of LNG from the U.S. mainland when major shale gas company Cheniere Energy's first LNG cargo left the Sabine Pass terminal in Texas. There are expectations that the beginning of U.S. LNG exports may trigger flexible trading. To the year 2020, U.S. LNG exports to North-East Asia will be increased. Low oil prices are hastening the possibility of strengthened regional cooperation and greater co-prosperity through the development of a gas trading hub in North-East Asia. Russia will seek to keep U.S. LNG in check through price negotiations. The evolution of an Asian gas hub will be to a great extent influenced by how Russia and China will reconsider their energy strategies.

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