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King Abdullah Petroleum Studies and Research Center

The Impact of Low Oil and Gas Prices on Gas Markets: A Retrospective Look at 2014-15

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May 2016/ KS-1634-DP028

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Key Points

In the past year, global gas prices have dropped significantly, albeit at unequal paces depending on the region. All else being equal, economists would suggest that this should have generated a positive demand response. However, “all else” was not equal. Prices of other commodities also declined while economic growth forecasts were downgraded.

Prices at benchmark points such as the U.K. National Balancing Point (NBP), U.S. Henry Hub (HH) and Japan/Korea Marker (JKM) slumped due to lower oil prices, liquefied natural gas (LNG) oversupply and unseasonal weather. Yet, the prices of natural gas in local currencies have increased in a number of developing countries in Africa, the Middle East, Latin America, former Soviet Union (FSU) and Asia.

North America experienced demand growth while gas in Europe and Asia faced rising competition from cheaper coal, renewables and, in some instances, nuclear. Gains to European demand were mostly weather related while increases in Africa and Latin America were not significant.

For LNG, Europe became the market of last resort as Asian consumption declined. Moreover, an anticipated surge in LNG supply, brought on by several new projects, may lead to a confrontation with Russian or other pipeline gas suppliers to Europe. At the same time, Asian buyers are seeking concessions on pricing and flexibility in their long-term contracts.

Looking ahead, natural gas has to prove itself a credible and affordable alternative to coal, notably in Asia, if the world is to reach its climate change targets. The future of the gas industry will also depend on oil prices, evolution of Chinese energy demand and impact of COP21 on national energy policies. Current low prices mean there is likely to be a pause in final investment decisions (FIDs) on LNG projects in the coming years.

Summary for Policymakers

The era of high Asian gas prices and large divergences between the Asian, European and U.S. markets came to an end in 2014. Over the period 2011-2014, imported LNG prices were above $14/MMBtu – sometimes as much as $18/MMBtu – in several Asian countries, making gas increasingly uncompetitive. Even in Europe where prices were substantially lower at between $8 and $10/MMBtu, gas was losing ground to coal in power generation. Such high prices were harming future growth potential in established markets and in developing countries.

As we enter 2016, gas prices in Europe, Asia and North America have dropped to historical lows and have also started to converge. As of March 2016, NBP prices were at $4.23/MMBtu, Asian spot $4.45/MMBtu and Henry Hub $1.81/MMBtu. Such a slump is usually accompanied by a high demand growth trajectory, but it appears that the price effect has not been sufficient to trigger a massive rebound in demand, with the exception of the U.S. There are some signs that the situation is improving, but it also appears that low prices need to be supported by policy that would consider the environmental benefits of gas against other fossil fuels and help countries meet their climate change targets. There are two main reasons for the moderate demand growth. Firstly, the prices of other competing commodities – coal and also oil – have declined sharply. Coal-fired power stations remain more competitive than gas-fired in most regions, especially in Asia and Europe. The situation started to change in late 2015 as gas prices fell even further. Secondly, economic growth prospects were revised down, making it more difficult to evaluate the impact of lower gas prices.

In April 2014, the International Monetary Fund (IMF) had forecast that global economic growth will increase from 3 percent in 2013 to 3.6 percent in 2014 and 3.9 percent in 2015 (IMF 2014). In January 2016, the IMF revised this down to 3.4 percent in 2014 with expectations for 2015 and 2016 at 3.1 percent and 3.4 percent respectively (IMF 2016).

While most analyses focus on the main markets – largely due to better data availability – another important pricing trend is taking shape. Gas prices in local currencies have increased in a number of developing countries, which in the past have tended to be kept low. Price hikes were due to the need to attract more imported gas, develop domestic resources or budget constraints. Altogether, these countries (excluding Russia) represent a consumption of about 685 bcm in 2014, or 20 percent of global demand. The lack of timely demand data means we cannot yet analyze the impact of these price increases on demand and local production. In most of these countries, demand has often been considered as price-inelastic. So it remains to be seen whether demand growth trends will continue. According to the IEA's latest World Energy Outlook, additional demand from the Middle East, Africa and non-OECD Asia (excluding China and India) over 2013-2040 will amount to about 680 bcm, or around 40 percent of the world's incremental demand.

Last year also witnessed a small shift in trade. When LNG project sponsors approved FIDs over 2009-2014, they were mostly targeting Asia. However, Asia has yet to fulfill this promise, with demand dropping in the three largest markets – Japan, Korea and China. Consequently, additional LNG supply went to new importers in developing countries and was also shipped back to Europe. Looking ahead, as LNG supply builds up from 2017 onwards, sales to Europe are likely to face competition from pipeline sources, notably Europe's largest pipeline supplier, Russia, which is the only exporter to have large spare capacity. What happens in Europe will largely depend on how much LNG will be backed out of Asia.

Finally, a key question is the impact of lower oil and gas prices on production. There has not been enough history to perform a definitive analysis, but a slowdown in U.S. gas production growth has been observed. However, the larger impact of lower prices is likely to be felt as a result of companies cutting upstream investments generally. There is also the probability of a pause in FIDs on LNG projects in the coming years.

Understanding the New Pricing Environment

The impact of lower oil prices on gas is not as direct as some may think. The influence of oil indexation is mostly at the level of global trade as oil prices are used in the pricing of most long-term LNG and some pipeline contracts. However, this reflects a small part of the full gas pricing picture as only one-third of global demand is traded while two-thirds is consumed where it is produced.

The International Gas Union's (IGU) wholesale gas pricing survey categorizes eight different types of pricing mechanisms: oil price escalation (OPE), gas-on-gas competition (GOG), bilateral monopoly (BIM), netback from final product (NET), regulation cost of service (RCS), regulation social and political (RSP), regulation below cost (RBC) and no price (NP) (IGU 2015). It estimated that GOG represented the majority of world price formation of natural gas consumption in 2014 with a share of 43 percent, well ahead of oil-indexed gas prices (17 percent) (see Table 1). Various regulated gas prices totaled 35 percent, mostly in the FSU, Asia, Africa, Latin America and Middle East. Consequently, the direct impact of lower oil prices on gas at the point of consumption is relatively limited. This does not include the indirect impact of oil prices on other pricing mechanisms. For example, prices based on GOG will depend on the equilibrium between demand and supply, where the price of other supply sources could be based on OPE. This is notably the case in Europe.

Two pricing mechanisms dominate LNG and pipeline imports – GOG and OPE. OPE is used in 74 percent of LNG imports and 38 percent of pipeline imports. Lower oil prices will therefore have a bigger impact on LNG imports and a reduced effect on

Table 1. Gas Price Formation Mechanisms (percent), 2014

	GOG	OPE	BIM	NET	RCS	RSP	RBC	NP
Consumption	43	17	4	0	11	17	7	1
Production	42	6	3	1	15	23	9	1
Pipeline Imports	51	38	11	0	0	0	0	0
LNG Imports	26	74	0	0	0	0	0	0

Source: IGU

pipeline gas. As countries turn to imports, they are likely to be affected by the evolution of oil prices, especially if they contract LNG on a long-term basis.

The GOG mechanism reflects regional supply/demand balances and is also influenced by the state of the global LNG market in regions where imports represent a meaningful source of supply. The collapse in some spot prices is due to the LNG market flipping from being tight to oversupplied in 2014. Before mid-2014, LNG was a seller's market. As new supply sources came online (beginning with Papua New Guinea (PNG) in May 2014) and the expected demand increase failed to materialize, LNG turned into a buyer's market. Consequently, Asian spot prices halved from early to late 2014, from $19/MMBtu to about $10/MMBtu as of end 2014 and have continued to drop, reaching $4-$5/MMBtu in March 2016, according to World Gas Intelligence assessments.

There is usually a misunderstanding between pricing mechanisms and price levels, often based on the belief that oil-indexed gas prices are always high and spot low. This assertion may be true when oil prices are high and regional gas markets sufficiently supplied. However, this also very much depends on the formulae of the OPE (the slope and the S-curve) and regional supply/demand conditions. This misunderstanding was exacerbated during 2011-2014, when high oil prices sent Asian oil-indexed LNG-import prices to record levels while HH spot remained at or below $4/MMBtu. As oil prices collapsed and Asian LNG demand slowed, Japan's average LNG import prices dropped from $16.20/MMBtu in 2014 to about $9-$10/MMBtu in summer 2015. However, spot prices are not always cheaper. For example, the Algonquin Citygate spot price in the Northeast of the U.S. is regularly higher than the much-quoted HH as the region is pipeline constrained. In particular, it averaged $22.50/MMBtu from Jan. 1 to Feb. 18, 2013 due to extreme cold weather and supply shortages (EIA 2014), compared with HH at $3.30/MMBtu over the same period. In January 2014, Platts' JKM – the LNG benchmark price assessment for spot physical cargoes delivered ex-ship into Japan and South Korea – reached $19/MMBtu due to increased tightness on global LNG markets (Platts 2014).

Market Prices on a Downward Trend

Widely reported market prices such as NBP, HH and various gas import prices such as those in Germany and Japan have all declined over the past two years, albeit at different paces, reflecting the different indexations and market fundamentals prevailing in each region (Figure 1). The declines in Japanese import price is highly correlated to the fall in oil price, but the drops elsewhere stem from regional dynamics as well as a surplus in LNG.

The LNG oversupply situation, prevalent since end-2014, has triggered a partial convergence between Asian and European spot prices, as Europe remains the market of last resort for excess LNG. In Europe, the average German import price is very close to NBP spot levels, while most other European spot prices have also converged around NBP. In Asia, however, there remain strong disparities between a country's import price and LNG spot indices. U.S. gas prices have continued their downward slide due to the strong buildup of production that has not been fully absorbed by demand and pipeline exports.

HH Looking for a Floor

HH gas prices throughout the majority of 2014 were kept above $4/MMBtu, supported by an extremely cold winter in the first quarter of 2014, which reduced inventories to record lows.

HH Looking for a Floor

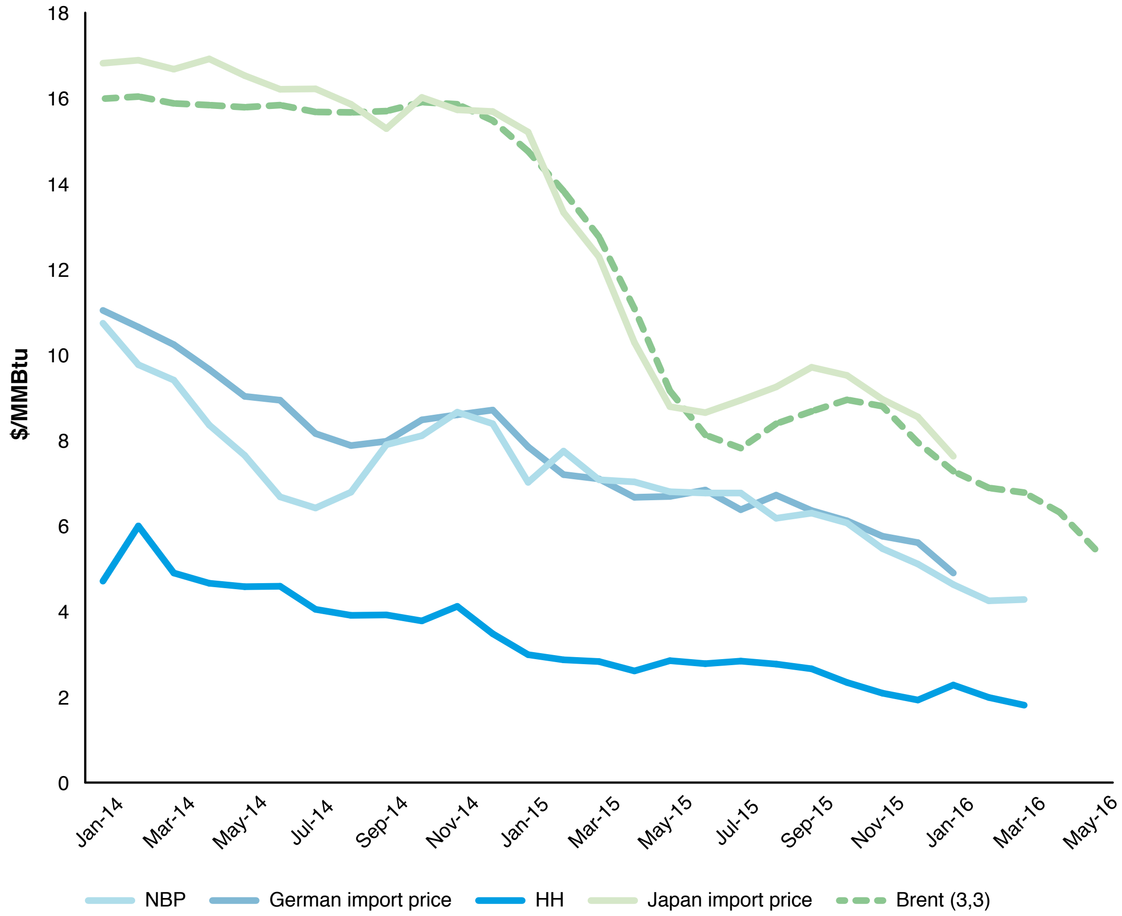

Figure 1. Regional Gas Prices

Source: IGU

But temperatures during the 2014/2015 heating season were somewhat closer to normal and natural gas inventories climbed back toward normal levels. By the second-half of 2015, production growth outstripped demand and gas in storage exceeded the five-year average, lowering prices by 40 percent to $2.70/MMBtu. HH even dropped below $2/MMBtu for two consecutive weeks in December 2015. Warmer-than-normal temperatures (notably in the North-East) during the fourth quarter, along with production growth, contributed to inventory levels rising to an historical high of 4,009 bcf while forecasts for a warm winter continued to put downward pressure on spot prices. Prices stabilized at around $2.20/MMBtu in January 2016 and dropped to around $1.81/MMBtu in March 2016, representing much lower levels than summer 2015 indicating that the abundance of supply is dampening any seasonality effect. Until U.S. LNG exports from Cheniere started on Feb. 24, 2016, the only outlet for additional production was higher pipeline exports to Mexico and Canada, and storage buildup.

Natural gas production benefited tremendously from higher oil prices in liquid-rich formations over 2011-2014, but with the substantial narrowing of oil and gas price differential in 2015, as shown in Figure 2, producers were forced to cut capital spending and focus drilling activity on their most prolific assets.

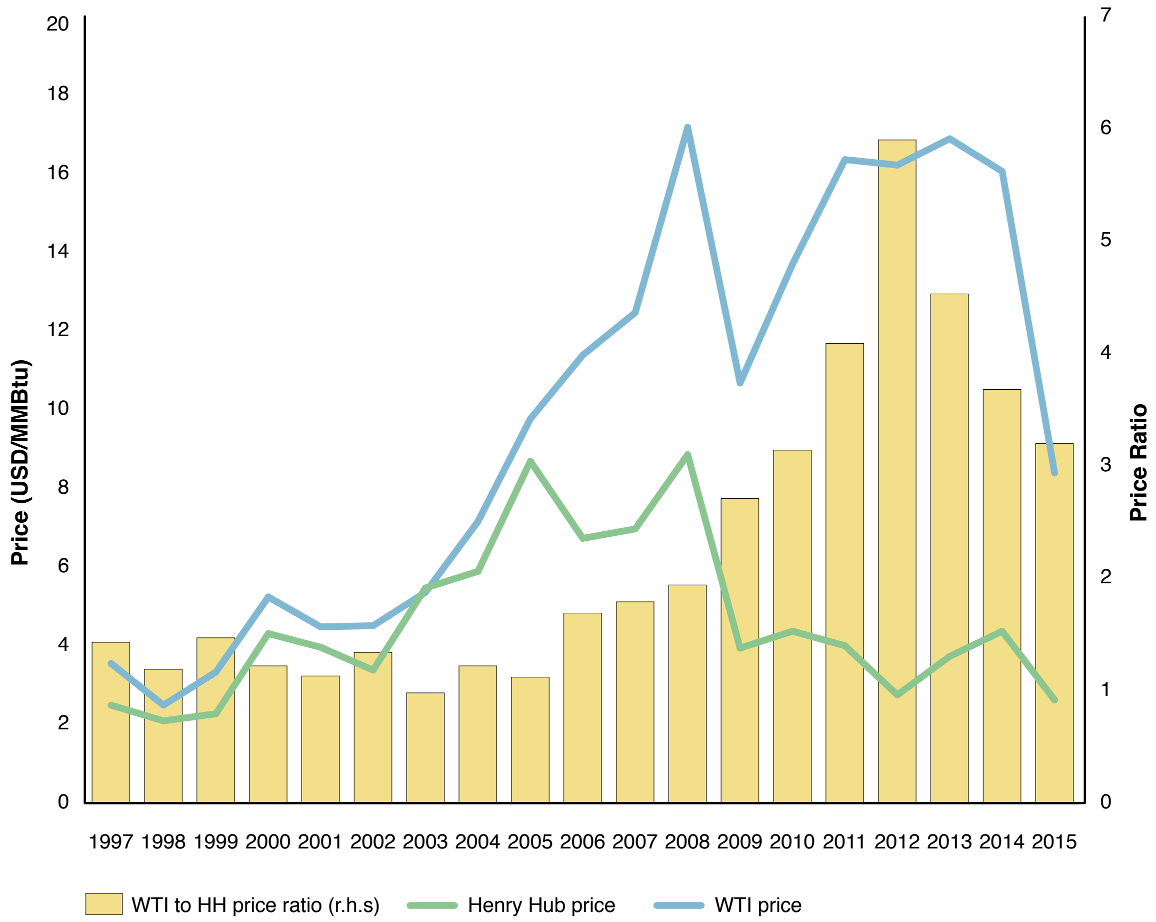

Figure 2. U.S. Natural Gas and Oil Price Evolution

Source: KAPSARC, EIA

One would have expected the low oil price environment to negatively impact U.S. natural gas production, but so far it has only slowed year-on-year growth, which fell from 9 percent in January to 2 percent in December. U.S. gas production gained 38 bcm in 2015 over the previous year. Drilling efficiencies and higher well performance are continuously yielding improvements and are enabling operators to produce at lower unit cost. Producers are showing faster drilling-to-completion rates, longer lateral wells and enhanced well completion techniques as a precursor to an increase in production. The efficiency gains and learnings adopted in the past several years have also decreased supply costs in dry gas regions, such as Haynesville, making them more competitive and have brought about a slight uptick in activity more recently. The Haynesville break-even cost has dropped to $2.30-$2.40/MMBtu from $4 in 2013, according to Energy Aspects, with analysts pointing to drilling efficiencies and 'refracking' of old wells (Bloomberg 2015a). Advancements in upstream developments are not the only reason for production growth this year. Output from the Marcellus and Utica regions, which together comprise 42 percent of U.S. shale gas production, got a boost from newly added and reversed pipeline capacity that allowed gas flows to expand within the U.S. Northeast and access premium markets in the Midwest and the Gulf Coast. In total, around 55 bcm/y (5.4 bcf/d) of capacity was added to debottleneck the region in 2015.

Asian Gas Prices Halved in One Year

The oil price collapse has coincided with LNG turning from a seller's to a buyer's market, even though there is no direct link between the two phenomena.

In Asia, both long-term contract and spot LNG prices such as the JKM collapsed over the past year, albeit at different speeds. LNG contract prices in Asia are still heavily influenced by oil as long-term contracts use JCC indexation, albeit with different slopes and S-curve parameters. Consequently, the decrease in oil prices has impacted LNG contract prices but with a lag. Meanwhile, Asia has become the main off taker of spot and short-term LNG representing 47 mtpa as of 2015, against total Asian LNG imports of 177 mtpa. Still, average import prices remain mostly determined by the evolution of oil prices. Despite oil dropping in mid-2014, LNG prices only started declining in earnest during the first quarter of 2015. This meant that in early 2015, oil was actually cheaper than imported LNG on an energy-content basis. Oil at $40-$60/bbl resulted in LNG import prices dropping from $16/MMBtu in mid-2014 to $8-$10/MMBtu in late-2015 in Japan and Korea. Chinese LNG prices were slightly lower, at around $7-$8/MMBtu in late-2015, due to the legacy of some historically cheap contracts.

In a tight market, oil-indexed gas prices usually act as a floor, but now in an oversupplied market they are providing a ceiling. Asian spot prices reflect the transition from a tight to a loose market. In January 2014, JKM was reported at $19/MMBtu – well above average import prices – as Asian and Latin American buyers sought LNG cargoes and offered premiums to secure supplies. Asian spot prices dropped in 2014 reflecting lower demand over the summer as well as the arrival of new supply with the start of PNG LNG. Despite an uptick in October 2014, weaker Asian demand combined with new supply put pressure on spot prices as early as November.

Subsequently, structural oversupply kept prices below the average import levels for most of 2015. From $10/MMBtu in January 2015, JKM dropped to about $7-$8/MMBtu for most of 2015 and settled at an estimated $4.25 for April 2016 (Platts 2016a). While such prices are still higher than what historical LNG suppliers such as Indonesia, Malaysia, Brunei and Qatar were getting before 2005, new projects coming online in Australia or the U.S. were counting on much higher levels. A price of $7/MMBtu requires HH to be about $1.7/MMBtu (based on Cheniere's formulae and assuming a transport cost of $2/MMBtu) and is in line with an oil-linked gas prices with oil at $40/bbl. At levels of $4.25/MMBtu, the liquefaction fee is considered as a sunk cost.

Looking at the price Japan pays for its LNG imports from different countries, there are some notable differences. Purchases from Oman stand at much lower levels compared with others, while Malaysia and Qatar tend to be the most expensive (see Figure 3). Nigerian supplies – a source of spot LNG – were more expensive than the average LNG price until end-2014, but were imported at a discount due to oversupply, especially over the last months of 2015. The same applies to Algeria. The average LNG import price was close to a three-month averaged, three-month lagged Brent price. Consequently, oil prices below $55/bbl observed since July 2015 started impacting Japan's average LNG import price by January 2016 as it dropped to $7.60/MMBtu. We can expect it to decrease progressively to below $7/MMBtu by the second quarter of 2016. Should oil stay at around $30/bbl, prices would drop to about $4.50/MMBtu, unless the S-curve of contracts changes the slope at lower oil prices.

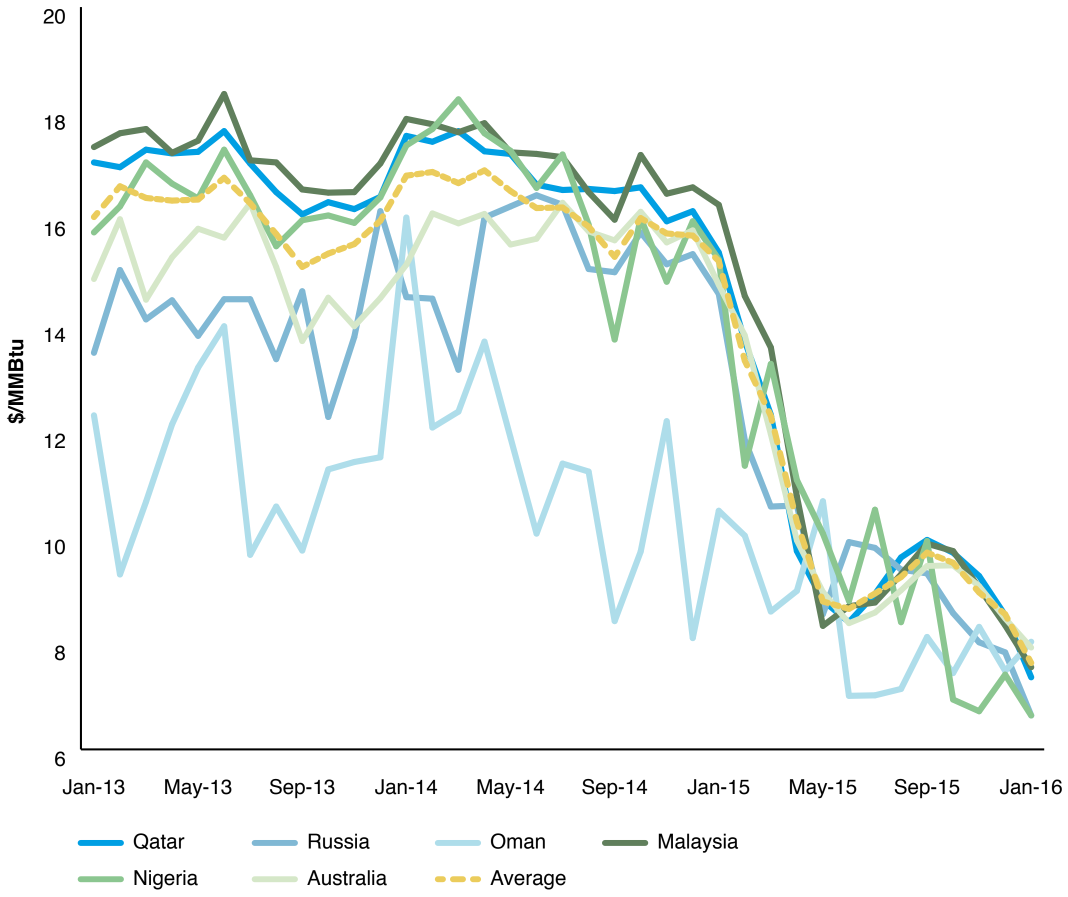

Figure 3. Selected Prices of Japan's LNG Imports

Source: Japanese Customs, European Central Bank for the exchange rates

European Gas Moves Toward $4/ MMBtu

European gas prices reflect two different pricing mechanisms: OPE and GOG. Over the past few years, GOG has become increasingly important representing 61 percent of total consumption in 2014 versus 22 percent in 2007. Most long-term contracts, which were previously predominantly linked to oil, are now based on a mix including oil and regional spot prices (and possibly coal). The economic crisis in 2009 and the availability of cheap LNG at levels lower than oil-linked gas put some utilities in financial difficulty as they were committed to buy contracted oil-linked gas and were undercut by competitors using cheaper spot-indexed gas. This prompted a renegotiation of long-term contracts to include partial spot indexation.

Since 2010, European gas prices have been decoupling from oil indexation, unlike in Asia, but oil-indexed prices still retain some influence on long-term contracts and therefore on European gas. In a relatively balanced market, oil-linked gas still serves as a reference point for hub prices.

Three factors have therefore influenced the development of European gas prices recently: the drop in oil prices, rising LNG imports, as the region starts to act as the residual market for surplus volumes of flexible LNG as Asian demand fell, and the role of storage. Both spot and average import prices declined over the past two years. This drop, in absolute terms, was nevertheless less spectacular than in Asia. NBP fell from $10.70/MMBtu in 2013 to $8.20/MMBtu in 2014 and $6.50/MMBtu in 2015 while the average German import price – a traditional marker for long-term contracts – declined from $10.7/MMBtu in 2013 to $9.10/MMBtu in 2014 and $6.60/MMBtu in 2015. While European gas prices have been low, they were not enough to trigger a switch from coal-fired to gas-fired plants, except for a short period in the U.K. in summer 2014 (see section on European gas demand). This changed in early 2016 as NBP dropped to $4.60/MMBtu in January 2016 and even further thereafter to around $4.20/MMBtu, enabling a switch from coal to gas. The fall in oil prices filtered through to long-term oil-indexed gas contracts driving the average German border price down in 2015. Since the end of 2014, the NBP and average German import prices have been extremely close, highlighting a growing share of spot-linked pricing in contracts. Storage has also played a role in pricing dynamics. Buyers postponed injections into storage in 2015 in order to benefit from lower prices later in the year.

It is worth noting that seasonality, which put NBP at a discount to continental contract prices in summer and at a premium in winter, has disappeared. Besides the difference between spot and long-term contract prices, substantial differences still exist between European countries, even though they tend to be less than in the past. Wholesale gas prices at hubs in Belgium, Germany, the U.K., Austria, the Netherlands and France have shown a strong convergence in 2015, but prices at the Italian PSV hub remained substantially higher than their European counterparts, with an average premium of 2.30 euros/MWh ($0.74/MMBtu) above the Dutch spot price TTF (DG Energy 2015).

European LNG imports increased slightly in 2015, after reaching a record low in 2014, as Europe became the market of last resort for unwanted cargoes. But the decisive drivers were the region's largest supplier and domestic producers, i.e., Russia, Norway and the Netherlands. In June 2015, the Dutch Economy Minister Henk Kamp lowered the cap on Groningen's annual gas production from 42 bcm in 2014 to 30 bcm in 2015. This restriction directly benefited Russia and Norway. According to the IEA's trade flow data, Norway's pipeline exports to Europe increased to 113 bcm in 2015 from 104 bcm in 2014; this is the highest level recorded. The high level of imports chalked up in the first quarter may be the result of buyers opting for cheaper spot-indexed gas while waiting for lower oil prices to be reflected in the price of Russian gas later in 2015. Additionally, Russia sent reduced gas volumes over winter 2014/15 in order to prevent re-exports to Ukraine. Russian gas exports to Europe rebounded in 2015, but the average price at which Russia sold its gas collapsed from $345/'000m3 ($11.1/MMBtu) in 2014 to an estimated $237-240/'000m3 (~$7.6/MMBtu) (Gazprom 2015). But in the absence of a massive supply of U.S. LNG landing in Europe, Russia is not in a fight for market share.

Regulated Prices Rise

While market prices, as described in the previous section, have declined over the past year, regulated gas prices, in local currencies, have increased in many parts of the world. This trend is not new and has been taking place for several years. When looking at gas prices, most analysts and specialized press such as World Gas Intelligence, Argus, and Platts tend to look at and comment on the market prices described earlier. These are either based on GOG or OPE and change at least on a monthly if not daily basis.

However, regulated prices have not received the same coverage, apart from the IGU in its annual report. The main reason is that these prices shift on a very ad hoc basis and depend more on policy decisions than on market influences even when they rely on imports. The IGU reports wholesale gas prices across more than 50 consuming countries. In 2014, 24 countries from the Middle East, Africa, North and Latin America, FSU and Asia had prices at or below $4/MMBtu.

Many of these countries are facing the challenge of low regulated gas prices against the need to develop more expensive domestic gas resources or to import. Some regulated prices have increased due to particular issues in a country, these may be lower oil revenues impacting the state's budget and making subsidized gas prices unsustainable. External market influences matter when countries turn to imports. Mexico, Argentina, Pakistan, Egypt, Kuwait and Venezuela are net-importing countries as of 2015; all except Venezuela have turned to LNG. Meanwhile, Mexico, Argentina, Pakistan, Egypt, Kuwait, the UAE, and Canada are LNG importers (since 2015 for Pakistan and Egypt), while Venezuela, Mexico, the UAE and Oman are pipeline gas importers. Imported gas prices are either influenced by GOG, oil prices or are fixed through BIM. Even though LNG contract prices have declined due to the oil linkage and spot due to oversupply of gas, they are often higher than regulated prices prevailing in these countries. Finally, the value of national currencies does matter. Countries have reacted differently to the drop in oil prices and economic slowdown in China. Some such as Saudi Arabia, Oman and the UAE had limited or no depreciation against the U.S. dollar, while others in the FSU and Latin America for example have depreciated their currencies.

While comparing the evolution of regulated gas prices across countries, it appears that they have taken different decisions on how to increase prices. The list below is not exhaustive as increases are not always clearly reported. Some have raised prices for all users albeit in different proportions, others have targeted specific users such as industrials or power generators; or increased across the board.

MENA

In Egypt, where gas production has declined substantially since 2013, the new government decided to raise prices in 2014. Prices increased between 33 percent and 650 percent depending on the type of user. CNG gained 175 percent to 1.1 Egyptian pound per cubic meter. Gas for electricity generation was hiked from $1.77/MMBtu to $3/MMBtu while prices for residential users were also increased, but differentiated depending on the consumption – in the most extreme case by as much as 650 percent. These increases have proven quite timely as Egypt started to import LNG in 2015. The government also announced in late 2015 that it would raise the price paid to ENI for new discoveries to $4-$5.88/MMBtu from $2.65/MMBtu previously as a way to boost domestic production, notably from the recent gas discovery (Zohr gas field). In March 2016, Minister of Industry Tarek Kabil announced that Egypt would reduce prices to steel and iron factories to $4.50/MMBtu (Reuters 2016a).

In Nigeria, gas pricing for the regulated market rose from 50 cents to $1/MMBtu in 2010 to $1.50 by 2011 and then $2 by the end of 2013. In January 2015, the Nigerian Electricity Regulatory Commission (NERC) set the price at $2.50/MMBtu (Realnews 2014).

Oman was the first GCC country to increase domestic gas prices as it faced increasing shortages. Prices for some industrials were raised from $1.50/MMBtu in 2012 to $2/MMBtu in 2013, $2.50 in 2014 and finally to $3/MMBtu in 2015. In late 2014, the Ministry of Oil and Gas doubled the price of natural gas to electricity generation plants from Jan. 1, 2015. It was raised from $1.50 to $3/MMBtu. Thereafter, it will be increased by 3 percent annually.

Bahrain raised the price of gas sold to industrials (notably aluminum company ALBA) by $0.25/MMBtu from April 1, 2015, to $2.50/MMBtu. A 25 cents increase will be made every year on April 1 until it reaches $4 by April 1, 2021. The last revision took place in January 2012 from $1.5/MMBtu.

The National Iranian Gas Company announced in May 2015 that the price of gas supplied to households, businesses and state-run buildings will increase by 15 percent. However, rates to industries will remain unchanged (PressTV 2015). Iran also decided to cut the price of gas for petrochemicals in January 2016 by one-third from $130 to $80/'000 m3 ($4.50/MMBtu to $2.80/MMBtu) (Natural Gas Europe 2016).

Asia

Bangladesh had the lowest reported wholesale gas price in Asia for 2014 (around $2.20/MMBtu), according to the IGU. However, monthly prices for residential users increased to Tk600 and Tk650 ($7.50 and $8.10) for single and double burners respectively, up from Tk400 and Tk450 ($5 and $5.60) previously. Prices for captive producers were doubled, while tariffs for industrial as well as commercial and CNG users were also increased. However, prices for electricity generators and fertilizer producers remained unchanged.

In Pakistan, the government raised natural gas tariffs by 4 percent to 67 percent for various users on Sept. 1, 2015. This was one of the key requirements of the IMF before releasing the $506 million loan tranche to the country. Residential users paid 3.77 percent to 13 percent more depending on their consumption; tariffs for general industry, power and fertilizer sectors rose by 23 percent and that of CNG by 16.7 percent. The rate for captive power plants increased by 4.7 percent and by less than 1 percent for cement industry. The highest rise was for fertilizer feed stock at 63 percent to 66.7 percent (Dawn 2015).

In Malaysia, Tenaga Nasional Bhd (TNB) will have to pay 7.7 percent more for gas from Petronas from July 2015 (The Star Online 2015). Additionally, Gas Malaysia Bhd announced an average rise of 10.3 percent from July 2015 (Reuters 2015a). These moves were part of the government's plan to cut subsidies and reduce its budget deficit, which include a review of the Petronas gas price to TNB every six months.

In Thailand, the NGV price was raised by Baht 0.50 ($0.014)/kg to Baht 13 ($0.36)/kg for private transport operators and by the same amount to Baht 10 ($0.28)/kg for public transport operators in February 2015 (Reuters 2015b).

FSU

While prices were increased in some FSU countries, the local currencies have also depreciated. Consequently, the increase in $/MMBtu terms would be much lower or could even be a decline. In Russia, Kazakhstan and Azerbaijan the drop in the value of local currencies was massive. As a result, gas prices in dollar terms currently are only half of what they used to be in 2014 in spite of some increases of regulated prices in local currencies.

In Russia, the average regulated residential price increased from 3,852 rubles to 4,141 rubles from 2014 to 2015. In spite of this hike, gas prices are currently only two-thirds of what they used to be in 2014 in dollar terms at $2/MMBtu.

Table 2. Deprecation of Local Currencies in FSU Countries Vs the U.S. Dollar

	Russia	Azerbaijan	Kazakhstan	Uzbekistan	Turkmenistan
Percent of local currency depreciation $ 2015 vs. 2014	59%	31%	25%	11%	23%
Percent of local currency depreciation $ average 2015 vs. Jan. 1, 2016	89%	99%	90%	19%	19%
Percent of local currency depreciation $ Jan. 1, 2016 vs. Jan. 1, 2014	123%	99%	121%	23%	19%

Source: Russian Central Bank

In Uzbekistan, price increases of 9 percent in April 2014, 10 percent in October 2014 and 7.5 percent in May 2015 were reported (Trend 2015).

Turkmenistan used to provide natural gas for free. However, since 2014 it is chargeable at $7 per 1,000 m3 for consumption above 50 m3 per person. As the decline in oil prices has strongly impacted the country's revenues, the government is trying to cut back even further on public welfare expenditure.

Latin America

In Argentina, both the previous and current governments have reduced subsidies. In June 2015, residential gas tariffs increased on average by 3.5 percent as a result of increases for Transportadora de Gas del Norte (TGN) and Transportadora de Gas del Sur. The regulator authorized distribution companies to transfer these price increases to consumers unless they achieved a 20 percent saving on their consumption. Savings of between 5 percent and 20 percent will increase rates by 1.4 percent and 3.8 percent, but those with savings of less than 5 percent will incur rises of between 1.7 percent and 5.6 percent. Meanwhile, the new government announced in December 2015 that subsidies will be partially removed for gas and electricity, except for the low income. The reduction in subsidies will be based on different parameters such as the level of energy consumption and purchasing power of the household (Infobae 2015).

Gas prices from the main fields also increased in Colombia after negotiations between producers and consumers (distribution companies and power generators). The average price from Cusiana increased by 16 percent to $3.40/MMBtu while that from La Guajira rose by 25 percent to $4.70/MMBtu (El Tiempo 2016).

Some price changes were announced in late 2015 that will only impact markets in 2016. Saudi Arabia will increase its natural gas price from $0.75/MMBtu to $1.25/MMBtu as of 2016 along with higher gasoline and electricity prices, while Algeria raised its gas tariffs through a new regulation published on December 29, 2015.

Table 3. Evolution of Selected Regulated Gas Prices in the World

Country	Before	After price change	Before	After price change
Egypt	Cement: $6/MMBtu	$8/MMBtu	Power generation: $1.77/ MMBtu	$3/MMBtu
	Bricks: $6/MMBtu	$5/MMBtu	Residential: $0.80/MMBtu	$1.70/MMBtu (<25 m3)
	Iron/Steel: $3/MMBtu	$7/MMBtu*		$4/MMBtu (25 m3< x <25 m3)
	Fertiliser/petchem: $3/ MMBtu	$4.50/MMBtu		$6/MMBtu (>50 m3)
	Float gass, ceramic: $2.3/MMBtu	$7/MMBtu	CNG LE 0.45/m3	LE 1.1/m3
Nigeria	Regulated market: $2/ MMBtu	$2.50/MMBtu		
Bahrain	Industry: $2.25/MMBtu	$2.50/MMBtu (+$0.25 every April 1 until 2021)		
Iran			Households, businesses and state-run buildings	+15%
Oman	Industrials: $2/MMBtu	$3/MMBtu	Power: $1.50/MMBtu	$3/MMBtu
Bangladesh	Industrials: $2.11/MMBtu	$2.42/MMBtu	Commercial: $3.41/MMBtu	$4.09/MMBtu
	Captive power: $1.5/ MMBtu	$3.01/MMBtu	CNG: $10.79/MMBtu	$12.59/MMBtu
	Tea producers: $2.11/ MMBtu	$2.32/MMBtu	Meter based users: $1.86/ MMBtu	$2.52/MMBtu
Malaysia	Gas Malaysia Bhd: $4.63/MMBtu	$5.11/MMBtu	Power (TNB): $3.56/MMBtu	$3.91/MMBtu
Pakistan	Industry/power: $4.60/ MMBtu	$5.70/MMBtu	Residential (<100 m3): $1/ MMBtu	$1.04/MMBtu
	Cement: $7.02/MMBtu	$7.09/MMBtu	(100 m3< x <300 m3): $2/ MMBtu	$2.08/MMBtu
	Fertilizer (old): $1.16/ MMBtu	$1.89/MMBtu	(>100 m3): $5/MMBtu	$5.67/MMBtu
	Fertilizer (new): $0.41/ MMBtu	$0.68/MMBtu	CNG: $5.70/MMBtu	$6.60/MMBtu
			Captive power: $5.40/ MMBtu	$5.70/MMBtu
			Commercial: $6.02/MMBtu	$6.61/MMBtu
Thailand			CNG (private): $0.015/kg	$0.39/kg
			CNG (public): $0.015/kg	$0.30/kg

Source: press releases, IISS.

Note: *Egypt plans to drop the price back to $4.5/MMBtu.

How Natural Gas Demand Responded to the Price Drop

North America Benefits

North America, especially the U.S., continues to be the region where seasonally-adjusted gas demand is growing. U.S. consumption reached 778 bcm in 2015, up from 756 bcm in 2014, led by the power sector, which increased by an average of just over 43 bcm (~4.2 bcf/d) from last year. Lower HH prices raised competitiveness of combined cycle gas turbine (CCGT) plants over coal, as shown in Figure 4, incentivizing utilities to switch from burning coal to gas. Electricity generated from gas-fired plants in 2015 was only slightly lower than that from coal-fired at 1,335 TWh versus 1,356 TWh respectively. This compares with 2010 when coal-fired generation was about 90 percent higher than gas. Coal-to-gas switching persisted even during the 2015/2016 heating season as a powerful El Niño spread considerably warmer weather across large parts of the Midwest and Northeast. HH traded as low as $1.65/MMBtu in the middle of December 2015, the lowest level since 1998. At these prices, natural gas can compete with a number of different quality coal, including CAPP and Illinois Basin.

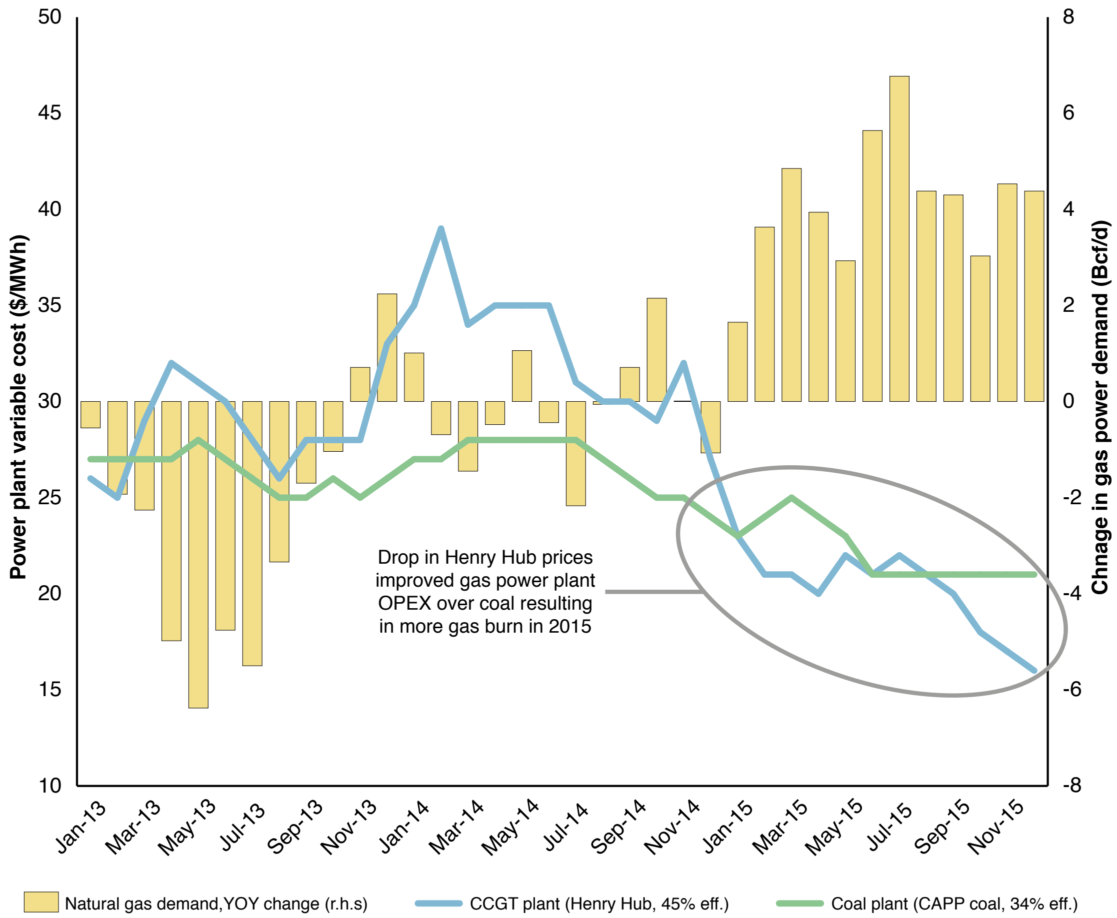

Figure 4. Natural Gas and Coal Power Plant Generation Cost

Source: KAPSARC, Bloomberg, EIA

Note: Assumed $15/ton average transportation cost for CAPP coal

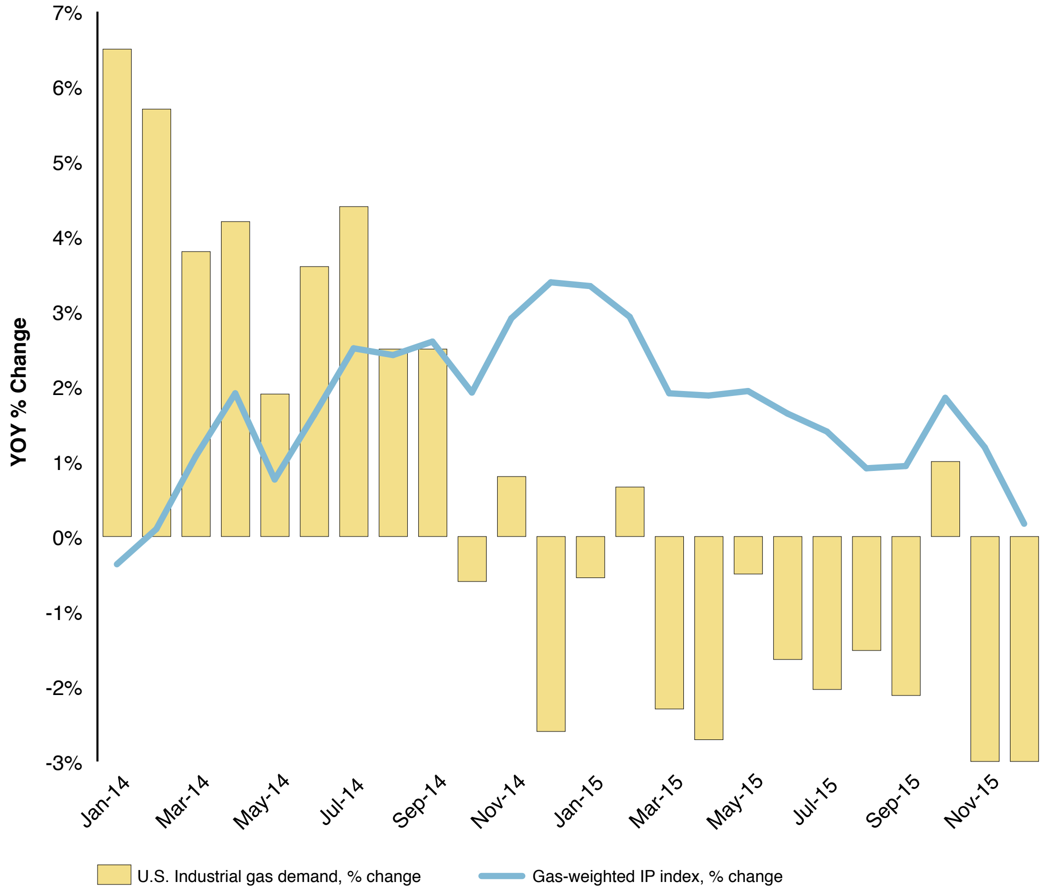

Figure 5. U.S. Industrial Gas Demand vs. Gas-Weighted IP Index

Source: KAPSARC, Federal Reserve, Manufacturing Energy Consumption Survey 2010, EIA

This switching occurred predominantly in the Midwest and Southeastern parts of the country. In addition, utilities permanently shut almost 13,500 MW of coal-fired capacity over the year, which had been planned in anticipation of the Environmental Protection Agency's (EPA) Mercury and Toxic Standard (MATS) rule that came into effect in April. The U.S. Supreme Court overturned the decision for utilities to comply with MATS on June 29, 2015 because it identified that the EPA did not properly consider compliance cost before finalizing the regulation. However, the Court of Appeals issued a ruling to keep MATS in place until the EPA releases its conclusions on cost impacts. Nonetheless, most utilities have committed investments to abide by the rule.

In the industrial sector, gas demand averaged just under 213 bcm (20.6 bcf/d) last year, about 1.5 percent less than 2014 levels. The weakness could partially be explained by the correlation between industrial gas demand and output from gas-intensive industries. The chart in Figure 5 shows that U.S. industrial production (IP) index, a key indicator for the sector, was losing momentum in the beginning of 2015 as a result of slower global economic growth, lower commodity prices and, to some extent, a relatively stronger dollar putting pressure on exports. Delving into the sub-sectoral IP indices indicates strength in some gas-intensive industries such as refineries but it was more than offset by weaker growth in steel and chemicals among others.

In Mexico, gas production is in continuous decline in both associated and non-associated fields. In addition, sporadic outages have exacerbated the issue of supply availability. The country has resorted to cheap pipeline gas from the U.S. to meet growing power and industrial demand, which has displaced some LNG imports. About 25 bcm (2.6 bcf/d) of pipeline capacity was added in 2014-15. However, gas demand in Mexico dropped by 0.2 bcf/d in 2015 while data from the Secretariat of Energy (SENER) showed a significant increase, almost 68 percent on average, in coal-fired generation as of October 2015 versus same time in the prior year. The decline in global coal prices may have incentivized more coal imports and priced out LNG, but this may reverse as more gas pipeline capacity becomes available.

Overall, the resilience of North American production, particularly in the U.S., to counter low prices throughout 2015 was surprisingly impressive. Nevertheless, the persistently low gas and oil prices, have started to show year-on-year declines in gas production growth in some shale basins at the tail end of 2015. Regional demand response beyond coal-to-gas switching and the extent of LNG exports will be a key driver to how prices play out in the future.

European Demand Remains Structurally Low

In Europe, gas is facing strong competition from coal and renewable energies in the power sector, while slow economic growth limits any demand increase in the industrial sector. OECD European gas demand has recovered by an estimated 4 percent over the year 2015. This growth is essentially due to a return to normal weather conditions compared with a mild 2014, which led to an increase in consumption from the residential/commercial sector. OECD demand dropped to 452 bcm in 2014, far below its peak of 566 bcm in 2010.

Even if demand rebounds to about 475-480 bcm in 2015, such levels remain structurally low, equivalent to levels seen in 2000.

The power sector used to be the main driver of European gas demand growth. It accounted for 35 percent of total consumption in 2008-11. This share dropped to 28 percent in 2013, while demand from the power sector dropped from 195 bcm in 2010 to 139 bcm in 2013. Gas-fired plants were squeezed by renewables and coal-fired plants in the context of low-power demand growth. The situation has not improved despite lower gas prices for most of last year, but it has changed since November 2015, especially in the U.K.

Competition between gas- and coal-fired plants is driven by short-run marginal costs (SRMCs). As coal prices dropped by around 23 percent from $3.10/MMBtu in 2014 to $2.40/MMBtu in 2015 while EU ETS CO_2 prices only recovered to about 8.50 euros/ton CO_2 over 2015, this was still insufficient to trigger a coal-to-gas switch.

The U.K., where the carbon tax, which is applied in addition to the EU ETS, was increased from £9/ton in 2014 to £18/ton in April 2015, is the only European country where gas-fired plants are competitive. In summer 2014, a significant switch from coal to gas occurred and triggered a 35 percent increase in the power and heat sector in Q3 2014 (Figure 6). This did not recur in Q3 2015 as a continuous growth in renewables has been cutting into combustible fuels' share of power generation while the dark spread/spark spread was not particularly favorable to natural gas. But this changed since November 2015 amid a strong increase in the use of gas for power in January 2016 (Platts 2016b). Residential demand in major European gas-consuming countries increased by double digits over the first nine months of 2015, except in Spain where heating demand needs dropped (see Table 4).

European Demand Remains Structurally Low

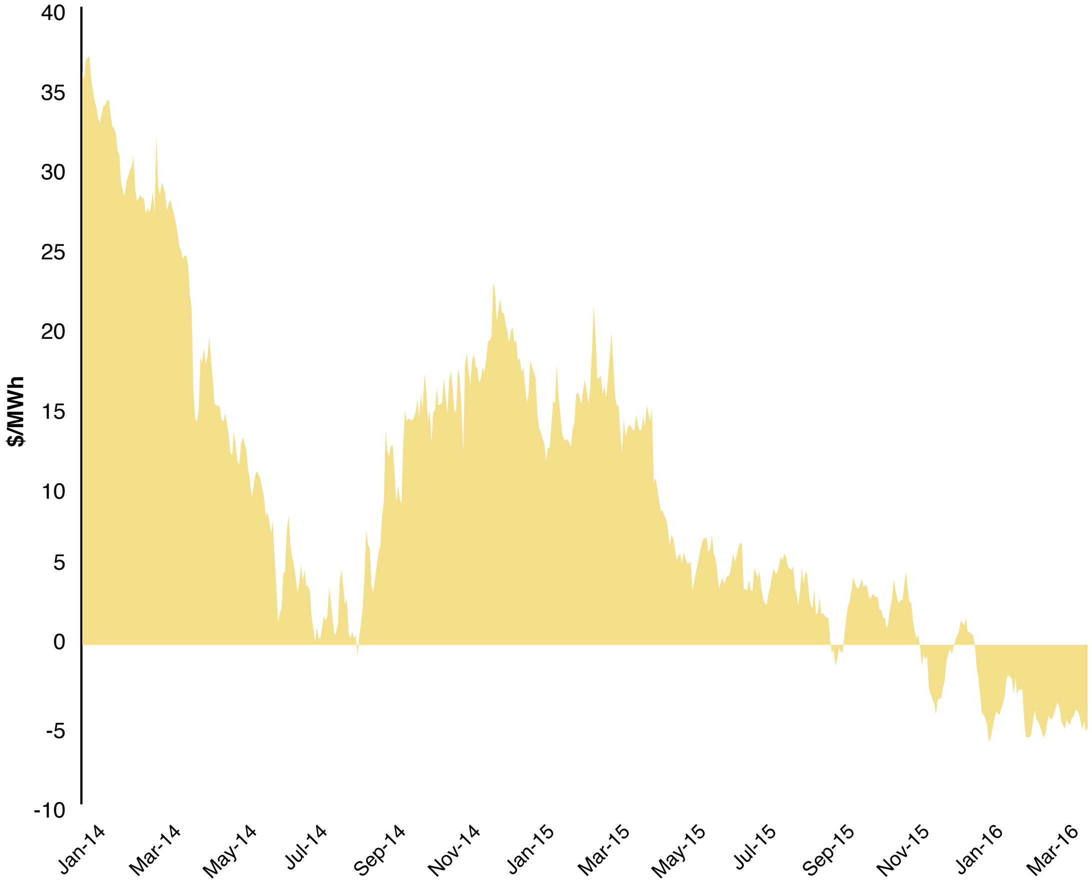

Figure 6. Dark Spread Vs Spark Spread in the U.K.

Source: Bloomberg

The power and industrial sectors offer a contradictory picture at first glance. Data available from individual countries, which represent over 80 percent of OECD Europe gas demand, show some increases in the power and industrial sectors. Despite an unfavorable comparison between SRMCs of coal and gas-fired plants, power generators' gas consumption increased in a few countries. However, this reflects these countries' specific situation in terms of overall power mix rather than a genuine improvement of the competitiveness of gas-fired plants:

> Belgium suffered a substantial reduction in nuclear generation, by 23 percent in the year 2015. Combustible fuels contributed to replace 60 percent of that loss.

> Italy faced a heat wave in the summer; electricity demand in July 2015 was 12 percent higher than in July 2014 while hydro generation in 2015 dropped by 23 percent from a year ago.

> The combination of higher power demand (+4 percent), lower hydro and renewables (-24 percent and -1 percent respectively) contributed to the increase in the use of combustible fuels in Spain's power sector.

Table 4. Selected Sectoral Demand Evolution in Major OECD European Countries

Country	Estimated variation (Year)	Sectoral evolution
Belgium	+10%	Residential/commercial: +11% Industry: +5% Power:+12%
France	+8%	Residential/commercial/small industry: +6% Industry/Power: +10%
Germany	+5%	No sectoral data available
Italy	+9%	Residential/commercial: +11% Industry: -2% Power:+17%
Netherlands	0%	Regional grid: +8% Other users to the main grid: -4% Power:-5%
Spain	+4%	Residential/commercial/Industry: +1% Power:+19%
Turkey	-2%	No sectoral data available
United Kingdom	+2%	Residential/commercial: +6% Industry: +1% Power:-4%

Source: IEF JODI Gas, Synergrid, SNAM, Pegase, CBS statistics Netherlands, CORES

Similarly, industrial gas demand showed some positive trends in Belgium, France and the U.K. In the case of France and the U.K., a small increase in industrial production may have helped this recovery. The increase in the U.K. was particularly strong in the iron and steel sector.

Asian Demand Stalls

In total, Asian (including Japan, Korea and non-OECD Asia) gas demand gained more than 115 bcm over 2009-14, in spite of a high price environment. But in 2015, contrary to what may have been expected, demand did not enjoy a large uptick following a substantial drop in prices. Gas demand growth is in fact likely to fall below the five-year average annual increase of 23 bcm. The demand picture was not uniform across Asia with a large number of countries experiencing drops, including Japan, Korea, Thailand, New Zealand, Australia and the Philippines, while China faced a slowdown and in some places such as Singapore, Taiwan,

Asian Demand Stalls

India, Brunei and Indonesia consumption actually rose. Economic growth slowed in China, but is forecast to continue at a robust pace in India and ASEAN-5 and recover in Japan, according to the IMF World Economic Outlook of January 2016. All Asian countries face competition between cheap coal and gas, whereby gas is still not low enough to be competitive. Coal prices in the Pacific Basin have declined significantly as a result of lower Chinese demand and the resulting oversupply. The price of coal for power at Qinhuangdao, a major trading hub for coal in northern China, was at record low of $54 per metric ton in December 2015, about half the value compared with December 2013.

Although China only imports a small share of its total coal consumption due to its massive domestic production, these volumes are sufficient to swing the market.

Average LNG import prices only started to decline in early 2015 and reached lower levels in spring 2015, while prices were hiked for power generation in a number of countries (see section on prices at the beginning of this report). As noted earlier, a further drop in prices is expected in 2016. Demand for gas in power generation in Japan, Korea and China has been weak due to a milder-than-normal winter and a cooler summer, the penetration of

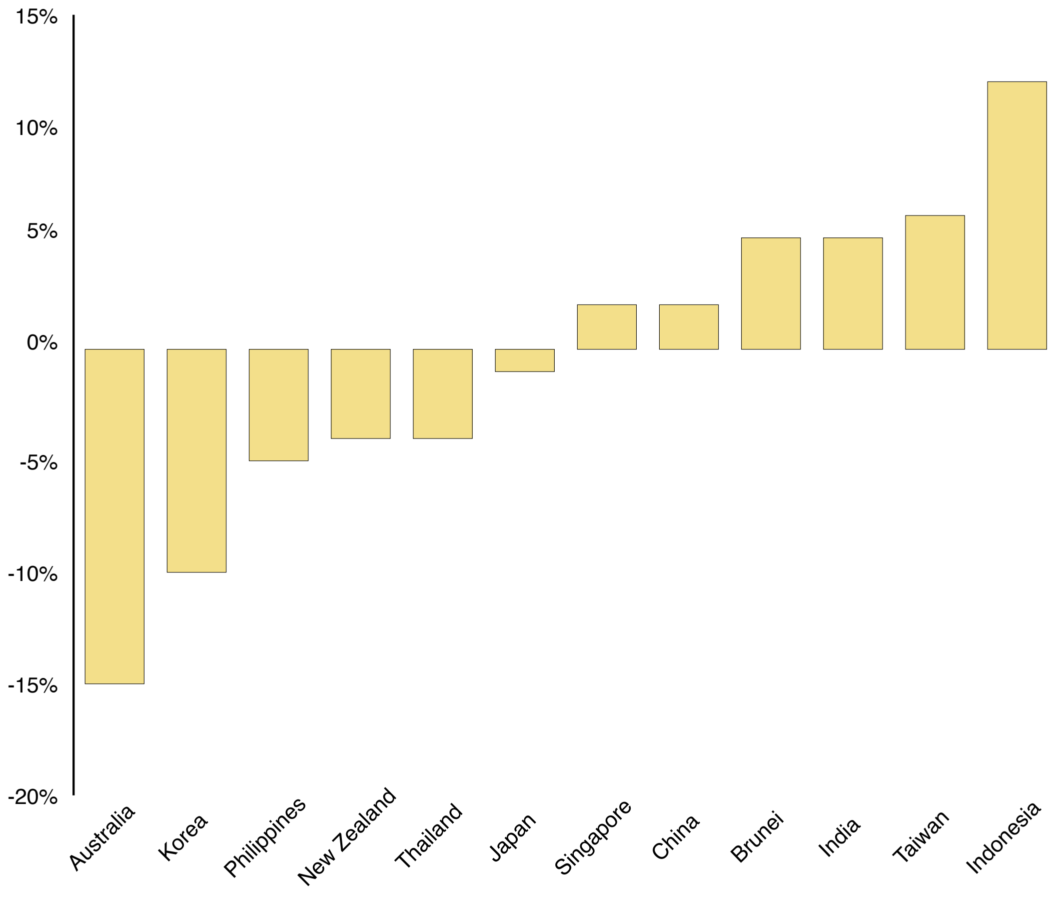

Figure 7. Year-On-Year Growth of Gas Demand 2015 versus 2014

Source: IEF

Note: data for Indonesia are only available for six months renewables and especially more-competitive coal. Slower global economic growth, particularly from China, also impacted gas demand growth. In Japan as well as Korea, gradual restarts of nuclear power plants are also eating into the share of gas in power generation, which more than likely means that the regional 'golden age of gas' post-Fukushima has come to an end. Year-on-year demand in Japan and Korea fell by 1 percent and 10 percent respectively from 2014 to 2015.

Electricity generation by the 10 largest utilities in Japan dropped 3.6 percent on cooler weather during the peak summer months of 2015 compared with 2014. Heating demand at the start of the 2015/2016 season was also low due to unusually warm weather. Weather data show temperatures in Tokyo and Seoul were 13 percent and 3 percent warmer, respectively. In addition, exports from Japan and Korea dropped by 2 percent and 8 percent respectively, as slow economic growth in China, one of the biggest markets for both countries, weighed on manufacturing in OECD Asia.

Nuclear generation in Japan reached a milestone with the restart of two 890 MW units at the Sendai nuclear plant, the first since the 2011 earthquake, which idled more than 40 GW of nuclear capacity. Nuclear plants are expected to slowly win back their share of the power mix from fuel oil and LNG. In 2015, the generation by plants using fuel oil and crude dropped by 23 percent and 27 percent respectively, while gas-fired power lost 6 percent and coal 2 percent (LNG Intelligence 2016).

The share of fuel oil in power generation in Japan has doubled since Fukushima. At higher oil prices, LNG competed with fuel oil on the margin, and it was argued that plants burning fuel oil would be displaced first with the return of the nuclear fleet. Japan's long-term strategy foresees only 3 percent of oil in the power mix by 2030, against 15 percent in 2013. But in the current pricing environment, fuel oil powered generation is competitive against less-efficient gas plants (Figure 8). Although most fuel oil plants will be left as reserves for peaking purposes, a further decrease in oil prices may have an impact on the dispatching order and demand for LNG. Meanwhile, coal-fired plants remain more attractive than gas given the drop in coal prices. The new Energy Strategy approved by the Advisory Committee on Energy and Natural Resources gives a strong role to coal with 26 percent of the power mix by 2030.

China's apparent gas consumption increase is estimated at only 3.7 percent last year against 8.4 percent in 2014, according to the CNPC Economic and Technology Research Institute (ETRI) (Xinhua Finance Agency 2016), while it is estimated at 4.8 percent by the Energy Research Institute (+8.4 bcm). The key driver was lower economic growth impacting industrial demand for energy, notably from key energy-intensive industries in the construction sector such as steel and cement. Natural gas accounts for only 4 percent of power generation in China. Power demand has grown 0.5 percent in 2015 compared to 2014 (Reuters 2016b). Meanwhile, China has continued to add wind, nuclear and hydro capacity, putting pressure on thermal generation. But another important driver of the slowdown has been that gas prices have remained high for non-residential users. The National Development and Reform Commission (NDRC) only decreased city gate gas price in November 2015, too late to have an impact for the year. City gate price increased by 36 percent from July 2013 to April 2015, while coal dropped by 33 percent, according to CNPC. Consequently, the levelized cost of electricity from gas-fired plants before the reform was more than twice that of coal-fired plants and is also higher than nuclear, and coal-,

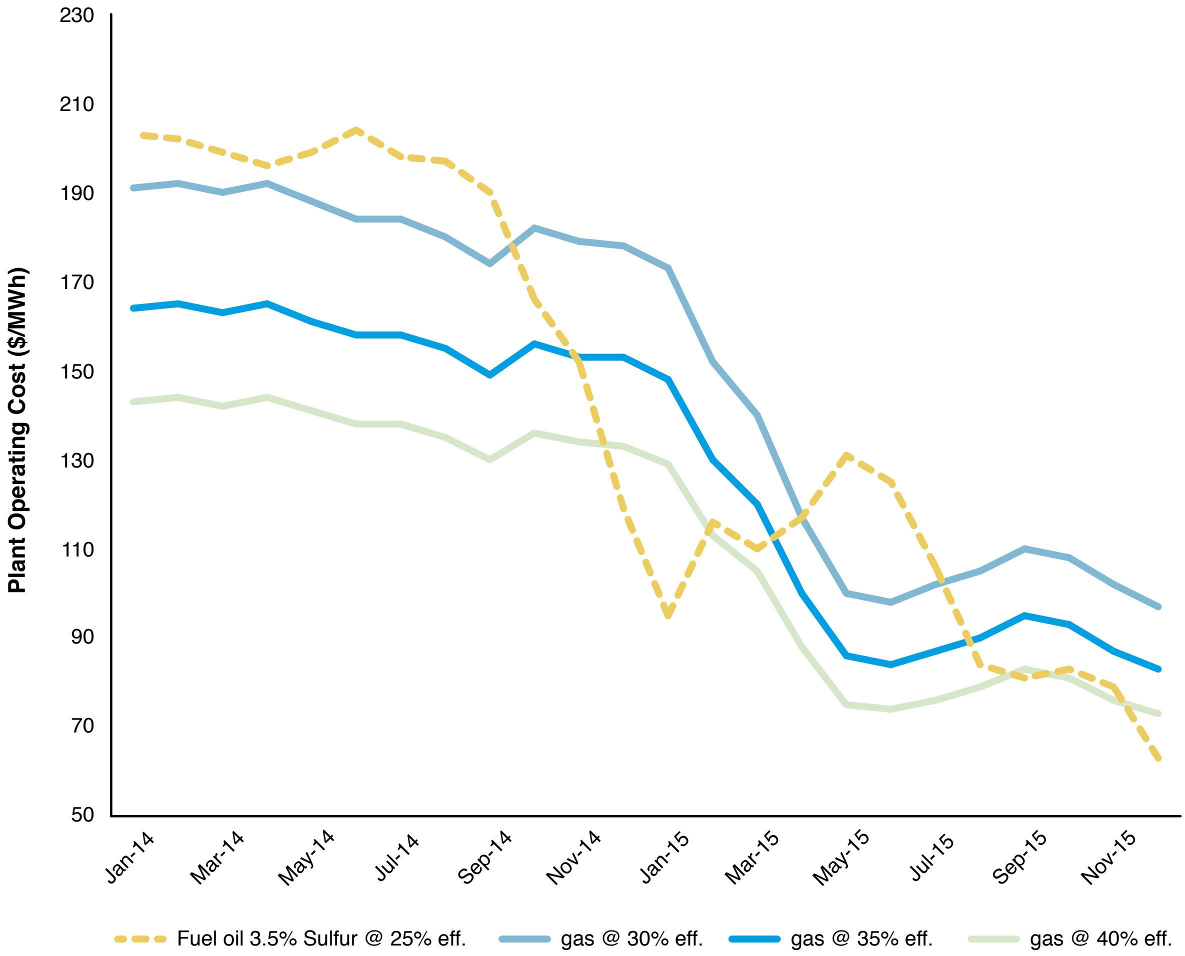

Figure 8. Fuel Oil and Gas Competition Under Different Efficiency Scenarios in Japan

Sources: KAPSARC, Trade Statistics of Japan, Platts

wind- and hydro-by-wire. The drop has reduced the gap, but gas-fired plants remain less competitive than coal (CNPC 2015). High gas prices have affected industries as highlighted by Quanzhou's ceramics makers who complained that it had pushed their business to the edge (E&E Publishing 2015). Looking forward, these reforms may be ineffective in stimulating demand for gas due to the monopolization of the distribution sector (CNPC 2015).

Indonesia, India, the Philippines, Bangladesh and Pakistan face gas shortages as their potential demand is much higher than actual consumption, but their respective demand has evolved differently. Indonesia witnessed a large demand increase over the first six months of 2015, according to APEC data. Additional supply may have come from the conversion of Arun LNG, one of Indonesia's LNG liquefaction plants, into an import facility in 2014. Data show a slight decline in consumption from the Indonesian power sector, where gas faces acute competition from domestic coal, pointing to an increase from the industrial sector, notably fertilizer producers, announced earlier in 2015 (Reuters 2015c).

India seems to be one of the few countries benefiting from lower gas prices. It has been struggling to stop the abrupt decline in domestic production, which continued in 2015 (a 2 percent drop over April-November 2015 compared to the same period of 2014). India took advantage of lower spot prices to import more spot LNG, while taking fewer contracted supplies from Qatar: consequently its LNG imports in 2015 dropped. The contract, which featured a much higher price than its neighbors, was renegotiated in December 2015. Indian LNG imports are limited by its regasification capacity as the Kochi terminal is not connected to the grid and Dabhol is operating below capacity as it lacks a breakwater facility, which means it is not operational during monsoons.

Bangladesh does not import gas, even though the country has plans to build either pipeline or LNG import infrastructure – without any success so far. Consequently, it depends entirely on domestic production, which is insufficient to cover total potential demand. Data from Petrobangla shows an increase of gas production over the first six months of 2015, with most of the fields producing at their maximum. Only data for the fiscal year (FY) are available (July-June), and they indicate an 8.5 percent growth from FY 2013-2014 to FY 2014-2015. Similar to Bangladesh, the Philippines depends solely on gas production; the decline in domestic output directly impacts gas demand. The country expects to have an LNG import facility operational in 2016 or 2017. No data are available for Pakistan, but unlike Bangladesh and the Philippines, it started importing LNG in 2015, providing additional supply on top of domestic production.

While Thailand is not gas short as it has LNG import facilities, data show a surprising decline in consumption. The lack of appetite from Thailand is more visible after PTT said it planned to delay two new long-term contracts with BP and Shell that were due to start by mid-2016.

Finally, both Brunei and Taiwan had a positive demand evolution. Brunei witnessed a 6 percent increase in gas production, which resulted in higher exports as well as increased demand (+9 percent). Taiwan is one of the few countries with a genuine growth in consumption despite strong competition from coal in the power generation sector.

African Consumption Hit by Production Issues

Gas demand evolution in North Africa depends heavily on the development of domestic production. Overall North African demand is set to increase despite the weakness in Egypt and Tunisia. Egypt's gas production is continuing its dramatic drop; after losing 14 bcm (-23 percent) over 2009-14, it lost another 9 percent in the first 11 months of 2015. In this country, the reform in gas prices is crucial to reverse this trend and encourage gas production. This decline has effectively constrained demand in the first four months, until Egypt started importing LNG in mid-2015, benefiting from low spot prices. While LNG imports have effectively boosted demand by 0.3-0.5 bcm per month, it remains 1 percent lower than in 2014. In this context, demand for electricity has risen faster than total demand as gas supplies were redirected to generators to avoid more power cuts, while supplies to industries were reduced.

In Algeria, natural gas consumption was exacerbated by low prices. While demand from the power sector is growing by 11 percent, demand from industry was the main driver behind the 19 percent

African Consumption Hit by Production Issues

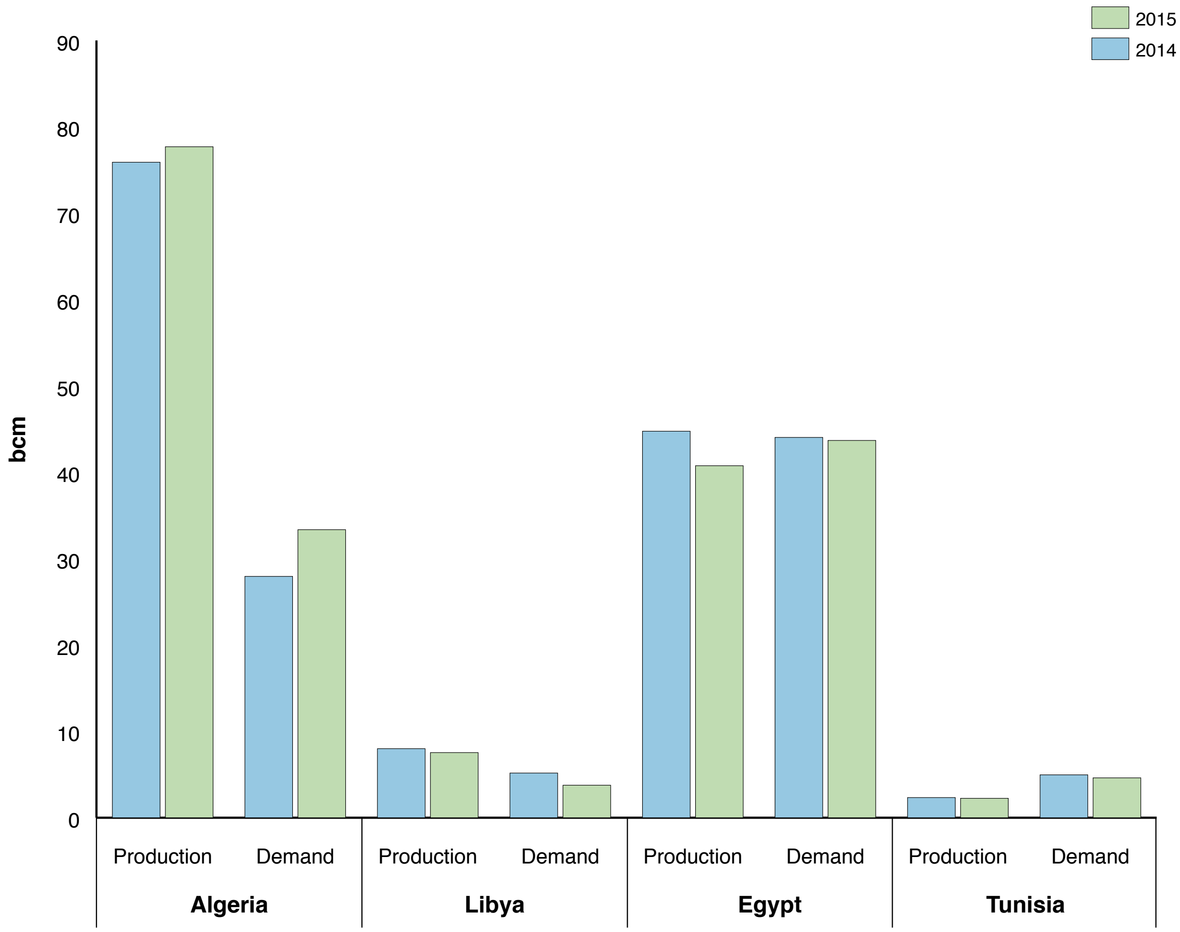

Figure 9. Year-On-Year Growth of Gas Demand in North Africa in 2015 (first nine months)

Source: JODI –GAS (IEF)

growth seen in the first 11 months of 2015. A new fertilizer plant came online in early 2015 sponsored by Sonatrach and Oman's Suhail Bahwan Holding Group (SBGH). Modernization and expansion of two other fertilizer plants were announced. As consumption grew faster than production, exports dropped considerably by around 4 bcm over the first nine months. Meanwhile, Tunisia's gas demand was directly impacted by lower domestic production as well as reduced transit revenues from Algeria, especially during the first half of 2015.

Latin America Weighed by Rain and Domestic Output

Similar to Africa, the region's gas demand depends heavily on domestic production as well as LNG imports. Another important factor is hydro generation, which makes gas-fired plants a flexible tool in the power sector. Brazil has been the most dynamic market over the past five years in Latin America, but demand is showing signs of weakness due to shrinking economic growth.

Data from the Ministry of Energy shows demand declining in 2015 compared to 2014 (Ministerio de Minas e Energia 2016). Demand for gas was higher than the average for 2014 in almost every month of 2015 except July and August when heavy rainfall boosted hydro output and reduced the call on gas-fired generation. Despite gloomy economic conditions, gas demand from industry is on a slight upward trend, which may be a consequence of rapidly declining prices. In Brazil, industrials paid oil-indexed gas prices, which are almost at parity with those in Europe.

Trinidad's 6 percent decline in gas production resulted in a corresponding 4 percent drop in demand. Chile's gas demand increased by a marginal 3 percent; Chile does not seem to have taken advantage of lower LNG import prices, even though the country depends heavily on LNG imports. As Venezuela started production at the Perla gas field in the Cardon IV block, it decided in mid-2015 to stop importing natural gas from Colombia (Reuters 2015d). Finally, Bolivia's gas production was flat in 2015 and as demand increased, this impacted exports.

LNG Swings Back to Europe, New Buyers Emerge

In a slowly expanding LNG market, declining demand in Asia has removed the strongest pillar of support just as the first new LNG projects in Papua New Guinea, Australia and Indonesia come on stream. Around 150 mtpa of export capacity is expected to start in 2015-20. This sets the stage for a structural overbuild of LNG globally with Europe emerging as the main beneficiary, while new importers absorb small quantities. In this context, Europe appears as the only market able to absorb large amounts of unwanted LNG, acting as the residual market. This is helped by third-party access to underutilized LNG capacity and sufficient interconnectivity within Europe to absorb additional volumes as well as the existence of a large, liquid traded market. Europe's growing import needs in 2015 have prevented these additional LNG supplies from competing with Russian pipeline gas by accommodating an increase in both Russian gas and LNG.

Supply Increases Modestly

On LNG supply, 2015 was a mixed year. Three projects started or expanded, marking the start of the ramp up of Australian LNG, which will continue over the coming years. Despite the drop in oil prices, cost overruns of Australian LNG projects mean the companies need revenue more than ever. Following the start of Queensland Curtis LNG in December 2014, a second train began commercial operations in November 2015. Gladstone LNG shipped its first cargo in October. The third CBM-to-LNG project, Australia Pacific LNG, failed to start in 2015, while in the U.S. the start of Sabine Pass was delayed to February 2016. The 2 mpta Donggi-Senoro plant in Indonesia shipped its first cargo in August. The start of all Northwest Australian LNG projects was postponed to 2016 at the earliest.

Meanwhile, some LNG plants stopped or reduced production. Yemen LNG declared a force majeure in April 2015 and stopped exports. In Algeria, the Skikda plant was shut for maintenance for two months during the first quarter. Overall, net global LNG supply growth is estimated at about 6 mtpa or +2.5 percent year-on-year, according to GIIGNL. This is much lower than what could have been initially expected and is due to production issues and postponements by operators such Gorgon or APLNG. This raises the question whether a lower oil price environment would not incentivize LNG producers to start later – if their contracts allowed them to do so.

LNG Returns to Europe

Over 2010-14, Europe's role in the LNG market eroded as its imports declined from 65 mtpa in 2010 to 32 mtpa in 2014 (GIIGNL 2015). In that period, LNG was progressively diverted to more attractive Asian markets, which altogether accounted for 75 percent of global LNG imports, up from 61 percent in 2010. There were three main drivers behind this phenomenon:

> OECD Europe gas demand collapsed from 567 bcm in 2010 to 452 bcm in 2014.

> Japan needed additional LNG after Fukushima in order to fuel gas-fired plants to replace nuclear generation. In 2010, Japanese nuclear power plants produced 280 TWh, while from September 2013 until August 2015 there was no nuclear generation. At the same time, demand in China gained 75 bcm and the rest of non-OECD Asia by 10 bcm. By 2014, China had become the third-largest importer and was taking more LNG than any European country.

As stated earlier, gas prices diverged between Europe and Asia. Asian LNG import prices substantially increased after 2011 as Japan paid an average \$16-\$17/MMBtu over 2012-2014. The Chinese average climbed from \$4.50/MMBtu in 2009 to almost \$13/MMBtu in 2014. Even new LNG importers had to pay the so-called Asian premium; for example, Thailand paid around \$15.50/MMBtu 2014 (Interfax 2015). In contrast, European gas prices were on average below \$10/MMBtu over 2012-2014.

The large price gap between the regions (Asia and Latin America on one side and Europe on the other) also led to an increase in re-exports. Although the U.S. was involved in a large part of the re-export business from 2009 till 2011, they have almost stopped re-exporting LNG as of 2015. Meanwhile, the oversupplied European gas market became a key source of LNG re-exports – 6 mtpa in 2014 out of 6.4 mtpa globally (Spain – 3.8 mtpa, followed by Belgium with 1.1 mtpa). Among the key drivers were price differentials, over-contracting and destination clauses in some European LNG supply contracts, preventing LNG from being diverted before reaching its contractual destination. Among the inflexible supply contracts are those to Spain, France and Portugal, as well as Qatari LNG supply into Zeebrugge (Timera Energy 2013).

However, the tide turned in 2015. The three factors stated above no longer applied.

European demand increased by around 4 percent over the year 2015 compared to 2014 as weather conditions returned to normal. The drop in domestic production driven mostly by the cap on the Dutch Groningen gas field raised import needs.

Demand fell in both Korea and Japan, while Chinese LNG use declined.

The price gap between Asia and Europe shrank significantly. The Asian Premium (gap between NBP and Japan LNG import price) dropped from almost \$10/MMBtu in mid-2014 to \$2-\$3/MMBtu in mid-2015. An Asian premium based on the gap between Asian and European LNG spot prices dropped from \$7.40/MMBtu in H1 2014 to \$0.77/MMBtu in H1 2015, Cedigaz reports.

This contributed to attracting LNG back to Europe as the market regained some attractiveness and absorbed surplus cargoes. Consequently, LNG imports increased by 20 percent in 2015 (+6.2 mtpa), while re-exports, notably from Spain, fell substantially (Reuters 2015e). In order for re-exports to make sense, the price differential needs to cover transport costs, as well as reloading and any logistics costs occurred at the reloading terminal. Re-exported LNG also needs to be competitive with Asian spot LNG.

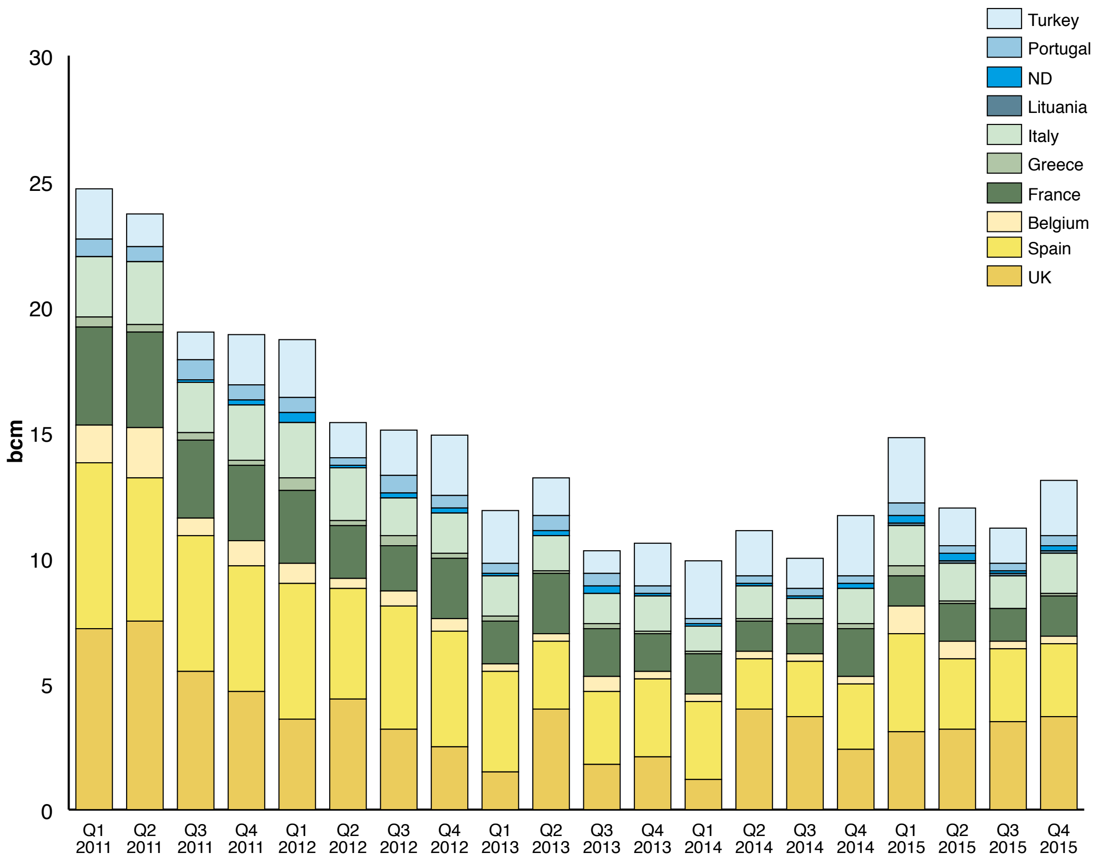

Figure 10. European LNG Imports by Country 2011-15

Source: IEA, Gas trade flow in Europe

New Importing Countries

Three countries started importing LNG in 2015: Pakistan, Egypt and Jordan. All faced shortages and opted for floating storage and regasification units (FSRUs). They took advantage of low LNG prices resulting from the cheap oil price environment and an oversupplied market to cover their domestic energy shortfalls.

Pakistan has a long history of trying to secure either LNG or pipeline imports to meet its potential gas demand. Egypt faced a sharp production decline over the past five years (-14 bcm or 23 percent of its output over 2009-14) leading to demand being curtailed and also to power shortages. Jordan, which used to import pipeline gas from Egypt, was also affected by Egypt's supply difficulties as its imports were reduced. Pakistan received its first LNG cargo in late March 2015, Egypt in April and Jordan in May – all from Qatar. Egypt got a second FSRU in October 2015 and has announced plans for a third to be located in Safaga. Egypt, Jordan and Pakistan imported an estimated 2.6 mtpa, 1.9 mtpa and 1.1 mtpa, respectively (GIIGNL 2016). They issued tenders for LNG cargoes. Jordan's National Electric Company awarded half of its tender to Shell for deliveries in 2016 and 2017. Egypt awarded to companies such as Shell, Gazprom, Trafigura and Vitol. Gunvor will supply Pakistan with 60 cargoes at 13.37 percent Brent price over the next five years. Finally, Pakistan signed a deal with Qatar for 3.5 mtpa over 15 years.

Asia

Beyond the demand drop in the three largest LNG markets in Asia, the other crucial development in 2015 is how buyers are turning the tables on producers and asking for concessions on their existing LNG long-term contracts. This includes not only better prices, but also improved contractual terms such as relaxing destination clauses, shorter-term contracts as well as bigger downward quantity tolerance (DQT). Petronet, one of the largest buyers of Qatari LNG, has managed to negotiate a better price with RasGas for its 7.5 mtpa long-term contract, but also agreed to increase contracted quantities by 1 mtpa. Asian buyers are also trying to get more flexibility in their contracts. Chinese NOCs have received exemptions to their destination clauses, which have allowed them to resell some of their cargoes on the international market (CNPC 2015). Meanwhile, Sinopec no longer seems keen to take its 7.6 mtpa of contracted LNG from Australia's APLNG, for which the start has been delayed to 2016 (The Sydney Morning Herald 2015). Finally, PetroChina asked Qatargas in 2015 to skew deliveries under its 3 mtpa long-term contract toward the peak demand winter period (Reuters 2015f). Although this does not change the nature of the contract, it is a major concession in terms of flexibility.

Some Japanese utilities have said they will no longer sign contracts with destination clauses (Bloomberg 2015b). JERA, the joint venture between TEPCO and Chubu Electric Power, wants to reduce the share of long-term LNG contracts to about half of its portfolio and increase the share of spot and short-term supplies. With the Japanese power market liberalizing in 2016 and the retail gas market in 2017, Japanese utilities will face increased uncertainties on their demand.

Looking Ahead to 2016

More substantial effects of lower oil and gas prices can be expected in the medium to long-term. So far, there is little evidence of the impact of lower oil prices on gas output apart from the slowdown of production growth in U.S. projects coming on stream in 2014-2015, which were sanctioned years ago and where most of the investments had been made before oil prices collapsed. Reported cuts of more than 20 percent in upstream investment by many oil companies in 2015 will impact future gas production as upstream projects at the planning stage are deferred or canceled (IEA 2015). As of January 2016, the world's big oil and gas companies were reported to have shelved $400 billion of spending on new oil and gas investments, including Canada's oil sands and deep water projects (FT 2016). This compares with a July 2015 estimate of $200 billion; oil prices have dropped from $55/bbl to $30/bbl during this timeframe (FT 2015). Against this backdrop, LNG projects are particularly at risk. Low gas prices in Asia and in Europe, the two largest LNG importing regions, combined with heavy demand uncertainties will impact FIDs. Projects in Eastern Africa and Canada have already been deferred. Buyers are putting pressure on LNG sellers to obtain better contract conditions, either in terms of pricing or being more flexible. Even though lower oil prices no longer incentivize LNG buyers to move away from OPE, the rationality issue remains. Buyers are also reluctant to commit for long periods given the market uncertainties.

There is a potential risk for a pause in terms of FID over the coming years as companies wait for market conditions to improve and work to lower costs. This may also impact the long-term future of natural gas in the energy mix as LNG has always been considered as the only means to penetrate new markets and expand gas' market share.

Meanwhile, lower oil prices mean oil-linked gas prices will also be cheaper, thus helping reduce the energy costs of consumers. But an improvement of gas over other fuels – notably coal – will require even lower gas prices. Even as the narrative of gas displacing expensive fuel oil continues in Japan, Central America and Africa, the reality of competing fuels becoming cheaper also becomes more evident. In Europe, a gas-fired plant would need a price of about $3.90/MMBtu to compete against a coal-fired plant with a carbon price of 10 euros/ton. NBP was about $4.23/MMBtu in March 2016. Even if gas-fired plants became competitive again against coal-fired plants, renewables have grown over the past five years and will continue to do so in the context of flat power demand. The real challenge for gas is to become a credible and affordable alternative in Asia where the share of coal could be reduced in order for the world to reach its climate change targets. The gas industry also faces many other uncertainties including future oil prices, the evolution of Chinese energy demand and the impact of COP21 on national energy policies.

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Notes

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About the Project

KAPSARC is analyzing the shifting dynamics of the global gas markets. Global gas markets have turned upside down during the past five years: North America has emerged as a large potential future LNG exporter while gas demand growth has been slowing down as natural gas gets squeezed between coal and renewables. While the coming years will witness the fastest LNG export capacity expansion ever seen, many questions are raised on the next generation of LNG supply, the impact of low oil and gas prices on supply and demand patterns and how pricing and contractual structure may be affected by both the arrival of U.S. LNG on global gas markets and the desire of Asian buyers for cheaper gas.

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