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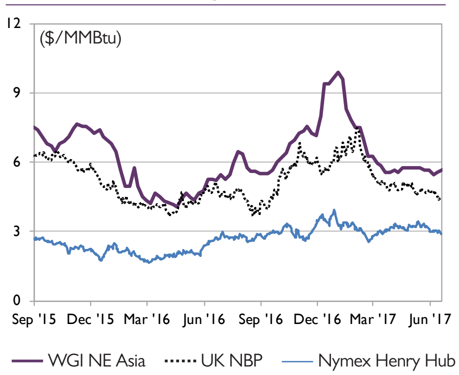
Global Gas Pricing



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VIEWPOINT

Oil Price Bet Makes No Sense

Long-term contracts that index LNG or international pipeline gas prices to oil for decades into the future are becoming counterproductive. Sellers have historically favored oil indexation, as have project lenders. They argued this provided the price stability needed to underpin the enormous upfront investment such projects require. As long as oil was on a long-term growth track and Opec was able to keep a floor under prices most of the time, this made sense. It doesn't make sense for companies that at the same time insist that gas will be the growth fossil fuel of the future, long after oil succumbs to efficiency and electric vehicles (p5).

Buyers went along with oil indexation for a time. Europe started to push back early this century, gradually developing spot and futures markets and other means of price discovery that allow gas prices to better reflect regional supply and demand fundamentals. But oil indexation remains in many legacy contracts, and for this and other less-transparent reasons, gas has only rarely become cheap enough in continental Europe to compete with coal in the absence of a steep carbon price. Consumption has declined as a result.

In Asia, oil indexation is still the dominant mode of long-term pricing, not least because no deep, dependable spot and futures markets exist to provide an alternative. Growing supplies of spot LNG, and the entry into global markets of potentially even larger volumes of flexibly priced US LNG, are starting to change this. But it's happening slowly. In the meantime, sellers and their financiers are still trying to extend oil-indexation further into the future — a future in which oil won't necessarily be the globally dominant fuel.

Baseline forecasts from BP, Exxon and the International Energy Agency all show oil demand continuing to grow for the next 20 years or so. But the Grantham Institute and Carbon Tracker project demand peaking by 2020, as does the recent RethinkX report on *Rethinking Transportation 2020-2030*. Nobody knows what will happen once it becomes clear that oil demand has nowhere to go but down, but prices will probably become chronically weak and unstable. For sellers who believe gas consumption will continue to grow for longer, that makes a price link to oil illogical. The potential for extended spikes in oil prices also makes indexation risky for gas buyers, who might be unable to push the higher costs on to customers. Such interludes could even speed the full transition to renewables and electricity storage, chopping years off the bridge-life of gas.

Pricing gas in relation to the fundamentals of the gas market itself would avoid this precarious link — and perhaps slightly improve the odds that gas will remain a mainstream competitor in the power generation market long after oil becomes a niche product. Obtaining price signals remains a problem, particularly in Asia. But the ongoing buildup in LNG spot trading will help ease this if confidence can be established in price reporting services or other discovery mechanisms. Oil market risk going forward is simply too high to bet your international gas future on. ■

LNG Markets Pass Qatar Stress Test

Global LNG markets have passed the Qatar stress test with flying colors. Spot prices in the Atlantic and Pacific Basins are roughly back to where they were on Jun. 4, the day before four of Qatar's Arab neighbors, led by Saudi Arabia, cut off trade and diplomatic links (WGI Jun.14'17). Kuwaiti-led mediation efforts have yet to produce tangible results. But with Qatar determined to play down any sense of crisis, LNG deliveries continue as normal. And backing up Qatar Petroleum's (QP) claims that "it's business as usual," subsidiary QatarGas this week signed a five-year LNG supply deal with Royal Dutch Shell, while piped gas shipments to the United Arab Emirates and Oman continue via the Dolphin pipeline.

Under the deal with Shell, which starts in January 2019, QatarGas will supply 1.1 million tons annually over five years from QatarGas 4 — its joint venture with the Anglo-Dutch major — for delivery into the Dragon terminal in the UK and Gate in the Netherlands. QatarGas CEO Khalid Bin Khalifa al-Thani said this would provide "QatarGas with access to Shell's gas sales portfolio in the UK and continental Europe, as well as the flexibility to manage LNG deliveries to our global client portfolio." Qatar has become more exposed to the spot market, last year selling over 20 million tons of its 79 million ton exports on spot or short-term deals of less than four years, according to GIIGNL, the International Group of LNG Importers, and one source reckons the deal shows how desperate it is to secure buyers for uncontracted volumes.

A large chunk of Qatar's term contracts are due to expire early next decade, including around 7 million tons/yr with Japanese buyers (WGI Jun.7'17). By then, it may also have a potential 15 million tons/yr of incremental output on offer after recently lifting the moratorium on new gas developments based on its giant North Field. Buyers have been demanding more flexibility from Qatar, which has traditionally driven a hard bargain on the grounds it is a reliable supplier. Although one source from a buyer country told *World Gas Intelligence* the crisis may heighten perceptions of political risk, Jonathan Stern with the Oxford Institute for Energy Studies believes it won't affect the marketing of new Qatari volumes as they will be so competitive.

In addition to being the biggest LNG exporter on the planet, Qatar is the largest exporter of helium, derived from natural gas through processing. Here, the economic blockade has had more impact, forcing RasGas to shut two large helium production plants with combined capacity of roughly 2 billion cubic feet per day, or the equivalent of one third of global demand. Since the sanctions were announced, Saudi Arabia, the UAE, Bahrain and Egypt have banned Qatari-owned or -operated vessels from entering their ports. The UAE has also banned third-party ships either heading to or from Qatar. That has prompted QP to start offering ship-to-ship fuel bunkering at Ras Laffan to any vessels laden with Qatari imports or exports. The Qatari helium is normally exported on trucks through Saudi Arabia and into the UAE, where it's loaded onto ships at Dubai's Jebel Ali port. Demand comes mainly from Asia, where helium is used in making electronics; it's also used to fill balloons, as a gas for scuba diving and a coolant for satellites. Germany's Linde, one of the world's biggest helium suppliers, said this week that "all affected business parties are working together to quickly find solutions so that all supply obligations to customers can be met. This includes both redirecting helium deliveries from other sources as well as seeking acceptable alternative routes out of Qatar."

Dubai has stopped importing Qatari LNG, but QP Chief Saad al-Kaabi reiterated over the weekend that Qatar wouldn't cut off piped gas deliveries via the Dolphin pipeline, even though the situation technically allows it to declare force majeure. The dispute appears to make plans to expand Dolphin in a second phase unlikely, Stern said. The pipe now pumps around 2 Bcf/d (21 billion cubic meters per year) to Dubai and on to Oman, accounting for around a third of the UAE's gas, and there are concerns shipments could be curtailed if the crisis escalates. Sharjah, another of the seven emirates making up the UAE, plans to start importing 3 million-4 million tons/yr of LNG via a floating unit in 2019. Sharjah National Oil Co. (SNOC)

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CEO Hatem al-Mosa said on Jun. 18 it had "not been asked to speed up the project in the event of the Dolphin pipeline being switched off. If something happens between now and 2019, the project will not be ready to cope. But it will be a big saver once it becomes operational." He said SNOC is eyeing a 10-year term contract as well as spot supply, but not from Qatar. ■

Staff reports

US Sanctions May Dent Gazprom Pipelines

The future of Gazprom's prize Nord Stream 2 gas pipeline to Germany is looking more uncertain. The 55 billion cubic meter per year (5.3 billion cubic feet per day) project already splits opinion in Europe, with Germany and France in favor, and many Central and Eastern European countries against. The US is now throwing its weight around too. The Senate last week passed a bill that would allow the president to impose sanctions on individuals or businesses that invest in Russian energy-export pipelines. The measure was attached to a new Iran sanctions bill. As it doesn't specifically mention punishing US entities, fears are that the Senate is eyeing "secondary" sanctions that would also penalize businesses and individuals outside the US.

Russia is already under US and European sanctions over its role in the conflict in Ukraine, and the latest measures are designed to hurt it for alleged meddling in the US 2016 presidential elections. To become law, the bill — which would also target Gazprom's proposed Turk Stream pipe to Turkey — has to be approved by the House of Representatives and the president. The Republican leadership in the House has sent the legislation to the Foreign Affairs Committee for review, and any major changes would have to be squared with the Senate bill. But it has already attracted criticism from Germany and Austria, which accuse the US of threatening Europe's energy supplies and trying to push Russian gas aside in favor of US LNG.

The bill would bar one-off investments of $1 million or more in Russian pipelines, or investments of $5 million or more over a full year. Sanctions would include restrictions on export-import bank assistance, licenses to export goods or technology, loans, and banking or property deals. Sanctions could also be imposed for providing goods, services, technology, information or support "that could directly and significantly facilitate the maintenance or expansion of the construction, modernization, or repair of energy pipelines."

But the wording is vague, and Gazprom and its European Nord Stream 2 partners are hoping this means they would be able to dodge any sanctions. The Europeans — Royal Dutch Shell, Germany's Uniper and Wintershall, France's Engie and Austria's OMV — are funding half the €9.5 billion ($10.6 billion) pipeline. Gazprom, the sole shareholder in the project company, is financing the other 50%, and the partners intend to raise project finance to cover 70%, or €6.65 billion, of the costs. The European firms agreed in April to provide up to €950 million each, ponying up 30% this year. Gazprom Deputy CEO Alexander Medvedev said last week they had already lent more than €1 billion, while Gazprom injected a similar amount (WGI Apr.26'17). But the sanctions could hurt plans to raise project finance for both Nord Stream 2 and Turk Stream if Gazprom couldn't agree bank deals before the bill became law. Medvedev said negotiations with banks will open as soon as possible. Any problems could force the Russian gas giant to dig deeper into its own pockets. It is already spending substantial amounts on upstream and pipeline projects, including the $55 billion Power of Siberia pipe to China, at a time when its European export prices are low and the domestic tax burden is growing.

The bill reflects continued US opposition to Gazprom's plans to send more gas to Europe, but a number of observers see it as a blatant attempt to force Europe to buy more US LNG. "The bill aims to protect US jobs in the natural gas and petroleum industries," Austrian Chancellor Christian Kern and German Foreign Minister Sigmar Gabriel said in a joint statement last week. "Threatening to punish companies in Germany, Austria and other European countries ... for participating in or financing natural gas projects such as Nord Stream 2 with Russia is bringing a completely new and very negative quality to European-American relations."

US Energy Secretary Rick Perry touted the possibility of more US LNG earlier this month in a statement marking the back-to-back arrivals of the first two Sabine Pass cargoes into northern Europe. "US LNG has begun arriving in Europe with some frequency, providing a diverse source of supply and ensuring energy security for Europe," he said. "Europe has been looking to the United States as a key potential source for energy diversification to decrease Russia's leverage as the region's dominant gas supplier."

The sanctions threat comes as the European Commission has said it wants to negotiate a special legal regime for the Baltic section of Nord Stream 2, even though EU antimonopoly regulations don't normally apply to offshore pipelines. Brussels has asked EU members for a mandate for the negotiations, for which Moscow has said it sees no need (WGI Jun.7'17). ■

Vitaly Sokolov, Moscow

BP Raises Indian Gas Growth Hopes

BP and Reliance Industries, India's second most valuable company, surprised everyone in February 2011 when they unveiled a "transformational partnership" that saw the UK major splash out \$7.2 billion buying 30% of 23 blocks owned by the Indian refiner, including KG-D6 in the Bay of Bengal (WGI Sep.7'11). Given the subsequent problems, perhaps even more surprising was the announcement earlier this month that they plan to spend over \$6 billion boosting gas production from the deepwater block off eastern India.

The initial move six years ago came as Reliance was struggling to turn round production at KG-D6 — once seen as the answer to India's energy shortages — and BP was selling assets to raise money to settle claims stemming from its *Deepwater Horizon* disaster in 2010. Some were puzzled by the UK firm's motives, given India's reputation for bureaucratic hassle and red tape, but most considered it a good bet. Things quickly went haywire, however. The partners became embroiled in controversy over costs and output, and are still in arbitration with the government. After peaking at 2.12 billion cubic feet per day in the first half of 2010, D6 production has dwindled to just 275 million cubic feet per day. Discouraging results from other acreage led to relinquishments, and the duo have spent only \$1.6 billion on exploration and production. Reliance has in the interim shifted its business focus away from oil and gas to telecoms, while BP has slashed spending. The KG-D6 fiasco also proved costly for India, which is trying to promote cleaner fuels as part of the low-carbon transition. It scared off investors and stunted growth in gas demand.

Many observers were thus taken aback when the two firms told a media briefing in New Delhi on Jun. 15 that they intend to spend 400 billion rupees (\$6.2 billion) on KG-D6, unlocking 3 trillion cubic feet (85 billion cubic meters) of reserves and producing an extra 1.06 Bcf-1.24 Bcf/d by 2022 — equivalent to around a third of India's existing gas production — sustaining output for seven or eight years. The gas would come on stream just as the global surplus is expected to end and could generate up to \$20 billion in import substitution, BP boss Bob Dudley said. "Because oil prices have been low for the last three years, everyone has scarce capital so we have to choose very carefully the projects that we select," he said, adding that KG-D6 has in the past two years become "very competitive in our global portfolio." He said the partners will press on with investment despite pending arbitration cases, where they hope to get a "fair resolution."

What prompted the companies to open the purse strings? It's partly because they discovered more resources, and partly because prices of deepwater gas production have been liberalized. Reliance and BP in October 2013 announced plans to invest \$8 billion-\$10 billion in KG-D6 after the previous government said it would introduce a new formula doubling gas prices from \$4.20 per million Btu. But Prime Minister Narendra Modi's Bharatiya Janata Party junked that idea after coming to power in May 2014 in favor of a formula linking prices to those in the US, Russia and Canada, which are all gas exporters. Prices are revised twice a year, in April and October, and are now just \$2.80/MMBtu on a net calorific value basis (WGI Oct.22'14). With explorers like Reliance holding back on investment, the government in March 2016 allowed pricing and marketing freedom for difficult offshore acreage, although with a price cap to protect consumers. This is currently \$6.20/MMBtu.

The policy change will likely benefit Reliance, as well as state-owned flagship explorer Oil and Natural Gas Corp. (ONGC) and GSPC, analysts say. Their new investment should help almost double Indian production to 5.75 Bcf/d (59 billion cubic meters per year) by March 2023 from 3.14 Bcf/d (32 Bcm/yr) in the year to March 2017, IDFC Securities analyst Probal Sen said (WGI Dec.16'15). But this higher production coupled with over 700 MMcf/d in US LNG contracted by Gail could leave India awash in supply around 2021-23, Bank of America Merrill Lynch said. This may not bode well for future LNG demand unless the government introduces concrete policies to back up its goal of doubling gas' share of the primary energy mix to 15% from 6% now. ■

Rakesh Sharma, New Delhi

Gas Struggles to Compete with Cheap Renewables

Europe's largest gas conference, Flame, was briefly lit by optimism last month as industry spirits were lifted by bigger LNG appetites in China and India and more resilient gas demand in Europe (WGI May10'17). But BP's latest annual statistical review brought them back down to earth with a bump, and producers that have been weighting their portfolios more heavily to gas should probably look away now: The UK major's report paints a grim picture for gas in 2016. While coal consumption dropped for the second year in a row, growth in gas demand slowed to match oil's — for now undermining assumptions that gas will do the best of any fossil fuel in a carbon-constrained world — while renewables rocketed.

Opportunities were there for gas to make inroads. Coal consumption dropped by 1.7% in 2016, giving it a 28.1% share of the global primary energy mix, its lowest since 2004. BP attributed this "decisive break from the past" to structural factors such as the pricing and availability of natural gas and renewables, and the policy and societal shift to lower carbon energy. Global gas demand rose by 1.5% to 3.54 trillion cubic meters (342 billion cubic feet per day) — below the 10-year average of 2.3%, BP said. Production inched up 0.3% to 3.55 Tcm — the weakest growth in almost 35 years other than right after the global financial crisis. Gas replicated what was seen in most other energy sources, with higher consumption paired with low production in response to a global energy surplus and low oil and gas prices. Gas output in the US actually fell 2.5% to 749.2 Bcm — the first year-on-year drop since the shale gas revolution kicked off last decade.

Natural Gas Consumption in BP Statistical Review of World Energy 2017

	2016 (Bcm)	Y-o-Y Growth (%)	2005-15 Growth (%)
North America	968.0	0.3	2.1
South & Central America	171.9	-2.5	3.6
Europe & Eurasia	1,029.9	1.7	-0.8
Middle East	512.3	3.5	5.9
Africa	138.2	1.4	4.8
Asia Pacific	722.5	2.7	5.6
Total World	3,542.9	1.5	2.3

Source: BP Statistical Review of World Energy 2017

Renewables — including wind, solar, geothermal, biomass and waste but excluding hydro — were the fastest growing energy source in 2016, rising 12% to account for 4% of the primary energy mix. China surpassed the US as the largest producer, contributing 40% of global growth. Wind power increased by 15.6% and solar by 29.6%. BP chief economist Spencer Dale said the growth of solar is immense: Of the 67 countries analyzed in the BP report, 75% report significant use of wind power today versus 15% 20 years ago; solar penetration has increased to the same level in less than half the time.

Forecasts of future uptake don't offer gas produces much encouragement, either. Norwegian Statoil recently set out three scenarios in its *Energy Perspectives 2017* report showing global gas demand increasing in the 2020s but slowing after that, accounting for 19%-23% of the global primary energy mix in 2050 against 21% in 2014. Renewables' share is meanwhile projected to increase to around 20% by mid-century from just over 1% in 2014.

According to Bloomberg New Energy Finance (BNEF), gas will be playing a background role by 2030, acting more as a flexible supply source to meet peaks in power demand than replacing baseload coal. BNEF's *New Energy Outlook 2017,* released last week, said wind and solar will account for 48% of installed capacity and 34% of electricity generation globally by 2040, compared to 12% and 5%, respectively, now. Regionally, gas fares well in the US, Europe, and the Middle East and North Africa, despite encroachment by renewables, but is decimated by coal and and renewables in Asia, BNEF said.

BP was a lot more bullish about gas' medium- to long-term future in its *2017 Energy Outlook* published in February, which said it will be the world's fastest growing fossil fuel out to 2035 (WGI Feb.8'17). The company projected annual demand growth of 1.6%, with LNG the key factor behind the increase, with consumption rocketing 38% by 2035. ■

Jaime Concha, Copenhagen

Consumption in BP Statistical Review of World Energy 2017

	Gas	Y-o-Y Growth (%)	Oil	Y-o-Y Growth (%)	Coal	Y-o-Y Growth (%)	Renewables	Y-o-Y Growth (%)	Nuclear	Y-o-Y Growth (%)	Hydro	Y-o-Y Growth (%)	Primary Energy	Y-o-Y Growth (%)
North America	870.1	-2.5	1,046.9	0.4	386.9	-9.0	97.1	15.7	217.4	0.7	153.9	3.5	2,788.9	-0.4
South & Central America	159.3	-0.8	326.2	-2.7	34.7	-3.7	28.2	17.1	5.5	10.7	156.0	1.8	705.3	-1.0
Europe & Eurasia	900.1	0.2	884.6	1.9	451.6	-4.5	144.0	1.5	258.2	-2.4	201.8	3.4	2,867.1	0.4
Middle East	574.0	3.3	417.8	0.9	9.3	-9.5	0.7	42.0	1.4	75.3	4.7	-20.5	895.1	2.1
Africa	187.5	-1.1	185.4	1.5	95.9	0.4	5.0	18.5	3.6	29.7	25.8	-4.3	440.1	1.2
Asia Pacific	521.9	2.9	1,557.3	3.1	2,753.6	-0.1	144.5	27.9	105.9	11.3	368.1	3.5	5,579.7	2.1
Total World	3,212.9	0.3	4,418.2	1.5	3,732.0	-1.7	419.6	14.1	592.1	1.3	910.3	2.8	13,276.3	1.0

Note: all energy sources in million tons of oil equivalent, oil in million tons. *Source: BP Statistical Review of World Energy 2017*

Australia's Santos Fends off LNG Attacks

The CEO of Australian independent Santos has come out swinging, saying the reason domestic gas prices are high is down to geology, not his company's Gladstone LNG (GLNG) project. GLNG is one of three liquefaction plants built simultaneously on Curtis Island in Queensland that are blamed for creating gas shortages and price spikes in eastern Australia, prompting government moves to limit LNG exports. But Santos Chief Kevin Gallagher said last week that prices have risen because "all the cheap gas has been developed, so it is costing more to get gas out of the ground."

Prime Minister Malcolm Turnbull announced in April that restrictions would be introduced from July to ensure the domestic market was adequately supplied before gas exports were allowed (WGI May3'17). Under the Australian Domestic Gas Security Mechanism (ADGSM), exporters that are not net contributors to the domestic market — they take out more gas than they put in — must explain how they intend to plug the gap (WGI Mar.22'17). Unlike conventional LNG plants in northern and western Australia, the three coalbed methane-fed projects in Queensland require new wells to be drilled to maintain production or third-party gas to be bought in. GLNG sources more than half its feedstock from third-party contracts, and Gallagher said the ADGSM "unfairly targets" his project as it is the only one that is not a net contributor. The other two, Royal Dutch Shell's QCLNG and Origin Energy-ConocoPhillips' APLNG, have their own gas.

Gallagher has also taken exception to assertions that Australian prices are higher than in markets like Japan where the gas is sold. "It has been widely publicized that Australian gas is sold in Japan cheaper than it can be purchased in Australia. The GLNG project does not sell gas to Japan [it has long-term contracts with Malaysia and South Korea] ... Given that all of GLNG's gas is contracted overseas, GLNG has no cheap, surplus gas — indeed it's all contracted at premium prices."

There is one piece of good news. Turnbull's decision was made partly on the basis of forecasts from the Australia Energy Market Operator (AEMO) of shortages as LNG projects ramped up and domestic production declined. But in an update last week, AEMO said it has raised supply projections, although gas markets "remain finely balanced," and much will hinge on the Queensland plants.

UBS analyst Nik Burns said AEMO's updated supply/demand balance means there is less likelihood that GLNG will be asked to address physical gas shortfalls in eastern Australia by, for example, reducing exports or making more gas available to the domestic market. But as the ADGSM runs until the end of 2023, "the issue of supply adequacy will be revisited every year, leading to a degree of lingering uncertainty around GLNG." Minh Hoang, a credit analyst with ratings agency Standard & Poor's, reckons that even if the mechanism were invoked, GLNG partners would be given the chance to make up supply through means such as LNG swaps.

Santos has a 30% operating interest in the $18.5 billion plant; its partners are Total (27.5%), Malaysia's Petronas (27.5%) and South Korea's Kogas (15%). To say the project has been a challenge is an understatement. Gas supply problems have forced the partners to write down billions, with Santos alone writing down $1.5 billion (WGI Sep.21'16). GLNG has also been operating well below its 7.8 million ton per year nameplate capacity. It produced just 1.4 million tons in the first quarter of 2017 and Santos has said it will only ramp up to 6 million tons/yr by 2019. The Institute for Energy Economics and Financial Analysis, a US-based think tank, said recently that a combination of lower-than-expected production and low oil prices, off which the LNG is priced, may lead to further write-downs. Chinese equity firm Hony Capital and gas distributor ENN Group recently increased their stake in Santos to 15.1% through share purchases on the open market, saying they would "act in concert" at shareholder meetings. There is speculation the Chinese may be looking to take over the company, whose share price has tumbled 25% since the start of the year.

With debt of US$3.1 billion, Santos has been moving to restructure and refocus its portfolio to improve its balance sheet and growth potential (EIF Dec.14'16). The focus is gas and LNG projects. It has 13.5% of Exxon Mobil's PNG LNG scheme in Papua New Guinea, where it hopes to expand. It also has an 11.5% stake in Darwin LNG in Northern Australia, and domestic gas positions in western and eastern Australia. ■

Shani Alexander, Singapore

Assessing Global LNG Export Risks

The crisis engulfing Qatar apparently took many gas traders by surprise, even though tensions between the world's largest LNG exporter and its neighbors have been evident for years. It underlines the way risks can blindside LNG project investors and buyers in countries considered politically and economically stable — let alone ones that aren't (p2). Libya, which in 1971 became the third country after Algeria and the US (Alaska) to start LNG exports, stopped exporting amid civil war in 2011. Egyptian exports began drying up in late 2012 when it diverted gas to the domestic market. Civil war closed the 6.7 million ton/yr Yemen LNG plant in April 2015. World Gas Intelligence *assesses the risks in other top exporters, or those like the US fast rising up the ranks.*

Algeria — One for gas traders and European buyers to watch. The world's sixth-largest LNG exporter in 2016 and third-largest gas supplier to Europe, Algiers faces a host of domestic economic challenges and an ongoing succession contest. If piped gas and LNG supplies were affected, European buyers like Spain and Italy would have to scramble for alternatives.

Political and economic risk is high. Eighty-year-old President Abdelaziz Bouteflika is in poor health and there are several claimants to power. The IMF puts youth unemployment at about 20%, and the economy relies heavily on oil and gas revenues from maturing fields. But Algeria is at the same time suffering from Egypt's problem of rising domestic demand starting to outstrip marketed exports.

Nearly 40 foreign hostages were killed in January 2013 in a terrorist attack on the BP/Statoil/Sonatrach In Amenas gas plant in the southwest. Security has since been stepped up, but the plant was again targeted by a rocket attack in March 2016.

Australia — The country will soon overtake Qatar as the world's biggest LNG exporter. Last year, Qatar had over 30% of the market, Australia 17%, Malaysia 9.5% and the US less than 1%. By 2020, Australia should have 22%, Qatar 21% and the US 14%, according to analysts at Barclays.

Project developers in Australia see sovereign and regulatory risk rising. The government shocked the industry this year by giving itself powers to restrict LNG exports during domestic gas shortages. This is happening at the same time Canberra is contemplating changes to the Petroleum Resource Rent Tax and state governments are prohibiting onshore gas development. The government sees next month's introduction of the Australian Domestic Gas Security Mechanism (ADGSM) as the only way to ensure Australians benefit from the gas bounty (WGI May24'17). The draft ADGSM policy says it will run until the end of 2023 and give the resources minister the power to restrict exports when he/she determines there will be a domestic shortfall in any calendar year. The export controls will apply Australia-wide, not just in the area deemed as being in shortfall. "During a domestic shortfall year, all exports of LNG will be prohibited without an Export Permission," the draft said. Controls would if necessary start in January 2018.

The industry argues that the measure will undermine the country's reputation as a safe place to invest. The CEO of Australian LNG developer Santos says it creates sovereign risk for future investment. "Retrospectively punishing LNG exporters squanders our natural advantage as a low risk country with a transparent rule of law for investors, with no nasty surprises," Kevin Gallagher said. "With a further half-trillion dollars in new gas investment up for grabs globally as Asia grows, this is a real risk to take."

Indonesia — The country was overtaken by Qatar as the world's largest LNG exporter in 2006, and its importance has continued to diminish as domestic production falls while demand rises. From being the fourth-largest exporter last year, Indonesia could become a net importer by the end of the decade, when the supply-demand gap could reach around 2.5 billion cubic feet per day (25.85 billion cubic meters year), excluding LNG imports.

World's Top LNG Exporters, 2016

Qatar	79.62
Australia	44.88
Malaysia	25.08
Indonesia	19.95
Nigeria	17.78
Algeria	11.44
Global Total	263.62

In million tons. *Source: GIIGNL*

Political risk that could affect exports is substantial, given the concerns over meeting domestic demand. In the early 2000s, Jakarta reduced deliveries of contracted supply to Asian buyers from Arun and Bontang in favor of supply into the domestic market. Despite the clear breaches of contract, buyers in Japan and Taiwan did not seek arbitration. The strategy of favoring domestic buyers has since become more explicit, with the domestic market obligation for gas set at 25% of production. As if that weren't bad enough, Indonesia in 2015 tried to require overseas buyers of LNG and other natural resources to pay with letters of credit — something Asian buyers have never done with Indonesia — or risk having exports cut off. An exemption for LNG exports was agreed at the last minute, but the move continues to weigh on Indonesia's credibility as a supplier.

The fiscal regime is not conducive to investment. Recent changes to production-sharing contracts have failed to lure international investment in domestic gas projects, which will force the country to rely more heavily on LNG imports. While BP last year sanctioned a third 3.8 million ton/yr train at Tangguh, Abadi has slowed down after Indonesia said last year the LNG project should be land-based, not floating, as partners Inpex and Shell intended.

Malaysia — Like Indonesia, the Southeast Asian producer has started importing LNG. Unlike Indonesia, the risk of disruptions is low: State Petronas has a reputation for being a reliable supplier and has not broken contracts, despite declining domestic production. In 2011, gas shortages prompted it to temporarily curtail supply to Malaysian power utility Tenaga, but not pricier LNG exports to Japan, South Korea and Taiwan. Indeed, at current prices, it makes financial sense for Petronas to continue exporting to Northeast Asia while importing cheaper spot cargoes to meet domestic demand.

Petronas has done much better than Indonesian peer Pertamina in sourcing LNG abroad. Company strategy has been to become a portfolio supplier, based partly on competitive supply from its Bintulu plant, and partly on supply from Australia and, potentially, Canada in the future. As a Gladstone LNG shareholder and offtaker, it may be affected by Australian export curbs. But it should be able to source replacement cargoes from Bintulu, where output from the new Train 9 is being sold on the spot market. Petronas growing portfolio also means it should have no problems meeting existing contract commitments as well as domestic requirements following startup of a second import terminal later this year.

The company has been working on some challenging gas developments to ensure feedstock for the bigger Bintulu plant and monetizing stranded gas reserves at floating liquefaction projects. Despite Total's withdrawal, it is still pursuing the K5 sour gas project off Sarawak, due to start up in 2018, and attracting partners for Block SK316, also off Sarawak, which again has high CO2 levels.

Nigeria — Problems with theft and sabotage are persistent and deep-rooted, affecting all parts of the oil and gas industry — indeed, they are so bad on the oil side that Nigeria has been exempted from Opec production cuts. Ongoing attacks on feeder pipelines amid local power struggles restricted exports from the 22 million ton/yr capacity Nigeria LNG (NLNG) to 17.8 million tons last year, down from 19.5 million tons the year before. The six-train plant on Bonny Island is owned by Nigerian National Petroleum Corp., Shell, Total and Eni. There has been talk for the past decade of building two more trains, but most observers believe that's unlikely.

NLNG was far less active in LNG spot markets in 2016 than the year before, selling 14% less. The plant has this year continued to issue sell tenders for a small number of cargoes every month, but as an analyst says: "Things may look stable now, but problems have a habit of popping up out of nowhere." NLNG has long been thought to have received preferential treatment in terms of cheap feedgas prices, which could make it the subject of future investigations by lawmakers.

United States — From roughly 13.5 million tons today, annual liquefaction capacity should reach nearly 65 million tons by 2020. There is no reserve risk due to the country's huge shale potential, the fact exports are not monopolized by a single state firm and gas is easily available from the grid, so LNG could still be exported even if one liquefaction plant were out of action. Sovereign risk is not a concern, either.

What does worry Japanese buying giant Jera is regulatory risk — the possibility, stoked by developments in Australia, that licenses could be revoked for sales to countries without a free trade agreement with the US, a group that includes Japan, China, India and the EU. Other buyers are less concerned, however, viewing President Donald Trump as a supporter of LNG exports. The biggest challenge is price risk — the economics of LNG price-linked to the US Henry Hub gas benchmark versus oil-linked LNG. US LNG loses its advantage when oil is below $70-$80 per barrel. ■

Shani Alexander, Edwin Loh and Clara Tan, Singapore, and Alexandra Chapman, Jane Collin and Tom Pepper, London

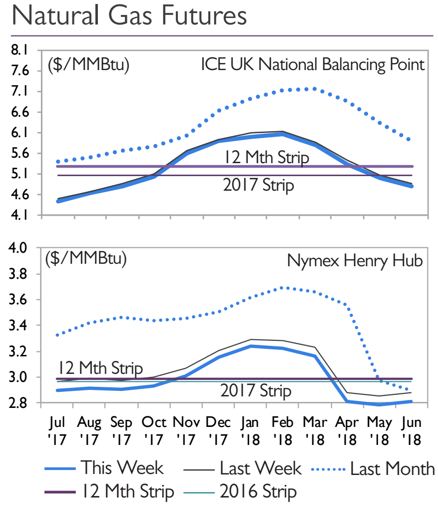
MARKET INSIGHT

TTF and NBP Still Dominate European Hub Trade

Most of Europe's gas-trading hubs are developing well, if at different speeds, the Oxford Institute for Energy Studies (OIES) says. More work is needed in Eastern Europe, where the EU goal of integrating all pricing regions in one single energy market for natural gas "is probably still many years away, if indeed it can ever be fully realized." The Title Transfer Facility (TTF) in the Netherlands and National Balancing Point (NBP) in the UK were Europe's most mature hubs in 2016, standing head and shoulders above the others according to the criteria analyzed by the OIES, which include the number of active participants, traded volumes and "churn" ratio — an indicator of liquidity.

The OIES said the TTF was continental Europe's chief benchmark pricing hub last year — confirming earlier findings from the London Energy Brokers' Association (WGI May17'17). According to the institute, it overtook the NBP in the second quarter of the year. Full-year TTF trades were about 10% higher than on the NBP, rising 30% year-on-year to 22,230 terawatt hours. The TTF is now seven times bigger than the German NetConnectGermany (NCG) and Gaspool hubs, and 25 times larger than Italy's PSV, the OIES said. NBP traded volumes fell 4%, making it Europe's second largest hub; NCG and Gaspool were third and fourth, replacing the Belgian Zeebrugge and ZTP hubs, with trades rising 16% and 17%, respectively. The TTF and NBP remain Europe's risk management hubs, as they are the only ones with substantial trade in contracts beyond month-ahead or options trading. Around 70% of total trades on the TTF represent trading in quarters, seasons and year-ahead contracts, and 62% on the NBP.

Natural Gas Futures



A similar pattern emerges in the churn ratio, which measures how often a gas molecule is traded. The OIES considers a hub mature when total traded volumes are at least 10 times greater than physically traded volumes — parameters met only by the TTF and NBP. The TTF last year had a churn ratio of 57, up from 14 five years earlier, and the NBP 22. Austria's VTP hub had a churn ratio of 5.7, the Zeebrugge and German hubs below 5, and the French TRS and Spanish PVB hubs below 1.

The OIES reckons Europe's hubs provide a reliable pricing reference. "As far as the price analysis is concerned, it is clear that the growth in liquidity and the increasing use of hubs for balancing has resulted in the fact that traded gas now has a 'price tag' in most of the gas hubs in Europe, including in emerging ones," it said. There is also a stronger pricing correlation between markets in Northwest Europe — TTF, NCG, Gaspool, Zeebrugge and Peg Nord in France — and the Czech VOB hub than with other continental hubs. The Northwest Europe pricing group has a strong alignment — indeed, can almost be considered a single pricing area — while VOB is strongly linked to the NCG market.

Other continental gas hubs show a pricing mismatch with neighboring markets. This stems either from physical barriers to trade, such as congestion on market interconnections, or nonphysical barriers, such as lack of transmission capacity between hubs. Examples of physical barriers include the NBP, where congestion can occur on the Interconnector UK pipe to Belgium — as in September 2016, when NBP prices were at a discount of over €1.50 per megawatt hour (48¢ per million Btu) to Zeebrugge. Others are the French TRS links to Peg Nord, and Austria's VTP to Germany's NCG. Italy's PSV offers a clear example of nonphysical barriers: OIES said problematic connections to the Northwest Europe pricing group are due to "inefficient utilization" of the Transitgas pipeline after Eni booked 80% of capacity on the NCG/TTF to PSV route via Switzerland. The Spanish PVB connections to the TRS and Polish VPGS hub to Gaspool are similarly troubled.

The NBP could be adversely affected by the uncertainty surrounding the UK's decision to leave the EU, the OIES said (WGI Jun.29'16). The impact of Brexit on the regulation of gas interconnectors could result in greater volatility in NBP prices and "more frequent delinkages" with other European hubs (WGI Mar.9'16). The loss of UK influence over European market liberalization is another factor. "There are many European countries, especially in Eastern Europe, that have a different political agenda and without the influence of the UK it may be difficult for the EU to enforce its Energy Directives," the report said. This week's confirmation by Centrica Storage that it is closing the Rough storage site indefinitely will only add to NBP pricing volatility, particularly in the high demand winter season, when the UK relies on sizable storage in continental Europe to meet peak consumption (WGI Feb.22'17). ■

Jaime Concha, Copenhagen

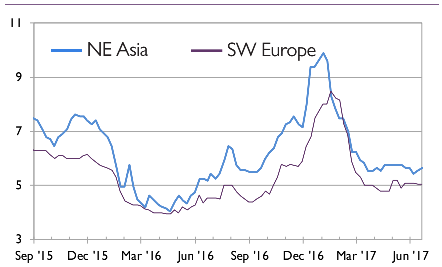
SPOT LNG

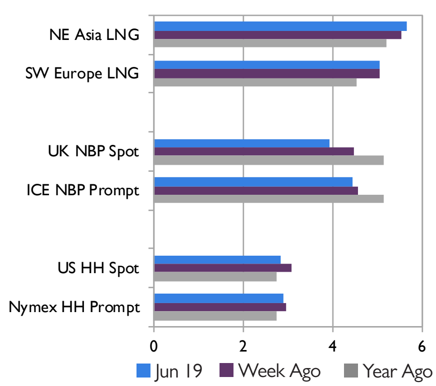
Asian Prices Creep up on Supply Jitters While Europe Stays Flat

Spot LNG prices in Northeast Asia rose 10¢ to $5.65 per million Btu as offers crept up in anticipation of tighter supply later this summer, according to *World Gas Intelligence* assessments for cargoes for delivery four to eight weeks ahead. In Southwest Europe, spot LNG prices remained flat at $5.05/MMBtu. The UK National Balancing Point day-ahead price tumbled 56¢ to $3.92/MMBtu, while July futures dropped 11¢ to $4.44/MMBtu. Netbacks for Mideast sellers in Asia were almost 40¢ higher than in Southwest Europe. UK-Belgian netbacks for Mideast sellers lagged Asia by over 90¢.

Much to end-users' chagrin, offer levels in Asia have been creeping up to $5.60/MMBtu or more in the belief that supply for the later months of summer might be slightly tighter than expected because of fresh demand in South Korea and China. Bid levels remain flat in the low-$5s. But even though prices have inched up for August deliveries, most sources reckon weak oil prices will cap spot LNG prices. The oil-slope equivalent of current spot prices is 12% — a level not seen since mid-February.

Indicative LNG Prices





Exxon Mobil has awarded its sell tender for a single late-June or early-July delivery from Australia's Gorgon to China National Offshore Oil Corp., possibly at around $5.60/MMBtu, sources said. The tender, which closed on Jun. 14, is for a cargo to be loaded aboard *Beidou Star*. PNG LNG in Papua New Guinea issued a sell tender on Jun. 19 offering a single cargo loading on Aug. 5-Aug. 6. It closed on Jun. 21 with bids valid until Jun. 23. The tender offers a possible delivery window of Aug. 14-Aug. 16 to Japan and Taiwan, Aug. 15-Aug. 17 to South Korea and China, and Aug. 21 to Dahej, India.

In the Atlantic Basin, the focus is on the US Gulf, where a tropical storm warning has been issued for a section of Louisiana's coast that could potentially affect loadings from Cheniere's Sabine Pass LNG project.

Further south, Mexico's CFE on Jun. 16 issued a buy tender for nine cargoes for delivery into Altamira, on the Atlantic, between late-June and August. It closes on Jun. 21. CFE's requirement for one cargo per week took traders by surprise, with most attention focused on a very prompt cargo for delivery from Jun. 26-Jun. 28. Given the brewing storm in the Gulf, traders are keen to see if it will be awarded. One European trader said the tender smacked of panic buying. Sources speculate that it may have been sparked by a US pipeline outage or contract inflexibility that has left Mexico short of supply.

Indicative Natural Gas Prices

$/MMBtu	Jun 19	Week Ago	Year Ago
NE Asia LNG	5.65	5.55	5.20
SW Europe LNG	5.05	5.05	4.55
UK NBP Spot	3.92	4.48	5.15
ICE NBP Prompt	4.44	4.55	5.14
US HH Spot	2.85	3.08	2.74
Nymex HH Prompt	2.89	2.97	2.75

Source: WGI assessments of spot prices for LNG in NE Asia and SW Europe and for day-ahead gas in the UK. NGW spot assessment for US. All prices are for Monday, Jun 19.

Prices held steady in Southwest Europe despite the Mexico tender, with traders reporting little activity and weak demand. Despite soaring temperatures across much of the region, "we're still waiting for airconditioning demand to kick in," another European trader said. Traders are awaiting news of the latest buy tender from Portugal's EDP, which is seeking one cargo for August delivery. In Italy, WGI understands that two of the three August and September cargoes being sought by OLT have been awarded. The tender closed on Jun. 14.

Traders are keeping an eye on Egypt amid reports that state Egas will be cutting monthly deliveries from around 10 cargoes to seven cargoes by September and five by the end of 2017 on expectations that Eni's giant Zohr gas field will start production later this year. There was almost palpable relief last week. ■

CURRENT

Sub-Saharan Africa Set for Leapfrog on Renewables

Sub-Saharan Africa has vast, untapped renewable potential. Countries in the north look ideal for wind, the east and west are hydropower hotspots, and virtually the entire region has massive solar potential. But lack of power infrastructure and inadequate policy support have slowed efforts to harness low-carbon resources. Sub-Saharan Africa has to date attracted less than 1% of global energy investment and 600 million people — or six in 10 of the population — lack access to electricity.

Right now, the region depends largely on gas, coal and hydropower for electricity generation. Within a couple of decades, that could look very different, with gas playing the dominant role backed by hydropower, solar and coal. The International Energy Agency (IEA) forecasts a massive growth spurt for renewables in its World Energy Outlook (WEO) 2017: It sees sub-Saharan Africa's installed capacity of mainly gas-, coal-, oil-fired power stations and hydro plants growing from 185 gigawatts in 2014 to 563 GW by 2040. Gas would have a share of 40% by 2040, hydro 19%, coal 14% and solar photovoltaics 12%. Wind and geothermal are bundled in with "other renewables" and would account for 6%. Laura Cozzi, head of WEO's demand division, says "sub-Saharan Africa has the potential to leapfrog to a new development path fueled by renewables and natural gas."

The International Renewable Energy Agency (Irena) is forecasting a similarly explosive future. It says regional electricity demand may triple by 2040, fueled by a growing population and efforts to increase access to power. As in the telecoms industry, where sub-Saharan countries skipped telephone landlines and went straight to mobile phone technology, Irena says the region is in a "unique position to leapfrog the traditional centralized-utility model" and build decentralized renewables such as wind and solar.

European utilities including France's Engie and Italy's Enel are eyeing the region, lured by the growth potential. Engie last week signed a deal with Eleqtra, a developer of power and transportation projects in sub-Saharan Africa, to build a 50 megawatt wind farm costing roughly $120 million in Ghana's Greater Accra region. The French firm has a 40% stake in the project, which could be operational in early 2019. Ghana wants to get 10% of electricity from renewables by 2020 and aims to become a power generation hub in West Africa, exporting electricity to the other 14 members of the West African Power Pool. The country relies heavily on hydropower, but capacity is frequently severely reduced by drought.

Developers are often held hostage by lack of grid capacity. Networks are often unable to accommodate large new volumes of renewable capacity, and domestic grid operators aren't building infrastructure quickly enough. Sub-Saharan Africa's biggest onshore wind farm, the 310 MW Lake Turkana in Kenya, is a case in point. With the capacity to meet 15% of Kenya's electricity needs, the $670 million project was completed earlier in 2017 (WGI Aug.12'15). But grid connection problems mean it won't be operational before 2018.

On the solar side, utility-scale PV projects with a combined capacity of 11 GW could be built across the region from 2017-22, Benjamin Attia, global solar analyst at Boston-based GT Research, tells *World Gas Intelligence.* South Africa has bigger projects of up to 90 MW capacity in the pipeline, backed up with power purchase agreements, but the average project will be 20 MW-25 MW, he said. Nigeria heads the list of hotspot markets, which also includes Tanzania, South Africa, Kenya, Rwanda, Zambia and Uganda. While European utilities have become involved in onshore wind in sub-Saharan Africa, they are largely absent from the utility-scale solar PV sector, which is dominated by risk-tolerant "institutional money." ■

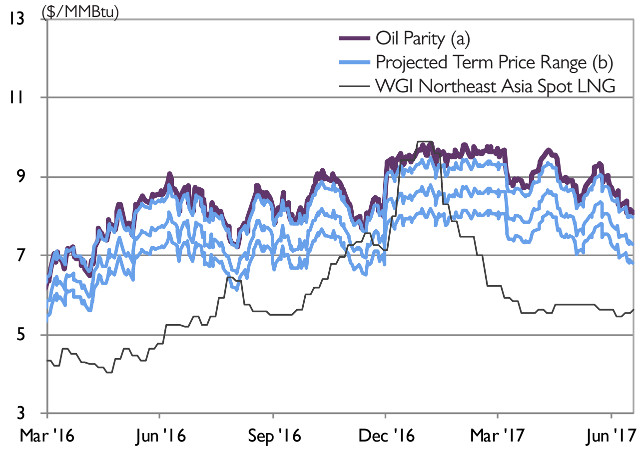
Jay Eden, London

WORLD GAS INTELLIGENCE LNG ANALYTICS

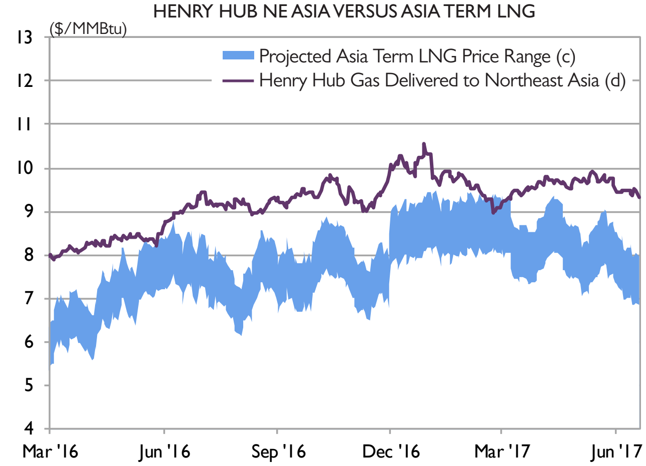
Vol. 28, No. 25 June 21, 2017

The following graphs provide weekly comparative insights into key LNG market relationships over the previous 12 months, with particular emphasis on the price of competing supplies in Asia and key inter-market price spreads.

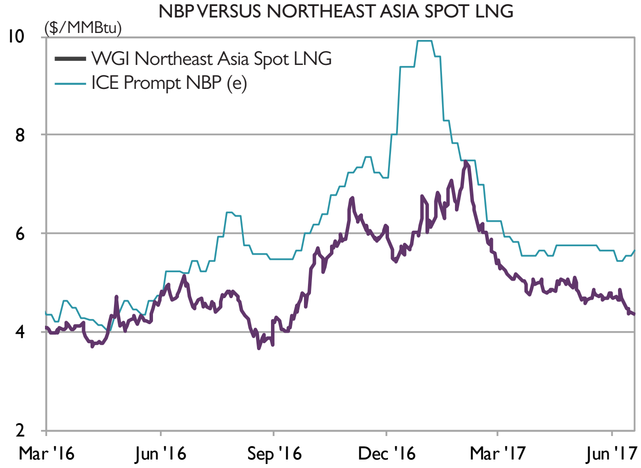
NORTHEAST ASIA SPOT LNG VERSUS ASIA TERM LNG



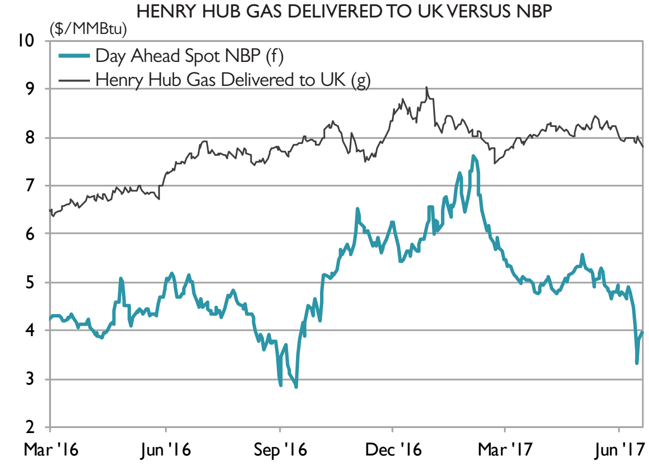
HENRY HUB NE ASIA VERSUS ASIA TERM LNG



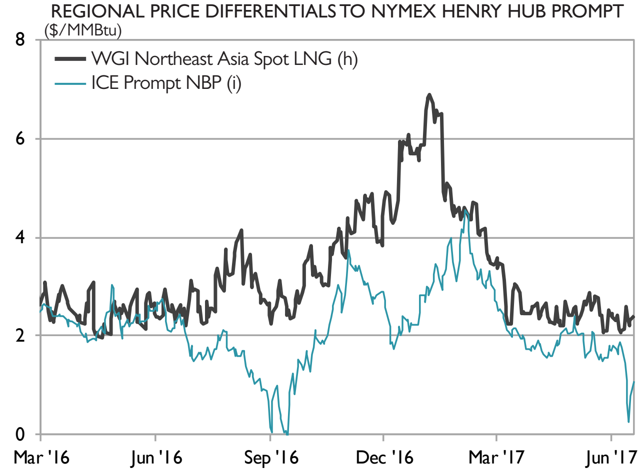
NBP VERSUS NORTHEAST ASIA SPOT LNG



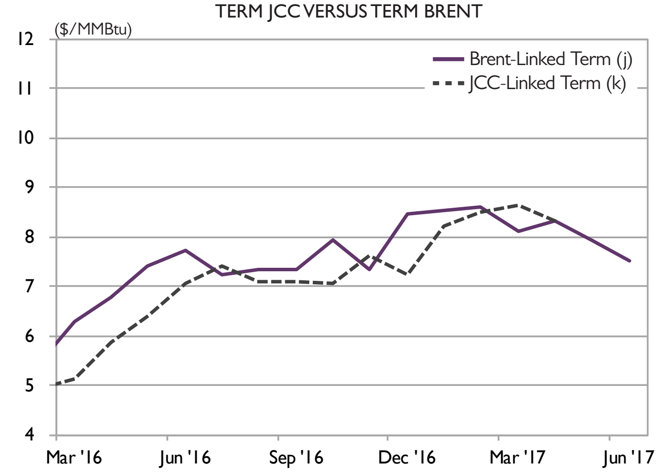
HENRY HUB GAS DELIVERED TO UK VERSUS NBP



REGIONAL PRICE DIFFERENTIALS TO NYMEX HENRY HUB PROMPT



TERM JCC VERSUS TERM BRENT



(a) Oil parity = 17.24% of Brent-Linked Asian Term. **(b)** Estimated low, middle, and high cases for contract terms: 13.5% of Brent+$0.50, 14.5% of Brent+$0.50, and 14.85% of Brent+$1.00, respectively. **(c)** Brent-Linked Asian Term LNG, high and low cases. **(d)** Per Cheniere formula: 115% Henry Hub plus $3.50 for liquefaction and $2.50 for shipping. **(e)** ICE prompt NBP converted from pence/therm to US$/MMBtu. **(f)** Thomson Reuters Day Ahead NBP converted from pence/therm to US$/MMBtu. **(g)** Per Cheniere formula: 115% of Henry Hub plus $3.50 for liquefaction and $1.00 for shipping **(h)** Northeast Asia Spot vs Nymex Henry Hub Prompt. **(i)** Day Ahead UK NBP vs Nymex Henry Hub Prompt. **(j)** Term prices based on current month average against mid-case formula for delivery 3 months later; **(k)** JCC is Monthly Japan Crude Cocktail Price reported by Japan's Ministry of Finance.

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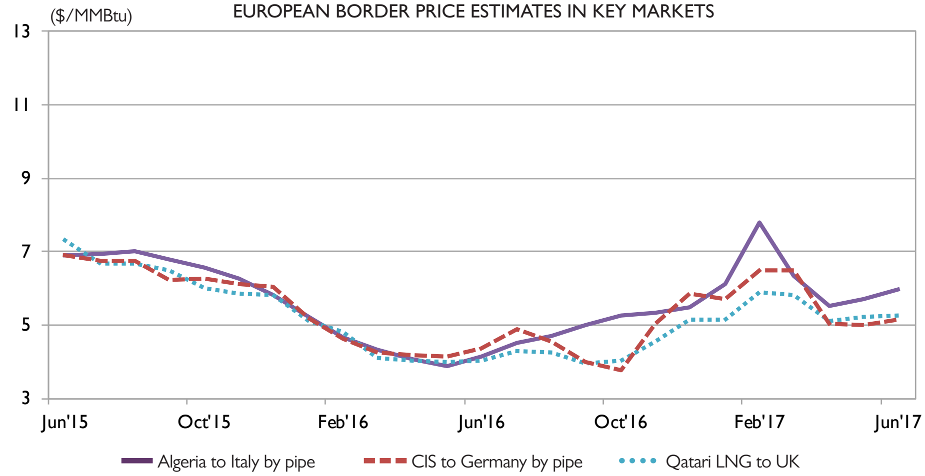
EUROPEAN BORDER PRICE ESTIMATES (MID-MONTH, US$/MMBTU)

	Jun'17	May'17	Jun'16
To Belgium from:			
Netherlands Pipe	5.22	5.16	4.26
Norway	5.02	4.98	4.26
UK	5.02	4.98	4.18
Qatar LNG	5.02	4.98	4.18
Average*	5.07	5.03	4.22
To France from:			
CIS	5.21	5.11	3.77
Netherlands	5.12	5.07	4.29
Norway	5.21	5.11	4.30
Qatar LNG	5.21	5.11	4.18
Algeria LNG	5.77	5.66	3.81
Average*	5.30	5.21	4.07
To Germany from:			
CIS	5.27	5.22	4.04
Netherlands	5.12	5.07	4.19
Norway	5.24	5.22	4.31-4.37
Average*	5.21	5.17	4.20
To Italy from:			
CIS	6.02	6.35	3.99
Netherlands	5.59	5.52	4.18
Norway	5.24	5.69	4.23
Algeria Pipeline†	5.96	5.69	4.15
Average*	5.70	5.81	4.14

	Jun'17	May'17	Jun'16
To Netherlands			
CIS	5.12	5.07	3.84
Norway	5.12	5.07	4.47
UK	5.12	5.07	4.24
Average*	5.12	5.07	4.18
To Spain			
Norway	5.87	5.73	4.75
Algeria LNG	5.91	5.81	3.48
Algeria Pipeline†	6.21	6.16	4.43
Average*	6.00	5.90	4.22
To UK			
Norway	5.14	5.01	4.36
Qatar LNG	4.64	4.51	4.36
Average*	4.89	4.76	4.36
Average* from:			
CIS	5.40	5.44	3.91
Netherlands	5.26	5.20	4.23
Norway	5.26	5.26	4.39
Qatar LNG	4.96	4.87	4.24
Algeria LNG	5.84	5.73	3.65
Algeria Pipeline†	6.08	5.92	4.29
Average* x/UK	5.47	5.40	4.12
UK	5.07	5.03	4.21
Average* All	5.41	5.35	4.13

Source: WGI's own calculations from information gathered from companies and official bodies. *Average price includes UK supply, totals are unweighted, and do not compare like with like (ie landed LNG before regas charges, versus in pipe for non-LNG supply). †For Algerian gas at landfall into Spain (Zahara de los Atunes) or southern Italy.

EUROPEAN BORDER PRICE ESTIMATES IN KEY MARKETS



GAS, POWER PRICES & SPARK SPREADS FOR GENERATORS AT MAJOR HUBS

Europe	Jun 19	Week Ago	Last Year
Gas Price ($/MMBtu)			
NBP(UK)	3.92	4.48	5.15
Zeebrugge	4.86	4.72	4.90
Dutch TTF	5.04	4.95	4.98
German NCG	5.12	5.08	5.06
Power Price ($/MWh)			
UK Power Grid	49.81	47.31	54.02
Tennet T	39.85	39.57	37.83
Powernext	43.07	40.58	37.60
Amprion	39.71	36.66	37.37
Spark Spreads ($/MWh)			
NBP/UK Power Grid	+22.35	+15.95	+17.97
Zee/TenneT	+5.83	+6.53	+3.53
Zee/Powernext	+9.05	+7.54	+3.30
Dutch TTF / TenneT	+4.60	+4.92	+2.97
German NCG/Amprion	+3.89	+1.10	+1.95

US	Jun 19	Week Ago	Last Year
Gas Price ($/MMBtu)			
Transco Z6 NNY	2.25	2.59	1.79
Houston SC	3.00	3.06	2.56
Socal Border (Calif.)	2.88	2.61	2.80
Stanfield (Wash.)	2.47	2.41	2.23
Power Price ($/MWh)			
PJM West	31.80	35.40	34.80
Ercot	38.20	37.20	33.40
Palo Verde	42.60	26.00	38.60
Mid-Columbia	15.40	12.40	24.00
Spark Spreads ($/MWh)			
TZ6 NNY/PJM W	+16.02	+17.28	+22.28
Houston SC/Ercot	+17.18	+15.79	+15.46
Socal/Palo Verde	+22.43	+7.70	+19.02
Stanfield/Mid-Col.	-1.87	-4.45	+8.37

US prices are the weighted average of assessments by *Natural Gas Week* for five trading days, spanning Jun 12-Jun 19. European gas prices are WGI assessments on Jun 20 for day-ahead delivery Jun 21. European power prices are from exchanges on Jun 19 for day-ahead power Jun 20. Gas quotes on top, power below. Heat efficiency of 7,000, or 48%, is used to calculate spark spreads, i.e. 7 MMBtu of gas generates 1 MWh of electricity.

SPOT LNG EXPORTER NETBACKS AT KEY MARKETS ($/MMBTU)

	Jun 19	Week Ago	Two Weeks Ago	Year Ago
NE Asia				
Algeria	4.03	4.30	4.20	4.24
Australia	4.52	4.79	4.69	4.65
Indonesia	4.57	4.84	4.74	4.69
Malaysia	4.52	4.79	4.69	4.64
Nigeria	4.02	4.29	4.19	4.25
Norway	2.94	3.20	3.10	3.37
Peru	3.72	3.98	3.89	4.02
Qatar	4.36	4.63	4.53	4.52
Russia	4.66	4.94	4.84	4.77
Trinidad	3.79	4.06	3.96	4.06
US Gulf	3.40	3.67	3.57	3.72
India				
Algeria	2.73	3.00	2.90	2.88
Australia	2.91	3.18	3.08	3.04
Indonesia	2.90	3.17	3.07	3.04
Malaysia	2.87	3.14	3.04	3.01
Nigeria	2.62	2.89	2.79	2.80
Norway	2.57	2.84	2.74	2.76
Peru	2.50	2.77	2.67	2.72
Qatar	3.03	3.30	3.20	3.14
Russia	2.80	3.07	2.97	2.96
Trinidad	2.52	2.79	2.69	2.72
US Gulf	2.43	2.70	2.60	2.65
SW Europe				
Algeria	4.33	4.46	4.51	4.05
Australia	3.78	3.91	3.96	3.60
Indonesia	3.78	3.91	3.96	3.60
Malaysia	3.77	3.90	3.95	3.58
Nigeria	4.12	4.26	4.31	3.88
Norway	4.10	4.23	4.28	3.87
Peru	3.52	3.66	3.70	3.38
Qatar	3.97	4.11	4.16	3.75
Russia	3.66	3.79	3.84	3.50
Trinidad	4.19	4.32	4.37	3.94
US Gulf	3.86	3.99	4.04	3.68
UK				
Algeria	3.31	3.44	4.01	4.42
Australia	2.75	2.88	3.45	3.95
Indonesia	2.76	2.89	3.45	3.95
Malaysia	2.74	2.87	3.43	3.93
Nigeria	3.12	3.25	3.82	4.26
Norway	3.26	3.39	3.96	4.38
Peru	2.53	2.66	3.22	3.75
Qatar	2.95	3.08	3.65	4.11
Russia	2.63	2.76	3.33	3.85
Trinidad	3.20	3.33	3.90	4.33
US Gulf	2.90	3.03	3.59	4.08
Zeebrugge				
Algeria	4.28	3.49	3.59	4.59
Australia	3.71	2.93	3.03	4.12
Indonesia	3.72	2.94	3.04	4.13
Malaysia	3.70	2.92	3.02	4.10
Nigeria	4.08	3.29	3.40	4.42
Norway	4.23	3.44	3.55	4.55
Peru	3.48	2.71	2.81	3.92
Qatar	3.91	3.13	3.23	4.28
Russia	3.59	2.81	2.91	4.02
Trinidad	4.16	3.38	3.48	4.50
US Gulf	3.86	3.08	3.18	4.26
US East Coast				
Algeria	1.98	1.55	1.66	4.04
Nigeria	1.85	1.41	1.52	3.92
Norway	1.83	1.40	1.51	3.91
Peru	1.61	1.18	1.29	3.70
Qatar	1.62	1.19	1.30	3.72
Trinidad	2.07	1.63	1.74	4.11

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