S&P Global Platts

Insight

Sep/Oct 2017

TOP 250
GLOBAL ENERGY
COMPANY RANKINGS

LNG confronts capacity pressure

US crude exports accelerate

Asia looks further afield for crude

The rise of the utilities

Energy's new frontiers

Insight

ISSN 2153-1528 (print)
ISSN 2153-1536 (online)

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With unprecedented geopolitical shifts dominating headlines over the past year, the attraction of safe havens is clearly stronger than ever.

The biggest trend to emerge from the S&P Global Platts Top 250 Global Energy Company Rankings® this year is the rise of diversified utility and pipeline companies.

Notably, illustrating this most clearly wasn’t Russia’s Public Joint Stock Company Gazprom moving to the top of the list, ending ExxonMobil’s 12-year hold on the position, but Germany’s E.ON shooting up 112 places to No. 2 from No. 114.

Riding the same wave, Britain’s Centrica, Brazil’s Centrais Eletricas Brasileiras or Eletrobras and US’ CenterPoint Energy all jumped more than 100 places up the rankings.

But amid the undeniable attraction of stable cash flows and strong returns on invested capital that such utilities can provide, the new frontiers of the energy landscape cannot be ignored.

The rise of shale and the growing exports of LNG and oil from the US are changing the energy landscape, while efforts by Asian refiners to diversify their crude purchases beyond the Middle East are seeing producers globally sit up and take notice.

Japan is looking even further forward, targeting the commercial extraction of methane hydrate—gas from undersea ice—in less than 15 years.

Amid this, China is grappling with its export policies, Mexico with its need for imports, and the shipping sector with its requirement to shift to cleaner fuel.

All these trends have not escaped the attention of S&P Global Platts’ team of specialists, and their analysis in the following pages provides significant food for thought.

Notably, this edition of Insight has expanded to include analysis from recent partners to the S&P Global Platts portfolio, PIRA Energy Group and Bentek Energy, for the first time, as our capabilities expand to reflect our expanding market coverage.

The energy landscape of today has changed significantly in my decade working at Platts, with talk of peak oil now long forgotten amid coordinated output cuts between OPEC and non-OPEC producers.

But the relative stability in global markets this year is fooling no one; paradigm shifts are underway in energy markets, and S&P Global Platts remains as committed as ever to providing our subscribers with the news, pricing and analytics they need to make decisions with confidence. This is more important than ever as our sector grapples with the devastation wrought by Hurricane Harvey on the US Gulf Coast, which has reverberations from Houston to Beijing. The thoughts of the entire S&P Global Platts team are with those affected.

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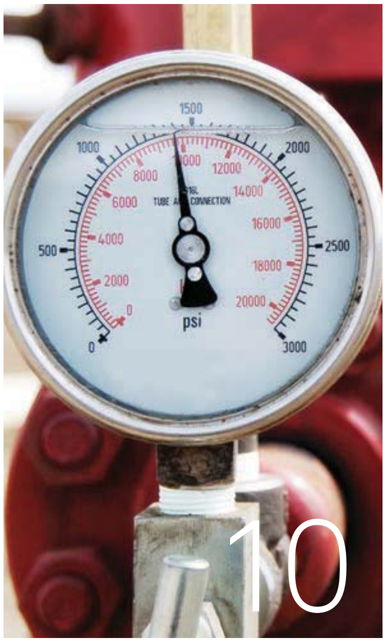

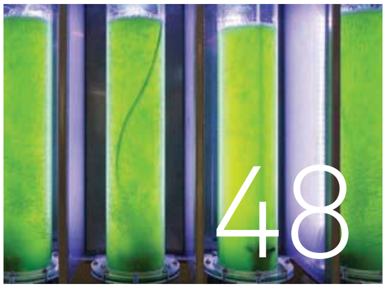
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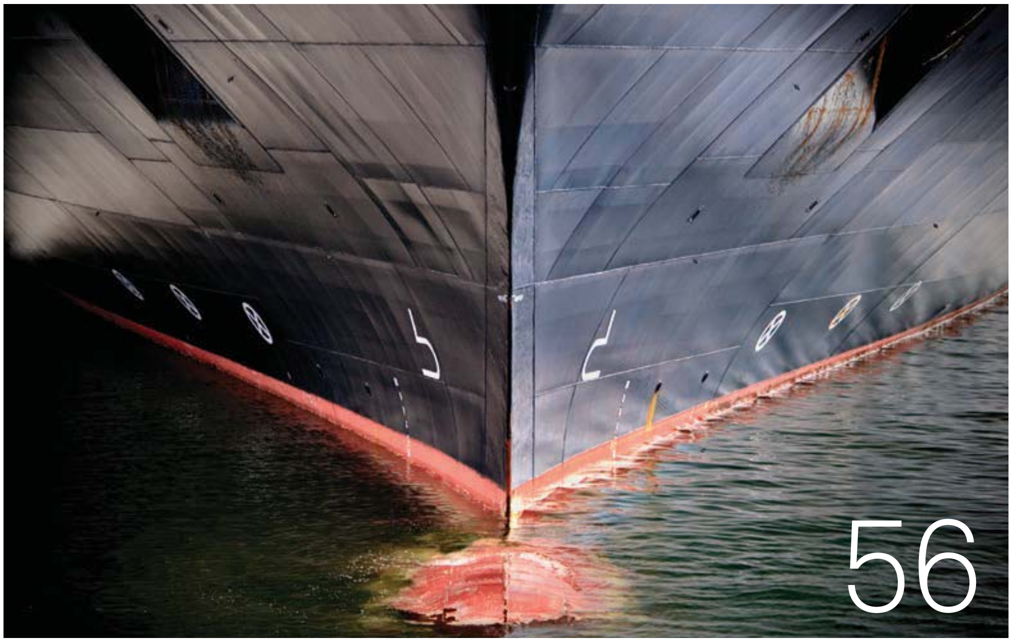
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US crude exports set to surge

The US is poised to become a major crude exporter and Gulf Coast infrastructure capacity is unlikely to impede its rapid growth

By Jenna Delaney

The US has been playing a growing role as an oil exporter to global markets in recent years. As US production growth surged early in the decade, exports to Canada increased rapidly, reaching more than 300,000 b/d during 2014.

In addition to flows headed north, during 2014 the US government approved the requests of select companies to export processed, light condensate oil under the existing crude oil export ban in place since the 1970s.

The lifting of that 40-year ban in late 2015, however, has put US crude exports on an accelerated path.

US crude exports averaged 520,000 b/d in 2016. Exports in the first half of 2017 are already averaging more than 80% higher, at nearly 950,000 b/d, with 700,000 b/d of that being exported from the Gulf Coast.

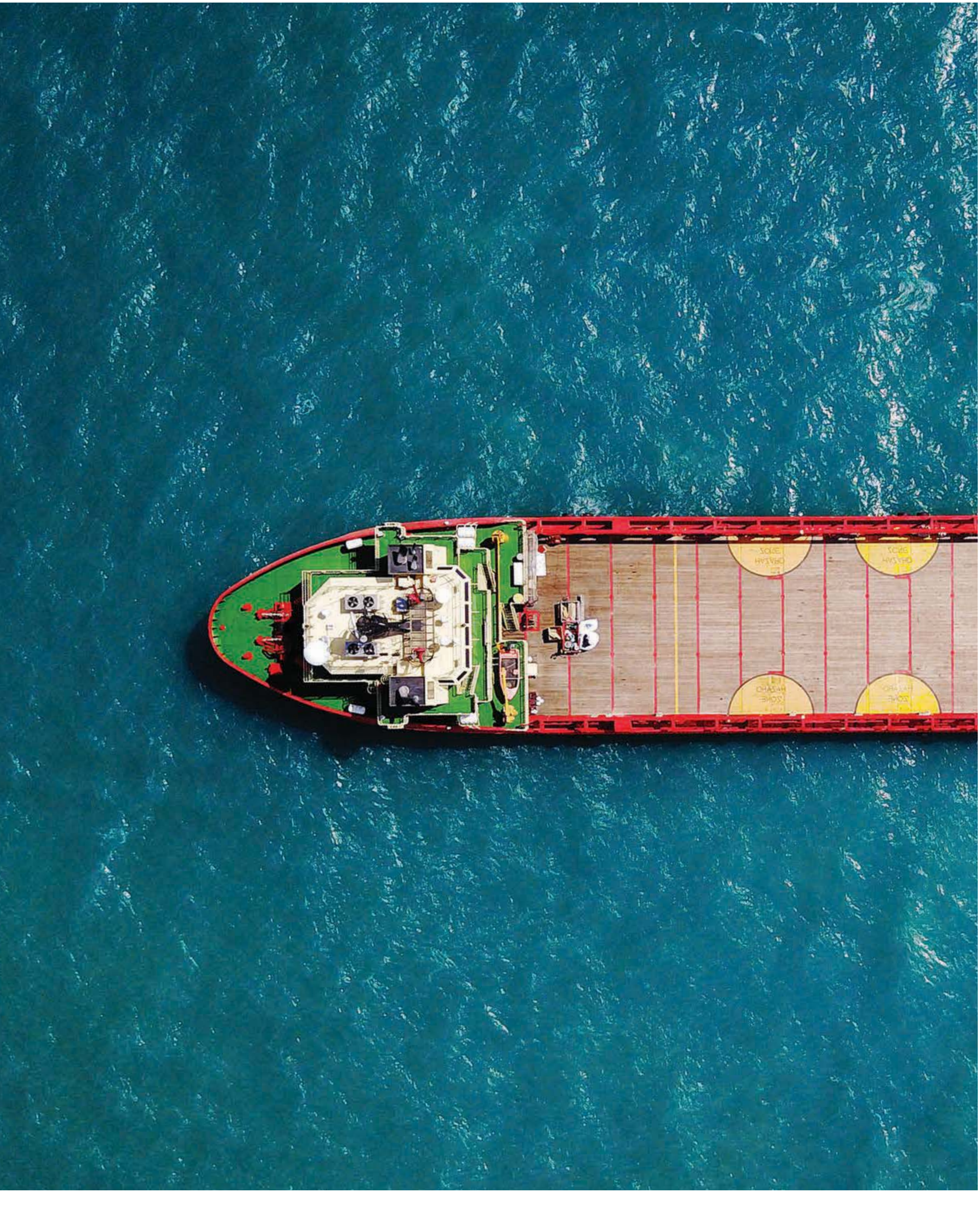
Looking forward, we believe US crude exports will reach 2.25 million b/d by 2020, a quadrupling of 2016 levels and rivaling many OPEC exporters including Kuwait and Nigeria.

The US is poised to become one of the top ten crude exporters in the world.

This important transformation in the US's crude trade position is grounded on strong domestic production. Light sweet crude supplies from shale production, especially in the Permian, but also the Eagle Ford, will drive much of the export growth.

Exports will provide an outlet for rising shale production to balance the US market. International companies have also expressed interest in purchasing the intermediate grades that are produced offshore in the Gulf of Mexico. The majority of US crude oil exports are currently shipped from the Gulf Coast, and we believe the Gulf Coast will experience most of the growth into the future.

Concerns have arisen over whether infrastructure in the US can accommodate such high levels of exports.



In our view, the US has not yet pushed the bounds of its existing export capacity, and we believe the Gulf Coast is well positioned to absorb the growing volumes. We expect significant redevelopment of infrastructure along the US Gulf Coast. Activity on this front has already begun, and more announcements are likely in the months and years ahead.

We estimate there are currently 19 active export terminals across the four main regions along the US Gulf Coast—Corpus Christi/Brownsville, Houston, Beaumont/Nederland and Louisiana—with export capacity totaling at least 2.9 million b/d.

Each have their distinct advantages and challenges. For some, logistical challenges may be enduring, while for others projects are already underway to alleviate constraints and achieve logistical scale.

Corpus Christi is positioned to become an increasingly prominent area for US exports. We estimate operating loading capacity in the Corpus Christi and Brownsville region stands at close to 1.2 million b/d.

Several other facilities are under construction or have been proposed, which could increase export capacity to more than 1.4 million b/d by mid-2019. This estimate could easily be higher with new announcements that are likely in coming years.

Corpus Christi benefits from close proximity to the Eagle Ford shale formation, and projected pipeline expansions connecting it to the Permian offer it access to rapidly rising and cheap supplies.

The Corpus Christi ship channel faces near-term logistical challenges—vessels larger than an Aframax are constrained by both the depth of the water and the height of the Harbor Bridge. However, the Corpus Christi Ship Channel Improvement Project aims to deepen and widen the channel, and increase the height of the bridge to accommodate a fully laden, larger Suezmax vessel to pass through the channel. Funding approvals from the federal government are underway.

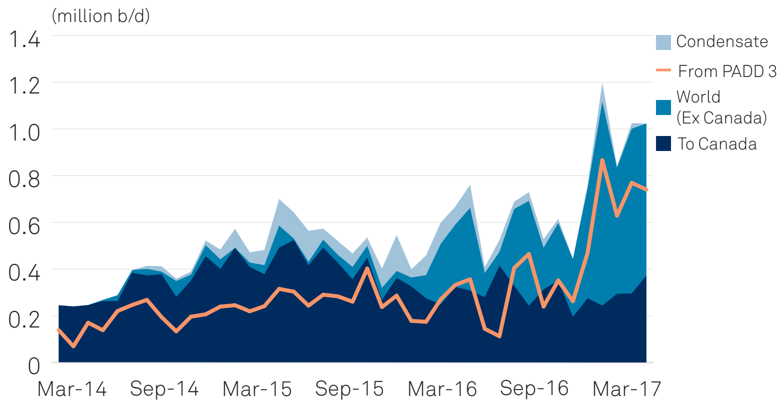
The greater Houston area, which includes facilities from Galveston through the Houston Ship Channel and Freeport, is estimated to have export capacity of nearly 1 million b/d. This estimate is conservative; a lack of transparency in this region means capacity may be several hundred thousand barrels higher. Some companies have announced expansion plans (HOFTCO, Magellan), but in our view Houston is unlikely to gain as much traction as Corpus Christi as a hub for exports.

Similar to Corpus, the majority of the Houston Ship Channel faces water depth constraints. However, modifications to deepen the channel and accommodate larger ships are unlikely at this point. The Port of Houston says it takes some $50 million/year of sustained capital deployment to maintain the channel's current capabilities.

Still, the region remains a major refining center on the Gulf Coast and benefits from the most intricate pipeline system in the country, leaving a lot of options for incoming barrels.

Nederland and Beaumont loading capacity is estimated at about 400,000 b/d, much smaller than Corpus Christi and Houston. Still, it is an interesting option

US crude oil exports



Source: US EIA

as an export location given that it is the termination point for the Dakota Access/ETCO pipeline system and 675,000 b/d of pipeline capacity from the Permian basin—potentially more if planned pipeline expansions take place—and houses several refineries.

At this point, few companies have planned or announced expansions for new terminals in the area. It also faces shallow water depths at Sabine Pass, constraining terminals to take only Aframax vessels if fully laden.

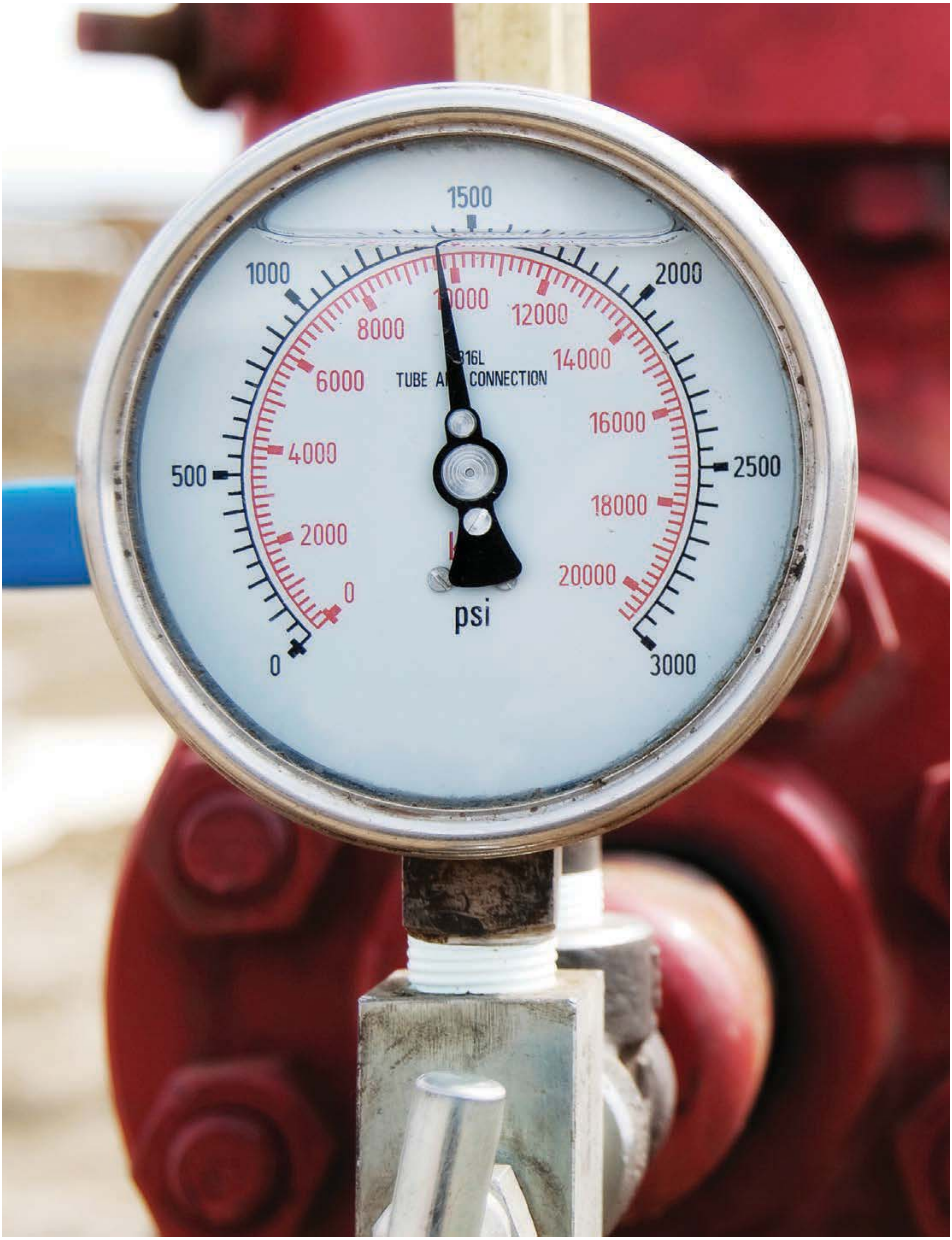
Export capacity in Louisiana is best estimated at 425,000 b/d, though information on facilities in the area is fairly opaque. These facilities vary widely in water depth, but the largest vessel that can currently be loaded to full capacity is an Aframax. The Louisiana Offshore Oil Port (LOOP), which has no vessel size restrictions, recently announced plans to add export capabilities. This will allow VLCCs to be loaded from the terminal by early-2018, or potentially sooner.

In aggregate, we believe there is currently at least 2.9 million b/d of operational capacity for crude oil and condensate exports on the Gulf Coast, which will likely expand by at least 700,000 b/d by the end of 2018.

We expect monthly crude oil exports from PADD III could regularly reach more than 1 million b/d during 2018. Shippers will likely have to absorb their share of reverse lightering costs and face other logistical challenges as volumes flowing into the Gulf Coast increase rapidly over the next year.

Nevertheless, considering both the terminals where we have visibility into their capabilities and those that we don't, we believe that the Gulf Coast is well positioned to absorb these volumes.

The US has not yet pushed the bounds of its export capacity, and Gulf Coast infrastructure will not likely impede US light sweet crude oil from reaching the world's appetite.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Capacity pressure weighs on LNG prices

A paradigm shift is taking place in the way LNG is priced around the globe as production in the US and Australia ramps up

By Ross Wyeno

Exports of LNG have long been touted as the metaphoric savior of the US gas markets, tempting producers and midstream players alike with the allure of global demand. Indeed, global LNG demand rose to 37.6 Bcf/d during the first half of 2017, a 4.1 Bcf/d (15%) increase year on year.

The rise in imports was led by the large East Asian economies Japan, South Korea and China, which represent around 57% of global demand and collectively added 2.8 Bcf/d of incremental demand this year.

China's LNG market alone has grown at a particularly rapid rate to date this year, importing 4.4 Bcf/d since January, a 1.3 Bcf/d (43%) increase over last year. The upswing in demand has been supported by a substantial buildout of new export capacity, led by Australia and the US, which added 1.7 Bcf/d and 1.4 Bcf/d of additional supply during the first six months of the year respectively.

However, despite rising demand in East Asia, LNG spot prices have slipped back into territory not seen since prior to the 2011 Fukushima disaster, which led to Japan shuttering 47.5 GW of nuclear generation capacity.

The recent dip in global LNG prices is a clear sign of a rebalancing occurring in global gas markets, which could prove a difficult environment for US LNG exporters, potentially driving underutilization during protracted periods of depressed prices.

By 2022, global liquefaction capacity is set to grow to 63.5 Bcf/d, a 17.1 Bcf/d (38%) build over 2016 levels.

While Australia is expected to add another 4.8 Bcf/d of liquefaction over that time frame, raising total export capacity to 11.5 Bcf/d, the US is leading a vast majority of the buildout over the next five years, adding 9.3 Bcf/d of export capacity between 2016 and 2022 (See Figure 1).

With all of this capacity set to come online in the next four years, it begs the question: Can the global gas markets really absorb this much additional LNG?

Surplus to continue

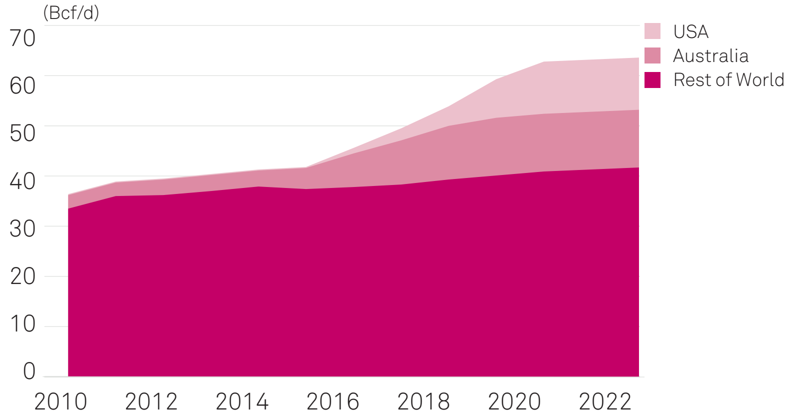
S&P Global Platts Analytics expects that the global surplus will continue to rise through 2020, which will require a tremendous ramp-up in price-sensitive demand if all supply is to be dispatched. If demand growth fails to meet the rising tide of production, the highest cost suppliers are likely to face economic driven shut-ins.

The primary assumptions guiding the evolution of demand in Northeast Asia are nuclear restarts in Japan, a substantial buildout in coal and nuclear generating capacity in South Korea, and uncertainty surrounding the predominant gas pricing regime in China, which favors domestic production over cheaper LNG imports .

These factors are highly dependent on the prevailing political climate, which in many of these countries can change quite readily. This has been seen most recently in South Korea, with President Moon acting to reduce dependency on coal and nuclear generation in favor of LNG. More upside risk exists in China, which alone houses enough spare gas-fired generating capacity to all but absorb the global LNG surplus, if fully utilized.

For the oversupplied US gas market, global LNG markets held the promise of pent up demand, without which US gas production may face contractionary pressure. While the start of the first train at Sabine may signal the beginning of the end of US gas oversupply for some, it may come to pass that

Global liquefaction capacity



Source: S&P Global Platts Analytics

US exports begin just as the global market starts to wrestle with its own deluge of supply. We expect that six LNG export terminals will ultimately be built in the US over the next five years boasting a combined liquefaction capacity of 10.5 Bcf/d (See Figure 3).

Sabine Pass was the first project to begin commercial exports of LNG overseas. Year to date, Sabine Pass feed gas deliveries have averaged 1.9 Bcf/d, a build of 1.5 Bcf/d (370%) compared to last year. The projects that we expect to reach completion have all necessary US Federal Energy Regulatory Commission and Department of Energy approvals, all have received a final investment decision, and all trains projected to go forward are fully contracted. These six facilities represent about a fifth of the total proposed liquefaction capacity that has been announced in the US and, once built, will represent around 17% of global liquefaction capacity.

With the global LNG market expected to be well-supplied over the next five years, it appears unlikely that many new buyers will enter the market for additional US supplies being delivered before 2022-2023. However, assuming a five-year build time for most new liquefaction projects, new contracts may be signed in the next couple of years as buyers begin lining up supplies for the next decade.

However, proposed US LNG export projects face mounting competition from established global suppliers, which hope to defend their respective positions in the global energy markets.

Recently, Qatar announced it would double output from its North Field, allowing the country to increase exports to 13.3 Bcf/d, a 3 Bcf/d (30%) increase over current levels and defending Qatar's position as the world's largest LNG exporter. This buildout could further extend the global surplus into the mid-2020s and limit prospects for prospective US LNG export projects, which are still actively seeking buyers.

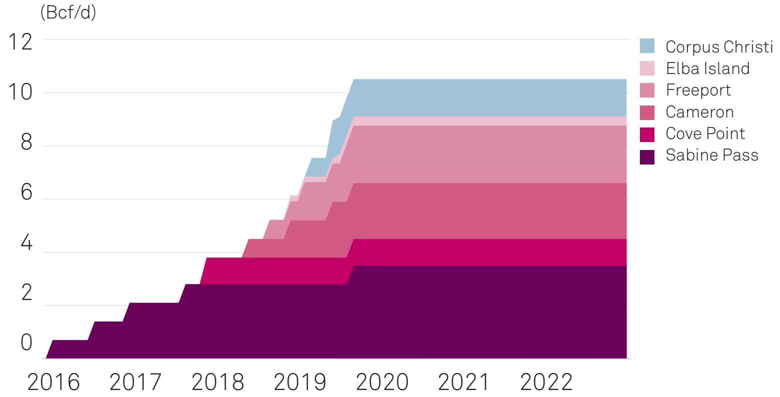
In an environment with plenty of length in the global LNG markets, which we appear to be entering, US LNG exporters may have to compete to deliver the marginal cargo into global demand markets. This would typically occur when global demand is low and there is plenty of length in the spot market, which tends to be during the shoulder months (spring and fall).

The marginal cost of delivering gas from the US into Asia and Europe is also set to become an important price support between now and the mid-2020s, during periods where supply far exceeds demand.

When global spot prices fall below the marginal cost to deliver a US LNG cargo to market (ignoring sunk costs), a US capacity holder may forgo their option to liquefy, thus depriving the market of supply and acting as a price floor. This optionality of US LNG exports, wherein supply can be turned "on" or "off" in response to price, will become a key price signal over the coming years, informing markets when additional US supply is needed and shutting in US supply during times of low demand.

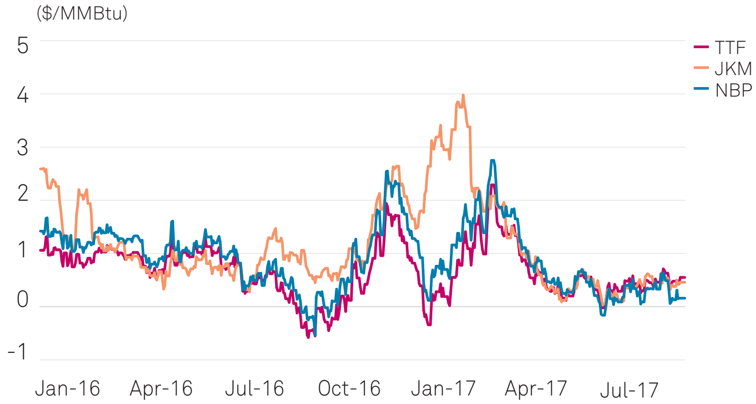
The risk of underutilization becomes more distinct when "netbacks", or the destination market prices minus the cost of feedgas, liquefaction and shipping, fall below zero.

US liquefaction capacity



Source: S&P Global Platts Analytics

US LNG netbacks



Source: S&P Global Platts Analytics

To date this year, US LNG netbacks to the UK's National Balancing Point have averaged 79 cents/MMBtu, whereas LNG netbacks to the Japan Korea Marker have averaged slightly higher at 96 cents/MMBtu.

However, as more export capacity has come online this year and global demand has fallen back to summer levels, netbacks have seen further downward pressure, even falling below zero during a brief period in May.

The continued buildout of US and Australian capacity is expected to further pressure these netback spreads, with the risk of underutilization becoming more pronounced towards the end of the decade.

US offshore drilling plans face headwinds

Trump administration looks to expand offshore drilling, but progress hinges on prices

By Brian Scheid

When real estate tycoon Donald Trump became US President Donald Trump in January, US Gulf of Mexico production averaged 1.76 million b/d, the highest monthly oil output ever, according to the US Energy Information Administration.

But Trump's arrival in Washington had very little, if anything, to do with that shift in supply, just as his administration cannot claim any credible credit in its subsequent decline. Production had fallen by 120,000 b/d by June, according to EIA.

The occupant of the White House has little to do with trends in US offshore production, which mainly swing on price movements, market fundamentals and weather.

But the Trump administration wants to change that and is looking to open up millions of new acres off US shores to oil and gas drilling, a plan they hope will boost output in the Gulf, but also in the Arctic and Atlantic.

In late April, the administration unveiled a plan which called on Interior Secretary Ryan Zinke to undertake a review of the current 2017-2022 federal offshore lease plan, which was finalized by the Obama administration in November and includes 10 sales in the Gulf of Mexico and one in the Cook Inlet offshore Alaska.

Sales once proposed in Arctic and Atlantic waters were removed from that plan before it was finalized and Trump's order aims to reschedule sales in those areas by 2022.

Katharine MacGregor, Interior's acting assistant for land and mineral management, told a House of Representatives Natural Resources Committee subcommittee in July that the efforts were part of the move towards domestic "energy dominance," a relatively new push by administration officials to go beyond long-standing policy aspirations for energy independence.

"Dominance does not stem from eliminating areas from future production," she said.

Interior has begun to scrap the current five-year plan and is expected to unveil a new plan, which will include sales in the Beaufort and Chukchi seas offshore Alaska, as well as sales in the mid- and south Atlantic Ocean. But the process is expected to take years and, even when completed, may generate little interest from an industry which has increasingly moved onshore over the past decade.

"It's difficult for me to see strong interest at current price levels given the long lead time required for these types of projects," said Michael Cohen, head of energy markets research at Barclays. "Even if prices spiked to $75/b in the next two months, the fact that the industry may see that as a temporary development may inhibit companies from undertaking the spending on exploration to translate these resources into proven reserves."

Not at $50/b

Adam Sieminski, the former head of the US EIA, now with the Center for Strategic and International Studies, said there was interest in drilling untapped federal waters when prices were above $110/b, but not at $50/b.

"There might be at $80/b, especially if the economics looked like oil prices might be rising over time by a couple of bucks per year in real terms," he said.

But that price scenario looks unlikely currently. While up from an average of $43.33/b in 2016, the EIA forecasts WTI spot prices to average $48.95/b this year and rise to just $49.58/b in 2018.

In addition to price uncertainty, numerous hurdles remain to expanding US offshore oil production in new areas.

The Arctic

Of all areas the administration is looking at, the Chukchi and Beaufort seas present, arguably, the biggest challenges.

First, it remains unclear if the Trump administration can overturn seemingly permanent prohibitions his predecessor Barack Obama put into place on oil and gas development in about 115 million acres of Arctic waters.

Last December, Obama used Section 12(a) of the Outer Continental Shelf Lands Act, a 63-year-old law that allows the president to “withdraw from disposition” any unleased lands in federal waters, to block development in those and some Atlantic waters.

Even if the Trump authorizes sales within these acres, the path forward may be tied up in federal court for years.

Second, Arctic drilling, if ultimately approved by the Trump administration, would take place in remote areas with little infrastructure, including pipelines, deepwater ports and ice breaking ships. This posed a major hurdle for Shell, which abandoned its efforts to drill in the Chukchi in 2015, after seven years and $7 billion spent.

Shell left the Arctic after an exploratory well failed to find significant oil and natural gas and needed a “huge discovery” in order to justify production in those waters, according to Walter Cruickshank, acting director of the Interior Department’s Bureau of Ocean Energy Management. Shell’s well was roughly 70 miles offshore and another 300 miles to the Trans-Alaska Pipeline System, he said.

Whether TAPS will still be running when an Arctic project is underway, perhaps decades from now, is also a question, Cruickshank said.

The Atlantic

The offshore effort also faces legal challenges from environmental groups and potential resistance from the Pentagon over concerns that oil and gas operations may interfere with Atlantic military operations.

There is also opposition from environmental groups over seismic testing needed before drilling begins.

The potential development of the Atlantic offshore is also constrained by a lack of infrastructure in such waters. There are no pipelines or marine facilities currently able to bring crude from US Atlantic waters to shore, as there are in the developed Gulf of Mexico.

Gulf Of Mexico

It’s unclear if the Trump administration plans to add to the 10 planned sales through 2022, but interest in Gulf sales has been waning for years.

It announced in July that it will lower royalty rates for certain shallow water Gulf of Mexico parcels up for lease to drum up commercial interest in a federal offshore oil and natural gas sale planned for next month.

In addition, federal law prohibits oil drilling in the Gulf within 125 miles off the coast of Florida, a moratorium set to expire when the five-year plan will end in 2022, leaving much of the Gulf off limits without congressional action.

Transition looms in Europe's gas prices

Oversupply will keep a lid on prices until 2023, but once the LNG surplus starts drying up, prices will rise

Henry Edwardes-Evans and Stuart Elliott

Oversupply of natural gas is set to keep pressure on Northwest European gas prices through to 2022, according to S&P Global Platts Analytics in its Summer 2017 Long Term PricePilot report. The global surplus in LNG is finding a home in Europe, despite robust Russian and Norwegian supplies via pipeline.

This wave of cheaper gas is set to encourage further switching from coal-fired to gas-fired power generation across Europe, although gas-for-power demand to mid-2020 is forecast to fall overall in the context of growing renewables.

Beyond 2023, European gas prices are forecast to recover as the global LNG surplus recedes. Longer term and into the 2030s, a new balance is arrived at with renewed growth in LNG acting to settle prices back at levels that will see price-sensitive demand pick up again in the power generation sector.

And it is in this decade that new demand could emerge as European governments seek to accelerate adoption of electric vehicles to 2040-50. Peak recharging periods will need fast-response power supply, with gas-fired capacity well-placed amongst current technology options, although widespread rollout of time-of-use tariffs will likely limit peak demand.

The near term

Northwest European gas demand has been relatively flat in recent years, with modest growth in distribution network consumption partly offset by lower industrial demand. At the same time, growth in global LNG supply, and strong flows of Russian and Norwegian pipeline gas, has meant there is plenty of gas looking for a flexible source of demand.

Power generation has provided a home for some of this gas during Summer 2017—offtakes were up 24% in the first six months of 2017 in a year-on-year comparison—and is set to do the same next summer as the LNG glut intensifies.

While Platts Analytics expects European gas prices to be supported by coal-to-gas switching in summer 2018, this will be limited by the "thermal gap"—power demand minus output from inflexible sources. This gap is reducing in Germany and the Netherlands, and will reduce in France next year if hydro resources return to more normal levels after an unusually weak 2017.

Platts Analytics forecasts a sub-Eur13/MWh gas price in Northwest Europe for Q2 and Q3 2018, comfortably below the price at which gas-fired operation is more economic than that of coal-fired power production.

The medium term

From 2018 to 2022, European gas prices are set to remain low as oversupply conditions gather pace, with Platts Analytics forecasting a price range of Eur10.5-Eur12.4/MWh as the market share of LNG rises to 17% in 2018-19 (48.9 Bcm) before peaking at 20% (54.4 Bcm) in 2019-20. This compares with 9% (26.1 Bcm) in 2015-16.

The LNG boom is set to force Russian gas imports to step back from 2016/2017 highs. Northwest European gas contracts economics are now mainly hub-driven, with buyers presented with cheaper options than additional oil-indexed Russian gas.

From 2020, however, Platts Analytics expects Russian volumes to pick up again, as hub prices rise as the LNG surplus erodes. There remains the possibility that Russia's Gazprom could move to a market-share strategy earlier in order to stave off LNG incursions into Europe, but this is yet to materialize.

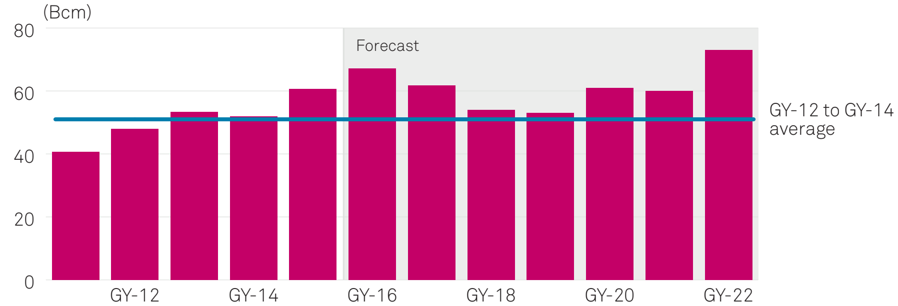
As noted a key driver of European gas market dynamics in the coming years is how gas competes versus coal, and how the respective commodity price shifts impact on gas-for-power demand.

The medium term price outlook clearly indicated an increasing trend toward coal-to-gas switching in power generation across Northwest Europe and the wider European region as a whole.

Additional demand is estimated at up to 70 million cu m/d in Northwest Europe, and up to 30 million-35 million cu m/d in the UK compared with minimum running needed from gas, irrespective of price.

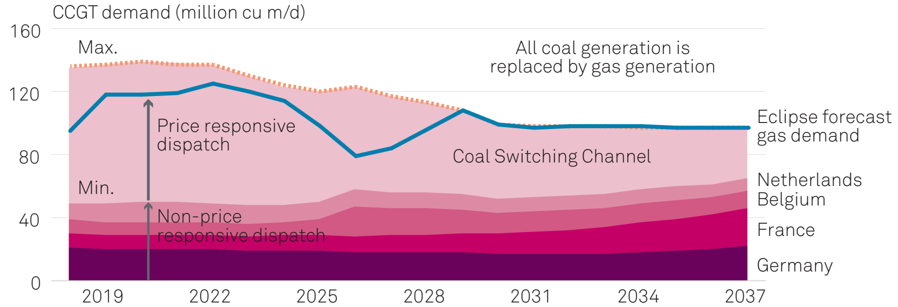
The trend for more coal-to-gas switching is likely to continue until the mid-2020s, though as more coal plants close across Europe the potential for gas to replace coal dwindles.

Russian gas exports to NW europe



Source: S&P Global Platts Analytics

NW europe coal-to-gas switching potential



Source: S&P Global Platts Analytics

Transition to stronger prices

As the LNG surplus recedes and Norwegian production declines, gas prices in Europe are forecast by Platts Analytics to rise strongly from Eur14/MWh in 2023 to around Eur18/MWh three years later.

The LNG market will see a paradigm shift during this transition period, with US LNG starting to require a premium above pure short run marginal cost pricing seen in the early oversupply period.

Rising hub prices will enable total LNG to NW Europe to increase slightly over the course of this time, but the main supply response comes from Russia, which is seen increasing deliveries from 73 Bcm in 2022 to 104 Bcm in 2026, capturing some 37% of the European market, compared with 17% for LNG.

These strong prices will see a steep decline in CCGT demand. In continental NW Europe, Platts Analytics sees CCGT switching demand decline from 22 Bcm in 2022 to 7 Bcm in 2025.

The long term

Thereafter the expectation is that Europe's gas markets will attain a new balance from 2027, despite further declining indigenous production. Norwegian gas production is forecast to reach 59 Bcm/year by the late 2030s, 29 Bcm/year lower than a decade earlier, while UK production falls to just 3 Bcm/year by the late 2030s.

The key supply response will be from LNG, forecast to increase to 89 Bcm/year by 2039 to attain a 31% market share. Russia, in turn, is expected to increase exports to NW Europe by 21 Bcm/year, with a peak market share of 44% in this period.

As prices step down from transition highs, the scope for coal-to-gas switching again increases with gas prices low enough to trigger the running of gas plants ahead of coal on the continent.

After only 7 Bcm of price-sensitive CCGT demand forecast in Gas Year 2025, Platts Analytics expects 20 Bcm/yr of CCGT switching demand by GY-28.

The revival lasts no more than a few years. With European coal plants gradually phased out in the 2030s, price-sensitive demand for gas-for-power declines again to around 7 Bcm/year by the end of the decade.

EVs and new demand

Finally, could the shift to electric vehicles prompt renewed gas demand for peak generation? The UK and France want to leave new-sale internal combustion engine vehicles behind by 2040. Germany is considering something similar. For cities across Europe, air quality is a huge political issue and the first fleets of electric buses and taxis are taking to the streets.

Strong growth in the electric vehicle market has the potential to increase peak UK electricity demand by 3.5 GW by 2030 and 18 GW by 2050, according to National Grid's most bullish scenarios, although an additional 5 GW by 2040 is seen by National Grid as most consistent with the government's emerging EV strategy.

UK peak electricity demand is currently around 60 GW and power generation margins are considered to be wafer thin. The country's capacity market is aimed at encouraging new gas-fired capacity, and it is arguable that similar mechanisms in NW Europe will, over time, also seek to replace aging coal plants with gas plants that are flexible enough to balance renewables and meet Europe's future EV re-charging needs.

Mexico's insatiable appetite for US gas

Mexico looks set to remain captive to US gas flows in the medium term, based on our outlook for 2018-2020

By Kevin Sakofs

Net pipeline flows to Mexico increased fourfold in six years to just under 4 Bcf/d last year from 1 Bcf/d in 2010, and look likely to continue rising over the next three years. To date in 2017, US gas flows across the border by pipeline have already risen to an average 4.1 Bcf/d.

Given the political climate of late, we have received numerous inquiries regarding our outlook for the sustainability of the US gas trade with Mexico.

In short, our forecast has not changed, and we maintain that risk to this assessment is minimal in the short to medium term.

To be sure, net cross-border exports of natural gas are expected to swell to around 6 Bcf/d by the end of the decade. Such a view is rooted in the reality that the growing gap between domestic supply and demand will heavily weigh on the country's ability to shun US imports, given alternative energy sources at this point in time are limited.

Moreover, with increasingly large capital investments targeting cross-border infrastructure—with more than 3 Bcf/d planned in 2017 alone—Mexico's ability to source cheap gas is increasing.

Likewise, and perhaps more importantly, growth in Mexican domestic pipeline infrastructure is growing at an accelerated clip—a positive sign for demand as intra-Mexico pipeline bottlenecks have often served to restrict much of the country's ability to access Lower 48 natural gas.

Consequently, with an enhanced pipeline system in the offing, US gas will begin to make its way into key consumption centers that have been short gas or have never had access to gas.

Given this backdrop, Mexico's domestic gas consumption should rapidly expand—with additional gas volumes required to feed around 10 GW of new combined-cycle electricity generation units scheduled to commence

service by the end of 2020. In terms of fuel switching, options are limited.

Indeed, Mexico is highly dependent on gas for electric generation, as gas accounts for almost 50% of fuel use in the sector.

Moreover, while some fuel oil to gas switching was visible in late 2015 and early 2016 when oil prices plunged, forward-looking oil prices suggest dispatch economics will continue to favor gas generation—with retro-fitting already under way at numerous fuel oil-fired plants to enable them to burn natural gas too.

Interestingly, Mexico has embarked on a process of cutting fuel oil-fired power consumption to around 20 MB/d by 2018—around 82% from recent levels—a very ambitious goal.

However, if the goal is achieved, an incremental 0.5 Bcf/d of gas demand could emerge. Importantly, this could offer upside momentum, above and beyond what is anticipated from combined cycle additions.

Pivoting to supply, domestic production is expected to continue to founder.

While Mexico's resource potential in undeniable, given it has the sixth largest gas and eighth largest oil technically recoverable shale resources or TRR in the world, short-term deliverability of the resource is highly constrained.

In particular, low oil prices have wreaked havoc on Pemex's financial conditions, which has severely weighed on its production capabilities.

Of importance, under this paradigm of low commodity prices and constrained budget, Pemex has been forced to focus on enhanced oil recovery or EOR, while investments in gas have suffered comparatively due to lower netbacks.

Indeed, around 2% of all wells completed in 2017 have targeted gas—a 90% decline from the prior periods' 3-year average. As a result, domestic gas production is expected to continue to showcase weakness, with year-on-year production already showcasing losses of around 0.5 Bcf/d.

Weighted towards oil

In addition, while reforms to stimulate foreign upstream investments are ongoing—with some success—the emergence of significant private capital funding of production is likely to be weighted more towards oil after this decade.

Indeed, oil production is forecast to decline through to 2020, offering little help to gas recovery via increased levels of associated volumes.

Taken altogether, with virtually no storage and declining local supply, if gas shipments across the US border were to stop or slow, negative implications for daily usage and economic growth would likely ensue.

Indeed, although Mexico is among the largest economies in the OECD, the gap in living standards is large, as productivity levels are far below the average.

Thus, Mexico recognizes the need to reduce energy costs in order to enhance its global competitiveness across industry and drive GDP higher.

In our view, this dependence on Lower 48 gas will remain intact until the electric generation sector has a more diverse fuel mix, the structural gas (and oil) production declines are stemmed, and/or storage capacity is developed.

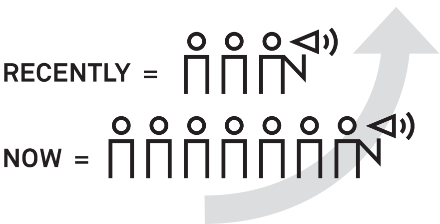
Given the current state of the market, achieving those three objectives—or any of them—will be difficult without adequate time and capital.

As such, despite escalating political saber-rattling surrounding trade, Mexico will remain a highly captive and growing market for US exports.

The evolution of North American natural gas benchmarks

www.platts.com/ice

It's important to all of us that natural gas markets are as transparent as they can be. That's why S&P Global Platts is making changes to our price assessment process and evolving with the marketplace.



It started with price reporters

For many years, Platts has produced volume-weighted average indices based on voluntary price reporting. The price reporting process was formed in bi-lateral markets. However, in recent years, the majority of physical natural gas trading and confirmation has moved to electronic platforms. It's time to change with the times.

It continues with ICE

Platts has partnered with Intercontinental Exchange to include anonymized ICE data regarding physical natural gas transactions in Platts natural gas daily and monthly price assessments in North America. By capturing the ICE trade data, our benchmarks will reflect greater trading volumes and more counterparties, advancing the goal of greater market transparency.

S&P Global Platts + ICE

What goes in:

- ICE trade data
- Matched eConfirm trades
- All other price reporter trades

The result? Indices that capture:

- Greater participation
- Increased number of counterparties
- Higher index volumes and deal counts

For price reporters... It's a new day

No more end of day emails! Price reporters can use ICE eConfirm, a platform that most companies are already using for trade confirmation, to submit transactions. The result — eConfirm users will no longer need to email trade data to Platts. If you're not an eConfirm user today, contact ICE today to learn more.

For more about the Platts natural gas price assessment evolution, go to www.platts.com/ice

S&P Global Platts

NATURAL GAS

Saudi Aramco pushes downstream

State oil giant aims to take on oil majors as it prepares for initial public offering

By Adal Mirza

As Saudi Aramco's initial public offering approaches, the company's most recent annual review, released July 13, provided some insight into its new strategic direction as "a global powerhouse in refining, chemicals and marketing."

With its eyes fixed firmly on potential investors, the state-owned oil giant is positioning itself as a new international oil major, a diversified energy enterprise with integrated downstream and sales operations spread across the globe. Aramco said in its 2016 annual review that it had 260.8 billion barrels of crude oil and condensate reserves. Although the figure was reviewed by Gaffney, Cline and Associates and by DeGolyer and MacNaughton, it is yet to be audited.

The fact that the reserves fell by 300 million barrels compared to 2015 may have raised some eyebrows with investors, but the figure is still leagues ahead of major oil companies like ExxonMobil with 20 billion barrels or Shell, with 6.258 billion barrels.

While Aramco produces significantly more crude than its competitors, it sells much less downstream product. Aramco has been diversifying downstream for the best part of four decades, but it has lagged behind its international oil company rivals. This is what Aramco now wants to change.

"We are determined to create additional value for the company," Aramco CEO Amin Nasser said in a statement on the results.

"We will maintain our focus on reliable energy supply to customers around the world, and envision pursuing ultra-clean sustainable oil, doubling our gas supplies, establishing a leading position in renewables and becoming a global powerhouse in refining, chemicals and marketing."

To this end, Aramco plans to invest more than $300 billion over the coming decade to reinforce its position in oil and maintain its spare oil production capacity, Nasser said at World Petroleum Congress in Istanbul July 10.

Central to the investments is Aramco's ambition to raise its global refining capacity to between 8 million and 10 million b/d, from 5.4 million b/d currently. This includes 2.91 million b/d from domestic refineries and 2.34 million b/d from overseas capacity either held 100% by Aramco or in a joint venture.

The Saudi National Transformation Program envisages domestic refining capacity rising from 2.9 million b/d to 3.3 million b/d by 2020 with the completion of the 400,000 b/d grassroots Jizan refinery in the southwest of the country.

"Right now Aramco doesn't have the breadth, or the depth of downstream, that western majors have," said Kristine Petrosyan, refining analyst for the IEA's oil market report. Depth means going further into retail as well as petrochemicals. Aramco is also limited in its downstream breadth, Petrosyan explained, with most of its assets at home in the Persian Gulf.

Currently, it refines only around a third of what it produces. The push downstream will also allow it to go deeper into petrochemicals.

Since it is already built up inside the kingdom, Aramco will have to look to big demand centers overseas—Saudi Aramco also has refining interests in the US, China, Japan and South Korea, with Malaysia and Indonesia soon to be added to that list.

"Its Asian projects have yet to materialize," Petrosyan said. In May, Aramco signed a $7 billion deal to buy 50% of Malaysia's 300,000 b/d RAPID refinery and petrochemical project and reaffirmed its partnership with Indonesia's Pertamina for the upgrade and expansion of the Cilacap refinery in central Java.

That same month, Aramco and China's state-owned North Industries Group and Panjin Xincheng Industrial Group held a groundbreaking ceremony for their new refinery project at Panjin, in China's northeast Liaoing province.

Aramco's downstream plans are not taking on the majors, said Fareed Mohamedi, chief economist of energy consultancy Rapidan Group.

"It's about securely placing crude with 'captive' refineries, capturing the downstream value-added and then integrating with petrochemical plants to increase the value-added further and get a less volatile end price than just crude and products," said Mohamedi, a corporate adviser to Aramco until mid-2016.

According to Petrosyan, one of the key drivers is a desire to balance out Aramco's over-reliance on

Aramco's current global refining network (b/d):

Refinery	Location	Capacity	Aramco stake (%)
Ras Tanura	Saudi Arabia	550,000	100
Riyadh	Saudi Arabia	126,000	100
Jeddah	Saudi Arabia	90,000	100
Yanbu	Saudi Arabia	240,000	100
PetroRabigh	Saudi Arabia	400,000	37.5
Samref	Saudi Arabia	400,000	50
Yasref	Saudi Arabia	400,000	62.5
Sasref	Saudi Arabia	305,000	50
Satorp	Saudi Arabia	400,000	62.5
Port Arthur	US	600,000	100
S-Oil	South Korea	669,000	63.4
Showa Shell	Japan	445,000	15
Fujian	China	280,000	25
Cilacap	Indonesia	348,000	45

Source: Saudi Aramco, S&P Global Platts

exploration and development. One of Aramco's objectives is to push deeper vertical integration across the petroleum value chain, with refining acting as a crude placement vehicle and retail creating captive demand for refining systems.

The new Panjin complex, for example, will significantly expand Aramco's footprint in China's downstream industry, where it already has a 25% stake in the 280,000 b/d Fujian refinery.

It also secures a captive market for Saudi crude. The kingdom was displaced by Russia as China's top crude supplier for the first time in 2016, as its market share fell to 13.4% last year from 15.1% in 2015.

The plan is also driven by concerns over economic development inside the kingdom, and the need to create jobs for Saudis and investment opportunities for the private sector.

"Also, if they IPO downstream assets, it deepens the stock and other financial markets and expands the financial services industry," he said.

As well as securing long term markets for its crude, the expansion of global refining would also add value and reduce Aramco's exposure to earning volatility, making its portfolio more robust in downturns.

But there is plenty for Aramco still to learn, warns Petrosyan.

"In some sense, Aramco also lacks negative experience. BP, Total and others have had to close, restructure or re-orient their downstream businesses many times. Negative experience in shrinking or high cost markets does add to robustness in the future."

Aramco has not been hugely active in non-asset based trading, either. The experience of simply being an intermediary in the crude or oil products supply chain would be a valuable addition to its portfolio.

These kinds of changes will take years to implement.

"I think it's at least 1.5-2 decades of focused strategy and imple-mentation to become a fully-fledged global downstream player," Petrosyan said.

Saudi Deputy Crown Prince Mohammed bin Salman, credited with masterminding the Saudi Arabia Vision 2030 economic plan, has been talking up the value of the kingdom's national petroleum company during a continent-hopping peregrination to promote both Vision and the IPO.

Priming potential stock markets for the world's biggest IPO, he has estimated Aramco's value at between $2 trillion and $2.5 trillion. Based on this, the expected offering of 5% of Aramco should raise as much as $125 billion.

Progress on the drive downstream will go a long way to help realizing this valuation.

Asia looks further afield for crude

Its traditional suppliers in the Middle East are starting to take notice

By Ada Taib

Efforts by Asian refiners to diversify crude purchases beyond their traditional sources in the Middle East are increasingly catching the eye of producers around the world, eager to take a piece of the pie. The moves to diversify the crude slate follow a strengthening of the sour crude complex in the Middle East in the wake of the OPEC/non-OPEC production cut deal, helped by lower freight rates and strong refining margins.

Most recently, Indian Oil Corp. sealed its first deal to import crude from the US in July, the first ever US crude purchase by a state-run refiner in India.

IOC bought a combined VLCC cargo comprising 1.6 million barrels of US Mars crude and 400,000 barrels of Western Canadian Select crude for delivery to its Paradip refinery in the first week of October.

The move came shortly after Indian Prime Minister Narendra Modi's visit to the US and is expected to pave the way for more purchases by Indian refiners, both state-run and private.

"So long as the prices remain favorable, we can buy more. We are looking at five to six grades from the US," IOC's Director of Finance A.K. Sharma said. Japan reported its first import of Mars crude from the US in May, and also took 522,500 barrels of Eagle Ford crude from the US in the month. US crude imports to Japan doubled in the first five months of this year to 33,022 b/d from the same period a year earlier.

China has also diversified its supply sources, buying 710,000 barrels of White Rose crude and a partial cargo of Hibernia crude from Canada that were co-loaded with an unspecified Latin grade in late February in a first-of-its-kind voyage.

South Korea's fourth-biggest refiner, Hyundai Oilbank, bought 2 million barrels of Southern Green Canyon crude from the US in April, the country's first import of the grade.

South Korean refiners began buying US crudes at the end of last year when GS Caltex, the country's second-

biggest refiner, bought US Eagle Ford crude. That was the country's first purchase of American crude other than condensate and Alaskan crude since Washington lifted a 40-year restriction on crude exports in late 2015.

The main driver of the change in crude flows into Asia this year is the strengthening of the Dubai crude benchmark, which most Middle East crudes are priced off, against the Brent and WTI crude benchmarks in the West, which make crudes from Europe and the Americas more price competitive to buyers in Asia.

This strengthening of the Dubai crude benchmark followed the November 2016 agreement by OPEC and key non-OPEC producers to hold production at 32.5 million b/d for the first six months of this year in a bid to arrest falling crude oil prices. This agreement, the first coordinated cut since the global financial crisis in 2008, was later extended by nine months to the end of March 2018.

The Brent/Dubai Exchange of Futures for Swaps, a key indicator of ICE Brent's premium to benchmark cash Dubai, has narrowed sharply since the start of the year, averaging 82 cents/b in the second quarter, down from $1.49/b in the first quarter, according to S&P Global Platts data.

This is down from an average of $2.31/b in the fourth quarter of last year, and is lower than the $2.94/b average for the whole of 2016. On a monthly basis, the EFS averaged at 73 cents/b in June, the narrowest since Platts started publishing the assessment in August 2011.

Dubai has commanded a premium to America's WTI crude benchmark for most of this year; a weaker WTI versus Dubai crude typically makes North, Central and South American crudes priced against WTI more competitive.

The spread between the front-month Dubai crude swap and the same-month WTI swap averaged at a premium of $1.28/b in the second quarter and 49 cents/b in the first quarter, Platts data showed.

In comparison, the spread between Dubai and WTI swaps averaged at a discount of $1.62/b in the fourth quarter of last year and minus $2.48/b for the whole of 2016.

Rising flows of non-traditional crudes into Asia, with the likely effect of decreasing dependency of crudes from the Middle East, have caused key suppliers in the Middle East to take notice.

While the Middle East remained China's top supplier by region for the first five months of this year, with a year-on-year increase of 4.7%, its market share fell to 44% from 48% over the same period.

Most noticeably, China received a record 1.97 million mt of crude from the US in the first five months of the year, compared to 72,339 mt in the corresponding period last year, according to data from the country's General Administration of Customs.

In Japan, crude imports from Middle East stood at 83.3% in May, down from 87.6% a year ago, marking the second consecutive month of year-on-year fall as the region's overall supplies fell from a year earlier except for Kuwait, according to data from Ministry of Economy, Trade and Industry.

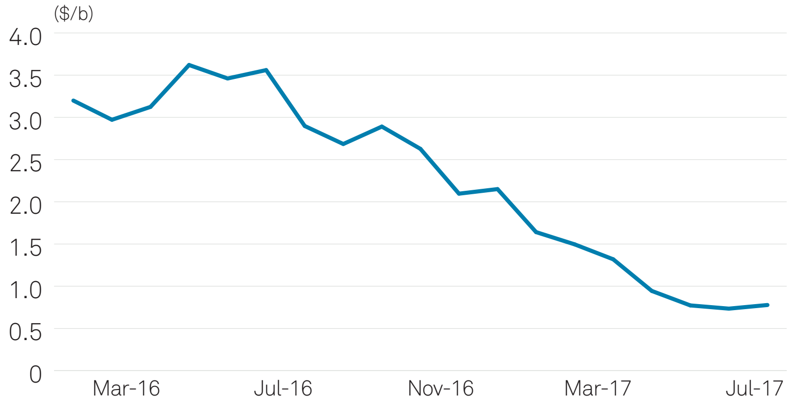
For the first five months of this year, Japan imported 2.6 million b/d of crude from the Middle East, edging down from 2.7 million b/d in the corresponding period of last year. However, Japan's crude imports from the US have grown 114% to 33,022 b/d in the first five months of this year from 15,440 b/d in the same period last year.

Similarly, South Korea imported 3.06 million barrels of US crudes in the first six months of the year, up from just 343,662 barrels in the same period last year, according to preliminary data by the Korea Customs Service.

The proportion of Middle East crude in the refiners' total crude imports remained largely steady at 85.3% over January-June, from 85.2% in the same period last year, highlighting South Korea's deep dependence on Middle Eastern crude. However, the proportion is expected to decline as South Korean refiners make more effort to diversify.

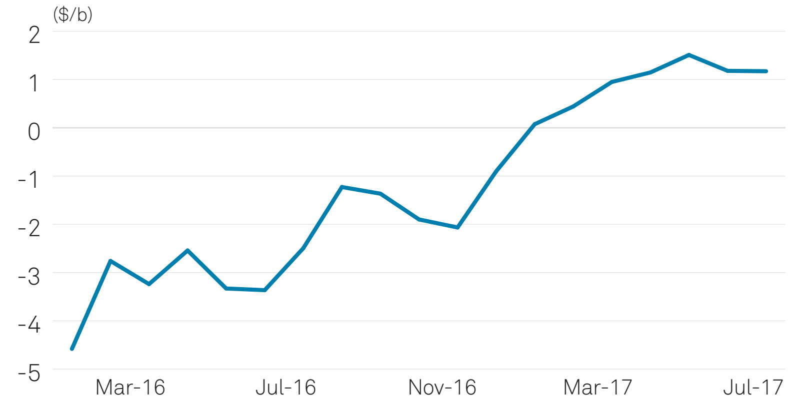
In a bid to retain their market share in Asia, Middle East producers have set the official selling price of crudes bound for Asia at competitive levels in the hope of staving off competition from arbitrage barrels, while term allocations to Asian refiners are little changed for the moment.

Brent/Dubai EFS



Source: S&P Global Platts

Dubai swap versus WTI swap



Source: S&P Global Platts

However, with the combined crude consumption of these key Asian countries representing a fifth of the world's total consumption, the recent changes in their crude procurement practices is giving their traditional major suppliers in the Middle East pause for thought.

Door opens for export, then closes

China's independent refiners find their new-found access to export quotas blocked within a year, but a ballooning domestic glut appears likely to pressure its reopening

By Oceana Zhou

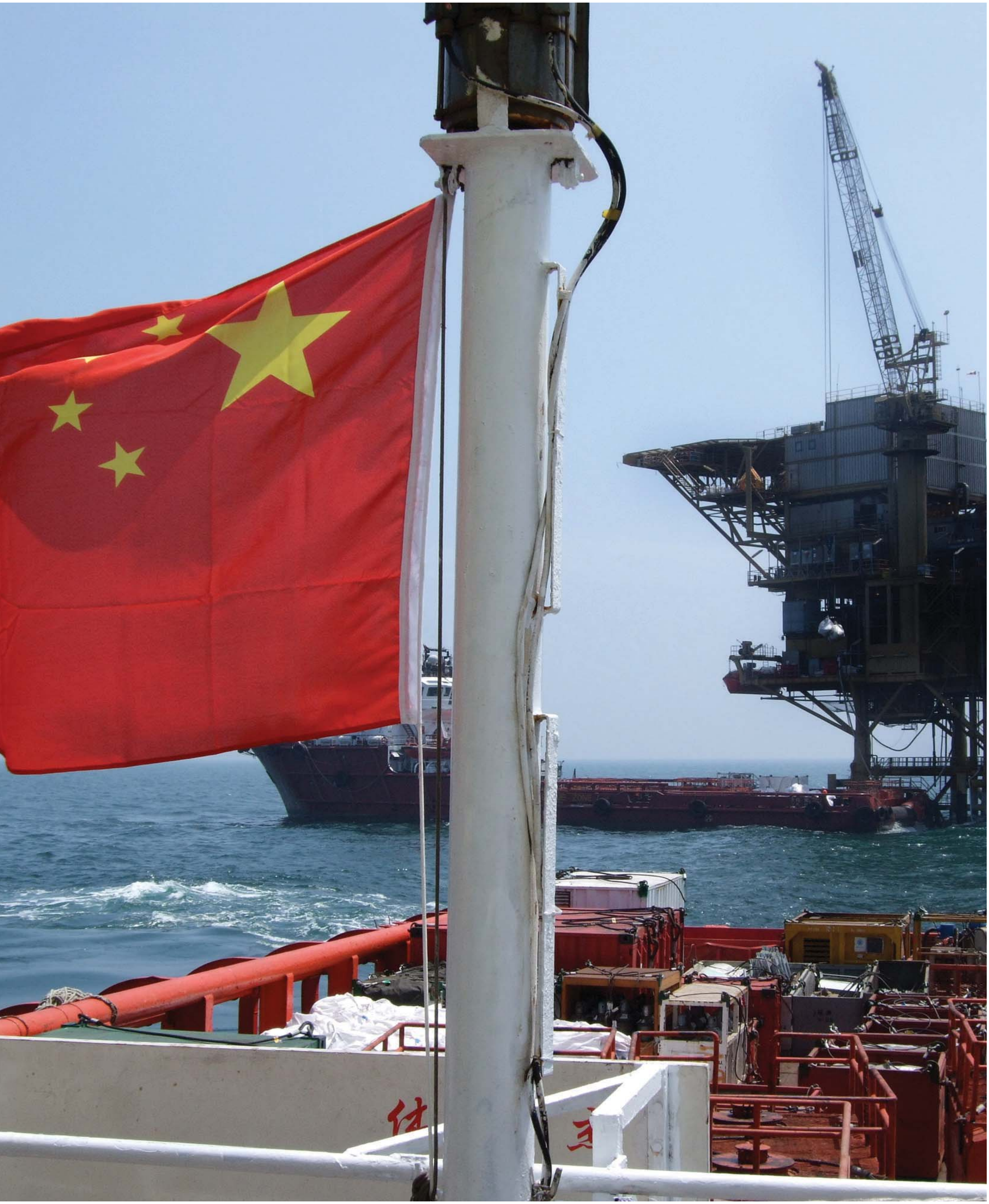
A year after joining the export bandwagon, China's independent refiners are finding their access to international markets blocked by Beijing's decision to stop awarding them export quotas. However, access is widely expected to be restored at some point as China grapples with a ballooning domestic surplus in the second half of 2017.

Twelve independent refiners were awarded quotas in 2016 under the so-called processing trade route to export 1.675 million mt of refined products, and subsequently exported a combined 900,000 mt of gasoline, gasoil and naphtha in the year.

While this volume was small, the move to allow independent refiners to export attracted the attention of the international market, as it was widely assumed this outflow would rapidly snowball.

This impression was fueled by independent refiners announcing plans to set up overseas trading arms, studying overseas oil product markets, and actively building trading networks and infrastructure in preparation.

In eastern Shandong province, home of China's independent refineries, the provincial government in late 2016 even released a plan to build seven new pipelines with a combined capacity of 44.5 million mt/year to send oil products from refining hubs to port.



But to date in 2017, Beijing has awarded export quotas only to the four state-owned oil refinery behemoths, and made no mention of the independents.

Policy observers attribute this to political wrangling over whether China wants to, or indeed should, become a major oil products exporter, as this would run counter to the government's high-profile plans to rein in excess refining capacity and clamp down on pollution.

While the wrangling continues, not only have no quotas been issued to independent refiners, but the quota volume for the state-owned ones has been capped at only slightly higher than total exports in 2016.

Independent refineries in China refers to those not built by state-owned oil majors China National Petroleum Corporation, Sinopec Group, China National Offshore Oil Corp and Sinochem Group, although CNOOC and Sinochem have acquired stakes in some independent refineries to meet their own strategic needs.

China exported a total 38.28 million mt of gasoline, gasoil, jet fuel and naphtha in 2016, and the total quota allocation for this year is widely expected to be below 39 million mt.

The quota is tight even for the volume that refineries under Sinopec and CNPC alone want to export, said sources from the two oil companies.

"The domestic market has been suffering from surplus and this has caused price wars in the retail market. Our stock level is high... We want to export more but quota is limited," said a PetroChina refiner under CNPC.

Both state-owned and independent oil companies have been actively lobbying the government for more export quotas this year.

However, there are no signs that the government will relax the controls, even though a research institute linked to the National Development and Reform Commission, China's top planner, recently proposed an increase in the total quota allocation.

While export controls may cap the country's oil products outflow, it does little to control excess refining capacity or China's rising crude oil imports, which are both factors contributing to the surplus in the domestic oil products market.

Moreover, the government has given the green light to several new refining projects in recent months, which will add further capacity and runs directly counter to moves to control exports.

"As the oversupply issue becomes more serious, issuing more quota looks like the only choice for Beijing to offset domestic pressure—at least allocate more quotas to the state-owned companies,"

said a Beijing-based state-owned trader with knowledge of the quota allocation process.

"Maintaining a stable domestic market is more important than any other target in China," said a Shanghai-based analyst. "To stabilize the domestic market, it is possible for a policy change to come suddenly as the government's decision-making is sometimes very quick," he added.

The surplus in the domestic market has triggered an unprecedented retail price war, with discounts of up to 20% being offered at the retail level, and even major player Sinopec involved in the discounting.

The current surplus can also be attributed to a liberalization of rules governing crude oil import quota allocations for independent refineries, which have had the effect of encouraging them to import and refine more crude.

In China, refineries that are not state-owned need to apply for a quota every year to import crude. State-owned refineries, including those run by CNPC, Sinopec, CNOOC and Sinochem, are granted quotas automatically.

To monitor the new crude oil import quota holders, the Ministry of Commerce adjusted the annual crude quota allocation to be in tranches in 2017 instead of one allocation for the year, as had been the case in previous years.

It said the first batch of import quotas for 2017 would reflect the applicants' imports over January-October 2016.

At first glance, that would appear to restrict independent refiners' crude imports.

However, the ministry indicated it would consider increasing the volumes of subsequent quota tranches if independent refiners could show they needed more crude to meet operational requirements.

Factbox: Processing trade route vs general trade route

- China allows oil product exports via two routes—the processing trade route and the general trade route —and issues separate quotas for the two.
- Under the processing trade route, there are no taxes on the oil products exported, but also no flexibility for the exporter.
- The exported product under this route must be refined from crude oil imported into China, must come from the specific refinery granted the export quota, and the seller of the crude oil must also be the buyer of the oil product, although it can later resell it.
- The state-owned refineries under the big four oil companies have mainly used this route for the past 10 years, while 12 independent refineries were also granted such a quota and exported about 900,000 mt products last year.
- Under the general trade route, quota holders can export oil products from any supplier in the domestic market, regardless of whether it was produced from domestic or imported crude oil.
- Products exported under this route incurred value added, consumption and other taxes until last November, when the government introduced rebates for VAT and consumption tax on products exported this way.

As a result, these refiners imported as much as they could in the first six months in order to secure higher import quotas in subsequent tranches.

Crude oil imports for independent refiners surged 68% to 1.99 million b/d in the first half of 2017 from 1.18 million b/d in the same period of last year, S&P Global Platts data showed.

Their utilization rate averaged 62% in the first half of 2017, jumping seven percentage points year on year, due mainly to the heavy crude imports encouraged by the new quota allocation rules.

This has resulted in a surge of oil products flowing into the domestic market at a time of modest demand growth in China. This, coupled with the tighter control on oil products exports, has triggered a rare retail price war.

The surplus is expected to intensify by 2020 as more new capacity is scheduled to come online. This includes PetroChina's 13 million mt/year Yunnan Petrochemical and CNOOC's 10 million mt/year expansion at Huizhou by end 2017, as well as independents Zhejiang Petrochemical and Dalian Hengli Petrochemical each bringing 20 million mt/year on stream by end 2020.

While there has been no export quota allocation to independent refineries this year, the recent resumption of quota allocations under the general trade route—one of the two routes for export—has enabled the four state-owned quota holders to, in theory, export barrels purchased from independent peers.

However, while the Ministry of Commerce allocated a total 8.21 million mt of export quotas under the general trade route in the first half of the year to the four major oil companies, almost all of it was used to export output from their own refineries.

The exception was Shandong-based Hongrun Petrochemical, which exported 53,000 mt of gasoline at end July, the first ever export by an independent refinery under the general trade route and the only cargo exported by an independent refiner to date in 2017.

It achieved this by utilizing its alliance with Sinochem to access Sinochem's allocation, and managed to negotiate the administrative and tax liabilities, setting a possible example for other independent refineries to follow, said a Beijing-based policy observer.

Theoretically, "independent refineries can sell products to general trade export quota holders in the domestic market with consumption tax and VAT, while the exporter with quota, who pays the taxes, will claim the export deal and get a refund a few months after the cargo is exported," the observer said.

However, whether this narrow window of opportunity will have any notable impact on China's flooded domestic oil products market remains to be seen.

Unified tax: a short-term pain

India's new GST looks set to inflict short-term pain on its oil and gas sector, but spur demand in the longer term if it boosts economic activity

By Sambit Mohanty

India has embarked on the gigantic task of embracing a unified tax structure across a wide range of goods and services. New Delhi has finally implemented the tax after years of debate on its economic and financial implications, but has decided to keep crude oil, natural gas and some oil products out of its purview for the moment.

The move will no doubt hit input costs of energy companies in the near term, thereby putting pressure on their balance sheets, but the general consensus is that it will do little to dent the country's steadily growing appetite for oil and gas over the longer term.

The Goods and Services Tax, or GST, is a unified indirect tax that has replaced various layers of taxes levied by the federal and provincial governments across India. It is expected to simplify the tax collection procedure, making it easier to administer and enforce, as well as help remove double taxation at various levels.

The GST came into force July 1, but the government has decided not to collect the tax on sales of crude oil, natural gas, gasoline, gasoil and jet fuel. LPG sales will be taxed at a rate of 5%, while naphtha and fuel oil sales will be taxed at 18%. Kerosene sold under the public distribution system will be taxed at 5% and in the open market at 18%.

While federal government officials have said that New Delhi would look into the possibility of bringing the five energy commodities under GST at a later date, it is widely expected that these products will remain outside the GST purview for at least a few years, in order to ensure a steady flow of revenue for the states from specific provincial taxes.

Pressure on oil firms

Oil companies, both state-run and private, have highlighted that the move to keep the five products out of the GST list could affect investments in infrastructure. This is because their input costs

would rise because of the GST, but they will not be able to pass on the added tax burden to consumers.

“The inclusion of some products under GST, but not all, will complicate the accounting process for downstream oil and gas companies,” said Rahul Prithiani, director, research, at CRISIL, a company of S&P Global.

“While a downstream player will pay GST on the procurement of plant, machinery and services for the production of petroleum products, it will not be able to claim input tax credit against the excise duty and value added tax paid on petrol, diesel and aviation turbine fuel as these products are outside the ambit of GST,” he added.

Petroleum minister Dharmendra Pradhan has assured oil companies that he would take up their concerns with the finance ministry.

“Oil companies will be bearing the additional tax burden if they can’t collect back taxes on product sales. That could lead to some losses. But the petroleum ministry is thinking of ways of how to neutralize the impact of those additional tax costs,” said a senior official at a state-owned oil company. “The government could offer incentives to oil companies on some other front.”

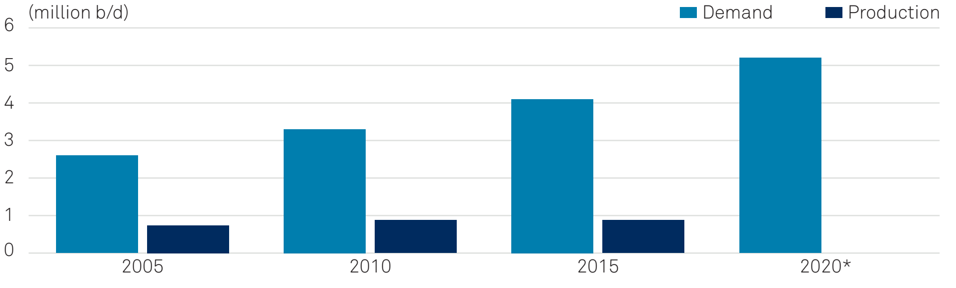
Analysts said the additional cost burden would be only temporary. GST will ultimately be positive for India’s oil products demand as it is expected to support broader economic activity and growth, which in turn would help give oil demand a boost.

Removing hurdles

Analysts have explained how GST would help to boost demand for gasoline and gasoil.

According to current industry estimates, trucks now lie idle for 30-40% of the time during their delivery schedule because of bureaucratic hurdles

India's crude oil demand to 2020



Source: CRISIL

*Forecast

and trade barriers between various provinces—such as paying entry taxes and local body taxes.

Once all these taxes get subsumed under the GST, it would cut a few layers of paperwork and help boost the utilization rates of truck fleets by operators.

Inter-state transit times are likely to fall further as border check posts get phased out, leading to an improvement in domestic freight traffic, which in turn would boost diesel demand growth.

And for gasoline, the market believes that the tax on SUVs could come down, which would eventually be positive for demand.

Some analysts, however, believe that the GST implementation could act as a double-edged sword—while it adds to inflationary pressures, it should help synchronize the complex tax structure prevailing in the country in the longer term.

But ultimately, GST would prove to be a boon for economic fundamentals, thereby helping oil and gas demand to grow. There was hardly any impact on demand when Malaysia introduced a GST on 97 RON gasoline in April 2015.

In Asia, one of the strongest pockets of oil demand growth is expected be in India, where, according to S&P Global Platts Analytics, demand growth is expected to outpace China's demand growth for a third year in a row.

While Indian demand is expected to grow 7% year on year to 4.13 million b/d in 2017, China's oil consumption is expected to rise 3% to 11.5 million b/d over the same period.

Indian upstream companies, such as Oil and Natural Gas Corporation Ltd., have expressed concerns that survey costs would rise as they would have to pay higher costs for the hiring of rigs and purchase of equipment. They would end up bearing additional costs because crude oil and gas would remain exempt from GST in the near future.

"Upstream companies will face the same issues as they cannot claim input tax credit on sales of crude oil as it is exempt from GST. In fact, upstream and downstream companies will have to absorb the additional costs, thus impacting their profitability," Prithiani said.

But market participants strongly believe that costs for upstream activity will not rise to an extent that would badly hurt those companies.

By their reckoning, since the government is keen to push up domestic production, it will find ways to ensure that upstream companies are adequately compensated to offset the impact of GST.

Extracting gas from undersea ice

Japan is targeting commercial methane hydrate output as early as the 2030s, at a production cost competitive against importing LNG, a senior government official says in this interview

By Takeo Kumagai

With progress being made in its second round of offshore production tests of methane hydrate, Japan—one of the world's major fossil fuel-consuming nations—remains committed to developing natural gas from icy deposits of hydrates below the seabed.

The development of methane hydrate offers Japan a potential domestic source of energy free of geopolitical constraints, and Tokyo sees it as "highly valued for the energy security," Daisuke Hirota, principal deputy director of the oil and gas division at the Ministry of Economy, Trade and Industry, said in an interview with S&P Global Platts.

"On the other side, there are many issues, including on technology as well as [lowering] costs for bringing it into a commercial basis; it is important that we take one step at a time," Hirota said.

Although there are a number of technical barriers to methane hydrate production, such as achieving sufficient flow rates to reduce output costs, known resources could be large enough to meet Japan's demand for about 10 years, based on its estimation of 40 Tcf of methane hydrate resources in place in the southern Sea of Kumano in 2007.

Commercialization of methane hydrates would involve extracting water and methane gas from dissolving solid, ice-like hydrates located deep underwater where cold temperatures and extreme pressure cause gas to condense and solidify.

Japan in late June completed a second series of production tests of pore-filling type methane hydrate offshore central Japan, with the second well producing a total of 200,000 cu m of natural gas over 24 days.

"We believe we have achieved certain results," Hirota said. "On the other hand, the production rate was lower than the first round, and there are technological

Courtesy MH21 Research Consortium

issues needed in the sense of technology to stabilize output, with a view to commercialize production."

METI ended its flare-test of gas extracted from methane hydrate from the second production well as planned on June 28, after having restarted the production test on June 5.

The offshore production test was restarted using the second well, after decreasing pressure in that well, after the output test at the first well was halted due to a massive inflow of sand.

After starting its flare test on May 4, Japan produced around 35,000 cu m of gas over 12 days at the Daini-Atsumi Knoll in Nankai Trough, 80 km (50 miles) south of the Atsumi Peninsula in Aichi prefecture.

Unlike the first well, which had used different sand control measures, the second well did not experience any inflow of sand, but neither did it see a clear increase in production rates during the output tests, METI said.

Japan drilled the two production wells to reach layers containing methane hydrates about 300 meters below the seabed at a water depth of around 1,000 meters.

This was the second round of offshore methane hydrate production tests globally after Japan produced 120,000 cu m, or 20,000 cu m/day, of gas from methane hydrate at an earlier offshore production test at the Daini-Atsumi Knoll in March 2013. That first output test was stopped after six days—though it had been planned to run for two weeks—due to an inflow of sand into the sole production well.

After the 2013 offshore production test, Japan adopted a decreasing pressure system for the second round of methane hydrate output tests in 2017, in which it used shape memory polymers as sand control measures in the two production wells, and drilled two monitoring wells to record changes in temperatures and pressures in different seabed layers during the production test.

State-owned Japan Oil, Gas and Metals National Corp., or Jogmec, is leading the methane hydrate output test for METI. Operator Japan Methane Hydrate Operating Co., a joint venture of 11 Japanese companies, chartered the Chikyu drilling ship.

The second round of offshore production tests is now estimated to cost a total of about Yen 25 billion ($226 million at end of July) for producing from two wells, as well as plugging and abandoning the production wells in fiscal 2018-19, according to METI.

Following the end of this series of offshore production tests, METI will scrutinize results with external experts from autumn and aim to decide on a final draft of Japan's road map for commercializing methane

Courtesy MH21 Research Consortium

hydrate output, as the Japanese government will be reviewing its five-year Basic Plan on Ocean Policy that will expire at the end of March 2018, Hirota said.

Under the current five-year plan, Japan aims to build technologies targeted at achieving commercialization by fiscal 2018-19 (April-March) and start a private-led commercial project in the late 2020s.

"The issue of production rate, and whether the result [of the second production test] was to do with technology, the geology or the location to be the watershed" were being scrutinized to decide on the road map, Hirota said.

Japan, currently the world's largest LNG importer, aims to commercialize gas production from pore-filling type methane hydrate in the country in around 2030-40s but will seek a flexible approach with its reviews on the status of progress under its road map, Hirota said.

Under a new methane hydrate development road map plan presented by METI at its energy policy meeting on June 21, Japan has placed a "gate" to review the progress of each phase of pore-filling type methane hydrate development every four to six years beyond fiscal 2018-19.

"In the event of making no progress, it gives us an opportunity to think about whether to make steps back greatly to basic research, or even face a situation of giving up," Hirota said.

"Basically we are firmly committed to proceeding this, but we should also be flexible with our approach and not forcibly balance the accounts," he said. "This is about checking at each juncture, any of which could also result in taking a step back."

Road map

Under the new methane hydrate development road map plan, Japan plans to spend the next four to six years from March 2018 verifying technical issues for stable production.

During this phase, Japan will consider gaining experience in drilling from working with the US on onshore methane hydrate output tests in Alaska, or consider running offshore production tests with India, Hirota said.

Japan will then spend the next four to five years considering options to run mid- to long-term offshore methane hydrate production tests using multiple wells, then start a pilot project for commercialization in the following five year period.

With a view to commercializing methane hydrate production, METI said June 21 that Japan should aim for production costs of around \$6-\$7/MMBtu to be competitive against Japan's LNG import prices of around \$11-\$12/MMBtu in the 2030-50s, as forecast by the International Energy Agency and the US Energy Information Administration.

The target production costs of around \$6-\$7/MMBtu are based on the assumption of a production rate of more than 150,000 cubic meters/day per well in a concentrated zone with more than 50 billion cu m, or 2 Tcf, of in-place resources, METI said.

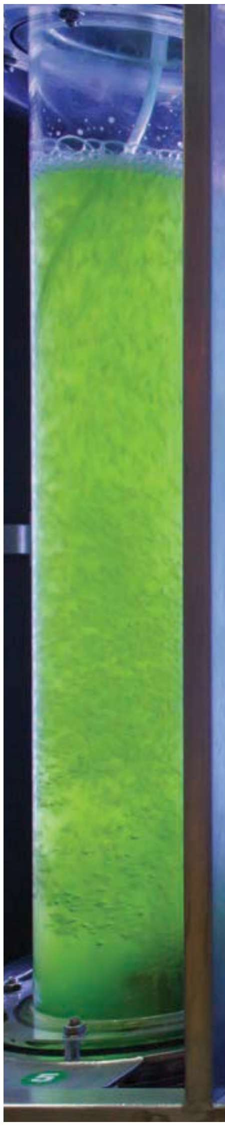
"Unless we are aiming for this level at least, we believe we will not be able to match," said Hirota, referring to market expectations of gas prices staying low for longer than oil prices. "In that sense, we cannot optimistically look at production costs of \$12/MMBtu."

"In order to achieve this, we will verify what went wrong [in the second offshore production test] and whether it was to do with the location or technology," he added.

No turning back: UK biofuels after Brexit

The UK's decision to leave the European Union leaves the country's biofuel and agriculture sector facing uncertain times

By Tim Worledge

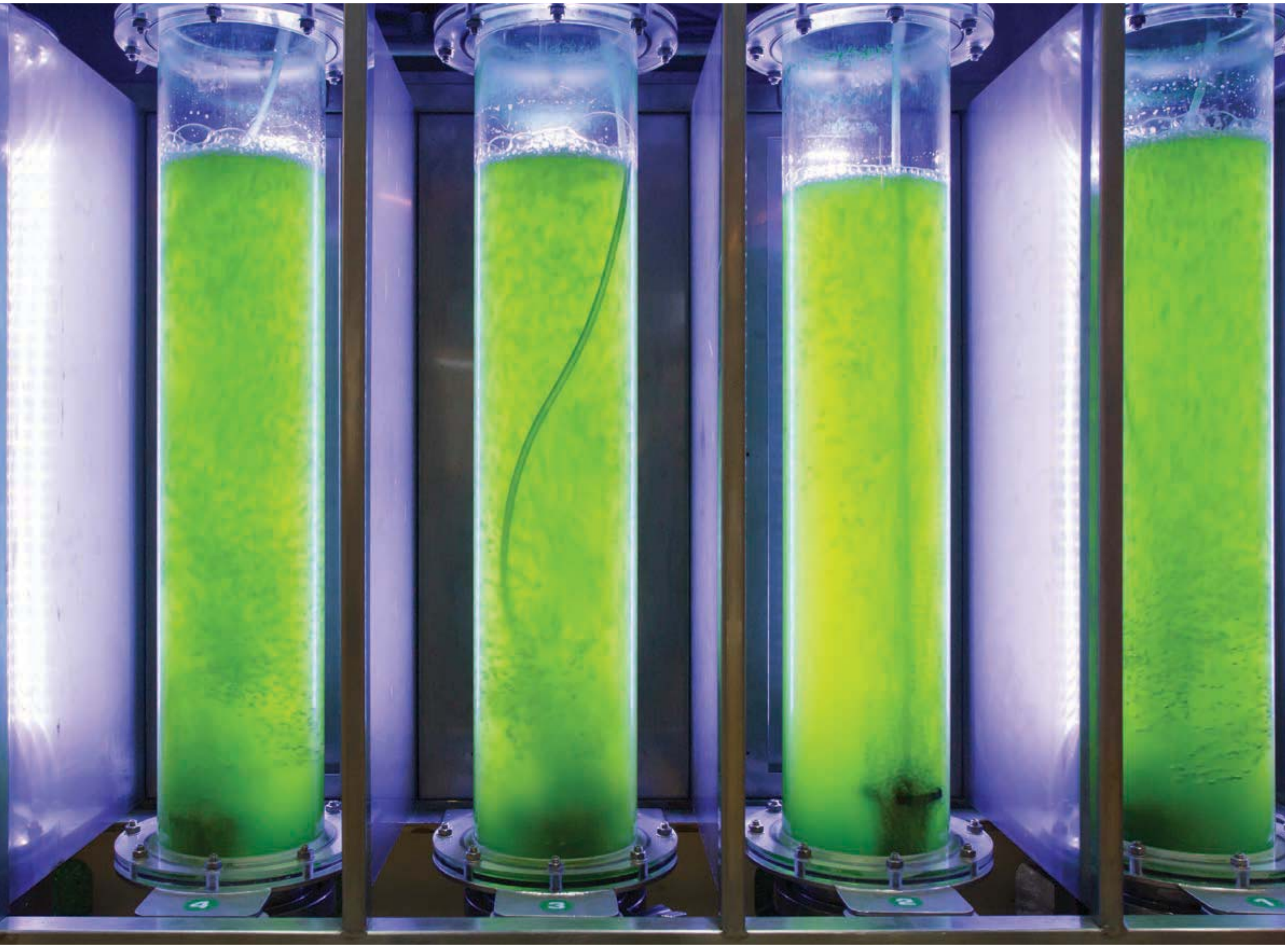


Maybe Marx had it the wrong way round. History may well repeat itself, but recent headlines lead one to think that farce is now the first incarnation. Take the UK's decision to exit the European Union. It's nearly 18 months since the nation delivered its shock verdict in the referendum, and that's a long time in politics.

Much has happened since June 2016, when the referendum offered a simple Yes/No answer to a complex question. In March 2017, the government triggered the fabled Article 50 of the Lisbon Treaty, the clause enabling a country to notify the bloc of its intent to leave. A two-year countdown was initiated; the clock is ticking. Doubtless the incumbent Conservative government, under Theresa May, started with every confidence that it had both mandate and mission. Brexit meant Brexit, and the country was primed to start on the front foot.

However, infighting quickly dogged government appointments and a gamble on a general election—intended to deliver strong and stable government through the negotiations—backfired dramatically. Democracy has a sense of fun, and having voted for Brexit, the UK electorate duly hamstrung the ruling party charged with delivering it by removing its handsome majority. In its place came a slim minority government forced to rely upon the kindness of strangers.

With negotiations barely underway and concerns rapidly mounting, a former UK diplomat stated in August, in classic British understatement, that early talks 'have not begun well'.



Life in the fast lane

Biofuels is a sector that has relied almost entirely on government will to ensure clear adoption—and in EU terms that has come from the Renewable Energy Directive. The legislative framework sets out a road map for biofuels through to 2020 and states that 10% of all transportation fuels must be renewable.

Countries are left to figure out how to do that, and here the UK's green credentials are generally considered to be solid. Many EU initiatives are already written into UK law and will survive beyond Brexit. The UK has a diverse biofuel industry including one of Europe's largest ethanol plants, CropEnergies' Ensus facility in Northeast England.

The UK has also set out its own ambitious plans to slash carbon dioxide emissions, aiming to shave 57% off 1990 emission levels by 2032, and slash 80% off by 2050.

Biofuels already contribute 3% of the fuel mix for its 36 million cars, accounting for some 1.2 billion liters of biofuel in 2016, with S&P Global Platts biofuels analysts expecting that to rise to 1.5 billion liters in 2017. Around 28% of that supply is homegrown, according to the Department for Transport, with the rest imported from as far afield as the US and as close to home as France.

While the UK government remains supportive of biofuels in cutting emissions, it's become clear that other measures must also be considered.

The government pledged it would ensure all new cars were carbon neutral by 2040 before going one step further in July 2017 and matching France's ambition of banning diesel and petrol-powered cars by 2040.

Even if attained, the liquid fuel pool is likely to linger for decades after 2040, but demand could shrink rapidly. How you maintain healthy investment under those conditions remains to be seen. Meanwhile, EU antidumping legislation covering biodiesel and US ethanol may be swept away upon departure, potentially bringing new trade flows to the UK's shores.

Sugar rush

According to the Department for Transport, sugar beet or cane provided just under 10% of the UK's ethanol supply between April 2016 and April 2017. Beet has one of the best emission ratings for greenhouse gases (GHGs), but Brexit is one of two shocks to rattle the UK's sugar heartlands.

Europe's dominant sugar beet sector has enjoyed a protected environment of the type that drew punishment from the WTO. Limits on the bloc's capacity to export will be swept away on October 1, 2017, as the sector dismantles protected payments and guaranteed prices to beet farmers.

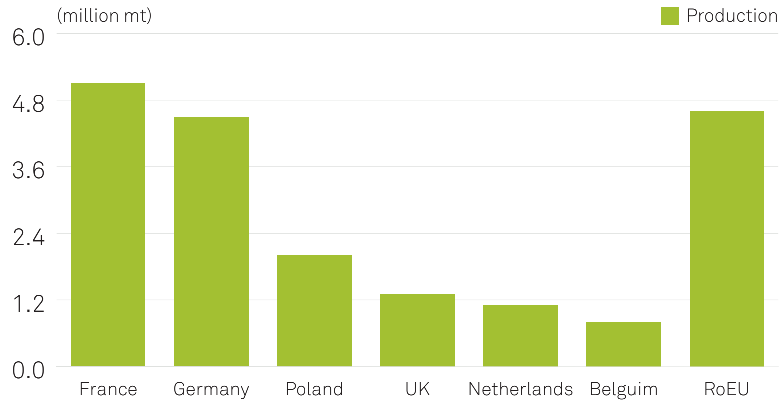
The UK is the fourth biggest producer of sugar in the EU, but the decision to leave has deepened tensions with the other portion of the UK's sugar complexion—the cane refiner.

London is home to Tate & Lyle's 1.2 million mt Thames refinery and the debate around deregulation of the beet sector pitched refiner and beet farmer into starkly contrasting positions, which then bled into the debate around EU membership.

For the cane refiner, deregulation meant an extension of what it saw as an unfair advantage being handed to beet producers. Leaving the EU heads off that inequality.

For UK farmers, beet economics may not be as good as once they were. After the Brexit vote some were concerned that the plunge in the pound's value meant exports would look more attractive and keep imports at bay. But the impact of rising fuel costs has hit farmers' margins. Beet is already seen as one of the weaker gross margin crops and some in the industry see little scope for further cost-cutting efficiencies as they face down competition not from France or Germany, but from within.

Britain's place in the EU sugar sector 2014/15



Source: S&P Global Platts

If the CAP fits

Another concern is how to replace the Common Agricultural Policy. Agriculture has always had an innate link to government—history is littered with examples of what happens when a populace either runs out, or thinks it's about to run out, of food. From the EU's earliest days farming has had a place at the top table.

UK farms get £3 billion under the CAP, while the EU provides 70% of the country's food imports and takes 62% of exports according to a 2016 report from the UK's Department for Environment, Farm and Rural Affairs.

Elements of the CAP are slowly being picked apart—the EU's dairy sector deregulated in 2015, EU sugar in October 2017—but the core twin goals of subsidizing farmers and preventing imports through duties make the program expensive to run and inflates food prices. Its loss, or at least its reform, has been seen as inevitable but replacing that £3 billion is a challenge.

A recent UK ministerial visit to the US saw the meat industry licking its lips at the prospect of access to the UK's markets, but prompted a flurry of nervous headlines decrying cheaper chickens dipped in chlorine wash and steroid-inflated beef. But there are positives too.

The EU has taken a strong position in banning genetically-modified organisms in agriculture and a stance on some pesticides has raised concerns that yields could stagnate, or even fall. Freed of EU rules, the UK could work more comfortably with GMO crops and potentially bolster yields—something that could be a significant factor as land use faces increasing competition.

Welcome to the Hotel California

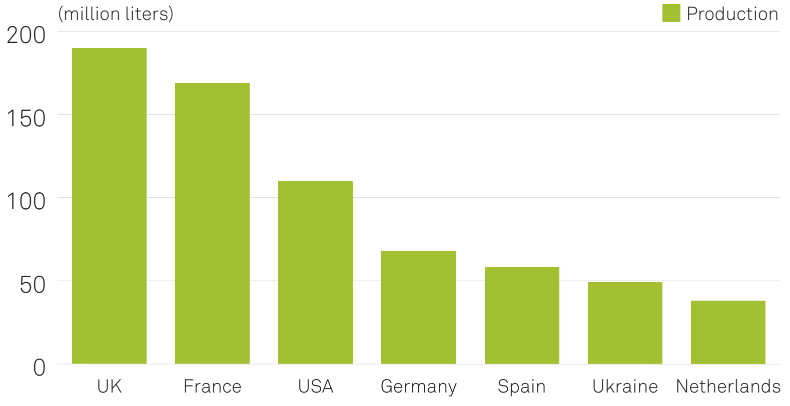
"You can check out any time you like, but you can never leave," quipped Greece's former finance minister Yanis Varoufakis on the subject of the UK's efforts at leaving the EU. Eighteen months on, and the To-Do list continues to grow, while progress is hard to discern.

The sheer complexity of separating two intimately entwined and interdependent economies is starting to become apparent, but both parties—the UK and the EU—now seem determined to see it through. March 2019 will be the ultimate test; keep the pink champagne on ice.

A tale of three currencies:
US dollar, British pound, Euro 2016-2017

Source: S&P Global Platts

UK biofuel supply (April 2016-April 2017)



Source: UK Department for Transport

China's coal conundrum

Despite high-profile efforts to diversify away from fossil fuels into renewable energy sources, China's appetite for coal continues to surprise

By Mike Cooper

Anyone with doubts about China's seemingly insatiable appetite for thermal coal to sustain and expand its gigantic economy should cast their eyes over the latest power generation data from Beijing's National Bureau of Statistics.

It reveals a treasure trove of indicators about the country's appetite for thermal coal, sourced both domestically and from major suppliers like Australia, Indonesia and Russia.

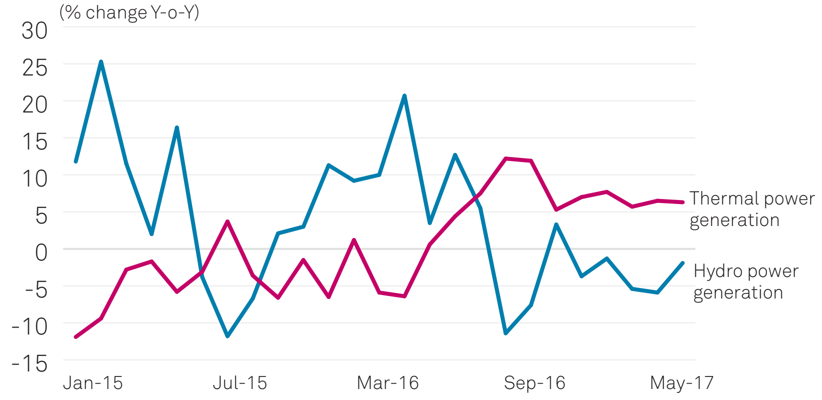
China's thermal power generation is dominated by coal, and output rose 4.5% to 371 billion kWh in June from 355 billion kWh in May, NBS data showed.

Importantly, the rate of year-on-year increases in China's electricity generation from thermal coal has been running at an average of 7% over June 2016 to June 2017, having peaked at 12.2% last September, at a time when domestic thermal coal prices in China were surging.

The persistently strong growth rate of electricity production from thermal coal in China is counter intuitive to most commentary on the country, which points to renewable energy sources eroding coal's share of the generation mix in China.

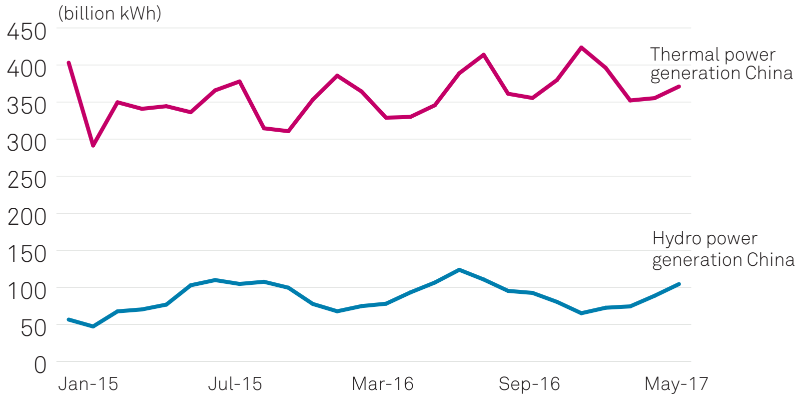
Some energy market analysts have been quick to write off China's growth potential as a market for thermal coal exports, advancing the argument that it is diversifying away from fossil fuels and into other energy sources such as solar and wind.

Year-on-year change in China's hydroelectric and coal-fired power generation output



Source: China's National Bureau of Statistics

China's hydroelectric and coal-fired power generation output



Source: China's National Bureau of Statistics

However, while it is true that wind, solar and other renewable energy production is rising in China, it is from a very low base.

Hydroelectric generation has not lived up to expectations and has recorded negative growth for five straight months since last November, based on NBS data.

China's hydroelectric sector generated 104.4 billion kWh in June and 88.6 billion kWh in May, down 4.9% and 2.3% year on year respectively, according to NBS data.

Hydropower generation in China typically surges mid-year, but in 2017 the uptick has been muted.

"Hydro was weak in June compared to last year," said one China energy market analyst. "China is experiencing very hot weather, so demand for coal is very strong," he added, noting this may retreat in subsequent months if there was significant rainfall.

Flagging hydropower generation has meant that China has had to maintain strong baseload generation from thermal coal to fuel its industrial base and keep the lights on in the megacities of Guangzhou, Shanghai, Shenzhen and Tianjin.

China's seemingly unquenchable appetite for energy from thermal coal has seen prices for seaborne-traded cargoes of 5,500 kcal/kg NAR grade thermal coal landed in China's southern ports surging almost 15% to $78/mt in mid-July from $68/mt CFR South China in early June, according to S&P Global Platts prices.

Indeed, it seems from an analysis of Platts prices that $70/mt CFR South China has become a new support level for 5,500 kcal/kg NAR thermal coal prices, after a rebound from January's Lunar New Year holiday lull.

China's government has tried various ways to tame wild price rises in its domestic thermal coal market in recent months, conscious of the effect they have on input costs in its domestic economy.

Beijing's mettle was tested in the second half of last year when FOB prices at Qinhuangdao port for domestic 5,500 kcal/kg NAR

thermal coal peaked at a US dollar equivalent price of $96/mt in mid-November, according to Platts China Coal price or PCC data.

Rising domestic thermal coal prices are keenly watched by traders as they open the door to more imports from Australia, Indonesia and Russia.

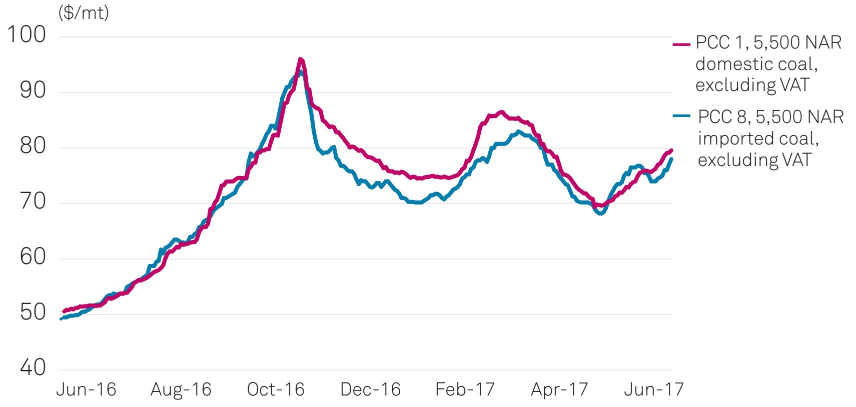
Last November's price rally for domestic thermal coal was fueled by supply restrictions imposed by Beijing earlier in the year, but their effect was quickly compounded by robust demand for power from China's industrial base and prices took off in a steep trajectory.

In order to bring prices under control, Beijing relented on its production controls for the domestic coal sector and the market stabilized over December to March, before going on a short-lived upturn in April.

Beijing tried a different policy measure in late June, this time turning its attention to the import trade, with 10 second-tier Chinese ports suddenly telling customers they would be unable to handle cargoes of imported thermal coal for six months.

Word of the informal embargo stunned participants in the seaborne trade, but after a couple of weeks the market settled down as buyers found different ports to bring imported cargoes into China.

PCC 1 and PCC 8 prices for China excluding taxes



Source: S&P Global Platts

The resilience of China's demand for thermal coal in the face of unpredictable Beijing policy changes has surprised some observers and market players, while others with a long time in the business have become accustomed to its vagaries.

Commenting on the robustness of China's coal import market after the various twists and changes to central government policy over the years, one veteran trader said dryly: "Beijing has run out of things to do."

Imports are highly valued in China's huge thermal coal market, as they provide an alternative fuel source for coastal power plants in competition to domestically-produced thermal coal, which has had a volatile price record in recent years. China's domestic coal sector is also content to live side-by-side with the trade in imported cargoes.

"Domestic coal producers want import prices to rally so they themselves can charge higher prices," one trader said.

This seemingly widely-held view should provide some fuel for thought to those who argue that China's thermal coal trade is running on borrowed time.

Shipping on course for LNG bunkering

Shaping up as one way to comply with IMO's 2020 global sulfur cap

By Surabhi Sahu

Despite skepticism in some quarters, LNG bunkering is set to play a key role in compliance with the International Maritime Organization's 2020 global sulfur cap. What there is no doubt about is that there will not be enough gasoil and scrubbers to meet demand for 0.5% sulfur-compliant marine fuels when the cap is imposed in less than three years' time.

"2020 creates a new reality—creating potential threats, but also an opportunity that can help reposition shipping. For the brave, there is an opportunity to take this and do something different," Lauran Wetemans, general manager of the downstream LNG and LNG fuel division at Shell, said at an industry event in March.

"We believe that 10-20% of all bunker fuel oil could switch to LNG by 2030," he said at the time.

Most LNG variants have no detectable sulfur, and emissions of particles and nitrogen oxide by LNG-fueled vessels are considerably lower than that of vessels using other marine fuels.

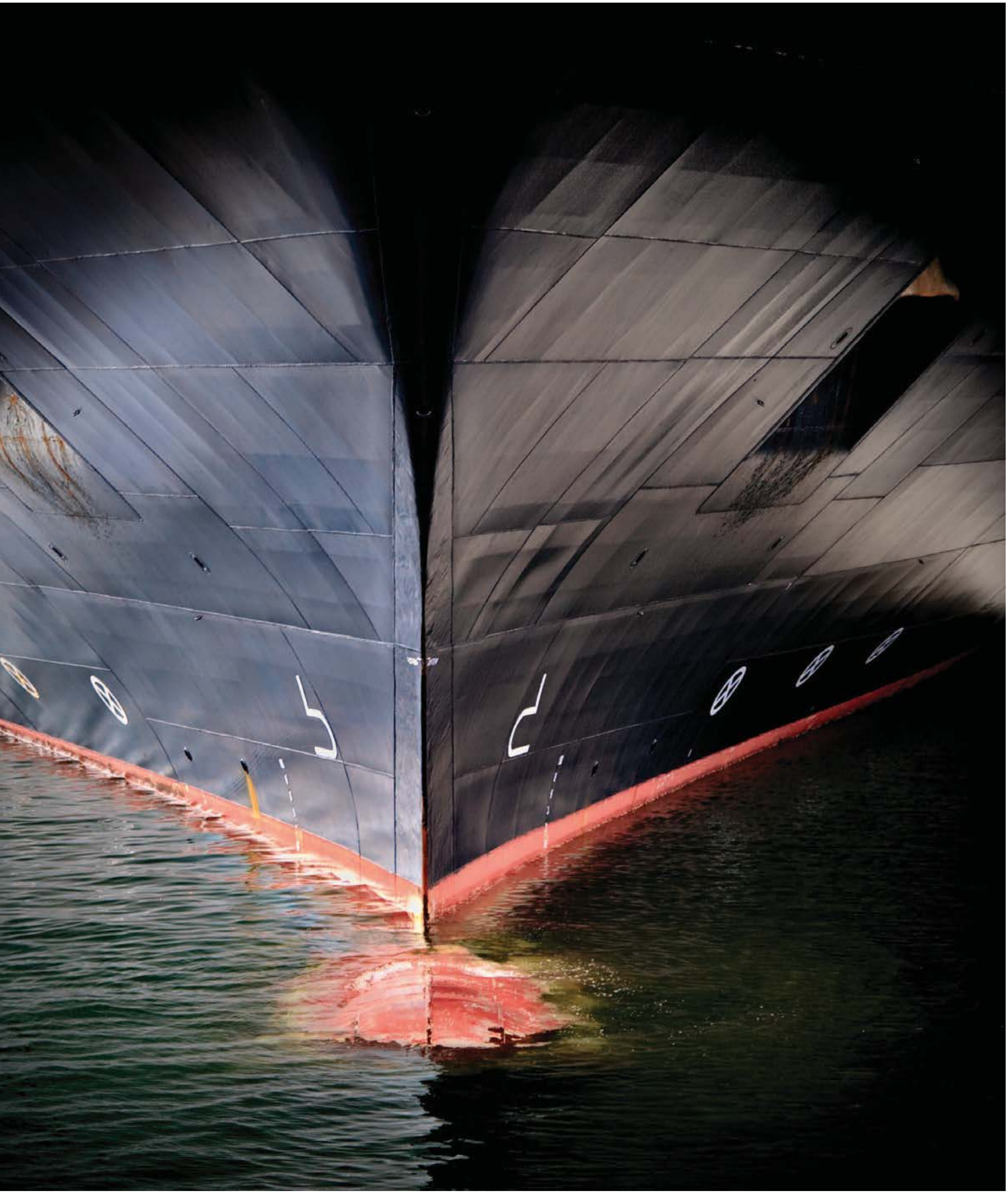
LNG's growing importance as a potential marine fuel is not only being reflected in an increasing number of organizations that have already joined or are planning to join industry coalitions such as SEA\LNG and the Society for Gas as a Marine Fuel to accelerate its use, but also by an ever growing number of bunker suppliers who want to expand their marine fuel oil portfolio to include LNG bunkering.

"The company and our group are very interested in moving into essential markets such as LNG bunkering," George Kounalakis, Managing Director Asia at BMS United Bunkers, told S&P Global Platts in an interview in July. "We will follow market demand. The group has strategically looked at physical expansion and LNG bunkering."

Ample LNG supply, due in part to burgeoning production from the US, means that fundamentals will not restrict its availability for bunkering.

Favorable pricing economics, further development of LNG infrastructure and technology, and harmonization of standards and procedures, are expected to give it a further boost.

The economics of LNG as a marine fuel hinge on several



factors, including the region in which the vessel operates, the life of the ship and most importantly, its relative price to other fuels.

A spread of $1-$6/MMBtu with a core $2-$4/MMBtu to marine diesel oil is likely to be required to promote its use as a marine fuel, John Harris, principal consultant at Enerdata, said at a PetroMin event in July.

Asian LNG spot prices at around $5.50/MMBtu in mid-July mean that after allowing for infrastructure and logistics costs, the LNG-MDO spread is only marginally higher than $2/MMBtu, making the economics of using LNG for bunkering marginal, he said.

However, spot LNG prices are expected to come down as supply availability grows, some sources said, adding this was expected to prompt some ship operators and owners to switch to its use.

Another aspect tilting in its favor is its increasing commoditization. Traditionally LNG contracts have stretched for 20 years or more. However, long term contracts are now giving way to more short-term arrangements, providing buyers with some flexibility in procurement, particularly at a time when shipping is facing strong headwinds due to a supply overhang and weak global macroeconomics.

Singapore, the world's largest bunkering port, has been at the helm of the initiative to promote LNG bunkering.

In 2016, the Maritime and Port Authority of Singapore, or MPA, awarded two LNG bunker supplier licenses to Pavilion Gas and a joint proposal from Keppel Offshore & Marine and BG Group.

"MPA will work with the two license holders to develop the necessary infrastructure for them to begin supplying LNG bunker to vessels in the Port of Singapore by early 2017," it said in a statement in January 2016.

Key first step

In April 2017, Singapore LNG Corp. and the MPA jointly launched the city-state's first LNG truck loading facility, an important first step in developing the LNG trucking business in Singapore, helping to facilitate truck-to-ship LNG bunkering in Singapore.

Singapore in April also launched its first technical reference—TR56—for LNG bunkering, which essentially is aimed at providing a safe and efficient framework for conducting LNG bunkering operations in Singapore.

Other ports in Asia are also making efforts to promote LNG bunkering.

A focus group, which was first formed in 2014 by the Maritime and Port Authority of Singapore, the Antwerp Port Authority, the Port of Rotterdam and Port of Zeebrugge, now consists of 11 ports and maritime administrations across Asia, Europe and North America, after China's Ningbo- Zhoushan port, the Port of Marseille Fos and Port of Vancouver joined the group in July.

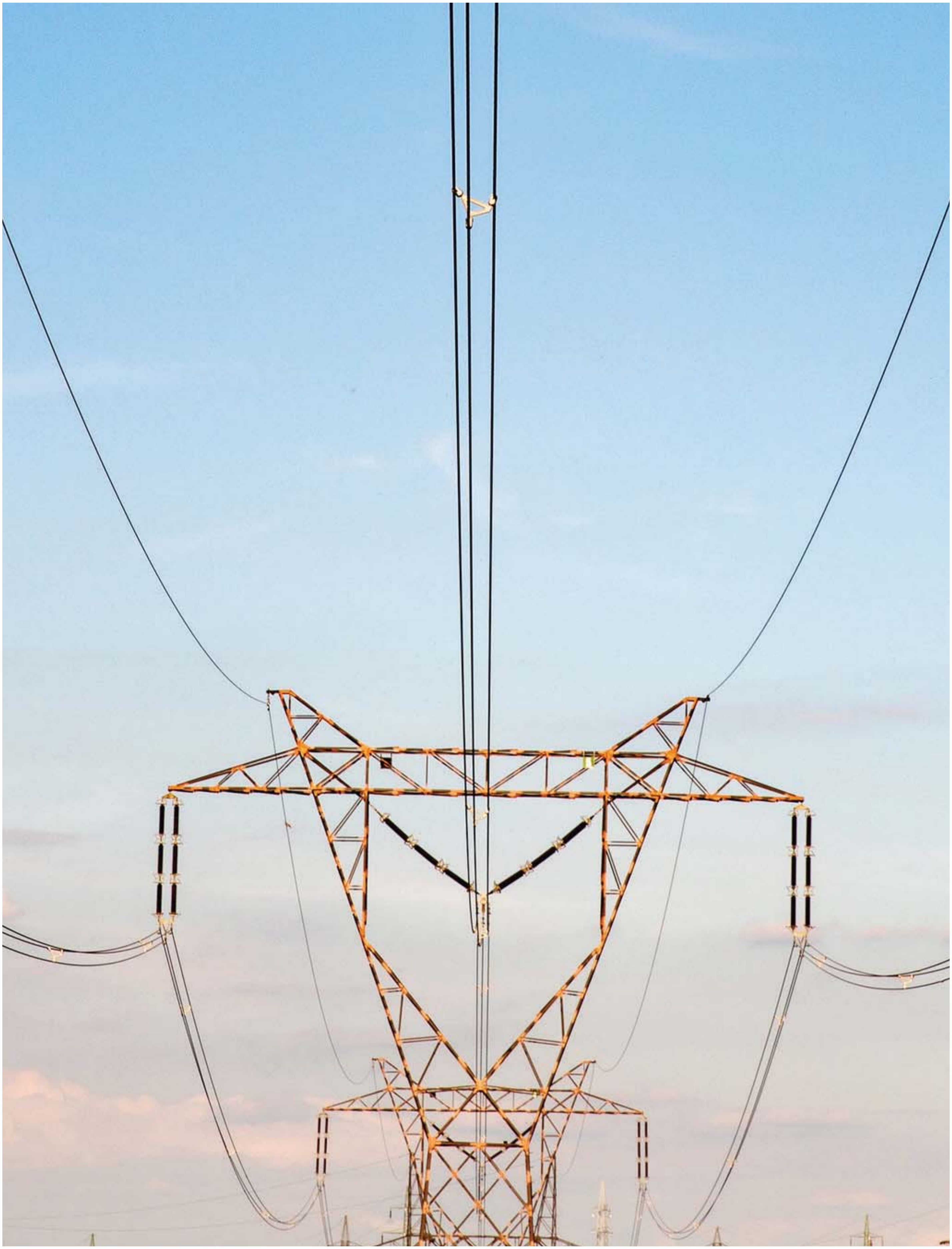
Japan's Ministry of Land, Infrastructure, Transport and Tourism and South Korea's Ulsan Port Authority became a part of the group in 2016.

Japan, the world's largest LNG importer accounting for about 35% of global demand, carried out a feasibility study for the development of an LNG bunkering hub at the port of Yokohama on its Pacific coast, which serves as a bunkering base on the Asian side of the Trans Pacific route.

A report by Japan's Ministry of Land, Infrastructure, Transport and Tourism last December set out a three-phase road map for the development of an LNG bunkering base. Phase I has already started with the introduction of truck-to-ship bunkering, it said.

India's LNG bunkering plans are on a fast track, with LNG-fueled river sea vessels and LNG refueling stations likely to emerge in the coming months, Arun Sharma, executive chairman of the Indian Register of Shipping or IRClass, a Mumbai-based globally recognized ship classification society, told S&P Global Platts in June.

Promoting LNG in the country's inland waterways would not only result in a lower cost per ton mile transported than other options such as road and rail but would also be significantly more environmentally friendly, Sharma said.



Changing of the guard

Gazprom ends ExxonMobil's 12-year reign at No.1, but the real story is utilities and pipelines

By Harry Weber

Commodity price volatility, geopolitical shifts and industry consolidation made investors seek out safe havens in 2016 in the form of strong returns on invested capital, long-term fixed fees, regulatory stability, and access to regional and world markets.

That helps explain why utilities and pipelines were able to differentiate themselves from other sectors, even as some operators struggled to boost revenue and underwent major transformations that included operational and management changes.

Integrated oil and gas companies continued to be in the mix, especially those that have made big bets on US shale plays in Texas and the Northeast and have streams of customers that are heavily reliant on their services, for power generation, to heat homes and to run trains, buses and automobiles.

But growing exports of LNG and oil from the US changed the state of play in the energy landscape, giving way to new entrants in the global pecking order.

"Utilities, by their nature, are natural monopolies, because obviously you don't have competing wires coming into your house. The government agencies allow them to make a profit over their costs," Ed Hirs, an energy economist at the University of Houston, said in an interview. "In an environment like we have had this past year, those companies such as ExxonMobil and Chevron who are exposed to the commodity price environment, you would expect them to fall behind versus those companies that have a government license to make a profit."

This year's S&P Global Platts Top 250 Global Energy Company Rankings® show that European utilities and North American pipeline operators were among the biggest movers upward, beneficiaries of their willingness to stick to what they know best and shy away from more risky enterprises and territories.

The advancement was not even across the sectors, with Asian gas utilities falling in the rankings. And some of the diversified energy majors slipped as the world oil price rout continued amid strong

S&P Global Platts Top 50 Companies 2017 vs. 2016*

Platts Rank 2017	Platts Rank 2016	Company Name	State or Country	Region	Industry
1	3	PJSC Gazprom	Russia	EMEA	IOG
2	114	E.ON SE	Germany	EMEA	DU
3	8	Reliance Industries Ltd	India	Asia/Pacific Rim	R&M
4	2	Korea Electric Power Corp	South Korea	Asia/Pacific Rim	EU
5	13	China Petroleum & Chemical Corp	China	Asia/Pacific Rim	IOG
6	6	PJSC LUKOIL	Russia	EMEA	IOG
7	14	Indian Oil Corp Ltd	India	Asia/Pacific Rim	R&M
8	5	Valero Energy Corp	Texas	Americas	R&M
9	1	Exxon Mobil Corp	Texas	Americas	IOG
10	12	TOTAL SA	France	EMEA	IOG
11	20	Oil & Natural Gas Corp Ltd	India	Asia/Pacific Rim	E&P
12	63	PTT Plc	Thailand	Asia/Pacific Rim	IOG
13	25	China Shenhua Energy Co Ltd	China	Asia/Pacific Rim	C&CF
14	33	PJSC Transneft	Russia	EMEA	S&T
15	156	Centrica plc	United Kingdom	EMEA	DU
16	54	SSE plc	United Kingdom	EMEA	EU
17	15	Enterprise Products Partners LP	Texas	Americas	S&T
18	19	NextEra Energy, Inc	Florida	Americas	EU
19	21	Iberdrola, SA	Spain	EMEA	EU
20	4	Phillips 66	Texas	Americas	R&M
21	55	SK Innovation Co, Ltd	South Korea	Asia/Pacific Rim	R&M
22	7	PJSC Rosneft Oil Co	Russia	EMEA	IOG
23	31	Royal Dutch Shell plc	Netherlands	EMEA	IOG
24	24	Enel SpA	Italy	EMEA	EU
25	50	Electricité de France SA	France	EMEA	EU
26	125	JXTG Holdings, Inc	Japan	Asia/Pacific Rim	R&M
27	35	Bharat Petroleum Corp Ltd	India	Asia/Pacific Rim	R&M
28	65	China Yangtze Power Co,Ltd	China	Asia/Pacific Rim	IPP
29	23	The Southern Co	Georgia	Americas	EU
30	11	National Grid plc	United Kingdom	EMEA	DU
31	26	Duke Energy Corp	North Carolina	Americas	EU
32	42	Tenaga Nasional Berhad	Malaysia	Asia/Pacific Rim	EU
33	44	Formosa Petrochemical Corp	Taiwan	Asia/Pacific Rim	R&M
34	10	Marathon Petroleum Corp	Ohio	Americas	R&M
35	123	Repsol, SA	Spain	EMEA	IOG
36	40	Dominion Energy, Inc	Virginia	Americas	DU
37	28	Gas Natural SDG, SA	Spain	EMEA	GU
38	57	PG&E Corp	California	Americas	EU
39	46	NTPC Ltd	India	Asia/Pacific Rim	IPP
40	52	Edison International	California	Americas	EU
41	37	CLP Holdings Ltd	Hong Kong	Asia/Pacific Rim	EU
42	41	The Kansai Electric Power Co, Incorporated	Japan	Asia/Pacific Rim	EU
43	58	Polski Koncern Naftowy ORLEN SA	Poland	EMEA	R&M
44	69	PAO NOVATEK	Russia	EMEA	E&P
45	38	Coal India Ltd	India	Asia/Pacific Rim	C&CF
46	62	PJSC Tatneft	Russia	EMEA	E&P
47	193	Centrais Elétricas Brasileiras SA - Eletrobras	Brazil	Americas	EU
48	48	Hindustan Petroleum Corp Ltd	India	Asia/Pacific Rim	R&M
49	39	Tokyo Electric Power Co Holdings, Incorporated	Japan	Asia/Pacific Rim	EU
50	153	Idemitsu Kosan Co Ltd	Japan	Asia/Pacific Rim	R&M

shale drilling in the US and new shipments to overseas markets.

Among the biggest losers in the rankings, by sector, were South American exploration companies and Chinese power providers.

The two dozen biggest movers up included a range of companies from EMEA and the Americas. The group was heavy with diversified utilities—which provide electricity and natural gas to residential, commercial and industrial users —and pipeline companies that carry oil and gas to market. Not surprisingly, both sectors rely on each other for supply and demand.

As a sector, the majority of the electric utilities that dominated the global leaders list serve primarily in regulated or government sponsored markets. That gives them an advantage because their revenues are largely defined and consistent, and are not as susceptible to swings in oil and gas prices.

Return on invested capital also is more stable for regulated utilities. In the US, for instance, utilities are reimbursed for the billions of dollars in infrastructure they have built over the years by pass-through charges on customers' bills, regardless of whether they are the retail provider of users. In Europe, utilities often enjoy large market share or monopolistic power because of their footprints and the market rules in their home countries.

The story is much the same for pipeline operators, which often are guaranteed long-term pre-

*For a complete listing of the Top 250 please see page 74

defined revenue for allowing oil and gas producers and power producers to reserve capacity on their infrastructure. The most sought after shippers are those that are credit worthy and have consistent demand.

Growing shale output in the US has created that demand for pipeline operators, especially the ones with broad networks that can serve multiple regions. The decline of coal-fired generation and nuclear and the rise of renewables in the US has increased the need for natural gas, both as a direct supply of fuel and as a bridge to address the intermittency of wind and solar.

These trends are expected to continue into the next decade as billions of dollars of new investment pour into pipeline projects in the US, Canada and Mexico. The growing ties between the US and Mexico on this front are especially noteworthy. Mexico is heavily reliant on US supplies of gas to feed its power needs, and that demand is forecast to increase over the next five to 10 years, data compiled by S&P Global Platts Analytics show. Mexico also has been a leading importer of US LNG, receiving by far the most shipments through the middle of 2017 from Cheniere Energy's Sabine Pass export terminal in Louisiana.

Case in point: S&P Global Platts Analytics expects that total US to Mexico border crossing capacity will grow to nearly 14.2 Bcf/d by mid-2019 based on currently announced pipeline expansions. Total US exports to Mexico are

Biggest Movers[1]

Biggest Movers – Up

Platts Rank 2017	Platts Rank 2016	Up	Company Name	Region	Industry
2	114	112	E.ON SE	EMEA	DU
12	63	51	PTT Plc	Asia/Pacific Rim	IOG
15	156	141	Centrica plc	EMEA	DU
26	125	99	JXTG Holdings, Inc	Asia/Pacific Rim	R&M
35	123	88	Repsol, SA	EMEA	IOG
47	193	146	Centrais Elétricas Brasileiras SA - Eletrobras	Americas	EU
50	153	103	Idemitsu Kosan Co Ltd	Asia/Pacific Rim	R&M
52	113	61	Enbridge Inc	Americas	S&T
65	215	150	MOL Hungarian Oil & Gas Co	EMEA	IOG
76	204	128	Cosmo Energy Holdings Co, Ltd	Asia/Pacific Rim	R&M
83	196	113	Husky Energy Inc	Americas	IOG
87	163	76	Ecopetrol SA	Americas	IOG
92	178	86	ONEOK Partners, LP	Americas	S&T
98	210	112	Woodside Petroleum Ltd	Asia/Pacific Rim	E&P
102	243	141	Interconexión Eléctrica SA E.S.P.	Americas	EU
105	220	115	CenterPoint Energy, Inc	Americas	DU
111	167	56	Yanzhou Coal Mining Co Ltd	Asia/Pacific Rim	C&CF
123	236	113	Hellenic Petroleum SA	EMEA	R&M
124	229	105	Fortum Oyj	EMEA	EU
129	208	79	VERBUND AG	EMEA	EU
157	216	59	Public Power Corp SA	EMEA	EU
163	239	76	A2A S.p.A.	EMEA	DU
164	218	54	ACEA S.p.A.	EMEA	DU
177	249	72	PT Adaro Energy Tbk	Asia/Pacific Rim	C&CF

Biggest Movers –Down

Platts Rank 2017	Platts Rank 2016	Down	Company Name	Region	Industry
100	47	53	Tokyo Gas Co, Ltd	Asia/Pacific Rim	GU
116	22	94	CNOOC Ltd	Asia/Pacific Rim	E&P
120	68	52	Snam S.p.A.	EMEA	S&T
121	17	104	Chevron Corp	Americas	IOG
161	101	60	The AES Corp	Americas	IPP
165	9	156	OJSC Surgutneftegas	EMEA	IOG
176	122	54	China Power International Development Ltd	Asia/Pacific Rim	IPP
179	120	59	RWE Aktiengesellschaft	EMEA	DU
181	106	75	Korea Gas Corp	Asia/Pacific Rim	GU
183	131	52	Oil & Gas Development Co Ltd	Asia/Pacific Rim	E&P
200	110	90	EnBW Energie Baden-Württemberg AG	EMEA	EU
202	95	107	Datang International Power Generation Co, Ltd	Asia/Pacific Rim	IPP
213	84	129	Companhia Energética de Minas Gerais	Americas	EU
219	76	143	FirstEnergy Corp	Americas	EU
226	97	129	Cenovus Energy Inc	Americas	IOG
228	111	117	YPF Sociedad Anonima	Americas	IOG
230	134	96	Guangdong Electric Power Development Co, Ltd	Asia/Pacific Rim	IPP
233	172	61	Beijing Jingneng Power Co, Ltd	China	IPP

[1] Biggest movers have ascended or descended more than 50 ranks year on year.

Leaders By Indicator

Assets

Assets Rank	Company Name	Assets (millions)	Overall Top 250 Rank
1	Royal Dutch Shell plc	411275	23
2	PetroChina Co Ltd	352682	57
3	Exxon Mobil Corp	330314	9
4	Electricité de France SA	316984	25
5	PJSC Gazprom	296840	1
6	BP p.l.c.	263316	99
7	Chevron Corp	260078	121
8	Petróleo Brasileiro SA - Petrobras	245912	141
9	TOTAL SA	230978	10
10	China Petroleum & Chemical Corp	220530	5

Revenues

Revenues Rank	Company Name	Revenues (millions)	Overall Top 250 Rank
1	China Petroleum & Chemical Corp	284146	5
2	PetroChina Co Ltd	237937	57
3	Royal Dutch Shell plc	233591	23
4	Exxon Mobil Corp	197518	9
5	BP p.l.c.	182648	99
6	TOTAL SA	127925	10
7	PJSC Gazprom	107217	1
8	Chevron Corp	103310	121
9	PJSC LUKOIL	91708	6
10	PJSC Rosneft Oil Co	83601	22

Profits

Profits Rank	Company Name	Profits (millions)	Overall Top 250 Rank
1	PJSC Gazprom	16696.32	1
2	Exxon Mobil Corp	7840	9
3	China Petroleum & Chemical Corp	6868.07	5
4	Korea Electric Power Corp	6268.8	4
5	TOTAL SA	6196	10
6	E.ON SE	6068.66	2
7	Reliance Industries Ltd	4638.33	3
8	Royal Dutch Shell plc	4575	23
9	PAO NOVATEK	4522.97	44
10	PJSC Transneft	4085.42	14

ROIC

ROIC Rank	Company Name	ROIC (%)	Overall Top 250 Rank
1	E.ON SE	34.8	2
2	Coal India Ltd	33.2	45
3	PAO NOVATEK	29.5	44
4	Hindustan Petroleum Corp Ltd	21.1	48
5	Formosa Petrochemical Corp	18.7	33
6	Neste Oyj	18	79
7	Centrica plc	17.8	15
8	Manila Electric Co	16.6	139
9	Bharat Petroleum Corp Ltd	14.8	27
10	PJSC Tatneft	14.1	46

expected to grow to 5.3 Bcf/d by 2019, a 1.6 Bcf/d build over 2016 levels, reaching average annual flows of 6.0 Bcf/d by 2022.

Meanwhile, the expected growth in LNG export volumes prompted Intercontinental Exchange in March to announce that it would begin trading the first-ever US LNG futures contract, to be cash settled against the Platts LNG Gulf Coast Marker price assessment. A statement at the time said ICE would use Platts-derived US GCM LNG forward curves for daily settlement purposes, and the curves would have an initial term of 48 months.

All that is good news for pipelines that provide feedgas to LNG terminals.

Top 10

This year's top 10 shows a changing of the guard is underway, albeit slowly.

Since the rankings were first released in 2002, IOGs have led the list every year, and that is true again for 2017.

But, ExxonMobil, which had led the rankings for 12 consecutive years, fell to No. 9 and was replaced at the top by Russia's Public Joint Stock Company Gazprom, which benefits from being majority-owned by the Moscow government and from European countries being heavily dependent on Gazprom's gas supplies. European companies have invested in Russia's Nord Stream 2 pipeline expansion opposed by some countries.

And while there has been a lot of talk about the potential for a coming gas price war between Gazprom and LNG suppliers, that has not crystallized as of yet. ExxonMobil, for its part, has been hit hard by the drop in oil prices.

The bigger story this year is not who is at No. 1, however.

Germany's E.ON shooting up 112 places to No. 2 from No. 114 for last year is something that reveals the broader trend for utilities making further inroads due to stable cash flows and strong returns on invested capital. In the US, cheap gas has made utility investments even healthier because it is a key feedstock for power plants. While they didn't crack the top 10, British utility Centrica jumped to No. 15 from No. 156 last year, Brazil's Centrais Eletricas Brasileiras, also known as Eletrobras, shot up to No. 47 from No. 193 and Houston-based CenterPoint Energy surged to No. 105 from No. 220 a year earlier.

In E.ON's latest annual report, the company talked about how 2016 was a transformative year.

It separated its fossil fuel assets into a separate company last year, in an effort to boost value for both sets of operations that would exceed the value of all the operations under one roof. That meant that E.ON would focus on renewables, energy networks and customer solutions, while the other company that was formed through the spinoff, Uniper, would consist of conventional power generation such as hydro, natural gas and coal, and global energy trading.

"From E.ON's perspective, our core businesses are no longer burdened by the risks of the old energy world, such as the uncertainties of commodity markets," CEO Johannes Teyssen said in a letter to shareholders in the annual report. "The spinoff relieved your company and its balance sheet of most of the burdens of the past."

While E.ON's 2016 revenue rank fell to 28th on this year's list from 7th on last year's list, its return on invested capital, or ROIC, jumped to 35%, ranking it No. 1 in that category on this year's list, up from 246th in 2015.

There were some familiar names rounding out the top 10, such as No. 4 South Korea's Korea Electric Power, which debuted in the top 10 just last year; China Petroleum & Chemical at No. 5; Russia's PJSC Lukoil at No. 6; Indian Oil Corp. at No. 7; and US refiner Valero Energy at No. 8.

But it was India's Reliance Industries rising to No. 3 from No. 8 last year and France's Total rising to No. 10 from No. 12 last year—returning to the top 10 after a two-year absence—that showed the strength of pipelines as the other sector that was among those that surged up this time around. Both have been making investments in the US that benefit from increasing supplies of natural gas and the new pipeline infrastructure that is being built to carry those resources to the Gulf Coast for regional use and for exports to overseas hubs.

Overall, thanks to the new entrants buoyed by utilities and pipelines, revenues of the Top 10 global energy companies surged more than 30% to $1.1 trillion from $830.2 billion in the 2016 rankings.

Regional breakdown

Refiners and midstream companies are making inroads in parts of the world where oil majors used to be the most promising growth engines, and Europe, the Middle East and Africa, as a region, is clawing back previously lost share in the rankings.

In the Americas, Valero, a refiner, tops the rankings, followed by ExxonMobil.

Most noteworthy, in terms of the trend in the rankings, is that for the region, utilities hold five of the top 10 spots and pipeline operators or transportation companies that hold pipeline interests hold

Regional Leaders

The Americas

Rank	Company Name	State or Country	Industry	Overall Top 250 Rank
1	Valero Energy Corp	Texas	R&M	8
2	Exxon Mobil Corp	Texas	IOG	9
3	Enterprise Products Partners LP	Texas	S&T	17
4	NextEra Energy, Inc	Florida	EU	18
5	Phillips 66	Texas	R&M	20
6	The Southern Co	Georgia	EU	29
7	Duke Energy Corp	North Carolina	EU	31
8	Marathon Petroleum Corp	Ohio	R&M	34
9	Dominion Energy, Inc	Virginia	DU	36
10	PG&E Corp	California	EU	38

Asia/Pacific Rim

Rank	Company Name	State or Country	Industry	Overall Top 250 Rank
1	Reliance Industries Ltd	India	R&M	3
2	Korea Electric Power Corp	South Korea	EU	4
3	China Petroleum & Chemical Corp	China	IOG	5
4	Indian Oil Corp Ltd	India	R&M	7
5	Oil & Natural Gas Corp Ltd	India	E&P	11
6	PTT Plc	Thailand	IOG	12
7	China Shenhua Energy Co Ltd	China	C&CF	13
8	SK Innovation Co, Ltd	South Korea	R&M	21
9	JXTG Holdings, Inc	Japan	R&M	26
10	Bharat Petroleum Corp Ltd	India	R&M	27

EMEA

Rank	Company Name	State or Country	Industry	Overall Top 250 Rank
1	PJSC Gazprom	Russia	IOG	1
2	E.ON SE	Germany	DU	2
3	PJSC LUKOIL	Russia	IOG	6
4	TOTAL SA	France	IOG	10
5	PJSC Transneft	Russia	S&T	14
6	Centrica plc	United Kingdom	DU	15
7	SSE plc	United Kingdom	EU	16
8	Iberdrola, SA	Spain	EU	19
9	PJSC Rosneft Oil Co	Russia	IOG	22
10	Royal Dutch Shell plc	Netherlands	IOG	23

three of the top 10 spots. Among those is Houston-based Enterprise Products Partners, an operator of crude and gas pipelines as well as NGL storage facilities and gas processing plants. Chief Financial Officer Bryan Bulawa said at an industry conference in March that Enterprise has been able to manage the low commodity price environment with investments in fee-based pipelines, fractionators and export facilities, which have provided more stable returns.

Refiners hold five of the top 10 spots in the Asia/Pacific Rim region, but only one utility is in the top 10 there, as some Asian utilities have been hit by high fuel costs. Asia is the biggest importer of LNG in the world, and LNG is converted back to dry gas and used to heat homes and as a power plant fuel.

In EMEA, IOGs and utilities collectively hold nine of the top 10 spots in the regional rankings. No. 5 is Russia's PJSC Transneft, a pipeline operator.

Also noteworthy for the EMEA is that there are 68 companies from the region in this year's Top 250, compared with 61 in 2016. The Americas slipped, with 94 companies from the region on this year's list, down from 98 last year. Asia/Pacific Rim also lost share, with 88 companies in the Top 250 this year, versus 91 in 2016.

Fastest growing

Compound growth rates analyzed in the latest rankings showed again the strength of utilities and pipelines.

Colombia's Interconexión Eléctrica posted the top three-year CGR at 49.9%, followed by Brazil's Eletrobras at 36.6%. Crude oil transportation and logistics provider National Shipping Co. of Saudi Arabia, or Bahri, was the third fastest growing, with a three-year CGR of 33.6%.

Hong Kong's Kunlun Energy posted a three-year CGR of 23.5%, ranking it No. 10 in the fastest growing segment. The storage and transportation company owes that growth in part to its expansion in the natural gas pipeline arena. The company said in a profile on its website that prior to 2008, it was primarily involved in domestic and overseas oil and gas exploration and development.

In the years after a strategic transformation that began in 2009, Kunlun, through acquisitions and other initiatives, moved into gas pipelines, receiving, processing, storage and transportation of LNG. It has made growth in its natural gas operations a priority.

Fifteen of the top 20 fastest growing energy companies on this year's list are tied to the power and utility industries. That's a trend that should continue, as more countries eye LNG as a cost-effective power plant fuel.

The US is now a key supplier of that LNG, with Cheniere Energy exporting from its Sabine Pass terminal in Louisiana and Dominion Energy expected to begin shipping cargoes from its Cove Point terminal in Maryland later this year. Several other export terminals in the US are under construction, while another two dozen are being proposed.

That supply will have an impact on the compound growth rates of end users such as gas and electric utilities, as well as storage and transportation providers.

50 Fastest Growing Energy Companies

Fastest Growing Rank	Company Name	State or Country	Industry	3 Year CGR %	Overall Top 250 Rank
1	Interconexión Eléctrica SA E.S.P.	Colombia	EU	49.9	102
2	Centrais Elétricas Brasileiras SA - Eletrobras	Brazil	EU	36.6	47
3	The National Shipping Co of Saudi Arabia	Saudi Arabia	S&T	33.6	191
4	Beijing Jingneng Clean Energy Co, Ltd	China	IPP	32.8	205
5	YPF Sociedad Anonima	Argentina	IOG	32.6	228
6	China Yangtze Power Co,Ltd	China	IPP	29.2	28
7	Reliance Power Ltd	India	IPP	26.2	249
8	Emera Incorporated	Canada	EU	24.2	201
9	CGN Power Co, Ltd	China	IPP	23.8	90
10	Kunlun Energy Co Ltd	Hong Kong	S&T	23.5	186
11	Yanzhou Coal Mining Co Ltd	China	C&CF	20.2	111
12	Guangxi Guiguan Electric Power Co, Ltd	China	IPP	20.1	215
13	Fortis Inc	Canada	EU	19.1	125
14	PAO NOVATEK	Russia	E&P	18.5	44
15	China National Nuclear Power Co, Ltd	China	IPP	18.4	109
16	WEC Energy Group, Inc	Wisconsin	DU	18.3	69
17	Power Grid Corp of India Ltd	India	EU	17.9	81
18	China Gas Holdings Ltd	Hong Kong	GU	17.5	175
19	Empresa de Energia de Bogotá SA E.S.P.	Colombia	GU	17	190
20	Huaneng Renewables Corp Ltd	China	IPP	16.1	195
21	ENN Energy Holdings Ltd	China	GU	14.1	146
22	China Resources Gas Group Ltd	Hong Kong	GU	13.9	134
23	Brookfield Renewable Partners LP	Bermuda	IPP	12.9	239
24	Companhia Paranaense de Energia - COPEL	Brazil	EU	12.6	167
25	TransCanada Corp	Canada	S&T	12.4	147
26	Cosan Ltd	Brazil	R&M	12.2	225
27	Saudi Electricity Co	Saudi Arabia	EU	12	82
28	GS Holdings Corp	South Korea	R&M	12	73
29	Reliance Infrastructure Ltd	India	EU	11.9	162
30	NGL Energy Partners LP	Oklahoma	S&T	10.3	216
31	Inter Pipeline Ltd	Canada	S&T	10.2	206
32	PJSC Inter RAO UES	Russia	EU	9.4	68
33	CPFL Energia SA	Brazil	EU	9.3	159
34	Companhia Energética de Minas Gerais	Brazil	EU	8.7	213
35	PJSC Tatneft	Russia	E&P	8.4	46
36	Ultrapar Participações SA	Brazil	S&T	8.3	95
37	Exelon Corp	Illinois	EU	8	55
38	Southwest Gas Holdings, Inc	Nevada	GU	8	238
39	Aboitiz Power Corp	Philippines	IPP	7.4	180
40	ENEA SA	Poland	EU	7.1	214
41	OJSC Surgutneftegas	Russia	IOG	6.8	165
42	Huadian Fuxin Energy Corp Ltd	China	IPP	6.3	199
43	Tenaga Nasional Berhad	Malaysia	EU	6.2	32
44	PJSC Federal Hydro-Generating Co - RusHydro	Russia	EU	6.2	91
45	Rosseti, PJSC	Russia	EU	6.1	56
46	PJSC Gazprom	Russia	IOG	5.9	1
47	The Southern Co	Georgia	EU	5.2	29
48	China Longyuan Power Group Corp Ltd	China	IPP	5.2	137
49	NHPC Ltd	India	IPP	5.2	168
50	Brookfield Infrastructure Partners LP	Bermuda	EU	5	196

Coal's challenge

While US President Donald Trump was elected in part based on his 2016 campaign promise to spark a resurgence in coal's fortunes, that is going to be difficult, if not impossible, based on the most recent trends.

Global coal consumption fell last year by 53 million tonnes of oil equivalent (mtoe), or 1.7%, the second consecutive annual decline, with its share within primary energy falling to its lowest level since 2004, according to BP's latest statistical review of world energy.

The largest declines in coal consumption were seen in the US (down 8.8%, or 33 mtoe) and China (down 1.6% or 26 mtoe). Coal consumption in the UK more than halved (down 52.5%, or 12 mtoe) to its lowest level in BP's records.

"Indeed, coal production and consumption in the UK completed an entire cycle, falling back to levels last seen almost 200 years ago around the time of the Industrial Revolution, with the UK power sector recording its first ever coal-free day in April of this year," the review found. "In contrast, renewable energy globally led by wind and solar power grew strongly, helped by continuing technological advances. Although the share of renewable energy within total energy remains small, at around 4%, it accounted for almost a third of the increase in primary energy last year."

Regional Fastest Growing Companies

The Americas

Fastest Growing Rank	Company Name	State or Country	Industry	3 Year CGR %	Overall Top 250 Rank
1	Interconexión Eléctrica SA E.S.P.	Colombia	EU	49.9	102
2	Centrais Elétricas Brasileiras SA - Eletrobras	Brazil	EU	36.6	47
3	YPF Sociedad Anonima	Argentina	IOG	32.6	228
4	Emera Incorporated	Canada	EU	24.2	201
5	Fortis Inc	Canada	EU	19.1	125
6	WEC Energy Group, Inc	Wisconsin	DU	18.3	69
7	Empresa de Energia de Bogotá SA E.S.P.	Colombia	GU	17	190
8	Brookfield Renewable Partners LP	Bermuda	IPP	12.9	239
9	Companhia Paranaense de Energia - COPEL	Brazil	EU	12.6	167
10	TransCanada Corp	Canada	S&T	12.4	147

Asia/Pacific Rim

Fastest Growing Rank	Company Name	State or Country	Industry	3 Year CGR %	Overall Top 250 Rank
1	Beijing Jingneng Clean Energy Co, Ltd	China	IPP	32.8	205
2	China Yangtze Power Co,Ltd	China	IPP	29.2	28
3	Reliance Power Ltd	India	IPP	26.2	249
4	CGN Power Co, Ltd	China	IPP	23.8	90
5	Kunlun Energy Co Ltd	Hong Kong	S&T	23.5	186
6	Yanzhou Coal Mining Co Ltd	China	C&CF	20.2	111
7	Guangxi Guiguan Electric Power Co, Ltd	China	IPP	20.1	215
8	China National Nuclear Power Co, Ltd	China	IPP	18.4	109
9	Power Grid Corp of India Ltd	India	EU	17.9	81
10	China Gas Holdings Ltd	Hong Kong	GU	17.5	175

EMEA

Fastest Growing Rank	Company Name	State or Country	Industry	3 Year CGR %	Overall Top 250 Rank
1	The National Shipping Co of Saudi Arabia	Saudi Arabia	S&T	33.6	191
2	PAO NOVATEK	Russia	E&P	18.5	44
3	Saudi Electricity Co	Saudi Arabia	EU	12	82
4	PJSC Inter RAO UES	Russia	EU	9.4	68
5	PJSC Tatneft	Russia	E&P	8.4	46
6	ENEA SA	Poland	EU	7.1	214
7	OJSC Surgutneftegas	Russia	IOG	6.8	165
8	PJSC Federal Hydro-Generating Co - RusHydro	Russia	EU	6.2	91
9	Rosseti, PJSC	Russia	EU	6.1	56
10	PJSC Gazprom	Russia	IOG	5.9	1

Coal's troubles were especially acute in Asia, with China's production falling by 7.9% or 140 mtoe, a record decline, the review found.

Those headwinds translated into swings in this year's Platts rankings for coal interests.

Coal India, for instance, slipped in the rankings to No. 45 from No. 38 last year. On a bright note, producer China Shenhua Energy rose to No. 13 from No. 25 last year as the price of coal there rose sharply following government output cuts.

Politics and economy

From a trend toward government-mandated price reductions in Romania and Hungary, to Sweden's efforts to enhance consumers' rights in the energy marketplace, to South Korea's participation in combating global climate change, to project permitting delays in the US amid a lack of a voting quorum at the Federal Energy Regulatory Commission, politics played a key role in how the world's top companies fared in the rankings.

Equally important were economic changes in many countries and the winds of change that drove new market rules to spur growth.

At ExxonMobil's analyst day meeting March 1, executives were asked, with global oil prices under pressure over the last 2-1/2 years, how have governments with which the

IOG does business responded to the new market realities and they have been willing to offer better terms to drive further investment in their countries.

That's been difficult in some of the countries where ExxonMobil did business in 2016, impacting its results.

"Obviously every government is wrestling with these low prices and how that's affecting their budgets," Mark Albers, a senior vice president at ExxonMobil, said in the presentation. "As part of the conversation around making things work in this price environment, we're going to governments and having candid conversations as we speak around this is how far we can take it with development concepts and planning but we need this to get something going in your country."

In terms of the macroeconomic environment, E.ON noted in its annual report that global growth was again weak in 2016, registering 3.1% according to an OECD estimate.

That meant a reduction in private and public investment activity worldwide, marked by declines in China, only moderate improvement in domestic demand in the eurozone, and weaker economic expansion than in the previous year in the Czech Republic and Turkey, the report said.

China's Guangdong Electric Power Development Co. fell 96 spots to No. 230 in this year's rankings and Beijing Jingneng Power Co. slid 61 spots to No. 233. Datang International Power Generation Co., also based in China, moved down to No. 202 in the Top 250 from No. 95 in 2016.

Türkiye Petrol Rafinerileri fell to No. 103 in this year's rankings from No. 66 in 2016. The Turkish company is involved in the refining of crude oil and petroleum products. Also hit was the Czech Republic's CEZ, an energy company involved in electricity generation, natural gas sales and coal extraction. It slipped to No. 97 in the Top 250 from No. 72 in 2016.

The US was a bright spot in 2016, attracting new investment from domestic and multinational energy companies.

"Growth was supported by private consumption and private investment, which were bolstered by a labor market almost at full employment," the E.ON report said.

In particular, shale plays such as the Permian, which spans parts of Texas and New Mexico, and the Marcellus in the US Northeast were hotbeds of activity, especially on the midstream oil and gas side, helping explain the uplift for pipelines. Kinder Morgan, for instance, moved up to No. 93 in this year's Top 250 from No. 103 last year. It is a growing Permian player, with plans for a 430-mile natural gas pipeline from the shale basin to the Corpus Christi, Texas, area.

"Ironically, the only constant within 2016 midstream markets was the incessant pivoting from one strategic/investment theme to the next," Jefferies analyst Christopher Sighinolfi said in an April 19 research note to clients.

While some investment advisers encouraged the US midstream sector as the year ended to become more diversified to limit the risk of focusing too heavily on one area, there was a continued appetite heading into 2017 for deals in areas that are hot.

The SCOOP and STACK in Oklahoma and the Eagle Ford in South Texas also were in the mix. Translation: Oneok, a big pipeline player in the SCOOP and STACK, advanced to No. 92 in the Top 250 from No. 158 last year. Oneok also is well-positioned in the Permian's Midland and Delaware sub-basins.

The future

While the Permian is largely an oil play, there is a lot of associated gas being lifted there, and that has been a big lure for IOG's as well as midstream infrastructure companies. That could re-order the rankings the next time around, which may be good news for ExxonMobil after falling in stature this year.

In January, it decided to spend up to $6.6 billion to more than double its position in the Permian, giving it the opportunity to play a bigger role in producing the growing volume of natural gas that is flowing from the region to Mexico for power generation and to the US Gulf Coast for LNG exports.

About 25% of the resource that ExxonMobil said it expected to capture through a series of purchases from the Bass family of Fort Worth is non-liquid—and firms need a home for that product to make their investments more worthwhile. Increasing exports give them the markets for the gas, and midstream operators are building infrastructure to provide the delivery link to those markets.

An analysis issued by PricewaterhouseCoopers in late July found that the first half of 2017 set a record for oil and gas mergers and acquisitions despite oil prices declining by 16% during the period. It said that 14 of the 20 megadeals were all-cash deals, reflecting acquirers' access to cash and their willingness to spend it.

While 2016 was the first year the US exported LNG produced from shale, 2017 brought new entrants and increased competition.

The industry has been closely watching to see at what point the market becomes too saturated to support further development. Some final investment decisions that were expected this year have been pushed off to 2018 and beyond. A number of developers with proposals in the permitting queue have announced preliminary offtake agreements with buyers, but firm final agreements have so far been fleeting.

Finding the right business model to deal with changes in market trends will be a key to determining how many of the second wave of LNG export projects that are currently being planned get off the ground, developers said.

Meanwhile, energy companies in many sectors have been overhauling their portfolios to focus on their core operations. That has seen some traditional gas pipeline companies get out of petrochemicals and some traditional producers and generators think twice about getting into building LNG terminals.

Williams, a pipeline operator based in Oklahoma, is hoping such a transformation will help it grow in the future, much like E.ON's moves helped it this year. And LNG demand growth may be the driver that pushes Williams up in next year's rankings, after falling to No. 197 this year from No. 173 in 2016. Williams' pipelines provide feedgas for LNG production at US export facilities.

"It is blocking and tackling first, and we are focused on that," Williams CEO Alan Armstrong said in an Aug. 3 investor call. "There's a pretty intense focus right now on delivering on what we have."

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1	PJSC Gazprom	Russia	EMEA	296840	5	107217	7	16696	1	7	41	5.9	IOG
2	E.ON SE	Germany	EMEA	71693	34	43559	28	6069	6	35	1	-31.4	DU
3	Reliance Industries Ltd	India	Asia/Pacific Rim	109641	21	51218	23	4638	7	7	42	-8.7	R&M
4	Korea Electric Power Corp	South Korea	Asia/Pacific Rim	158163	14	53152	22	6269	4	6	59	3.6	EU
5	China Petroleum & Chemical Corp	China	Asia/Pacific Rim	220530	10	284146	1	6868	3	5	89	-12.5	IOG
6	PJSC LUKOIL	Russia	EMEA	87982	27	91708	9	3628	12	5	62	-15.5	IOG
7	Indian Oil Corp Ltd	India	Asia/Pacific Rim	42436	69	55117	21	3162	15	12	15	-10.1	R&M
8	Valero Energy Corp	Texas	Americas	46173	58	70166	18	2286	27	8	29	-20.2	R&M
9	Exxon Mobil Corp	Texas	Americas	330314	3	197518	4	7840	2	4	128	-20.3	IOG
10	TOTAL SA	France	EMEA	230978	9	127925	6	6196	5	4	117	-17.5	IOG
11	Oil & Natural Gas Corp Ltd	India	Asia/Pacific Rim	57427	45	22051	50	3180	13	7	36	-6.6	E&P
12	PTT Plc	Thailand	Asia/Pacific Rim	65618	39	50525	24	2727	20	5	66	-15.4	IOG
13	China Shenhua Energy Co Ltd	China	Asia/Pacific Rim	84869	30	26948	41	3666	11	5	70	-13.6	C&CF
14	PJSC Transneft	Russia	EMEA	48542	54	14880	79	4085	10	10	23	4.2	S&T
15	Centrica plc	United Kingdom	EMEA	28377	102	35127	32	2167	28	18	7	0.7	DU
16	SSE plc	United Kingdom	EMEA	30998	92	37636	29	2073	30	11	20	-1.7	EU
17	Enterprise Products Partners LP	Texas	Americas	52194	48	23022	48	2500	24	5	60	-21.6	S&T
18	NextEra Energy, Inc	Florida	Americas	89993	25	16155	73	2912	18	5	66	2.2	EU
19	Iberdrola, SA	Spain	EMEA	120097	17	32882	33	3044	17	4	119	-2	EU
20	Phillips 66	Texas	Americas	51653	50	70898	17	1549	37	5	89	-23.4	R&M
21	SK Innovation Co, Ltd	South Korea	Asia/Pacific Rim	28977	99	35148	31	1466	41	7	42	-15.7	R&M
22	PJSC Rosneft Oil Co	Russia	EMEA	193520	11	83601	10	3176	14	2	179	1.6	IOG
23	Royal Dutch Shell plc	Netherlands	EMEA	411275	1	233591	3	4575	8	2	206	-19.7	IOG
24	Enel SpA	Italy	EMEA	175122	13	77839	13	2893	19	2	179	-3.3	EU
25	Electricité de France SA	France	EMEA	316984	4	80138	12	2554	22	2	189	-0.3	EU
26	JXTG Holdings, Inc	Japan	Asia/Pacific Rim	60882	44	74390	16	1464	42	4	128	-13.1	R&M
27	Bharat Petroleum Corp Ltd	India	Asia/Pacific Rim	16922	149	31219	36	1475	39	15	9	-8.7	R&M
28	China Yangtze Power Co,Ltd	China	Asia/Pacific Rim	43984	63	7202	143	3058	16	10	24	29.2	IPP
29	The Southern Co	Georgia	Americas	109697	20	19896	58	2448	25	3	145	5.2	EU
30	National Grid plc	United Kingdom	EMEA	85336	29	19487	60	2346	26	4	136	0.5	DU
31	Duke Energy Corp	North Carolina	Americas	132761	16	22381	49	2567	21	3	166	0.3	EU
32	Tenaga Nasional Berhad	Malaysia	Asia/Pacific Rim	31187	90	10450	105	1729	33	8	29	6.2	EU
33	Formosa Petrochemical Corp	Taiwan	Asia/Pacific Rim	14999	169	18109	63	2512	23	19	5	-16.3	R&M
34	Marathon Petroleum Corp	Ohio	Americas	44413	62	56011	20	1173	56	4	123	-15.8	R&M
35	Repsol, SA	Spain	EMEA	72987	33	32009	34	1586	36	3	160	-11.3	IOG
36	Dominion Energy, Inc	Virginia	Americas	71610	35	11737	95	2123	29	4	106	-3.6	DU
37	Gas Natural SDG, SA	Spain	EMEA	53026	47	26093	42	1467	40	4	136	-1.6	GU
38	PG&E Corp	California	Americas	68598	37	17666	65	1393	45	4	119	4.2	EU
39	NTPC Ltd	India	Asia/Pacific Rim	38548	78	12733	90	1663	34	5	66	1.3	IPP
40	Edison International	California	Americas	51319	51	11869	94	1299	49	5	80	-1.9	EU
41	CLP Holdings Ltd	Hong Kong	Asia/Pacific Rim	26427	106	10191	107	1631	35	8	28	-8.7	EU
42	The Kansai Electric Power Co, Incorporated	Japan	Asia/Pacific Rim	62661	43	27533	39	1287	51	3	149	-3.3	EU
43	Polski Koncern Naftowy ORLEN SA	Poland	EMEA	14886	172	21315	54	1410	44	14	12	-11.2	R&M
44	PAO NOVATEK	Russia	EMEA	16910	150	8711	123	4523	9	30	3	18.5	E&P
45	Coal India Ltd	India	Asia/Pacific Rim	18006	145	11707	96	1437	43	33	2	3.2	C&CF
46	PJSC Tatneft	Russia	EMEA	19205	136	10178	109	1884	32	14	10	8.4	E&P
47	Centrais Elétricas Brasileiras SA - Eletrobras	Brazil	Americas	52088	49	18559	62	1095	61	4	117	36.6	EU
48	Hindustan Petroleum Corp Ltd	India	Asia/Pacific Rim	12459	197	29074	38	1278	52	21	4	-7.1	R&M
49	Tokyo Electric Power Co Holdings, Incorporated	Japan	Asia/Pacific Rim	112257	19	48987	26	1214	55	2	192	-6.9	EU
50	Idemitsu Kosan Co Ltd	Japan	Asia/Pacific Rim	24153	115	29170	37	806	80	5	62	-14.1	R&M

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51	PPL Corp	Pennsylvania	Americas	38315	79	7517	139	1896	31	6	46	1.2	EU
52	Enbridge Inc	Canada	Americas	63565	41	25594	43	1315	47	3	174	1.6	S&T
53	Consolidated Edison, Inc	New York	Americas	48255	55	12075	92	1245	53	4	106	-0.8	DU
54	DONG Energy A/S	Denmark	EMEA	20653	129	8685	125	1525	38	12	17	-7.4	EU
55	Exelon Corp	Illinois	Americas	114904	18	31360	35	1134	59	2	198	8	EU
56	Rosseti, PJSC	Russia	EMEA	39769	76	15860	75	1309	48	4	112	6.1	EU
57	PetroChina Co Ltd	China	Asia/Pacific Rim	352682	2	237937	2	1156	57	0	253	-10.5	IOG
58	Sempra Energy	California	Americas	47786	56	10183	108	1370	46	4	104	-1.2	DU
59	Huaneng Power International, Inc	China	Asia/Pacific Rim	45533	61	16748	67	1297	50	3	149	-5.3	IPP
60	Chubu Electric Power Co, Incorporated	Japan	Asia/Pacific Rim	49486	53	23805	45	1048	66	3	166	-2.9	EU
61	Xcel Energy Inc	Minnesota	Americas	41155	74	11107	97	1123	60	4	101	0.6	EU
62	Energy Transfer Equity, LP	Texas	Americas	79011	32	37504	30	983	69	2	209	-8.1	S&T
63	EDP - Energias de Portugal, SA	Portugal	EMEA	49616	52	16427	71	1081	62	3	157	-3.6	EU
64	Tesoro Corp	Texas	Americas	20398	131	24005	44	724	84	5	84	-13.5	R&M
65	MOL Hungarian Oil & Gas Co	Hungary	EMEA	14988	170	12976	89	955	71	10	22	-13	IOG
66	S-Oil Corp	South Korea	Asia/Pacific Rim	12415	199	14516	81	1037	67	10	21	-19.4	R&M
67	DTE Energy Co	Michigan	Americas	32041	89	10630	101	866	78	4	106	3.2	DU
68	PJSC Inter RAO UES	Russia	EMEA	10029	226	15232	77	1066	64	14	11	9.4	EU
69	WEC Energy Group, Inc	Wisconsin	Americas	30123	96	7472	141	939	73	5	80	18.3	DU
70	Eversource Energy	Massachusetts	Americas	32053	88	7639	133	942	72	4	98	1.5	EU
71	China Resources Power Holdings Co Ltd	Hong Kong	Asia/Pacific Rim	25674	110	8495	127	989	68	5	89	-1.6	IPP
72	Public Service Enterprise Group Incorporated	New Jersey	Americas	40070	75	9061	116	887	76	4	128	-3.1	DU
73	GS Holdings Corp	South Korea	Asia/Pacific Rim	18091	142	11973	93	741	82	5	84	12	R&M
74	Kyushu Electric Power Co, Incorporated	Japan	Asia/Pacific Rim	41945	71	16710	68	693	88	2	184	0.7	EU
75	PJSOC Bashneft	Russia	EMEA	10249	221	9643	112	925	74	14	12	1.4	E&P
76	Cosmo Energy Holdings Co, Ltd	Japan	Asia/Pacific Rim	13950	178	20959	55	487	117	5	70	-13.5	R&M
77	American Electric Power Co, Inc	Ohio	Americas	63468	42	16380	72	613	98	2	209	3.4	EU
78	Tohoku Electric Power Co, Incorporated	Japan	Asia/Pacific Rim	37907	80	17826	64	639	95	2	182	-1.5	EU
79	Neste Oyj	Finland	EMEA	8377	250	10580	102	1057	65	18	6	-15.5	R&M
80	Zhejiang Zheneng Electric Power Co, Ltd	China	Asia/Pacific Rim	15575	159	5765	158	924	75	7	42	-10.1	IPP
81	Power Grid Corp of India Ltd	India	Asia/Pacific Rim	30349	95	3987	195	1156	58	5	89	17.9	EU
82	Saudi Electricity Co	Saudi Arabia	EMEA	107450	22	13310	85	561	104	1	229	12	EU
83	Husky Energy Inc	Canada	Americas	23891	116	9567	113	656	92	4	119	-17.9	IOG
84	Empresas Copec SA	Chile	Americas	21447	125	16699	69	554	107	3	145	-11.8	R&M
85	Polska Grupa Energetyczna SA	Poland	EMEA	18078	143	7527	137	688	89	5	80	-2.3	EU
86	Polskie Górnictwo Naftowe i Gazownictwo SA	Poland	EMEA	13309	186	8894	122	630	96	6	50	1.2	IOG
87	Ecopetrol SA	Colombia	Americas	41773	72	16437	70	539	110	2	206	-12.2	IOG
88	Osaka Gas Co, Ltd	Japan	Asia/Pacific Rim	17249	148	10824	100	560	105	4	106	-7.8	GU
89	Ameren Corp	Missouri	Americas	24699	113	5868	156	653	93	4	101	1.4	DU
90	CGN Power Co, Ltd	China	Asia/Pacific Rim	42327	70	4776	171	1072	63	3	160	23.8	IPP
91	PJSC Federal Hydro-Generating Co - RusHydro	Russia	EMEA	17254	147	6866	146	705	87	5	87	6.2	EU
92	ONEOK Partners, LP	Oklahoma	Americas	15469	163	8918	121	643	94	5	89	-9.1	S&T
93	Kinder Morgan, Inc	Texas	Americas	80305	31	13058	87	548	109	1	241	-2.5	S&T
94	Veolia Environnement SA	France	EMEA	42712	68	27451	40	354	144	1	216	2.2	DU
95	Ultrapar Participações SA	Brazil	Americas	7381	270	23631	47	477	120	8	31	8.3	S&T
96	The Hong Kong & China Gas Co Ltd	Hong Kong	Asia/Pacific Rim	14978	171	3664	199	956	70	8	34	0.4	GU
97	CEZ,a.s.	Czech Republic	EMEA	26986	105	8645	126	611	99	3	145	-2.1	EU
98	Woodside Petroleum Ltd	Australia	Asia/Pacific Rim	24753	111	4075	193	868	77	4	104	-11.7	E&P
99	BP p.l.c.	United Kingdom	EMEA	263316	6	182648	5	114	219	0	258	-21.6	IOG
100	Tokyo Gas Co, Ltd	Japan	Asia/Pacific Rim	20392	132	14511	82	486	118	3	157	-9.1	GU

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101	Suncor Energy Inc	Canada	Americas	65690	38	19852	59	321	153	1	241	-12.2	IOG
102	Interconexión Eléctrica SA E.S.P.	Colombia	Americas	13263	187	4180	187	736	83	7	36	49.9	EU
103	Türkiye Petrol Rafinerileri A.S.	Turkey	EMEA	8802	245	9828	111	506	114	9	26	-5.3	R&M
104	CMS Energy Corp	Michigan	Americas	21622	124	6399	152	551	108	4	119	-0.9	DU
105	CenterPoint Energy, Inc	Texas	Americas	21829	122	7528	136	432	128	4	128	-2.4	DU
106	GAIL (India) Ltd	India	Asia/Pacific Rim	9186	237	7535	135	522	113	8	31	-7.8	GU
107	Huadian Power International Corp Ltd	China	Asia/Pacific Rim	30919	93	9322	114	492	116	2	195	-1.7	IPP
108	SCANA Corp	South Carolina	Americas	18707	138	4227	185	595	101	4	96	-2	DU
109	China National Nuclear Power Co, Ltd	China	Asia/Pacific Rim	41505	73	4416	178	661	91	2	202	18.4	IPP
110	TERNA SpA	Italy	EMEA	18054	144	2302	243	713	86	5	80	3.5	EU
111	Yanzhou Coal Mining Co Ltd	China	Asia/Pacific Rim	21429	126	15007	78	304	156	2	198	20.2	C&CF
112	Hydro One Ltd	Canada	Americas	18774	137	4852	170	534	112	3	140	2.6	EU
113	Inpex Corp	Japan	Asia/Pacific Rim	39427	77	7995	130	422	129	1	226	-13.1	E&P
114	Thai Oil Pcl	Thailand	Asia/Pacific Rim	6400	299	6641	150	624	97	11	19	-17.3	R&M
115	CK Infrastructure Holdings Ltd	Hong Kong	Asia/Pacific Rim	16411	155	756	326	1236	54	8	31	2.1	EU
116	CNOOC Ltd	Hong Kong	Asia/Pacific Rim	93839	24	21492	53	94	233	0	258	-20.1	E&P
117	Red Eléctrica Corporación, SA	Spain	EMEA	11874	203	2220	246	717	85	8	34	3.5	EU
118	SDIC Power Holdings Co, Ltd	China	Asia/Pacific Rim	29916	97	4307	182	576	102	2	189	1.1	IPP
119	Pinnacle West Capital Corp	Arizona	Americas	16004	157	3499	203	442	126	5	84	0.4	EU
120	Snam S.p.A.	Italy	EMEA	22655	119	2815	222	665	90	3	140	-13.2	S&T
121	Chevron Corp	California	Americas	260078	7	103310	8	-497	294	0	266	-21.3	IOG
122	Acciona, SA	Spain	EMEA	19592	133	7352	142	396	134	3	166	-0.3	EU
123	Hellenic Petroleum SA	Greece	EMEA	8091	255	7518	138	371	140	7	42	-11.6	R&M
124	Fortum Oyj	Finland	EMEA	24720	112	4111	190	558	106	3	174	-11.9	EU
125	Fortis Inc	Canada	Americas	35476	86	5064	166	433	127	2	209	19.1	EU
126	ONEOK, Inc	Oklahoma	Americas	16139	156	8921	120	354	143	3	171	-9.1	S&T
127	China Coal Energy Co Ltd	China	Asia/Pacific Rim	35590	84	8922	119	298	157	1	231	-9.7	C&CF
128	Plains All American Pipeline, LP	Texas	Americas	24210	114	20182	56	200	190	1	231	-21.8	S&T
129	VERBUND AG	Austria	EMEA	12986	190	3158	215	478	119	5	70	-4.1	EU
130	Shaanxi Coal Industry Co Ltd	China	Asia/Pacific Rim	13787	182	4876	169	405	132	4	112	-8.5	C&CF
131	Electric Power Development Co, Ltd	Japan	Asia/Pacific Rim	23830	117	6806	147	379	138	2	195	1.7	IPP
132	ENGIE SA	France	EMEA	178389	12	75002	15	-631	302	-1	270	-8.8	DU
133	UGI Corp	Pennsylvania	Americas	10847	212	5686	160	365	141	5	87	-7.5	GU
134	China Resources Gas Group Ltd	Hong Kong	Asia/Pacific Rim	7656	263	4223	186	422	130	9	25	13.9	GU
135	Buckeye Partners, LP	Texas	Americas	9421	232	3248	211	536	111	6	53	-13.7	S&T
136	Showa Shell Sekiyu KK	Japan	Asia/Pacific Rim	8925	242	15782	76	155	204	4	98	-16.4	R&M
137	China Longyuan Power Group Corp Ltd	China	Asia/Pacific Rim	20405	130	3282	210	503	115	3	166	5.2	IPP
138	Eni S.p.A.	Italy	EMEA	140174	15	62760	19	-1183	317	-1	276	-17.3	IOG
139	Manila Electric Co	Philippines	Asia/Pacific Rim	5970	320	5186	164	387	136	17	8	-4.9	EU
140	Magellan Midstream Partners, LP	Oklahoma	Americas	6772	288	2205	247	803	81	13	14	4.2	S&T
141	Petróleo Brasileiro SA - Petrobras	Brazil	Americas	245912	8	81233	11	-4529	332	-2	282	-4.5	IOG
142	Alliant Energy Corp	Wisconsin	Americas	13374	185	3320	209	374	139	4	101	0.4	EU
143	NiSource Inc	Indiana	Americas	18692	140	4492	176	328	151	3	171	-1	DU
144	Power Assets Holdings Ltd	Hong Kong	Asia/Pacific Rim	16650	152	165	337	823	79	5	70	-51.9	EU
145	Galp Energia, SGPS, SA	Portugal	EMEA	14000	177	14859	80	202	188	2	195	-12.4	IOG
146	ENN Energy Holdings Ltd	China	Asia/Pacific Rim	7561	265	5018	167	317	154	6	54	14.1	GU
147	TransCanada Corp	Canada	Americas	65208	40	9261	115	92	235	0	257	12.4	S&T
148	Plains GP Holdings, LP	Texas	Americas	26103	108	20182	56	94	232	0	253	-21.8	S&T
149	Alpiq Holding AG	Switzerland	EMEA	10217	222	6309	153	271	171	4	106	-13.6	EU
150	BKW AG	Switzerland	EMEA	8900	243	2839	221	323	152	7	38	1.6	EU

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151	Atmos Energy Corp	Texas	Americas	10011	227	3350	207	350	145	5	76	-4.7	GU
152	Shenergy Co Ltd	China	Asia/Pacific Rim	7899	260	4085	192	362	142	5	62	2.5	IPP
153	Hawaiian Electric Industries, Inc	Hawaii	Americas	12426	198	2381	236	248	176	6	48	-9.7	EU
154	PBF Energy Inc	New Jersey	Americas	7622	264	15920	74	171	200	4	128	-6	R&M
155	Statoil ASA	Norway	EMEA	104530	23	45688	27	-2922	327	-4	300	-13.9	IOG
156	The Chugoku Electric Power Co, Incorporated	Japan	Asia/Pacific Rim	28351	103	10975	98	104	226	0	250	-1.5	EU
157	Public Power Corp SA	Greece	EMEA	19286	135	5877	155	204	186	2	202	-4.4	EU
158	Westar Energy, Inc	Kansas	Americas	11487	206	2562	228	346	147	4	98	2.6	EU
159	CPFL Energia SA	Brazil	Americas	12883	191	5839	157	275	168	3	166	9.3	EU
160	OGE Energy Corp	Oklahoma	Americas	9940	229	2259	245	338	148	5	60	-7.6	EU
161	The AES Corp	Virginia	Americas	36119	83	13586	84	8	261	0	261	-5.1	IPP
162	Reliance Infrastructure Ltd	India	Asia/Pacific Rim	15256	166	4132	188	233	181	3	157	11.9	EU
163	A2A S.p.A.	Italy	EMEA	11681	205	5468	161	250	174	3	155	-3.4	DU
164	ACEA S.p.A.	Italy	EMEA	7771	262	3049	216	295	159	6	58	-5.8	DU
165	OJSC Surgutneftegas	Russia	EMEA	68804	36	17649	66	-1090	315	-2	279	6.8	IOG
166	HK Electric Investments & HK Electric Investments Ltd	Hong Kong	Asia/Pacific Rim	13901	179	1465	285	462	124	4	112	3.8	EU
167	Companhia Paranaense de Energia - COPEL	Brazil	Americas	9298	235	4003	194	293	160	4	112	12.6	EU
168	NHPC Ltd	India	Asia/Pacific Rim	9335	233	1338	298	470	121	6	50	5.2	IPP
169	JSC KazMunaiGas Exploration Production	Kazakhstan	EMEA	6743	289	2323	242	420	131	7	40	-3.8	E&P
170	Hera S.p.A.	Italy	EMEA	9325	234	5315	162	233	180	4	128	0.6	DU
171	OMV Aktiengesellschaft	Austria	EMEA	36142	82	21677	52	-455	292	-2	281	-23.1	IOG
172	Enagás, SA	Spain	EMEA	10409	216	1337	299	470	122	5	70	-1.2	S&T
173	Koninklijke Vopak N.V.	Netherlands	EMEA	6282	307	1524	283	601	100	11	18	1.2	S&T
174	ConocoPhillips	Texas	Americas	89772	26	23745	46	-3615	330	-6	307	-25.3	E&P
175	China Gas Holdings Ltd	Hong Kong	Asia/Pacific Rim	6868	284	3738	198	292	163	5	66	17.5	GU
176	China Power International Development Ltd	Hong Kong	Asia/Pacific Rim	13419	184	2797	223	348	146	3	160	0.2	IPP
177	PT Adaro Energy Tbk	Indonesia	Asia/Pacific Rim	6522	293	2524	229	335	149	6	47	-8.4	C&CF
178	Uniper SE	Germany	EMEA	55004	46	75952	14	-3621	331	-20	330	-10.8	IPP
179	RWE Aktiengesellschaft	Germany	EMEA	85990	28	49722	25	-6427	337	-22	332	-4	DU
180	Aboitiz Power Corp	Philippines	Asia/Pacific Rim	7154	275	1798	266	403	133	6	50	7.4	IPP
181	Korea Gas Corp	South Korea	Asia/Pacific Rim	35511	85	18773	61	-603	300	-2	280	-17.8	GU
182	Inner Mongolia Yitai Coal Co,Ltd	China	Asia/Pacific Rim	10439	215	3364	206	292	161	3	149	-3	C&CF
183	Oil & Gas Development Co Ltd	Pakistan	Asia/Pacific Rim	5623	335	1553	280	572	103	12	15	-10	E&P
184	Pembina Pipeline Corp	Canada	Americas	11121	209	3159	214	292	162	3	149	-5.2	S&T
185	MDU Resources Group, Inc	North Dakota	Americas	6284	306	4129	189	232	182	6	57	1.7	DU
186	Kunlun Energy Co Ltd	Hong Kong	Asia/Pacific Rim	17804	146	10505	104	85	238	1	247	23.5	S&T
187	PT Perusahaan Gas Negara (Persero) Tbk	Indonesia	Asia/Pacific Rim	6834	285	2935	219	304	155	5	76	-0.7	GU
188	Canadian Natural Resources Ltd	Canada	Americas	43433	64	7793	132	-151	272	0	268	-13.3	E&P
189	Entergy Corp	Louisiana	Americas	45904	59	10846	99	-584	298	-2	284	-1.6	EU
190	Empresa de Energia de Bogotá SA E.S.P.	Colombia	Americas	8089	256	1079	313	444	125	6	48	17	GU
191	The National Shipping Co of Saudi Arabia	Saudi Arabia	EMEA	5688	332	1810	263	469	123	9	27	33.6	S&T
192	YTL Corp Berhad	Malaysia	Asia/Pacific Rim	15785	158	3608	200	215	183	2	206	-8.4	DU
193	ATCO Ltd	Canada	Americas	14607	174	2996	218	252	173	2	184	-2.5	DU
194	Great Plains Energy Incorporated	Missouri	Americas	13570	183	2676	225	274	169	3	174	3	EU
195	Huaneng Renewables Corp Ltd	China	Asia/Pacific Rim	12574	196	1360	295	391	135	4	128	16.1	IPP
196	Brookfield Infrastructure Partners LP	Bermuda	Americas	21275	127	2115	252	276	167	2	209	5	EU
197	The Williams Companies, Inc	Oklahoma	Americas	46835	57	7499	140	-424	289	-1	273	3	S&T
198	Calpine Corp	Texas	Americas	19317	134	6961	144	92	234	1	247	2.9	IPP
199	Huadian Fuxin Energy Corp Ltd	China	Asia/Pacific Rim	15134	168	2342	239	281	166	2	189	6.3	IPP
200	EnBW Energie Baden-Württemberg AG	Germany	EMEA	43371	65	21932	51	-2023	324	-16	328	-1.8	EU

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201	Emera Incorporated	Canada	Americas	21640	123	3167	213	168	201	1	231	24.2	EU
202	Datang International Power Generation Co, Ltd	China	Asia/Pacific Rim	34320	87	8701	124	-386	286	-1	276	-7.7	IPP
203	Occidental Petroleum Corp	Texas	Americas	43109	67	10090	110	-1002	313	-3	291	-20.6	IOG
204	NRG Energy, Inc	New Jersey	Americas	30355	94	12351	91	-701	307	-3	289	3	IPP
205	Beijing Jingneng Clean Energy Co, Ltd	China	Asia/Pacific Rim	7024	280	2154	251	288	164	5	89	32.8	IPP
206	Inter Pipeline Ltd	Canada	Americas	7518	268	1351	297	333	150	5	76	10.2	S&T
207	YTL Power International Berhad	Malaysia	Asia/Pacific Rim	10148	223	2404	235	249	175	3	160	-13.6	DU
208	California Resources Corp	California	Americas	6354	302	1753	268	273	170	6	55	-25.8	E&P
209	Hokkaido Electric Power Co, Incorporated	Japan	Asia/Pacific Rim	16728	151	6426	151	64	244	0	250	3.7	EU
210	Iren SpA	Italy	EMEA	8775	246	3484	204	196	194	3	155	-1.1	DU
211	Vectren Corp	Indiana	Americas	5801	327	2448	233	212	184	6	55	-0.6	DU
212	Shikoku Electric Power Co, Incorporated	Japan	Asia/Pacific Rim	11898	202	6259	154	104	225	1	222	2.5	EU
213	Companhia Energética de Minas Gerais	Brazil	Americas	12842	193	5735	159	102	227	1	226	8.7	EU
214	ENEA SA	Poland	EMEA	6574	292	3016	217	210	185	4	112	7.1	EU
215	Guangxi Guiguan Electric Power Co, Ltd	China	Asia/Pacific Rim	5820	326	1260	305	382	137	7	38	20.1	IPP
216	NGL Energy Partners LP	Oklahoma	Americas	6320	303	13022	88	107	224	2	192	10.3	S&T
217	The Tata Power Co Ltd	India	Asia/Pacific Rim	12741	195	4328	180	116	217	1	222	-8	EU
218	Origin Energy Ltd	Australia	Asia/Pacific Rim	21835	121	9009	117	-466	293	-2	284	-6.8	IOG
219	FirstEnergy Corp	Ohio	Americas	43148	66	14156	83	-6177	336	-22	331	-0.6	EU
220	WGL Holdings, Inc	District of Columbia	Americas	6059	319	2350	238	168	202	5	62	-1.6	GU
221	Portland General Electric Co	Oregon	Americas	7527	267	1923	258	193	195	4	106	2	EU
222	Rabigh Refining & Petrochemical Co	Saudi Arabia	EMEA	15500	161	6705	148	10	260	0	258	-20.8	R&M
223	Delek Group Ltd	Israel	EMEA	37119	81	1632	274	80	242	1	231	-11.2	R&M
224	Boardwalk Pipeline Partners, LP	Texas	Americas	8638	247	1307	300	296	158	4	123	2.7	S&T
225	Cosan Ltd	Brazil	Americas	15419	164	3824	197	96	231	1	239	12.2	R&M
226	Cenovus Energy Inc	Canada	Americas	18705	139	8986	118	-404	288	-3	290	-13.4	IOG
227	Anadarko Petroleum Corp	Texas	Americas	45564	60	8447	128	-3078	328	-10	320	-17.2	E&P
228	YPF Sociedad Anonima	Argentina	Americas	26318	107	13130	86	-1765	323	-10	321	32.6	IOG
229	EVN AG	Austria	EMEA	7379	271	2327	241	176	198	4	128	-0.8	EU
230	Guangdong Electric Power Development Co, Ltd	China	Asia/Pacific Rim	10401	217	3338	208	138	207	2	209	-9.7	IPP
231	Hubei Energy Group Co, Ltd	China	Asia/Pacific Rim	6145	310	1379	290	281	165	5	76	-5.5	IPP
232	Oil India Ltd	India	Asia/Pacific Rim	7948	257	1484	284	248	178	4	123	-0.4	E&P
233	Beijing Jingneng Power Co, Ltd	China	Asia/Pacific Rim	7928	259	1635	272	248	177	4	136	-4.4	IPP
234	Petron Corp	Philippines	Asia/Pacific Rim	6431	296	6934	145	114	220	2	184	-9.5	R&M
235	EOG Resources, Inc	Texas	Americas	29459	98	7544	134	-1097	316	-5	304	-19.5	E&P
236	TAURON Polska Energia SA	Poland	EMEA	8964	240	4728	172	98	229	1	216	-2.7	EU
237	MVV Energie AG	Germany	EMEA	5632	334	4598	175	120	215	4	136	0.2	DU
238	Southwest Gas Holdings, Inc	Nevada	Americas	5581	337	2460	231	152	205	5	89	8	GU
239	Brookfield Renewable Partners LP	Bermuda	Americas	27737	104	2452	232	-21	265	0	263	12.9	IPP
240	IdaCorp, Inc	Idaho	Americas	6290	305	1262	303	198	192	5	70	0.4	EU
241	Devon Energy Corp	Oklahoma	Americas	25913	109	10364	106	-3304	329	-16	328	-0.7	E&P
242	Hokuriku Electric Power Co	Japan	Asia/Pacific Rim	13880	180	4961	168	-6	264	0	263	2.1	EU
243	PJSC Moscow United Electric Grid Co	Russia	EMEA	5939	321	2515	230	165	203	4	123	3.5	EU
244	Shenzhen Energy Group Co, Ltd	China	Asia/Pacific Rim	8956	241	1666	271	198	193	3	174	-2.9	IPP
245	First Philippine Holdings Corp	Philippines	Asia/Pacific Rim	7003	281	1853	261	198	191	3	149	-0.4	EU
246	Vistra Energy Corp	Texas	Americas	15167	167	5164	165	-163	273	-1	278	-4.3	IPP
247	Enbridge Energy Partners, LP	Texas	Americas	18110	141	4482	177	-376	285	-2	282	-14.3	S&T
248	Colbún SA	Chile	Americas	6823	287	1436	287	201	189	4	123	-5.4	IPP
249	Reliance Power Ltd	India	Asia/Pacific Rim	9953	228	1613	277	171	199	2	184	26.2	IPP
250	Qatar Gas Transport Co Ltd (Nakilat) Q.S.C.	Qatar	EMEA	8301	251	864	320	261	172	3	149	0.8	S&T

Top 250 Methodology

This annual survey of global energy companies by S&P Global Platts measures companies' financial performance using four key metrics: asset worth, revenues, profits, and return on invested capital.

All companies on the list have assets greater than US $5.5 billion. The fundamental and market data comes from a database compiled and maintained by S&P Global Market Intelligence.

Energy companies were grouped according to their Global Industry Classification Standard (GICS) code. Each company is assigned to an industry according to the definition of its principal business activity. (Source of GICS Industry Classification: S&P Global and MSCI).

Because the survey is global, and because all countries do not share a common financial reporting standard, the information presented is for each company's most current reporting period. Since then, material changes to a company's financial health may have occurred. Data for US companies came from Securities and Exchange Commission (SEC) Form 10K.

The company rankings are derived using a special S&P Global Platts formula. We added each company's numerical ranking for asset worth, revenues, profits, and ROIC and assigned a rank of 1 to the company with the lowest total, 2 to the company with the second-lowest total, and so on.

Finally, ROIC figures-widely regarded as a driver of cash flow and value were calculated using the following equation: ROIC = [(Income before extraordinary items) - (Available for common stock)] ÷ (Total invested capital) x 100 where "Income before extraordinary items" is net income less preferred dividends and "Total invested capital" is the sum of total debt, preferred stock (value), noncontrolling interest, and total common equity.

Financial data were compiled and translated into USD on June 8, 2017