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2016 ASIA ENERGY OUTLOOK

CHINESE DRAGONS SLUMBER AFTER GLOBAL FORAY

MIDDLE EAST OIL EXPORTERS PUMP UP AS PRICES RETREAT

ARAB GULF FLEXES REFINING MUSCLE

A GAME-CHANGER YEAR
2015 Platts Top 250 Global Energy Company Rankings®

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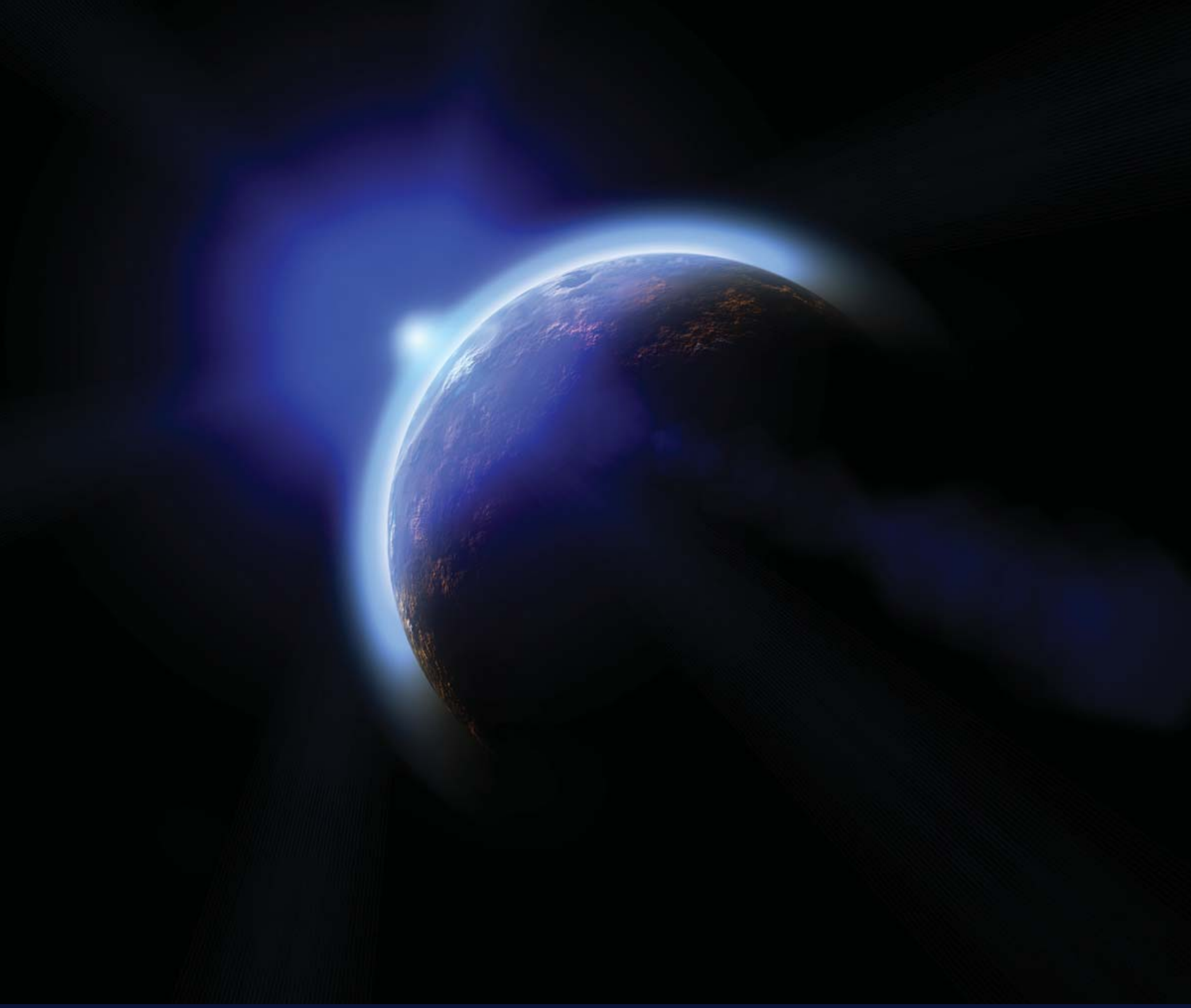

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EDITOR'S NOTE

We are living in interesting times.

Not just in China, which is seeing slowing growth, currency devaluation and stock market plunges; the rest of the energy world is also experiencing volatile times.

The oil price crash in the past year, makes this ever more so.

The times are testing the resilience, ingenuity and versatility of energy companies fight for a sliver of a globalized oil, gas and petrochemical market. While cheaper crude can help Asian refiners revive emaciated margins amid a regional glut, Chinese upstream giants are recalibrating their staggering global assets acquired when oil was expensive.

The oil and gas production surge in major consumer the United States, and Russia are testing the will of big Middle Eastern producers, especially Saudi Arabia, to keep the pumps flowing to support market share, but risking extended low prices.

The supply boom is offering Asian consumers wider and cheaper options. Global shipments, as well as weaker oil prices – which prompted traders to use vessels as storage – extend a lifeline to the tanker market that had floundered on oversupply in recent years.

Cheaper oil has helped China to build up reserves and entrench its clout as a global trader. It has emboldened governments, long saddled with hefty, but politically expedient subsidies, to push through protracted price reforms, helping to ease the pain of the slowing economy.

Mounting crude market competition has spurred Middle Eastern producers to diversify their industry, beefing up the oil refining as well as petrochemical sectors, by using abundant domestic feedstock, and enticing new customers. Rising refining capacities are inundating markets with diesel amid slowing demand growth; though escalating gasoline usage lifts profits.

Petrochemical makers are sharpening focus on the most value-added and specialized products, while leveraging the cheapest feedstocks from multiple sources.

We are witnessing spot LNG trade emerging in a hitherto long-term contract arena, as new supplies are turning the market from favoring sellers to buyers.

Cleaner and cheaper gas is asserting itself in markets once dominated by coal, as industries grapple with slowdown and emerging countries become sensitive to climate change. Yet, it is too soon to draw the curtains on thermal coal, as India seeks more imports to fill domestic shortfalls; while cheaper fuels slash mining costs in Indonesia.

The industry is exploring new opportunities, but must exercise prudence to sustain profitability, in an Asia-Pacific energy sector that holds a stable outlook, albeit with a negative bias. Japanese poet Kenji Miyazawa once said, "We must embrace pain and burn it as fuel for our journey." As the sands shift, which companies will show true grit?

— Ramthan Hussain, Editor


THE
POWER
TO
RECOGNIZE
TRENDS
BEFORE OTHERS DO

OCEANA ZHOU
Senior Analyst & Team Leader
China Market

Chinese DRAGONS SLUMBER

After a rush of global acquisitions worth more than $152 billion over the last 10 years to secure energy resources for China's booming economy, its state-controlled oil and gas giants are taking a breather and reflecting.

The oil price plunge, as well as energy sector reforms, the drive to improve management and clamp down on corruption amidst slowing economic growth, have prompted the companies to be more selective and subject the costs and value of investments to closer scrutiny.

Financial-services firm Dealogic recorded seven acquisitions completed so far in 2015, amounting to at least $1.6 billion. Another seven worth more than $630 million are pending. Of these, only two were concluded by state oil major Sinopec and the rest by Chinese investment funds and independent firms.

This compared with $3.5 billion for the whole of 2014 and a peak of $31.4 billion in 2012, mainly driven by state oil firms.

This underscores the cautious stance among international energy companies in the wake of the 60% slide in crude prices since June 2014. Barring Royal Dutch Shell's acquisition of BG Group and Australian Woodside Petroleum's all-share offer for Oil Search Ltd., "overall M&A deal value was relatively low compared to the past several years", consulting firm Deloitte said in a report in September.

As upstream companies expect oil prices to remain low, they are cutting costs and delaying capital projects to conserve cash, Deloitte added.

The experience is shared by Chinese state-owned oil companies. "The oil majors are unlikely to invest in oversea assets in the short term, as they have less cash compared with previous years," said a senior officer from the National Energy Administration, or NEA. The state firms are now expected to be run like independent enterprises and are responsible for their own investment returns, said the official who declined to be named.

PetroChina – listed entity of China National Petroleum Corp., or CNPC;

Sinopec and China National Offshore Oil Corp., or CNOOC, have all announced capital spending cuts of about one third this year compared with 2014.

PetroChina's capital expenditure in first-half 2015 was Yuan 61.65 billion ($9.63 billion), down 32% from Yuan 91.10 billion in the year-ago period. The company updated its estimated capex to Yuan 255 billion for full-year 2015, from Yuan 266 billion set at the start of this year.

Sinopec's first-half 2015 capex was Yuan 23.51 billion, down 40% from Yuan 39.19 billion in first-half 2014. In the beginning of 2015, the company targeted to cut total capex by 12% from 2014 to Yuan 135.9 billion this year.

Chinese oil majors' overall capex could shrink another 10-20% in 2016, investment bank Nomura said in a note published following the country's Oil & Gas Council meetings in Beijing in September.

The state oil companies must also evaluate a number of higher-priced overseas acquisitions made in the last few years, which saw thin returns, or even losses, when oil prices plunged and stayed low, analysts said.

Higher-priced acquisitions put under the microscope

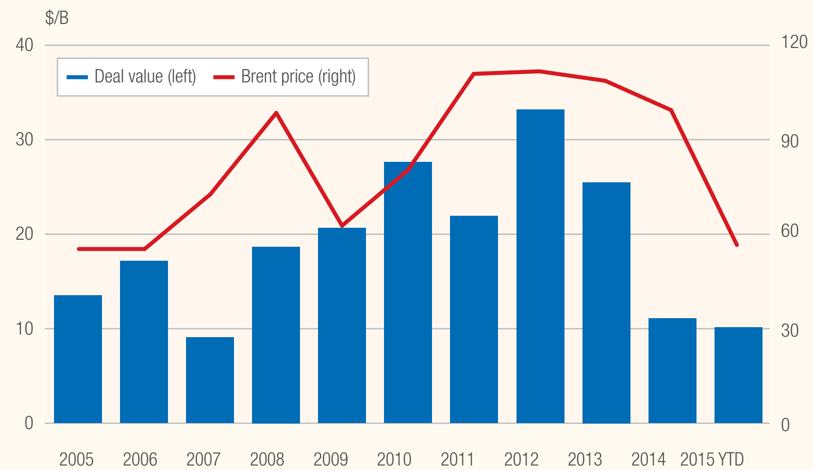
Under scrutiny are Chinese investments in Western Canada's energy sector and Angola. "These projects are doing badly because of their higher cost structures and low oil prices," said Gordon Kwan Head of Nomura Regional Oil/Gas Research, adding it was unlikely for them to return to profitability until oil prices rebound to $70/barrel and above by 2018, from below $50/b currently.

CHINA OUTBOUND M&A INTO OIL & GAS SECTOR – FULL YEAR

Announcement date by year	Deal value ($m)	No.
2005	6,636	10
2006	11,157	16
2007	1,016	10
2008	13,120	13
2009	15,586	22
2010	24,431	24
2011	17,158	26
2012	31,352	33
2013	21,695	22
2014	3,452	25
2015 YTD	2,327	14

Source: Dealogic, Platts

CHINA OUTBOUND M&A VOLUME IN OIL AND GAS SECTOR



Source: Dealogic, Platts

Since 2009, Chinese state-owned enterprises, or SOEs, have invested more than $23.94 billion in Western Canada.

Also in focus are Sinopec's acquisitions of oil blocks 18, 31 and 32 in Angola over 2009-2013.

The oil sands projects in Alberta are being closely examined, as production from several of the acquisitions in the Canadian province remains far from satisfactory, while Chinese SOEs are ▶

grappling with cost inflation in the North American country, Jiang Wenran, special advisor with the Alberta government, said early this year.

KEY OVERSEAS M&A BY STATE-OWNED MAJORS

Year	Company	Asset	Stake	Type	Location	Value ($ mil)
2015	Sinopec	Caspian Investment Resources	50%	Oil	Kazakhstan	1087
	Sinopec	SIBUR Holding OAO	10%	Oil/gas	Russia	Undisclosed
2014	Sinopec	Pacific Northwest	10%	LNG	Canada	827
	CNPC	Vankor	10%	Oil	E. Siberia, Russia	990
2013	Sinochem	Wolfcamp shale	40%	Shale gas	US	1700
	Sinopec	Mississippi Lime shale	50%	Shale gas	US	1000
	CNPC	Area 4	20%	Gas	Mozambique	4200
	CNPC	Yamal LNG	20%	LNG	Russia	Undisclosed
	Sinopec	Block 31	10%	Oil	Angola	1500
	Sinochem	BC-10	35%	Oil	Brazil	1500
	Sinopec	Apache Egypt	33%	Oil/gas	Egypt	3100
	CNPC/ PetroChina	Petrobras Peru Energia	100%	Oil/gas	Peru	2600
	CNPC	Kashagan	8.33%	Oil	Kazakhstan	5000
2012	Sinopec	Devon Energy shale	33.30%	Shale gas	US	2200
	Sinopec	Australia Pacific LNG	10%	LNG	Australia	1100
	CNOOC	Lake Albert Basin	33.30%	Oil	Uganda	1500
	Sinopec	Talisman Energy UK	49%	Oil/gas	UK	1500
	CNOOC	Nexen	100%	Various	Various	1510
	PetroChina	Browse LNG	10%	LNG	Australia	1600
2011	CNOOC	Chesapeake Denver-Julesburg/Powder River shale	33.30%	Shale gas	US	700
	PetroChina	Athabasca Oil Sands	40%	Oil sands	Canada	700
	Sinopec	Australia Pacific LNG	15%	LNG	Australia	1800
	CNOOC	OPTI Canada	100%	Oil sands	Canada	2100
	Sinopec	Daylight Energy	100%	Oil/gas	Canada	2200
	Sinopec	Petrogal Brasil	30%	Oil	Brazil	3500
2010	CNOOC	Bridas	50%	Oil	Argentina	3100
	Sinopec	Syncrude	9.03%	Oil sands	Canada	4700
	Sinochem	Peregrino	40%	Oil	Brazil	3100
	PetroChina	Arrow Energy	50%	Gas/LNG	Australia	1400
	CNOOC	Chesapeake Eagle Ford shale	33.30%	Shale gas	US	2200
	Sinopec	Repsol YPF Brasil	40%	Oil	Brazil	7100
	Sinopec	Gendalo-Gehem	18%	Gas	Indonesia	700
	Sinopec	Occidental Argentina	100%	Oil/gas	Argentina	2500

Source: Platts

"Chinese companies will be running the numbers now," Jiang said. "There is a raging domestic debate in China to determine if investments made by tax payers' money are justified by the returns."

CNOOC's takeover of Nexen in 2013, the biggest global investment by a Chinese oil company, contributed only 2%, or Yuan 1,078 million, to the upstream firm's overall profits that year.

Despite rising output since the deal was sealed and massive cost cuts, its contribution to CNOOC's profits was still limited by low oil prices, with a senior official in charge of CNOOC's strategy saying it stood around 3%.

The Canadian oil sands Long Lake facility in Alberta, where bitumen output has risen to 50,000 b/d from 30,000 b/d in 2013, suffered a pipeline "failure" in July, leaking some 31,500 barrels of bitumen emulsion. The incident led to a heavy environmental fine, thrusting the project to greater public attention and impacted efforts to boost production further.

Nexen shed about 400 jobs across its North America and UK divisions due to lower capital spending this year, even though CNOOC had promised no job cuts after the acquisition. Nexen had around 3,200 regular employees worldwide at the end of 2013, according to its website.

Given the abundance of global LNG supplies and slack growth in China's gas demand, there are also questions about the aggressive pursuit of gas assets in the last few years. CNPC, Sinopec, SinoChem and CNOOC have collectively spent more than $18.6 billion in the last five years to take stakes in

LNG or shale gas projects in various parts of the world, including North America, Russia, Australia and Mozambique.

Waiting for bargains

Despite unfavorable factors, Chinese state-owned giants remain open to making overseas investments that meet certain criteria, but face limited opportunities in the current low price environment.

"Investors need to think long-term as these projects are meant to last the next 20 years. If the big three has an attractive overseas deal, they would make exception to increase their capex budget," Kwan said. "But right now, sellers are reluctant to give up their assets at low oil prices. So the big three are waiting to negotiate for better bargains," he added.

Moreover, the extent of capex cuts by the state-owned giants has been smaller than the drop in oil prices, said a senior official at a state-owned oil major, indicating that there are financial possibilities for new overseas projects.

Wang Dongjin, vice president of CNPC said in PetroChina's 2015 interim results that the group continues to look for targets and good opportunities for overseas M&A, which will benefit from low oil prices. For example, CNPC and Sinopec are in active talks to join new oil and gas projects in Kazakhstan despite recent soft oil prices.

However, "good M&A opportunities are limited. The current offers [for overseas assets] are too high, at $70-80/barrel while oil price is lower than $50/b, because the potential sellers are able to sustain for a while," said the NEA officer. Sinopec's former chairman Fu Chengyu, said early this year: "The important thing about overseas assets is that future valuations are based on today's oil price. In this case, sellers will always say oil prices are bound to go up. And it is hard to get agreement between buyer and seller.

"The opportunity now is to monitor rather than to actually make deals. Oil prices are still volatile, it is not time yet."

Deloitte's report pointed out that industry lenders did not seek radical corrective action to increase the pressure on highly leveraged companies to sell assets.

"Chinese companies also lack the stimulator for massive M&As. It has been different from the start of the acquisition wave in 2008, when state-owned companies were forced to spend the US dollars in order to avoid further cash depreciation due to the US quantitative easing moves," said a senior official in China Investment Corp., a state-owned sovereign wealth fund. The country's foreign reserves peaked at $3.99 trillion in June 2014, before dipping to $3.56 trillion in August 2015, latest data released by the State Administration of Foreign Exchange show.

CNOOC chairman Yang Hua, said in the company's 2015 interim results that overseas investments can be done whether oil price is high or low, asserting that the key for a successful investment is value generation and good management on the asset. CNOOC has seen costs reduced by 18.5% in first-half 2015, much steeper than the 2.8% cuts for PetroChina and 2.4% for Sinopec, following the oil price slump. ▶

Reforms and anti-corruption drive

Chinese President Xi Jinping, who pursued a highly publicized anti-graft drive since taking office in 2013, has ensnared a long list of high-profile officials in the industry, including Zhou Yongkang, the now-disgraced energy and security tsar; former CNPC chairman Jiang Jiemin; former CNPC CEO Liao Yongyuan and former Sinopec CEO Wang Tianpu.

The campaign has reached the oil majors' overseas branches, which were considered to be more exposed to corruption through the transaction chains as the projects are far away from Beijing.

In mid-September, CNPC said it had trimmed the regional and overseas offices, adding that five officials who were, or are, in charge of the company's projects abroad are under investigation. The senior official from CNOOC said several of the overseas assets have been acquired at unreasonably high prices.

The house-cleaning has partly led to Chinese oil firms stepping back from overseas markets, the CNOOC official said, adding that several of the overseas assets have been acquired at unreasonably high prices.

The Chinese Communist Party in May announced new appointments at all three state oil firms to underscore the government's control, even as they attempt to modernize and improve corporate governance via reforms. The new chairmen of the three oil majors have been tasked with fighting corruption, as well as put their companies through reforms.

To comply with the party directive, the respective new chairmen of CNPC, Sinopec Group and CNOOC – Wang Yilin, Wang Yupu and Yang Hua – are believed to have put modernization and corporate governance as the top agenda.

China plans to achieve major reforms in key industries, including energy, by 2020. Since the NEA has yet to announce the detailed reform plan for the oil and gas sector, state oil majors need to be on the guard until it is carefully implemented. The scheme remains under consultations. "The uncertainties in reform also hold back significant overseas M&A," said the senior official at a state-owned oil major.

But Sinopec's Fu said the clampdown would not derail the company's overseas expansions, and could eventually help improve their development and make them more robust.

Kwan agreed, saying that the drive in recent years has helped state-owned firms to cut costs and build better management teams, though it was painful initially and slowed overseas acquisitions.

"The Big Three will resume massive M&A once they have completed their internal restructuring, existing assets portfolio review, and oil prices stabilize above $70/b, probably in 2017," said Nomura's Kwan.

Beijing is also supportive of the companies' acquisition drive, given that the government has been gradually easing control on approvals for global M&As.

China's top planner, National Development and Reform Commission, said in second-quarter 2014 that only overseas investments exceeding $1 billion, or located in unsafe regions, need its approval, up from $300 million set in 2004.

Chinese officials said overseas investments are just one part of the state firms' business and not the country's only strategy to ensure energy supply. "They [the oil companies] run the assets independently. China relies on crude trading to secure energy supplies rather than outputs from overseas assets," the NEA official said. ■

ALL CHINA OUTBOUND M&A DEALS INTO OIL & GAS SECTOR IN 2015 YTD

Announcement Date	Status	Target	Target Nationality	Target Advisor Parent	Acquiror	Acquiror GIG	Value $ (m)
10 Jun 2015	Completed	Caspian Investment Resources Ltd (50%)	Kazakhstan	Deutsche Bank	China Petrochemical Corp	Oil & Gas	1,087
28 May 2015	Pending	Zhejiang Benbao Industry Investment Co Ltd	United States		Yantai Xinchao Industry Co Ltd	Computers & Electronics	344
10 Aug 2015	Completed	CEFC International Ltd (16.6667%)	Singapore		Shanghai Tongtian International Holding Co Ltd (8.33% / 4.17% / 4.17%); Shanghai Shengzhou Oil Group Co Ltd; Hong Kong Great Wall Economic Cooperation Centre Ltd	Finance	178
26 May 2015	Completed	New Star Energy Ltd	Canada	Macquarie Group; National Bank Financial	Sinoenergy Pacific Corp	Oil & Gas	175
29 Jun 2015	Completed	Northern Offshore Ltd	United States		Shandong Offshore International Co Ltd	Oil & Gas	160
04 Aug 2015	Pending	Long Run Exploration Ltd (44.4766%)	Canada	National Bank Financial; Scotiabank; Scotiabank"	MIE Holdings Corp	Oil & Gas	153
08 Jan 2015	Pending	Oil & Gas Assets (Galaz contract area)	Kazakhstan		Xinjiang Zhundong Petroleum Technology Co Ltd	Oil & Gas	100
06 August 2015	Completed	RockEast Energy Corp (30%)	Canada		Loudong General Nice Resources (China) Holdings Ltd	Oil & Gas	67
26 May 2015	Completed	Range Resources Ltd (Stake%)	Australia	RSM Bird Cameron Partners	Beijing Sibo Investment Management LP	Finance	30
31 Aug 2015	Pending	Armour Energy Ltd	Australia	Morgans Financial Ltd; BDO	Landbridge Group Co Ltd	Oil & Gas	26
15 Jun 2015	Pending	South Derrik OsOO (13.61%)	Kyrgyzstan		Full Apex (Holdings) Ltd	Chemicals	6
03 Sep 2015	Pending	Yamal SPG OAO (9.9%)	Russian Fed		Silk Road Fund	Finance	
03 Sep 2015	Pending	SIBUR Holding OAO (10%)	Russian Fed		China Petrochemical Corp	Oil & Gas	
24 Sep 2015	Completed	Dyneff SA (51%)	France		Shanghai Energy Fund Investment Co Ltd	Finance	

Source: Dealogic

PERSIAN GULF

TAMSIN CARLISLE

Senior Editor
Platts News

LOW PRICES HIGH VOLUME

Persian Gulf oil exporters pump up the volume as prices retreat

More than a year after oil prices started to slide, Middle East Gulf producers are feeling distinctly pinched, but it is only recently that the biggest of them has admitted as much.

This was not a development that Saudi Arabia's government had foreseen.

Little over a year ago, in August 2014, its petroleum minister's top oil adviser, Ibrahim al-Muhanna, was arguing that the high cost of US shale oil extraction had put a $90/b floor under oil prices and that only minor departures from that level were to be expected.

Now, with international oil prices deep in the cellar, even some Saudi upstream oil projects may be at risk, as Riyadh prepares to cut "non-essential" spending.

The stand-out example is the planned $3 billion expansion of the giant Khurais oil field in Saudi Arabia's oil-rich Eastern Province, which has already had its construction phase extended for 12 months to help manage cash flow for the development.

Located near the world's biggest oil field, Ghawar, the recently developed Khurais field has a 1.2 million b/d production capacity. Plans for further development originally called for capacity to be increased by 300,000 b/d by early 2018.

However, during discussions earlier this year on cost savings between Saudi Aramco and Italy's Saipem, which won the $2 billion contract for the main processing facilities, the execution phase of the Khurais field expansion was stretched into 2019.

At the time, with oil prices at roughly half what they were in mid-2014, industry sources said Aramco might decide to scrap the project if insufficient potential cost-savings were identified. But by the time Dated Brent had slid below $45/b in late August, the Saudi national petroleum company had still not made a decision one way or the other.

A week later, Saudi Finance Minister Ibrahim al-Assaf said during a televised interview on CNBC Arabia that government spending cuts and delays to some state projects were in the works, a warning that could force Aramco's hand on Khurais.

Oil from the field, which started production in 2009, was intended to offset expected output declines from mature Saudi oil fields, including Ghawar. However, expanding Khurais is not Aramco's only option for offsetting future mature-field declines and may not be the most cost efficient.

"They may have concluded that they don't need all that oil from Khurais," Robin Mills, head of consulting for Dubai-based Manaar Energy Consulting and Project Management, said in a telephone interview soon after the minister's announcement. "They could increase investment in mature fields instead."

Aramco and Saipem officials were not immediately available for comment.

Defending market share

Nonetheless, from the November 2014 OPEC meeting right up until Assaf's announcement of impending government spending cuts, Saudi Arabia had been pumping crude as if there were no tomorrow, pushing output to a record of about 10.4 million b/d in August.

Oil Minister Ali al-Naimi's stated rationale for this was that the kingdom needed to defend its share of the increasingly competitive global oil market, even if that meant weathering a period of lower oil prices and reduced government revenues before rival producers with higher development and extraction costs were forced to curtail output.

This new policy meant Saudi Arabia, as OPEC's kingpin, would not cut crude output to sway market sentiment, as it had during several previous price downturns. Nonetheless, it was clear that oil revenue remained the kingdom's life-blood.

CRUDE PRODUCTION BY SELECTED PERSIAN GULF STATES (MILLION B/D)

	Jul-15	Jun-15	May-15	2014 average	Change: Jul-15 vs. 2014	% change
Saudi Arabia	10.35	10.31	10.19	9.68	0.67	6.92%
UAE	2.87	2.85	2.85	2.76	0.11	3.99%
Kuwait	2.70	2.70	2.71	2.77	-0.07	-2.53%
Iraq (incl. Kurdistan)	4.07	4.07	3.80	3.27	0.80	24.46%
Iran	2.86	2.83	2.84	2.77	0.09	3.25%
Oman	0.89	0.89	0.89	0.86	0.04	4.51%

Sources: OPEC, Oman Oi and Gas Ministry

Even in early September, with Riyadh on its way to realizing a hefty budget deficit, major changes to Aramco's upstream development program seemed improbable. Oil project deferments rather than outright cancellations, as well as discussions with contractors over mutual cost-saving initiatives, had been Aramco's preferred budget management tactics as oil prices began their descent. There seemed no immediate reason for that to change.

Analysts said priority upstream projects related to meeting domestic fuel and power demand had been ring-fenced. Those included most projects aimed at increasing Saudi natural gas production, whether from conventional or unconventional gas deposits, or even from gas caps associated with oil fields.

Since much of Saudi Arabia's gas supply is sourced from oil fields, while government efforts to diversify the economy away from oil has entailed the provision of ever larger volumes of subsidized gas to industry, this was ▶

another compelling reason why Riyadh could not afford to cut investment in upstream oil development by very much.

Assaf alluded to this in the broadcast interview when he said Saudi Arabia was in a good position to manage low oil prices and the government would continue to invest in some sectors of the economy, as it attempted to reduce reliance on oil revenues.

"We have built (financial) reserves, cut public debt to near-zero levels and we are now working on cutting unnecessary expenses while focusing on main development projects and on building human resources in the kingdom," he said, without specifying where cuts would be made.

The International Monetary Fund in August said Riyadh needed to save money through "comprehensive energy price reforms, firm control of the public sector wage bill, greater efficiency in public sector investment".

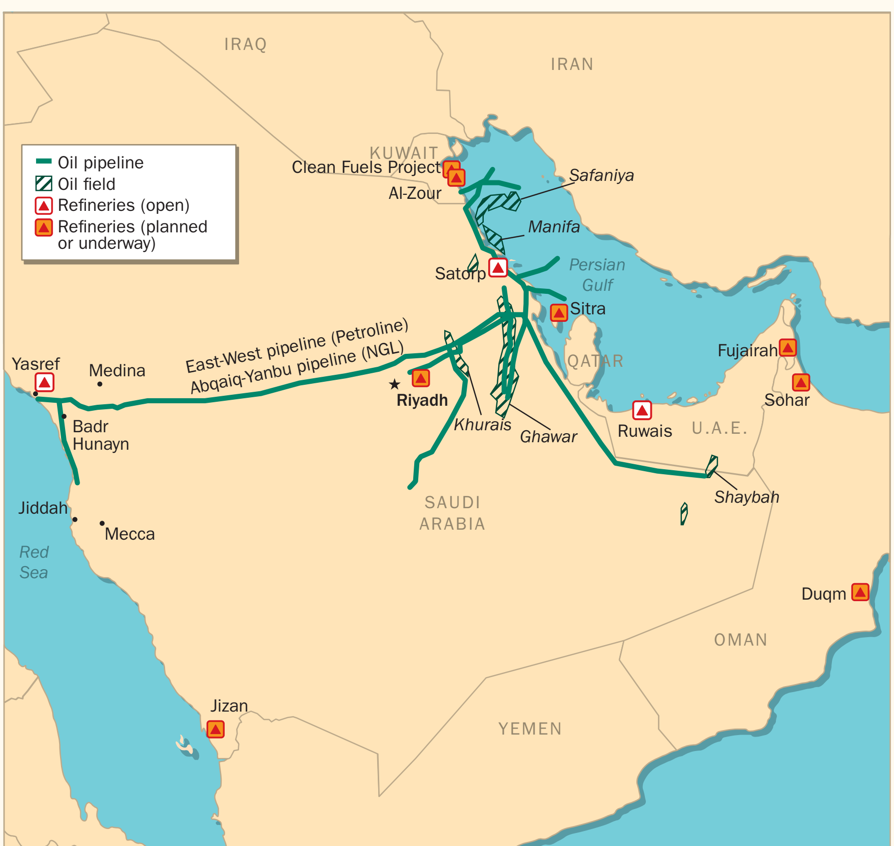
However, the Saudi government may be reluctant to follow that path as scrapping fuel subsidies and/or freezing public-sector salaries could ignite popular unrest. No sign has yet been given of an impending switch in oil policy to one defending prices in the interest of bolstering the dwindling flow of petro-dollars to the public purse.

That means the kingdom will not erode its ability to produce as much oil as it can sell, even as it steels itself for a protracted period of low oil prices. It will especially avoid doing so while Riyadh has a short-term need for ready cash to finance wars against Houthi rebels in Yemen and the Islamic State group in the wider Arab world.

"Maintaining market share is even more of a priority now for Saudi Arabia than when prices began to fall in the second half of 2014," Riyadh-based Jadwa Investment said in July in its latest quarterly oil market update. "Global oil markets are more competitive and the kingdom faces competition from both within OPEC and outside it."

With analysts expecting about 800,000 b/d of additional Iranian crude to enter the market during 2016, once sanctions on Iran start to be lifted in response to its nuclear agreement with the P5+1 group of international powers, the pressure on

SAUDI ARABIA MAJOR OIL INFRASTRUCTURE AND MIDDLE EAST REFINERIES



Source: EIA, Platts data

Aramco to keep pumping crude in defense of market share is unlikely to ease soon.

"Aramco will respond to whatever budget they are given, but they are clever at playing the bureaucracy," Mills said.

The region's other major producers face similar dilemmas, with most apparently reaching the conclusion that they need to pump up oil export volumes in the short term to offset lower prices and falling state revenues, and longer term to defend market share.

While Saudi Arabia in July was producing about 670,000 b/d, or nearly 7% more crude than it had averaged in 2014, UAE output was up about 4% and Oman's by 4.5%. Those increases were upstaged by an 800,000 b/d production surge in Iraq, where crude output grew almost a quarter from what it had averaged in 2014 to exceed 4 million b/d. Even Iran, under strict international sanctions targeting its petroleum sector, managed to raise oil output by more than 3% from last year's average.

On-track production

Of the major Gulf oil producers, only Kuwait has allowed production to slip.

By Manaar's reckoning, Kuwait has a fiscal break-even oil price of just under $50/b. This is the lowest in the six-member Gulf Cooperation Council, which includes Saudi Arabia, the UAE, Oman, Qatar and Bahrain. It compares with an oil price of above $100/b that Saudi Arabia would need to balance the record budget Riyadh tabled for 2015, while fiscal break-evens for Iran and Iraq are higher still.

Kuwait, while unlikely to run a deficit this year, is cognizant of the need to defend market share, particularly in the ultra-competitive Asian market.

Like Saudi Arabia, the UAE and particularly Oman, its oil-rig count has risen since the start of this year, showing Kuwait is taking steps to offset production declines from mature fields. In its latest effort to raise crude output, state-owned Kuwait Oil Co. has invited companies to bid on contracts to develop the East Raudhatain, West Raudhatain, West Sabriya and Umm Niqa heavy oil fields in the emirate's Jurassic basin.

The UAE, with a fiscal break-even oil price estimated around a relatively modest $55/b, has joined Saudi Arabia in costly air offensives against Yemen's Houthis and IS. Meanwhile, the country's much-touted 2017 deadline for increasing oil production capacity to 3.5 million b/d from the current 3 million b/d has slipped by at least a year, senior officials of Abu Dhabi National Oil Co. disclosed over the summer.

Abu Dhabi has had limited success in wooing major international oil companies and technology savvy second-tier producers as new partners for Abu Dhabi National Onshore Oil Co., or Adco, the operating consortium for the concession containing the UAE's major onshore oil fields.

The original Adco contract expired in January 2014, yet of the total 40% interest in the new concession reserved for international partners, less than half has been awarded with a 22% interest still up for grabs.

Of four oil majors that were partners in the old Adco group and were also invited to bid for stakes in the new ▶

concession, ExxonMobil declined to bid while BP and Shell recently withdrew theirs, deterred by low estimated rates of return and Abu Dhabi's demand for hefty signing fees. Of the original Adco partners, only Total has become a partner in the new Adco after its bid for a 10% stake was approved in January.

The other new Adco partners are Japan's Inpex (5%) and South Korea's GS Energy (3%). Both those companies' host countries are major importers of Abu Dhabi crude.

Even with such a lackluster response to the proffered new contract, Adco production is running smoothly with ADNOC as consortium leader marketing exports of the concession's Murban crude through the UAE's new Fujairah oil terminal on the Arabian Sea coast.

Initiatives to boost the volume and efficiency of output from Abu Dhabi's offshore oil fields in the Persian Gulf continue to make slow but steady progress, as indicated by project updates presented at international conferences.

However, some major upstream projects are starting to experience delays. Notably, the bidding deadline for a $2 billion integrated facilities development for the Bab oil field was moved to July 29 from June 1. Delays have also been announced for the UAE's Shah and Bab sour gas developments.

Oman, which is dependent on its oil sector for about 90% of state revenues yet has much smaller reserves and bigger technical challenges to extract its crude than most of its GCC neighbors, has surprised many by raising oil output this year after stating that it only hoped to keep production flat. Oil and gas ministry data show Oman's total liquids output in July surpassed 1 million b/d for the first time in the sultanate's history, of which nearly 890,000 b/d was crude.

Among other tactics, Oman has embarked on a drilling blitz to unlock reserves of heavy crude. It had 61 oil rigs operating in July, second in the Gulf region only to Saudi Arabia with 69 rigs.

Oman's oil and gas minister, Mohammed al-Rumhy, has criticized Saudi Arabia for failing to defend oil prices, reflecting the sultanate's comparative lack of financial buffers. This hasn't stopped Muscat from forging ahead with major upstream projects that leverage foreign partners' advanced technical expertise.

Shell, BP, Occidental Petroleum and Abu Dhabi state-owned Mubadala Petroleum have remained committed upstream partners in Oman despite the oil-price slide, while bidding rounds for new exploration blocks have brought in smaller and mid-sized producers from the region and further afield. The oil and gas ministry's latest bid round, launched August 2014, is set to close in October.

Despite severe cuts to its capital budget this year, BP said in April it would continue to invest in Oman's biggest-ever upstream project, the $16 billion Khazzan tight gas development. The BP-led project, in which Oman's government is a 40% partner, involves drilling some 300 wells over the next 15 years.

Iraq, Iran to play key role

Iraq, blessed or cursed with oil resources that may yet prove to rival those of Saudi

Arabia, was able to boost oil exports this year by adding much-needed infrastructure such as pipelines and single-point moorings in the south while its semi-autonomous Kurdistan region opened an export pipeline to Turkey.

However, both Iraq's central government and the Kurdistan Regional Government face immense financial, security, political and logistical hurdles that could cause petroleum sector momentum to reverse and even tear the country apart.

Among Iraq's well-known problems are the continuing sectarian unrest and intermittent violence that allowed Islamic State to seize large sectors of northern and western Iraq in the summer of 2014, the high cost of ongoing efforts to oust IS, widespread government corruption and bureaucratic inefficiency, the lingering and unresolved Baghdad-KRG dispute over oil jurisdiction, as well as the two governments' failure to agree on a new federal oil and gas law.

As of August, Baghdad's budget woes were causing some southern infrastructure projects to be delayed or scrapped. These include canceled plans to build a degassing station in the Zubair oil field and Shell's decision to delay investing in development of the Majnoon field. In July, KRG oil exports were suspended due to a sabotage attack in Turkish territory on the Kurdistan-Ceyhan pipeline.

However, Iraq has surprised many by continuing to hang together in the face of existential threats while still exporting crude. For the moment, while the south could still face intractable problems, the Kurdistan region appears to be clearing obstacles that had threatened to stall further development of its upstream oil sector.

After the Turkish pipeline was repaired and put back into service, the KRG in August announced plans to expand the capacity of its connecting export line to 1 million b/d in 2016 from the current 700,000 b/d. In September, the KRG resumed previously suspended payments to international contractors for Kurdish crude supplied for export.

A large question mark hovers over the future of Iran's petroleum sector. Even though the historic nuclear pact signed in July may not after all be blocked by the US Congress, it still has to be implemented. Nonetheless, Tehran has recently hosted a steady stream of foreign oil and service company officials eager to scout out opportunities for new business when sanctions are eased.

The reactions of GCC states to Iran's nuclear accord have been mixed, with Riyadh and Abu Dhabi voicing fears that its implementation could further destabilize the region, while Kuwait and Oman welcome the prospect of improved trade and business relations with Tehran.

Yet, it is highly unlikely that any GCC oil exporter will voluntarily allow their production to slip in order to accommodate Iran in markets awash with crude.

That means upstream oil development will continue in the Gulf region, even if governments must borrow to keep their main growth engine from sputtering. Local drilling and oilfield services contractors have noticed that while profit margins on projects may be leaner, the work is not drying up. ■

ARAB GULF OIL
ADAL MIRZA
Senior Oil Writer
Middle East Oil News

FLEXING REFINING MUSCLE

The long-expected deluge of oil products from new Middle Eastern refineries is about to hit export markets, which would turn the net-importing region into a global force in diesel and even gasoline by 2020.

Some projects are faring better than others, but if all were to proceed, Gulf Cooperation Council countries could have almost 3 million b/d of additional refining capacity by the end of the decade. These are on top of 4.8 million b/d in 2012, the Oxford Energy Institute, or OEI, said.

The Yasref refinery has reached its 400,000 b/d capacity within a year of starting up.

Analysts have said because of their ability to produce ultra-low sulfur diesel, or ULSD, Middle East refineries would give stiff competition to refiners in the US and Asia Pacific. China, India and countries such as Vietnam will be adding around 6 million b/d up to 2018, and had been struggling with poor cracking margins till recently.

Saudi Arabia's latest downstream complex, the 400,000 b/d Yasref refinery, a Saudi Aramco- Sinopec joint venture, ramped up to full production in August, and is on the verge of its maiden on-specification diesel and gasoline cargoes.

The refinery, located at the Yanbu Industrial City, started trial runs at the end of September last year and has been producing off-spec diesel.

It loaded its first diesel cargo from Yanbu in mid-January, with 300,000 barrels of 500 ppm sulfur grade for the domestic market in Jeddah and has been working to stabilize the density and quality of key products to produce on-spec diesel for the northwest European market as well as US-spec gasoline.

Yasref is expected to eventually produce 263,000 b/d of 10 ppm sulfur diesel and 90,000 b/d of gasoline, as well as 140,000 mt/year of benzene. It processes Arab Heavy and Arab Light crudes from the offshore Manifa oilfield.

The plant's operation takes Saudi Arabia's refining capacity to 2.9 million b/d, hoisting it to sixth place in the global capacity rankings, replacing South Korea. The kingdom plans to add 400,000 b/d with the completion of the Jizan refinery by the end of this decade, taking total capacity to 3.3 million b/d.

Yasref's start-up follows full operations at the 400,000 b/d SATORP refinery, Aramco's joint venture with France's Total at Jubail on the kingdom's eastern coast a year earlier. Aramco plans to build another 400,000 b/d refinery at Jizan by 2018, although the project has faced several hurdles, not least because of its remote location.

GCC REFINING CAPACITY EXPANSION AND CLOSURE PLANS (B/D)

Country	Refinery	Capacity additions	Planned completion date
New refineries			
Saudi Arabia	Satorp	400,000	Q4 2013
Saudi Arabia	Yasref	400,000	Q4 2014
UAE	Fujairah	200,000	2017
Oman	Duqm	230,000	2017
Saudi Arabia	Jizan	400,000	2017/2018
Kuwait	Al-Zour	615,000	2019
Expansions/upgrades			
UAE	Ruwais	417,000	Q4 2014
Oman	Sohar	81,000	2016
Kuwait	Mina Abdullah	186,000	2019
Kuwait	Mina al-Ahmadi	120,000	2019
Bahrain	Sitra	95,000	2019
Permanent Closures			
Saudi Arabia	Jeddah	-90,000	2016
Kuwait	Shuaiba	-200,000	2019
Total net capacity additions by 2020		2,854,000	

Source: Oxford Energy Institute, Platts calculations

UAE's ambitions

Abu Dhabi National Oil Co, or ADNOC, has also been busy commissioning $10 billion worth of new units at the Ruwais refinery which have doubled its capacity to 817,000 b/d, equivalent to around a quarter of the United Arab Emirates' daily oil output.

With the existing Ruwais and Abu Dhabi refineries, state-owned Takreer can process 510,000 b/d at its facilities, with 230,000 b/d of crude and 280,000 b/d of condensates.

After a three-year absence, Ruwais refinery resumed gasoil exports on a term basis in June after upgrades, including the new 420,000 b/d crude distillation unit and hydrotreater that started earlier this year. Term gasoil export contracts had not been signed since 2012 due to strong domestic consumption of 500 ppm sulfur gasoil and upgrade work.

ADNOC started up the new units at the end of 2014, which are expected to meet the UAE's domestic demand for refined products that is currently covered by imports.

Start-up operations since May have not been entirely smooth. Technical problems in July triggered the shutdown of the 125,000 b/d residue fluid catalytic cracker, which processes heavy fuel oil into higher value diesel and gasoline. ADNOC has been slowly ramping up the crude distillation units after the outage and aims to hit 75% of production by September. ▶

Abu Dhabi is pushing ahead with its carbon black and delayed coker project to utilize the RFCC slurry and vacuum residue, as well as eliminate fuel oil production. The project, due for end-year completion, will also produce value-added products such as carbon black, propylene and anode grade coke, which will be used in the emirates' aluminium and steel industries.

UAE's International Petroleum Investment Co., or IPIC, is expected to finally announce the winner of a major engineering, procurement and construction contract for a 200,000 b/d refinery at Fujairah.

> "Located on the Red Sea coast, refineries such as Yasref could be better placed to serve the European market, although it must compete with US and Russian refiners in an already crowded market."

With its strategic location outside the Strait of Hormuz and access to the Indian Ocean coast, Fujairah has become a major bunker and oil trading hub.

The UAE hopes the new refinery will drive Fujairah's growth further, rivalling Rotterdam and Singapore. Once construction contracts are awarded later this year, with a shortlist comprising South Korean bidders, the refinery could be ready in 2018 at the earliest.

This could be followed by 615,000 b/d from the Al-Zour refinery in Kuwait and 200,000 b/d at Fujairah by 2019. Oman is also planning a 230,000 b/d refinery at Duqm and Bahrain aims to expand its existing Sitra refinery.

Middle East refiners serve domestic, world markets

The GCC is expected to increase its gasoline capacity from 650,000 b/d in 2012 to just over 1 million b/d by 2018, while diesel is expected to double from 1.1 million to close to 2 million b/d. Kerosene will rise by 170,000 b/d and fuel oil output will jump 400,000 b/d, the OEI said.

Despite the oil price slump since mid-2014, the case for refinery expansions in the region remains compelling. Much of the new production is expected to be consumed domestically.

The OEI projected last December that gasoline demand by the six GCC states – Bahrain, Kuwait, Oman, Qatar, Saudi Arabia and the UAE – would grow by 450,000 b/d in 2018 to almost 1 million b/d. Diesel demand will rise to 1.35 million b/d from 940,000 b/d.

Based on this, the region will continue to face a small gasoline deficit, so the impact would be felt in reduced Saudi imports, rather than rising exports. The region would remain a net gasoline importer until 2018, after which exports of the auto fuel would start, the OEI said.

But diesel exports are expected to surge four-folds from 2012 during the same period. The region will remain a key net exporter of fuel oil, which will increase by 150,000 b/d by 2018.

Europe looks the most likely destination for much of the new volumes, particularly diesel. In 2009, the EU introduced the Euro-V fuel standards, reducing the maximum sulphur content for diesel to just 10 parts per million, or ppm, from the 50ppm set in 2005. Satorp shipped its first 80,000 mt cargo of ultra-low sulfur diesel from Jubail in October last year, claiming just 3ppm.

Analysts at Wood Mackenzie in the UK, forecast European demand for ULSD will rise to 710,000 b/d by 2016 from below 600,000 b/d in 2012.

Located on the Red Sea coast, refineries such as Yasref could be better placed to serve the European market, although it must compete with US and Russian refiners in an already crowded market.

Saudi Oil Minister Ali al-Naimi, speaking at the Jizan Economic Forum at the end of February, set out his ambitions to turn the kingdom into the second-largest exporter of refined products behind the US.

This will require huge investments in capacity additions; reduce fuel consumption by developing alternative gas feedstock for generation and a dramatic change in the region's culture of subsidies, given current domestic consumption patterns. There is little sign that the kingdom will cut subsidies yet.

Aramco's latest annual review showed Saudi Arabia produced 780 million barrels of products such as jet fuel, diesel and gasoline in 2013. It could consume more than 620 million barrels domestically, up from more than 588 million barrels in 2012. At this rate, domestic consumption will hit almost 900 million barrels by 2020, keeping it as a net importer, if the new capacities had not been built.

Tentative wave of optimism, oversupply looms

While global upstream projects have faced delays amid falling oil prices, the Middle East downstream sector is riding a temporary wave of optimism based on cheaper feedstock and improving margins across Europe and Asia recently.

This may have offered some relief from the drop in crude revenues, but the sector continues to face oversupply in coming years.

The squeeze on finances has meant national oil companies have had to scrutinize their capital spending plans. Aramco's decision this year to shelve its $3 billion Ras Tanura clean fuels project – a major rehabilitation – shows the downstream sector is not entirely immune from the effects of low oil prices.

The region's national oil companies have been relatively disciplined so far. None of the major greenfield refinery projects have been shelved in the face of lower oil prices, partly because most were envisaged before the oil price collapse.

The refinery project in Jizan, in Saudi Arabia's southern province near the Yemeni border, has been driven by a key economic priority: the need to create jobs in an underserved area.

The refinery is expected to supply 20% of Saudi Arabia's fast-growing demand for oil products – producing mainly gasoline and diesel, but no fuel oil. Located in a remote region, Saudi Aramco was mandated with a mammoth task to develop infrastructure, including water, sewage treatment, power distribution, communications network and roads. So it will be unsurprising if there are delays.

Designs for the refinery were completed in 2012, and a $4 billion lump-sum turnkey contract was awarded to Italy's Saipem in May 2014. Construction of the refinery and oil terminal should be completed by end-2017, with commissioning set to take at least six months, likely in second- half 2018.

After nearly a decade, state-owned Kuwait Petroleum Corp. finally awarded $11.5 billion worth of EPC contracts at the end of July for the Al-Zour refinery project. Some view the awards as turning the tide for Kuwait, as it looks past internal tensions to push on strategic projects.

The budget for the refinery, targeted for completion in late 2018 or early 2019, bulged earlier in September by about $2.5 billion to $16 billion. It is critical to the state's aims of boosting refining capacity to 1.415 million b/d from 936,000 b/d.

Al-Zour will produce about 250,000 b/d of low-sulfur fuel to run Kuwait's demanding power stations and desalination plants, and a growing petrochemical industry.

One factor for the refinery's approval is a change in attitude within the National Assembly, Kuwait's parliament. Where it had previously sought to scrutinize and block the oil ministry's contracts, it is now far less combative.

Greater political will from the al-Sabah government should also see it push aside any resistance from lawmakers who, over the past decade, had caused construction to be frequently delayed. ■

GAWOON PHILIP VAHN
Editor
Asia Crude Markets

LOVE FOR US CONDENSATES

More US condensates have reached South Korea and Japan this year and the trend could widen across Asia, where refiners are seeking cheaper options to costlier Qatari and Australian ultra-light crude.

As the top oil producer in 2014 vies for Asia's condensate market share, this could be a prelude to what is to come if the debate over the Jones Act tilts towards lifting the US crude oil export ban.

A year after the Commerce Department allowed exports of processed naphtha-rich condensates, monthly shipments are estimated at 3.5 million-4 million barrels, industry sources said.

The costs of shipping crude to Asia from North America, Europe and Africa are almost, or sometimes, more than double those from the Middle East.

But this has not deterred South Korean refiners from actively exploring the US condensate market this year, at a time of robust gasoline demand, as long as arbitrage economics are deemed attractive and if US crude export barriers are eventually lowered.

Traders and refiners elsewhere in Asia, including Japan and Singapore which had been looking to boost anemic processing margins, will seek opportunities to import US supplies when the spread between benchmark Brent and WTI crude futures are far apart.

Yet it remains to be seen if Asia's infatuation with US condensates could blossom into a long-term relationship, as many legal and political potholes remain in the US.

S. Koreans, Japanese on buying spree, others window shop

Trade sources said South Korea's top oil refiner SK Innovation purchased 400,000 barrels of US condensate for late-April loading from Japanese trader Mitsui & Co. Ltd.

The cargo, which Mitsui first bought from US midstream operator Plains All American, was heard to have reached SK's refining complex in Incheon in first-half June, making it SK's second US condensate import and the first to reach Asia this year.

AUSTRALIAN NORTH WEST SHELF CONDENSATE DIFFERENTIAL (VS DATED BRENT)

Source: Platts

Hanwha Total purchased from Mitsui 500,000 barrels of US condensate for mid-July delivery to its Daesan complex, traders said.

SK then bought two more 500,000-barrel cargoes from BHP Billiton and an unidentified seller for late-July arrival. The Korean refiner might have resold the BHP Black Hawk condensate to a Europe-based major oil firm, as its high paraffin content and 52 API gravity was more suited for European end users, traders said.

Mitsui's trading arm, Westport Petroleum, had loaded end-April the LR1 clean tanker, Hafnia Australia, with 60,000 mt of condensate at Corpus Christi, Texas, which arrived at Incheon June 9, according to shipping sources and cFlow, Platts trade flow software.

More recently, South Korea's GS Caltex and a Japanese end user could have jointly bought 500,000-barrels of US condensate from Mitsui. GS Caltex is awaiting its share of the cargo to arrive in Yeosu in second half-September/ early-October, traders said.

Tennessee-based Westport, which gives Mitsui the shipping edge to move US condensates, loaded the cargo from Corpus Christie in early August on the Altesse, at a rate of $2.5 million, sources said.

South Korean refinery officials told Platts in January they would seek more US condensates to diversify supplies, after the first such cargoes last year proved competitive against Middle Eastern ultra-light grades.

Singapore's Jurong Aromatics Corp. is also expressing interest. The company's condensate-based aromatics plant on Jurong Island has been offline since December, just three months after it started commercial operations, and it recently filed for receivership after debt-restructuring talks broke down, according to documents obtained by Platts.

"We have been processing major regional condensates like [Qatar's] Deodorized field condensate, Low sulfur condensate and [Australia's] North West Shelf condensate. Now, we are discussing the possibility to use other condensates for the purpose of future optimization, which include [condensates from] Corpus Christi and [BHP's] Black Hawk," Yan Jiasheng, a commercial manager at JAC's head office in the city state told Platts.

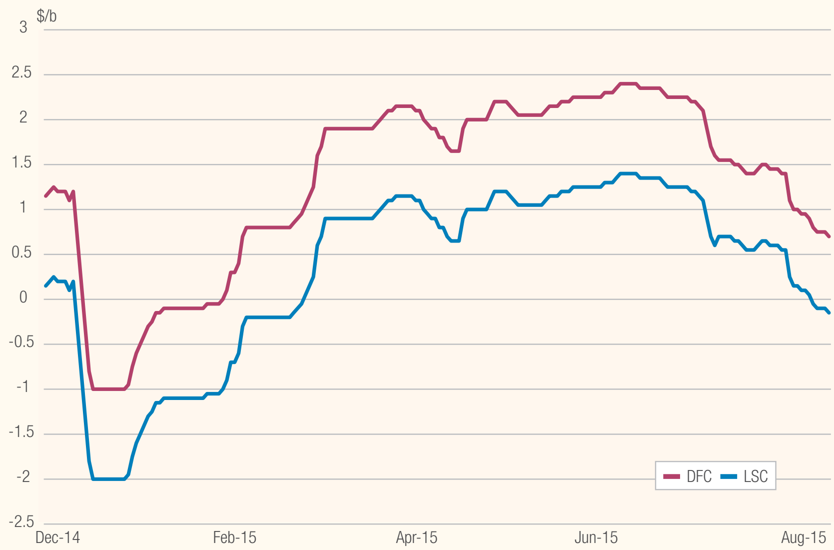
Lofty Qatari, Australian prices

The uptrend in Qatari and regional condensate price differentials likely prompted end users to actively seek cheaper alternatives, Singapore-based traders said. ▶

Australia's North West Shelf condensate hovered near multi-month highs in the second quarter amid healthy light distillate cracking margins and strong gasoline blending demand across Asia, traders said.

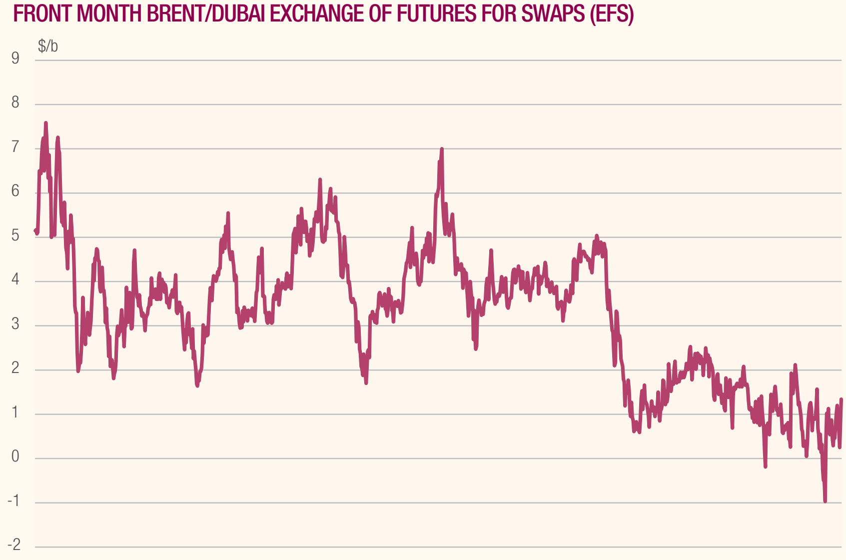
In late March and early April, NWS condensate was assessed at a 55 cents/b discount to Dated Brent, the widest since touching the 50 cents/b discount on October 4, 2013, Platts data showed.

QATARI CONDENSATE DIFFERENTIALS (VS FRONT-MONTH DUBAI)



Source: Platts

FRONT MONTH BRENT/DUBAI EXCHANGE OF FUTURES FOR SWAPS (EFS)



Source: Platts

Qatar's Deodorized field condensate hit an eight-month high premium of \$2.40/b to Platts front-month Dubai crude assessments in June.

Brent's narrowing premium to Dubai crude was one of the key reasons that triggered Asian end users to shift from Qatari ultra-light grades to US and African condensates in the second and third quarters this year.

"Dubai-linked condensates certainly look expensive due to the narrow [Brent-Dubai] EFS [Exchange of Futures for Swaps], so regional end users will be more than happy to take US condensates, if conditions are right," said a condensate trader at Hanwha Total in Seoul.

The front-month Brent/Dubai EFS – which enables holders of ICE Brent futures to exchange their Brent futures position for a forward-month Dubai crude swap – averaged 62 cents/b so far in the third quarter. The EFS averaged 96 cents/b in the second quarter and \$1.52/b in the first quarter this year.

Brent-WTI spread, freight, key to US exports to Asia

Trade sources said the benchmark Brent-WTI spreads and freight rates are crucial to buyers' decisions.

"If the Brent-WTI spread is \$7 or more, [the US-Asia condensate arbitrage is] quite possible," another South Korean trader said.

The front month ICE Brent-WTI futures spread settled at a 2015 high of \$12.81/b on February 27. It has largely been falling since, except for a few peaks.

Crude and condensate shipping costs from the Middle East to East Asia are roughly \$2.5-\$4.0/b and \$3.0/b from Australia to North East Asia, while freight from the US to Asia would be \$4.5-\$7.0/b, said Singapore-based sweet crude traders.

"For US condensate to come here, logistics is the issue," a Singapore-based trader said, adding that US-Asia shipping costs usually range from \$5 to \$6/b, but anything more will damage the arbitrage economics.

Shipping sources in the US, said rates on an LR1 clean tanker to move a 60,000-mt cargo from the Gulf Coast to Asia is \$2.3 million-\$2.5 million, or \$38-42/mt.

The tanker Brook Trout was fixed in mid-May with an Asia delivery option at \$1.85 million, while the Hafnia Australia was fixed mid-April to go East for \$2.1 million.

Data from the Port of Corpus Christi showed that Eagle Ford condensate exports to Asia and Europe were very competitive in April and May. Of the 45,083 b/d of Eagle Ford condensate exports from the port in May, 70% went to the US Gulf Coast market and 21% to East Asia.

In April, of the 53,489 b/d of condensate exports, 12% headed to the Netherlands and 29% to South Korea.

South Korean refiners have been the most active Asian buyers of US condensates, as they enjoy government subsidies when purchasing crude or condensate from Africa, Europe and the Americas. Reducing reliance on crude from the politically volatile Middle East has been a pillar of the country's energy import policy and the government last year renewed efforts to encourage refiners to widen supply sources.

FRONT MONTH ICE BRENT – WTI FUTURES SPREAD

Source: Platts

South Korea has been partially subsidizing refiners' crude transportation costs for non-Middle Eastern oil imports since 2004. It raised this coverage in 2011.

Growing calls for US export ban repeal

Asian end users are among the most vocal critics of the Jones Act, as the cost of bringing in 1 million barrels of US condensates could be cut by at least a quarter, if the controversial early 20th century law could be amended.

The Jones Act, enacted as the Merchant Marine Act of 1920, requires all vessels shipping cargoes between two US locations to be US-built, majority US-owned and have at least 75% of the crew to be US citizens. ▶

Jones Act-compliant ships are more expensive than non-Jones Act ones and are in short supply, making it difficult to move crude and refined products between US ports. The law quadruples the cost of moving tankers between U.S. ports before heading out to foreign ports, sources said.

"It is quite difficult and costly to arrange a VLCC-size tanker from Corpus Christi because of the shallow waters there," a Chinese condensate trader said. "Asian buyers must take into account extra costs involved when crude or condensates are carried by expensive Jones Act ships within US waters."

Current US regulations only allow natural gasoline or plant condensate to be exported as segregated condensate, industry sources said.

Field, or as it is known in the US, lease condensate, is considered crude and cannot be exported without processing. In reality, the two are almost chemically identical.

Typical condensate yields about 50% or more naphtha and produces marginal amounts of residual fuel. But the slightly processed condensate deemed exportable by US regulators has yielded 38%-40% naphtha and had residual content of up to 8%, a recent study by Asia-Pacific Energy Consulting said.

By having to process the material into what is perceived as a refined product, US producers and exporters negatively impact the quality of the condensate, the study said.

Asian buyers found the quality of US processed condensate unfavorable, so most cargoes have gone to Europe rather than the supposed natural market of Asia.

The study argued that US condensate sales would surge if producers and exporters can aggregate a condensate blend to meet Asian specifications.

However, prospects that the roughly 40-year old restrictions on US crude exports could be repealed in the near term are slim, analysts said.

One key argument against the easing is that since the US transportation system is mostly dependent on oil, its economy and energy security remains exposed to any price volatility and sudden supply disruptions.

In late July, the Senate Energy and Natural Resources Committee passed, in a 12-10 vote, a bill to repeal long-standing limits on US crude exports, setting up a possible full Senate vote on the export policy later this year.

The Obama administration has indicated it will not move to change the crude export policy before his term ends in January 2017, leaving any possible change to Congress.

"We believe that policymakers will be cautious to amend or adopt a full repeal of the US crude export ban, unless there is a clear benefit to American consumers," said Barclays energy analyst Paul Y. Cheng in a report.

"Arguments led by oil producers themselves are unlikely to provide enough incentives and political cover for policymakers unless they can clearly demonstrate an incremental benefit to consumers [potentially in the form of employment or product pricing]." ■

GASOLINE

JONATHAN NONIS

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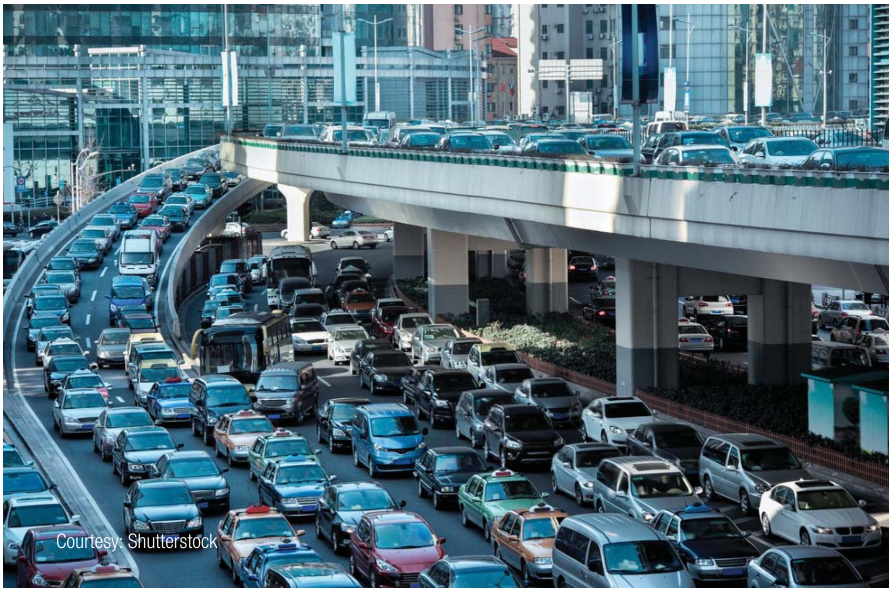
HAIL GASOLINE!

Asia's new refinery and upgrading projects have led to a gasoil surplus, though gasoline production has lagged steady demand growth, thrusting up its profit margins to the best among refined products.

This trend may persist as gasoline demand balloons along with car usage among Asia's burgeoning middle class.

Prospects for gasoil are hazy following huge investments over the past five years in upgrades to add value to heavy distillates, boosting production of this hitherto 'king of the barrel'. This was to meet projected growth in the industrial, utilities, agricultural/ fishing, construction, mining and transport sectors, but which was recently dampened by the slowing economy.



Courtesy: Shutterstock

Permanent closures of three refineries in major importer Australia over 2012-2015 have deepened Asia's gasoline gap, while lower US gasoline supply due to refinery outages earlier this year and a demand recovery, have revived flows of Asian barrels to the US.

According to the US Energy Information Agency, Asia's net deficit in gasoline production has persisted since 2003, and by 2012, the region is short of around 50,000 barrels/day. The region's net surplus in gasoil production by 2012 was almost 400,000 b/d.

"The main drivers [for the gasoline deficit) are India and China, where we forecast a combined increase in demand of 1.56 million b/d over the next 10 years," BMI Research said in a report in April. Gasoline demand will be stoked by healthy average annual growth in vehicle sales over the next five years at 5.7% in China and 5.9% in India, it added.

"China is shifting to a more consumer-led pattern of growth, which we believe will see gasoline demand growth continue to outstrip the growth in demand for diesel, which is used pervasively in the country's industrial sector."

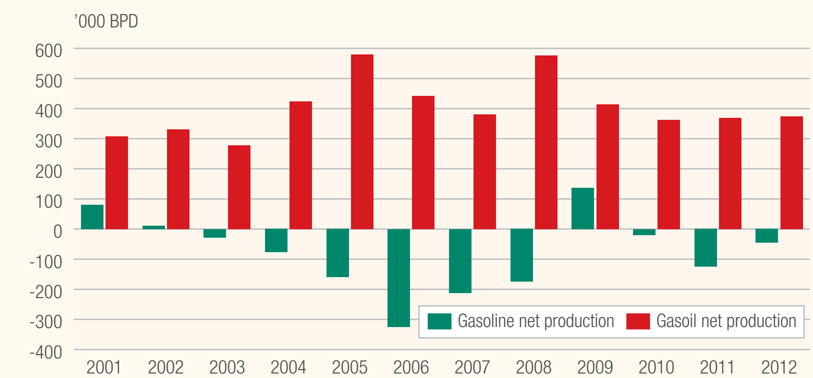
While rising fuels consumption in both countries requires a bullish outlook on the economy, a point to note is China's slowing growth at 7.4% last year, the softest in 24 years.

China's economy grew 7% in second-quarter 2015, consistent with the government's full-year target, though Goldman Sachs in end-August cut its forecasts to 6.8% for this year, 6.4% in 2016, 6.1% in 2017 and 5.8% in 2017, on widening worries over the Chinese economy.

India's economy – which grew 7.3% in fiscal 2014-2015 – is expected to expand by 7.4% for fiscal 2015-2016, the Asian Development Bank said recently, lowering its projection from 7.8% earlier, amid weak monsoons, poor external demand and government failure to push through reform legislations. ADB expected growth to recover to 7.8 percent in 2016-17.

As gasoline demand from the two Asian giants increases, regional supply is expected to hold steady beyond 2020 as refinery capacity expansions in Asia begin to stall, BMI Research said.

MIDDLE EAST, ASIA AND OCEANIA NET PRODUCTION



Source: EIA

"From 2015-2020, we forecast net capacity additions of 3.52 million b/day; this compares to 152,000 b/d in the period 2021-2024," it said. "It is also worth noting that planned new capacity is targeted towards increasing yields of high-specification diesel fuels. This would come in part at the expense of gasoline output, exacerbating the region's deficit."

While gasoil, or diesel, and gasoline can each make up around 40%, or more, of the yield from the new and sophisticated refineries in Asia and the Middle East, the gasoline-diesel ratio tends to be lower in this region than in the US, in line with traditional demand patterns, according to a study done for the International Council on Clean Transportation. In the US, where refineries are configured to maximize gasoline production, the gasoline-diesel ratio is higher during summer than winter, it said.

Gasoline margins batter gasoil

Gasoline consumption tends to be more price-sensitive, so when retail gasoline rates fall – as they did in line with crude oil – demand tends to pick up.

Since mid-April 2015, gasoline cash cracks – the price spread between FOB Singapore 92 RON gasoline cargoes against front-month cash Dubai – began to creep higher against the 500 ppm sulfur gasoil crack, Platts data show.

The spread between the gasoline and gasoil cracks stood at its widest on July 31, at $9.91/b, when the 92 RON gasoline crack was at $16.68/b, while the gasoil crack stood at $6.77/b.

Monthly gasoline cracks jumped to $19.23/b in June, 2015. The last time monthly average gasoline cracks were higher was on May 2007, at $23.35/b.

Crack spreads – the price difference between oil product and crude – often reflect a refinery's basic margin, or profitability.

Gasoline cash cracks were last higher than gasoil for a sustained and significant period in 2010. On February 2, 2010 the gasoil and gasoline cracks stood at their widest for that period at $4.08/b, when the gasoline crack was at $11.75/b and the gasoil crack stood at $7.67/b.

Asia's gasoline demand grew by a strong 600,000 b/d, year-on-year, to 6.24 million b/d in July, but diesel demand shrank by 49,000 b/d, year-on-year, to 8.35 million b/d, according to to Energy Aspects.

"This [decline] explains the sharp drop in Asian diesel cracks to single digits in July, which subsequently triggered run cuts throughout the region," Energy Aspects said.

"Gasoline and naphtha have been the mainstay for Asian oil demand growth this year and any slowdown in light ends demand is bearish for forward refining margins, which are already under pressure from rapidly deteriorating diesel balances."

On the derivatives side, gasoline crack swaps – the spread between front-month gasoline and Dubai swaps – also saw gasoline beating gasoil for pole position.

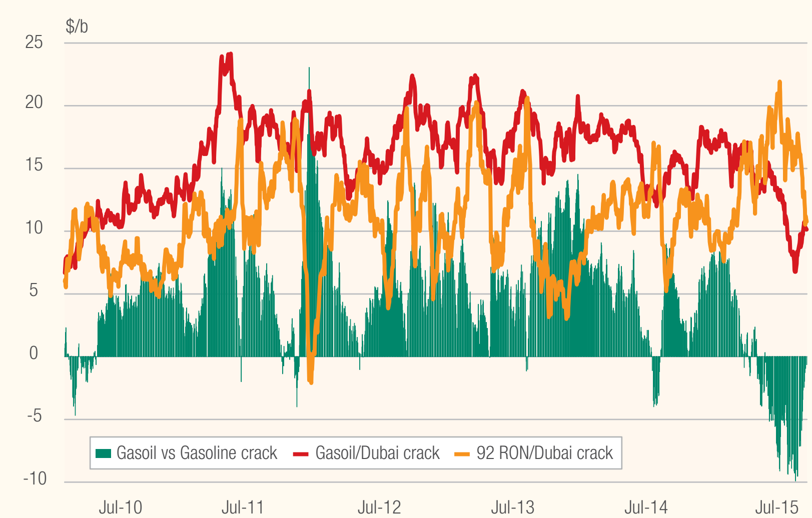
Since May 18, gasoline crack swaps have been assessed above gasoil crack swaps. The spread between gasoline and gasoil crack stood at their widest on July 31, at $8.30/b. On that day, gasoline crack swaps were at $15.75/b and gasoil cracks at $7.45/b.

US gasoline consumption improves with economy

Much of the strength in gasoline cracks over the past year was linked to the 50%-60% plunge in crude prices, as well as robust US and Asian demand.

This was particularly pronounced in 2015 when refinery disruptions and a recovery in US demand, rekindled arbitrage movements to the US West Coast from Northeast Asia.

GASOLINE MARGINS TRUMP GASOIL



Source: Platts data

"A common feature across all regions, notably in the past two months, has been the strength of demand, with gains in the US driven by income and price effects," BNP Paribas said in a July 7 report.

Pre-summer gasoline shipments from Asia across the Pacific Ocean were common in the 2000s. But with stagnant demand and high refining rates in the US in recent years, Asia-US West Coast flows had dissipated.

As a number of major oil companies used spare capacity at their US West Coast refineries to supply into short positions in Australia following the mothballing of refineries, occasional reverse arbitrage flows had emerged. But this reverse flow has ended, and Australian demand is filled by barrels from Singapore, North Asia and India, traders said.

US gasoline demand has risen this year amid better-than-expected second-quarter GDP growth and cheaper gasoline pump prices. "The US may see up to 240,000 b/d increase in gasoline consumption in 2015 [from] 8.91 million b/d in 2014," said Suresh Sivanandam, principal analyst at Wood Mackenzie.

Finished gasoline supplied in the US, or implied demand, hit a near eight-year high of 9.75 million b/d for the week ended July 17, EIA data showed.

For the first eight months this year, weekly finished gasoline supplied in the US averaged 9.13 million b/d, versus 8.76 million b/d for the same period in 2014.

Unplanned outages at Tesoro's Golden Eagle in Martinez, California and ExxonMobil's Torrance refinery during February-March also forced US refiners to step up imports from Asia. At least 90,000-140,000 mt of Northeast Asian gasoline and alkylate – including rare alkylate exports from Japan – were estimated to have arrived in March into the US West Coast due to the outages.

With the looming Northern Hemisphere winter – when gasoline consumption declines – it remains to be seen if gasoline margins could continue to surpass gasoil later this year.

In the longer run, the US could become a structural arbitrage supplier to Asia, as a mounting surplus in North America and yawning deficit in Asia should see a shift in regional trade and price dynamics beyond 2020, BMI said.

"Traditionally, US gasoline has held a premium over gasoline in Singapore. However, falling demand in North America and rising demand in Asia would erode this price premium and invert the differential. Should the differential be strong enough, we could expect to see an increasing number of gasoline cargoes flowing from the US to Asian markets," it said.

The widening gasoline surplus in North America will come from refinery expansions, higher utilization rates and a long-term consumption decline, helped by energy efficiencies, BMI added.

Asia can become natural arbitrage market

Over the first seven months this year, India imported 639,000 mt of gasoline, up from 328,000 mt in 2014, data from India's Petroleum Planning & Analysis Cell showed.

The country's gasoline consumption has risen to 12 million mt over January-July, ▶

or 1.71 million mt/month, versus 2014's total consumption of 18.38 million mt, or 1.53 million mt/month. This was largely due to the rising preference for gasoline over diesel after the price deregulation last year and higher passenger vehicle sales.

Credit Suisse said in a research note in May, India has seen a structural shift from diesel to gasoline for four wheelers and increasing consumer preference for scooters, which use more fuel for the same distance traveled versus motorbikes.

Imports from Indonesia, Asia's top gasoline buyer, are steady, with monthly volumes of between 9 million and 10 million barrels. Imports were above average during the peak festive season in June and July when state-run Pertamina imported 11.3 million barrels and 12 million barrels of gasoline, respectively, Platts data showed.

Wood Mackenzie's Sivanandam said Asia's gasoline demand for 2015 is forecast at 250,000-260,000 b/d higher than 5.9 million b/d last year.

Although Asia's gasoline prices remain low on a year-on-year basis, consumption could dip later this year, amid seasonal changes.

"Robust [gasoline] demand has been due to lower prices. Car sales in China have continued to be really strong, with people switching to buy sport utility vehicles, but sales [in recent months] have been slowing in China," Lim Jit Yang, Head of Asian products research at Energy Aspects Singapore, said.

"In addition, year-on-year gasoline demand growth in the second half of this year is likely to ease due to strong base last year as prices plunged in the second half of last year."

Asia's gasoil glut

China, India and Asia-Pacific nations such as Vietnam will be adding around 6 million b/d of refining capacities up to 2018; while Saudi Arabia, Kuwait, Oman and the UAE are building 2.82 million b/d between 2013 and 2018, most of them focused on gasoil production.

South Korea has been exporting more gasoil after the startup of two condensate splitters last year. Abu Dhabi National Oil Co. has raised exports of ultra-low sulfur diesel from its newly expanded 840,000 b/d refinery in Ruwais, while Saudi Aramco has cut imports of 500 ppm sulfur gasoil following the startup of two 400,000 b/d joint venture refineries in Jubail and Yanbu over the last two years.

China's slowing diesel consumption would also prompt higher exports, which could last through the year-end. "Apart from the already slowing economy, the Chinese government is trying to lead the economy towards private consumption, instead of infrastructure and industrial investment, which means less diesel consumption," Sivanandam said.

China's Ministry of Commerce in August issued a fourth batch of oil product export quotas for this year totaling 9.9 million mt, almost triple the volumes approved in the third batch in mid-July, to alleviate bulging stocks. Of these, gasoil accounted for 3.35 million mt, bringing its year-to-date export quota to 8.83 million mt, more than double the 4.02 million mt for full-year 2014.

"Estimated flat growth this year on diesel demand means China has to export the surplus, creating an oversupply in the region," Sivanandam added. ■

(Additional reporting by Dexter Wang, Associate Editor, Asia Gasoline)

TANKER MARKETS

SAMEER C. MOHINDRU

Senior Editor
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CHEAPER OIL *SPURS* TANKERS

Growing diversity of cheaper crude oil supplies, along with the US shale boom that is pushing more condensates and naphtha to Asia, has bolstered global trade flows and propelled tanker markets to seven-year highs.

Sustaining these lofty levels, which had also been supported by traders using vessels as storage when the spot oil market is weak, will be difficult, as newbuildings enter the market next year.

Earlier this year very large crude carriers ballasting from the US Gulf, on a Caribbean-to-China voyage, fetched daily earnings of almost $110,000 for owners. This reflected the benefits accruing to tanker owners from new and longer routes emerging in crude and oil products trading.

Traditional oil routes have been to the US Gulf from the Persian Gulf and West Africa. However, the Persian Gulf-US Gulf route has become more of a backhaul, which owners are ready to take up at a discount to lift cargoes for Asia from the Caribbean and West Africa.

"By and large it has been a magical year for tanker owners and an exceptional one at that, after a long period of meager earnings," said Dagfinn Lunde, Chairman, Executive Ship Management, or ESM and a Netherlands-based shipping consultant.

The key Persian Gulf-to-Japan Worldscale rate for VLCCs reached a year-to-date high of w88.5 on July 21, Platts data showed. After a brief plunge, the route again hit w88.5 on October 5, when daily earnings touched $100,000 for the first time in at least five years, versus less than $3,000 in early June 2014, market participants said.

The surge in rates is also driven by cheaper bunker fuel and consolidation of ships in large tanker pools.

Asian refiners who have undergone plant upgrades are experimenting by blending different crude grades from around the global, ranging from Mexico to the Middle East and Russia to Africa, to maximize margins amid intense competition.

This has translated into longer voyages and ton-mile demand, leading to firmer freight rates.

Courtesy: The Maritime and Port Authority of Singapore (MPA)

Ton-mile demand is calculated by multiplying the volume of cargo moved in metric tons by distance traveled in miles. It indicates the average distance a ship covers to deliver every ton of cargo.

Covering a longer distance implies diminished availability of ships, even if the total fleet size remains the same, or conversely it offsets the increase in tonnage supply.

In the drive to diversify the crude slate, South Korean refiners are receiving tax exemption for bringing in non-traditional grades.

Even though the freight is not competitive, Mexican crude flows into China, Japan and South Korea are rising because the cargoes are cheaper than other grades, including from the Middle East.

In what is probably a first, South Korea's Hyundai Oil Bank sealed a contract in August for loading crude on a VLCC from the east coast of Mexico. Earlier Mexican loadings for East Asia were ▶

on Suezmaxes from the west coast – Salina Cruz.

More recently, VLCC rates have been pushed up by a marked increase in Iraqi exports in October versus September, as well as healthy activity in the Atlantic Basin, forcing charterers to rush to fix vessels for early October loadings.

Contango and floating storage

At the start of the year, the contango in crude prices, indicating a weaker front market compared with future months, led to a jump in short-term time charter of VLCCs with options for floating storage.

While the euphoria didn't last long, it ensured that a substantial part of old tonnage was taken off the market for possible storage.

Even in August, as US NYMEX crude futures again fell below the key psychological mark of $40/barrel, at least seven VLCCs were taken for a time charter of 30-90 days with storage options, with companies exploring a possibility of storing cargoes now for selling later.

Up to 7% of the current VLCC fleet is currently used for storage, be it condensate, crude or fuel oil, said Ralph Leszczynski, research director at Bancosta, an Italian shipping brokerage and consultancy.

This trend, along with the upcoming increase in processing rates as the refinery maintenance season ends, has pulled freight rates off lows.

The impact of short-term time charter on freight rates was much more evident and in fact volatile and brutish on Aframaxes, when dozens were lapped up by trading firms to store fuel oil.

On June 18, worldscale rates for these ships, which can typically load up to 100,000-mt cargoes, moved to this year's high of w192.50 on the Indonesia-Japan routes, Platts data show.

However, the much anticipated spike in fuel oil prices didn't happen.

In their efforts to sell off the cargoes, trading firms lost millions of dollars, and by mid-August Aframax rates crashed to levels around w95.

Trading companies are still struggling to sell some of these cargoes stored on Aframaxes.

The spike-and-crash cycle illustrates the vulnerability of the Aframax market to the speculative instinct of oil trading companies, amid fewer voyages for such vessels on some of the long-haul routes.

The Persian Gulf-to-East was a thriving route for Aframaxes until a few years ago. But the voyages have now reduced to a trickle with fuel oil from the Middle East being replaced with VLCC cargoes from Rotterdam due to viable pricing economics.

Prior to the sanctions on Iran over its nuclear program, large fuel oil volumes from its ports were moving for bunkering to Fujairah port, while barrels from Saudi Arabian and Kuwaiti refineries were heading to Singapore.

If sanctions on Iran following the agreement with the P5+1 group of international powers were eased, it could potentially revive the trend and also boost the fledgling volumes on the Persian Gulf-to-East route for Aframaxes.

Even now, daily earnings on the Southeast Asia-to-North Asia routes for Aframaxes remain robust around $25,000-$30,000.

Another vibrant route giving handsome returns to owners is Kozmino, in eastern Russia, moving ESPO crude to North Asia. Ships doing Indonesia-Japan runs also prefer to ballast to Kozmino to pick up their next cargo.

One reason for decent returns for tanker owners this year is cheaper shipping fuel, which significantly reduced costs, said Masood Baig, director for crude tankers with Strait Shipbrokers, a Singapore-based shipping brokerage. On September 15, Platts assessed the 380-CST grade bunker delivered in Singapore at $229/mt, down from $577/mt a year earlier.

New buildings poser

Robust earnings are encouraging owners to add to their fleet, which could cap gains next year.

"I don't see any really big drivers of demand and even if one extra tanker is bidding for a cargo, it can kill the market," said ESM's Lunde.

There are now 56 VLCCs on order for deliveries next year, compared with just 25 in 2015, Bancosta's Leszczynski said.

Around 29 new newbuilding orders were placed in the first six months of this year, compared with 37 in the whole of 2014 and 43 in 2013, though most of these will be delivered from 2017 onwards, he said.

TOP FIVE OWNERS CONTROL 25% OF A FLEET OF 650 VLCCs

NITC	37
China Merchants Grp	36
Mitsui O.S.K. Lines	32
Bahri	31
Angelicoussis Group	28
Total	**164**

Source: Arctic Securities

OF THE 124 VLCCs UNDER NEWBUILDINGS, 46% HAVE BEEN ORDERED BY 5 FIRMS

Gener8 Maritime	20
Bahri	10
Cosco Group	10
China Merchants Group	9
Metrostar Management	8

Source: Arctic Securities

Earnings for crude tanker owners are expected to be strong in 2016, but not as high as this year, said Erik Nikolai Stavseth, a Norway-based shipping analyst with Arctic Securities.

"There is fun in the sun, but ship owners already playing with fire as new orders keep rolling in," Stavseth said.

During the global economic boom prior to the 2008 Lehman Brothers crash and subsequent recession, there was a large orderbook resulting in strong fleet growth during 2009-2012 and weak freight rates.

Arctic Securities has forecast average daily earnings for VLCCs at $40,000 next year, down from a projected $58,500 in 2015.

"Demolition of old tankers is almost nil now, as owners try to squeeze as much revenue from their old ships as possible and if this continues, global VLCC fleet could expand by as much as 7% year-on-year in 2016," Leszczynski ▶

said. Brokers estimate the current fleet to be around 650.

Notwithstanding the additional tonnage, owners hold an optimistic market outlook, pinning their hopes on further fleet consolidation.

Almost 15% of the global VLCC fleet is controlled by Frontline and three pool operators, Tanker International, Navig8 and Heidmar.

After accounting for Saudi Arabia's Bahri, Iran's NITC and Chinese shipping companies, big players' control of the chartering business is substantially larger.

Since they will be offering only one ship each from their fleet for any cargo, the tonnage may not always be in surplus.

Iran, the dark horse

Next year, the dark horse in the great oil freight game will be Iran. If international sanctions are completely lifted, there will be a release of another 2.0-2.5 million b/d of crude oil into world markets, forcing buyers to scurry for ships.

While a part of these incremental barrels will be moved in ships operated by National Iranian Tanker Co., they could also help soak up the newbuilding vessels sailing into the market next year.

Cheaper crude resulted in more stockpiling and refining this year and the strong demand for tankers to move cargoes may spill into 2016, shipping sources said.

Both overall tanker fleet and demand will grow by around 4% this year. While strong freight rates lack sustainability, low oil prices and higher prospects of exports by OPEC producing countries provide a silver lining, said Jarle Hammer, a Norway-based shipping researcher and consultant.

There is an inverse relationship between crude prices and demand for tankers to move cargoes. In 2014 and 2015, there had been a decline in refinery shutdowns as end users cash in on higher processing margins and pushing up freight rates.

Ship owners are hopeful that some of the new tankers may be absorbed in this mathematical equation. ■

FLEET GROWTH

Percentage growth from previous year

	2010	2011	2012	2013	2014	2015E	2016E	2017E	2018E
VLCC	8.4%	8.9%	7.9%	4.4%	2.3%	2.4%	3.8%	3.8%	1.4%
Suezmax	6.6%	7.3%	6.9%	5.4%	2.6%	0.8%	2.3%	4.1%	2.0%
Aframax	6.1%	4.7%	2.1%	-0.1%	-1.0%	1.4%	3.1%	2.8%	1.3%
Smaller	5.1%	4.9%	3.8%	3.0%	3.2%	3.8%	4.1%	2.7%	0.9%
Total fleet	**6.8%**	**6.7%**	**5.5%**	**3.3%**	**2.0%**	**2.4%**	**3.6%**	**3.3%**	**1.3%**
Actual fleet size (avg over year)									
VLCC	175.2	191.5	204.3	208.8	213.8	219.1	230.3	235.9	236.8
Suezmax	64.4	69.6	73.7	77.4	77.6	78.6	81.1	85.1	84.5
Aframax	93.1	96.3	97.1	96.1	95.2	98.7	101.3	104.3	103.9
Smaller	131.8	137.9	141.9	146.2	151.1	157.4	163.8	166.2	166.8
Total fleet	**464.4**	**495.2**	**517.0**	**528.5**	**537.6**	**553.8**	**576.5**	**591.4**	**591.9**
Scheduled deliveries	61.0	55.0	33.6	22.3	17.1	21.2	37.8	24.0	4.3
+ assumed new orders						0.0	0.0	6.3	10.9
- cancelled and slipped	18.8	13.9	0.0	0.0	0.0	-0.1	-3.6	-2.4	-0.4
Actual deliveries	**42.2**	**41.1**	**33.6**	**22.3**	**17.1**	**21.1**	**34.2**	**27.8**	**14.8**
- Conversions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
- Scrapping	-12.8	-10.3	-11.9	-10.8	-8.0	-4.9	-11.5	-12.9	-14.3
Total tanker fleet	**464.4**	**495.2**	**517.0**	**528.5**	**537.6**	**553.8**	**576.5**	**591.4**	**591.9**

Source: Arctic Securities


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PETROCHEMICALS

PREMA VISWANATHAN

Associate Editorial Director, Petrochemicals

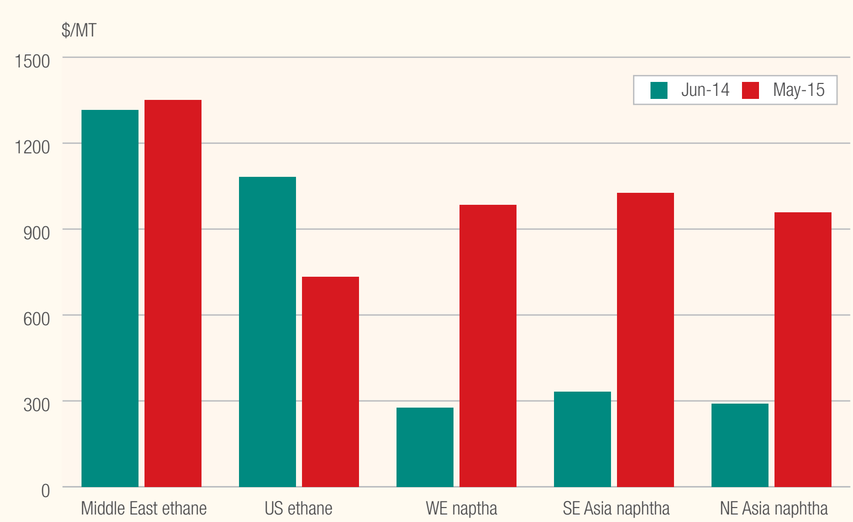
SHIFTING SANDS

The oil price collapse and slowing Chinese economy have caused a paradigm shift in the global petrochemical industry. This has thrown up new opportunities and challenges for producers, forcing them to forge strategies that will help secure long-term competitiveness.

Naphtha-based producers in Asia and Europe saw healthy variable margins in first-half 2015, thanks to the lag between feedstock and derivative prices.

As the chart compiled by Platts Petrochemicals Analytics shows, production margins of Asian and West European ethylene producers who mainly use naphtha as feedstock, had overtaken those of US ethane-based producers by May this year, reversing the situation in June 2014, before oil prices crashed.

PRODUCTION MARGINS



Source: Platts

The only producers who kept their competitive edge in the past year were those in the Middle East, whose ethane costs continue to be extremely low versus global counterparts.

However, in July this year, petrochemical producers were again engulfed in anxiety. The Platts Global Petrochemical Index (PGPI), expressed as a monthly average of petrochemical prices, fell $91/mt from June to $1,013/mt in July. The last time global petrochemical prices fell on a monthly average was in January this year, when prices shed 14% to $850/mt.

The PGPI is a benchmark basket of seven widely used petrochemicals.

"With crude oil prices down 9% and naphtha prices down 14%, there really wasn't anywhere for petrochemical prices to go but lower," said Jim Foster, Platts' head of analysis for petrochemicals and agriculture.

"Crude oil is now below $50/b. That ripples through the petrochemical feedstock market, lowering the cost of production for everything from aromatics to polymers."

Two recent events illustrate the New Normal that the global petrochemical sector is being compelled to adjust to.

On September 4, 2015, Brent crude futures fell to $49.72/b, marking a 52% year-on-year decline. Prices of naphtha, a key feedstock for petrochemicals in Asia, fell 49.8% in the same period to $451.75/mt CFR Japan.

And in late August, the People's Bank of China cut the one-year benchmark bank lending rate by 25 basis points to 4.6% and reduced the reserve requirement ratio for most big banks by 50 basis points to 18%.

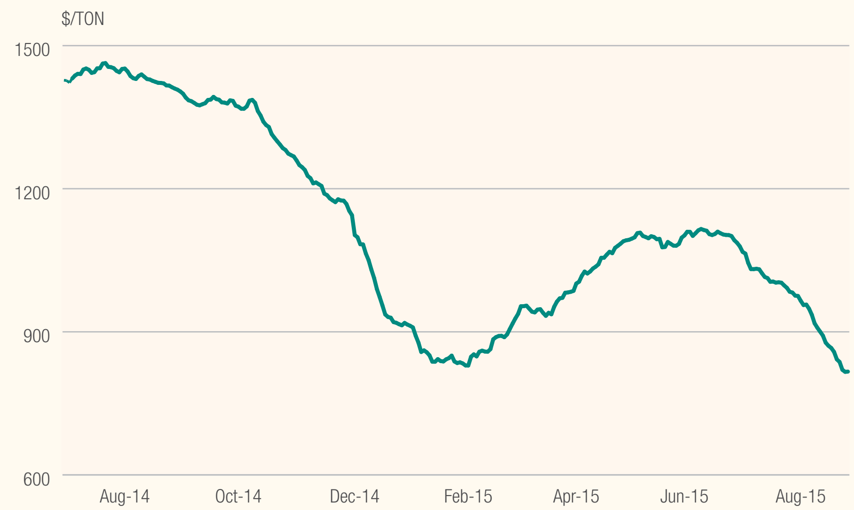
Market experts view the two measures, in tandem with the plunge in the Shanghai bourse that sent shock waves through petrochemical markets, as key moves to avert a hard landing for China's faltering economy.

Profits earned by Chinese industrial companies dropped 2.9% in July from a year ago, official data show, exposing the weakness in the economy.

Diversifying feedstock

While in the near term, the oil price fall signalled an improvement in the cost competitiveness of naphtha-based producers in Asia; longer-term concerns over crude price volatility have driven producers towards widening their feedstock slate.

GLOBAL PETROCHEMICAL INDEX



Source: Platts

Producers such as India's Reliance and China's Sinopec, who had been looking to import ethane from North America to vary their feedstock base so that they could better manage longer-term margins, may now have to rethink their plans.

For North American producers, the going is quite good at the moment. But if oil continues to slide, the shale gas-based cracker projects in North America, which are expected to yield around 10 million mt/year of ethylene/polyethylene capacity in the next five years, may have to fight hard to retain their competitive edge and justify the investments.

European cracker operators will continue to gain from falling crude and naphtha prices. But companies such as Sabic, ▶

Borealis and Ineos, which are retrofitting their naphtha crackers in Europe to crack imported ethane, may find it difficult to defend their new investments.

The impetus to diversify feedstocks has gripped even Middle Eastern producers, who remain the most competitive on the cost curve – the cost of producing one mt of ethylene, after factoring in co-product credits – thanks to access to cheap ethane.

Their need to diversify is based on the depletion of ethane reserves in key petrochemical producers such as Saudi Arabia and government policy geared towards adding value by going downstream through refinery to petrochemicals integration.

"The Middle East's development of gas resources will be an important factor for developing low-cost chemicals capacity, as current gas availability has constrained further investment. Iran may represent a big new opportunity for gas-based petrochemicals investment once sanctions are lifted," said Paul Bjacek, Accenture's Chemicals and Natural Resources Research Lead.

Despite international sanctions, Iran has been a key supplier of methanol to China and India. This reach may extend to other countries in Asia and Europe, once sanctions start to be lifted in response to Tehran's nuclear pact with the P5+1 group of international powers.

Iran accounted for 38% of China's methanol imports in 2014 at 1.7 million mt, slightly down from 42% in 2010. India's imports of methanol from Iran tripled in the same period to 1.09 million mt. Iran also accounted for 23% of China's PE imports of 9.1 million mt in 2014.

Governments in the Middle East are pushing producers to go in for refinery-to-petrochemicals integration in a bid to diversify the product slate.

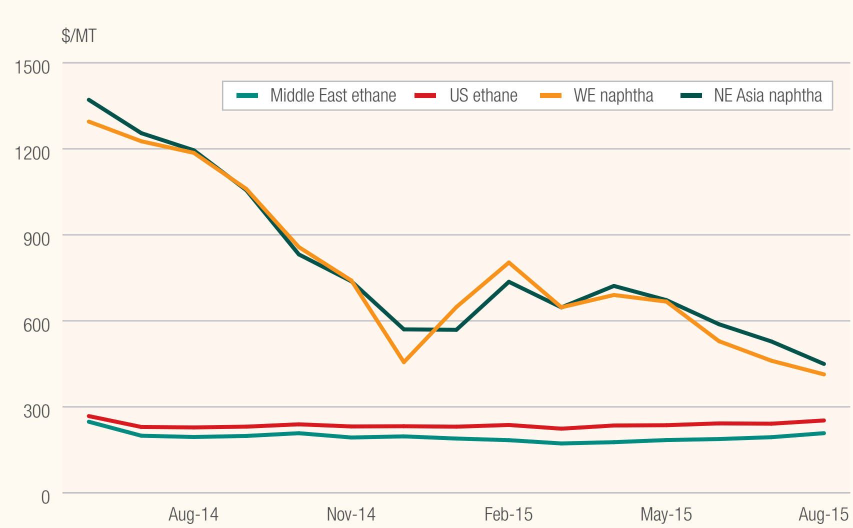
This may not be as easy a ride for Middle East players as gas-based production. "For liquids (e.g., naphtha) based chemicals in the Middle East to be competitive, chemicals companies will need to build new capacity at scale and ensure efficient supply chains to market for production," Bjacek said.

Integration for better margins

Volatile feedstock prices have also drawn attention to the advantage of integration in Asia, as integrated producers have been enjoying far better margins.

The economic slowdown in China, the world's biggest consumer of petrochemicals, has also unleashed anxiety among global suppliers, especially

CURRENT OIL PRICE IMPACT ON CRACKER COST BASE



Source: Platts

in the polymers segment, and forced them to shift focus to other markets.

China's imports of key petrochemical products such as polymers are increasing at a much slower pace than its 7.4% GDP growth. China's imports of polypropylene (PP) were a mere 4.8 million mt in 2014, almost unchanged from 2013. Its imports of polyethylene (PE) grew at just above 3% in the same period to 9.1 million mt.

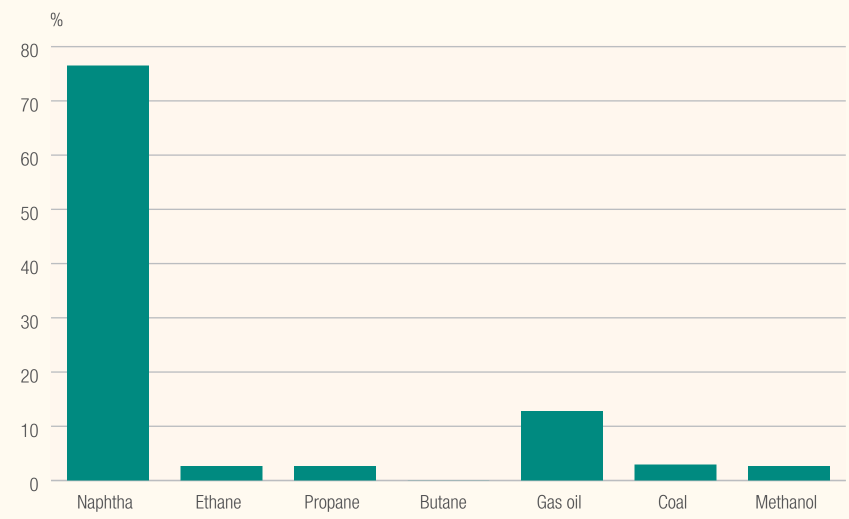
Coupled with the slowing growth in Chinese petrochemical demand is the accelerated drive towards self-sufficiency in the 13th Five Year Plan, which will take off in 2016. Despite public concern over sustainability, the government is likely to push ahead with its coal-to-olefins projects to secure feedstock and competitiveness, as China has one of the world's largest reserves of low-cost coal.

According to estimates by Platts Petrochemicals Analytics, the proportion of ethylene produced from coal will rise to 18.83% in 2024 from 2.87% in 2014, while ethylene production from naphtha will fall to 59.95% from 76.52% during the period.

The government's emphasis in the ongoing 12th Five Year Plan on spreading economic growth from the eastern and southern belts to western, northern and central China is a strong counter strategy to limit the dominance of exports in its economy. Such dominance had taken a toll on China's economy in 2009, as it constituted 37% of GDP.

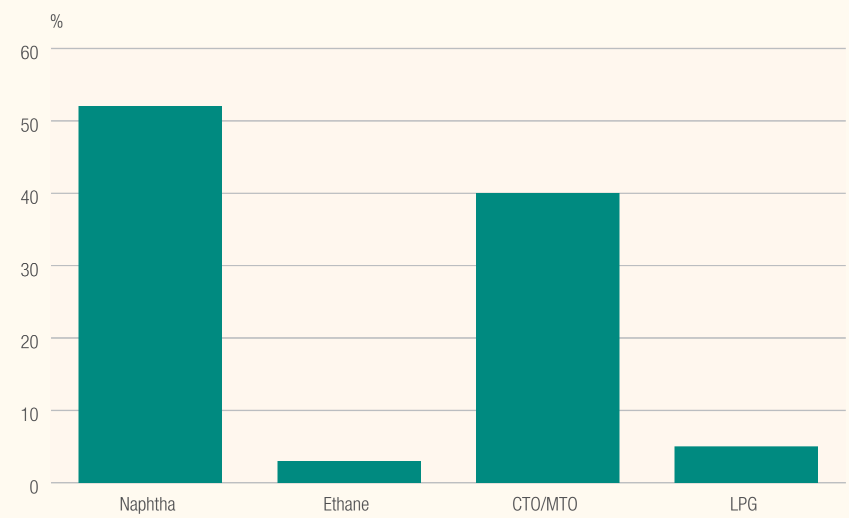
However, the government has been striving to meet this demand increasingly through local production,

ETHYLENE PRODUCED FROM – 2014



Source: Platts

CHINESE ETHYLENE CAPACITY ADDITIONS BY FEEDSTOCK



Source: Platts

mostly based on coal and methanol. Coal-to-olefins and methanol-to-olefins projects are estimated to produce 5.6 million mt of ethylene/PE in 2015, according to Platts Analytics.

The economics of coal-based production was far more advantageous when oil ▶

prices were high. But as oil and naphtha trend lower, this gain gets steadily eroded, and has even reversed in some cases when coal-based producers do not necessarily have a very low integrated advantaged coal price, as seen in the table below.

"If you compare the cost of producing one mt of ethylene from a coal-based plant and a naphtha-based cracker, you can see that the spread is now at $33.54/mt in September 2015, with naphtha-based producers being at an advantage, compared with $765.99/mt in June 2014, when coal-based producers were more advantaged. This is because naphtha costs have declined much more sharply than merchant coal costs," said Hetain Mistry, lead senior analyst with Platts.

Coal to chemicals is not expected to be a game-changer technology over the longer term, said Accenture's Bjacek.

"While these projects are resilient because China has a secure feedstock in domestic coal, they are less attractive in the current low-oil price environment that provides cheaper feedstocks. These plants also have capital, environmental and water-usage impacts as headwinds," he said.

"And while China has coal reserves that are among the largest in the world, it only has a current 30-year coal supply, based on existing production levels. This puts a damper on the extent of the development and the impact of future projects in the longer term."

The main concern over this trend is that coal-to-olefins projects consume more than seven times the water resources as naphtha-based plants, market players said.

There is also a heavy cost in treatment of effluents from a coal-based plant and the additional factor of carbon dioxide emissions from coal-based plants, which outweigh the volume of emissions from conventional naphtha crackers.

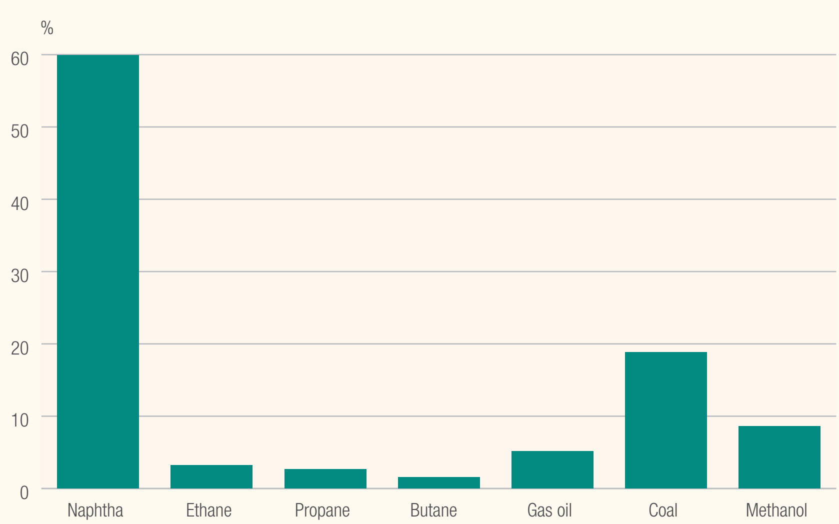
Sustainability in managing resources

China, the world's leading polluter, pledged earlier this year to cut greenhouse gas emissions per unit of GDP by 60-65% on 2005 levels by 2030.

Achieving these targets can prove a challenge, in view of government aims to spread consumption to the far corners of the country. The task could be easier if carbon capture and sequestering become more economical, which the government will be working on under the 13th Five Year Plan being rolled out in 2016.

Interestingly, it is in the Middle East, which has access to greener feedstocks such as ethane, that carbon capture and storage initiatives are beginning to come to fruition.

ETHYLENE PRODUCED FROM – 2024



Source: Platts

Sabic is planning to bring on stream a carbon dioxide utilization project at its new 500,000 mt/year monoethylene glycol facility in Al Jubail in Saudi Arabia, expected to start up by end-2015. Around 1,500 mt/day of CO2 emissions from the MEG plant will be used to produce methanol and urea.

As Sabic vice-chairman and CEO Yousef Al-Benyan said in the company's 2014 Sustainability Report, the initiative is driven by environmental as well as commercial imperatives.

"Sustainability is one of the foundation stones that supports the pillars of our strategy… Working in an industry that uses finite natural resources, we know that the way we secure our feedstock, manage our sites, develop our people and manage our product portfolio will not only impact the environment, but also our business success."

The prognosis for the global chemicals industry, therefore, is a mixed bag. The preponderance of good over bad news will to some extent be determined by factors not within the industry's control such as the direction of crude prices, the pace of global recovery and China's success in resuscitating its economy and propelling demand growth.

However, the industry's destiny will also be shaped by the prescience, flexibility and foresight of the players themselves, whether they are willing to sacrifice short-term gains for the sector's long-term survival. ■

INNER MONGOLIA SELF-OWNED MINE

	Sep-15	Jun-14
Feedstock Cost		
Coal Price (ex-plant)	$46.84	$63.83
Coal Consumption per/ton MeOH	1.4	1.4
Methanol Consumption per/ton olefins	3	3
Total Feedstock Cost per ton olefins	$196.72	$268.10
Co-Products		
Total co-product credits	$87.69	$161.14
Electricity		
Total electricity cost per ton olefins	109.2	109.2
Depreciation and Labor		
Total depreciation and Labor	$96.00	$96.00
Water cost		
Total water cost	$33.60	$33.60
Effluent treatment cost		
per ton olefins	$18.24	$18.24
Others		
others	$132.80	$132.80
Transportation cost for olefins product		
Transportation cost per ton olefins	$91.20	$91.20
Total production cost per ton olefins	$590.08	$588.00

EASTERN CHINA NAPHTHA CRACKER

	Sep-15	Jun-14
Naphtha Feedstock Cost		
Naphtha price (ex-plant)	$429.38	$991.63
Naphtha consumption per ton olefins	2	2
Feedstock cost per ton olefins	$858.76	$1,983.26
Co-Products		
Total co-product credits	$545.62	$872.67
Electricity		
Total electricity cost per ton olefins	$22.15	$22.15
Depreciation and Labor		
Total depreciation and Labor	$54.40	$54.40
Water Cost		
Total water cost	$4.99	$4.99
Effluent treatment cost		
per ton olefins	$2.50	$2.50
Others		
others	$159.36	$159.36
Transportation cost for olefins product		
Transportation cost per ton olefins	0	0
Total production cost per ton olefins	$556.54	$1,353.99

Source: Platts Analytics

ASIA FUEL PRICES

VANDANA HARI

Editorial Director
Platts Asia

PRICE REFORM BATTLES

Governments from Indonesia to India seized the window of opportunity provided by last year's oil price crash to jettison their fuel subsidy burdens, which had grown to billions of dollars in recent years, widening budget deficits and defying the most astute of policy planners.

Emboldened by a convergence of subsidized and free-market prices, and a fresh mandate from electorates in some instances, several countries decided to call it a day for fuel subsidies, adopting market-based pricing mechanisms, with periodic price adjustments.

At the same time, keen to share the low oil price bonanza, governments from China to India and Pakistan jacked up taxes on gasoil and gasoline, offsetting some of the benefit at home from sliding global crude prices. The new pricing formulae incorporated exchange rate fluctuations, so a sharp depreciation in several Asian currencies, especially through 2015, also provided resistance to pump prices fully tracking the fall in crude, especially as it slid to new six-and-a-half-year lows in the third quarter.

Consumers have begun questioning the discrepancy between crude plumbing new depths and their fuel bills easing by just a whisker in some cases.

If fuel subsidies were a tiger by the tail, that tiger is now loose and may soon be roaring in the face of the governments.

The second point of contention could be the definition of "deregulation". Governments continue to retain varying degrees of control over retail fuel price adjustments of the newly freed products, even after having committed to a formula that clearly spells out the market-related basis price, tax, and other components. Call it deregulation with an Asian flavor.

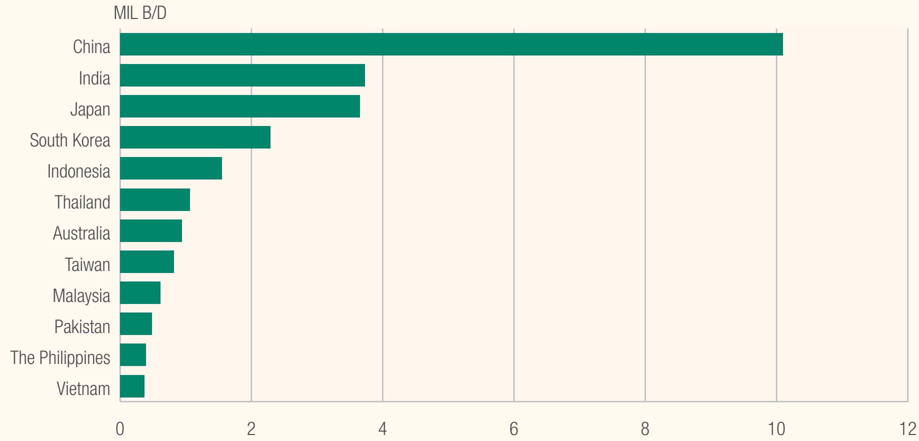
Need for transparency

As the pricing reforms increasingly extend to politically and economically sensitive products, such as gasoil and LPG, clear communication with the public on fuel pricing policies, future plans, and the extent and intent of regulation will become an imperative for these governments. Transparency will be key to earning public trust, giving the oil sector a stable governance regime, and ensuring the entire supply chain from refiners and importers to distributors and dealers functions efficiently. Governments need to be accountable for how they are using the considerable fuel subsidy savings and additional tax income.

We started with Asia's 12 largest oil consumers and looked at the liberalization efforts of the seven that have had some combination of government control and fuel subsidies for decades: China, India, Indonesia, Malaysia, Pakistan, Thailand and Vietnam.

The infographic to the right tracks their journey and the impact on pump prices. The latter is an important ingredient of the discourse over the so-called tailwinds of low prices boosting oil demand, especially in emerging Asia. ■

ASIA'S TOP 12 CONSUMERS – REFINED PRODUCT SALES



Source: Various official data

■ India, Indonesia, Malaysia and Thailand leapt ahead on price reforms for gasoline, gasoil, kerosene and LPG in 2014.

■ India ended subsidies on gasoil and migrated LPG household consumers to a new scheme that pays the subsidy amount directly to the buyer's bank account, thus eliminating misuse.

■ Indonesia ended subsidies on 88 RON gasoline, the most widely used grade in the country, and capped gasoil subsidy at Rupiah 1,000/liter.

■ Partial subsidies refer to either the subsidy amount being capped as with gasoil in Indonesia and the number of subsidized LPG cylinders available annually to a family in India, or targeted subsidies such as with 3 kg LPG cylinders for the poor in Indonesia.

■ Malaysia adopted a "managed float" system for 95 RON gasoline and gasoil, wherein prices are adjusted on a monthly basis in tandem with the Singapore benchmarks, as long as benchmark crude prices remain below $80/barrel.

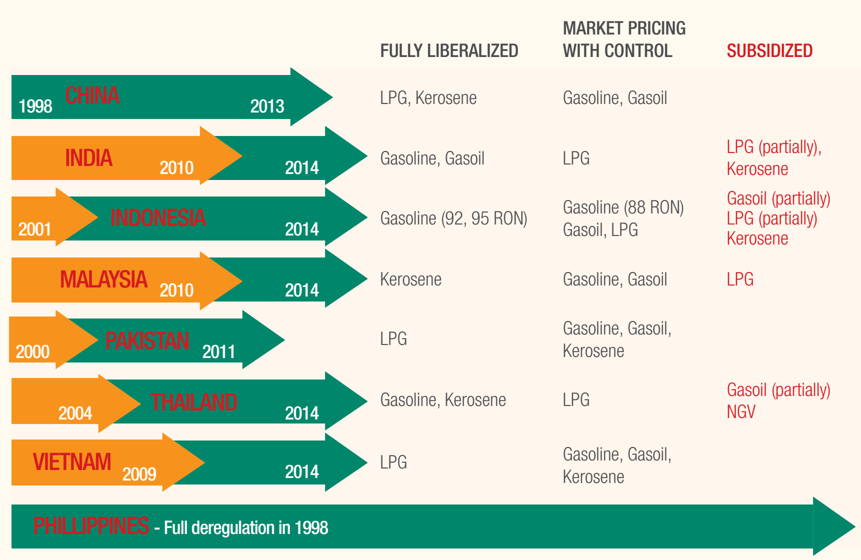
■ Thailand adopted a transparent market-linked formula for domestic LPG prices, and raised Natural Gas for Vehicles, or NGV, prices to close the gap with production costs.

■ Vietnam issued a government directive, encouraging Petrolimex to transparently publish its petroleum prices along with the input factors and the Oil Stabilization Fund balances. It also declared a sliding scale of import tariffs on oil products based on benchmark crude prices.

■ China did not make any changes to its gasoline and gasoil pricing mechanism, which was last adjusted in 2013, but raised taxes on both products.

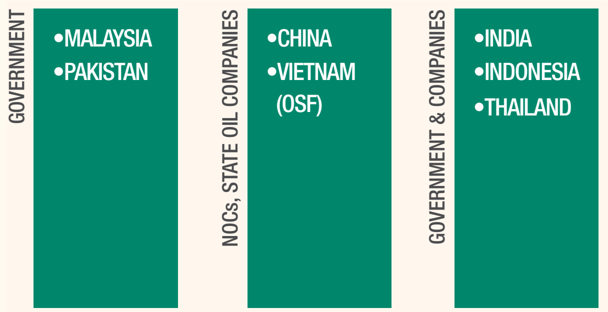
■ Pakistan did not make any policy changes.

2014 OIL PRICE SLUMP: MARKET ECONOMICS START TAKING HOLD



Source: Platts

WHO SUBSIDIZES?



OSF: Oil Stabilization Fund

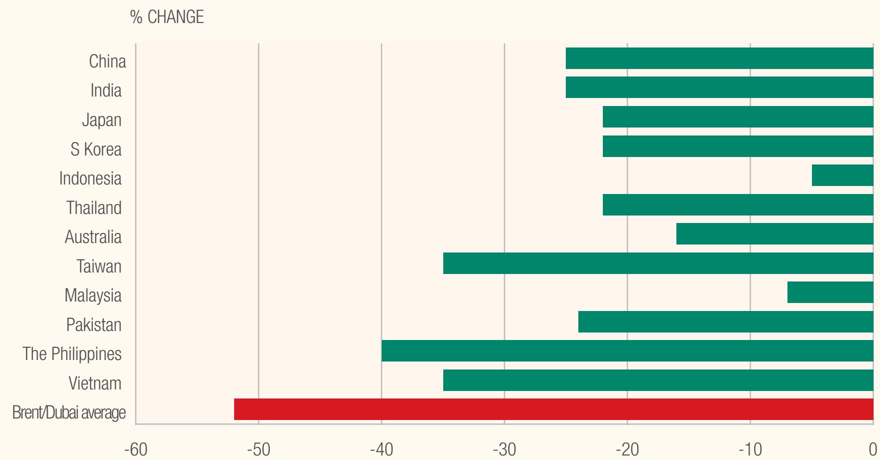
■ Over the years, governments have progressively shifted the burden of fuel subsidies on to national and state-owned oil companies with painful consequences.

■ The companies have to typically bear the cost upfront, and sometimes wait for months for the government to reimburse, in the process having to borrow heavily from the markets.

■ A few countries have experimented with oil price stabilization funds as a mechanism to transfer the benefit of lower oil price environment to times when the prices are high and smoothe volatility. Vietnam and Thailand are the only ones that continue to use it.

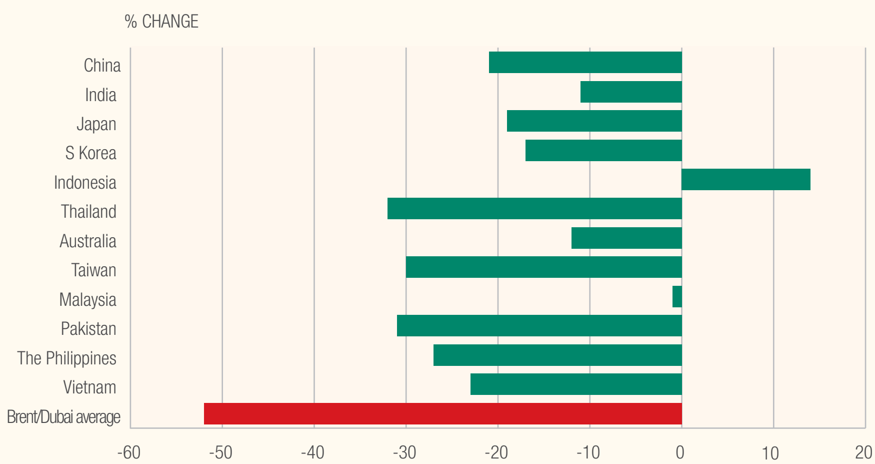
■ The fund has courted controversy and criticism in Vietnam, but the government renewed its commitment to maintaining it in November 2014.

GASOIL PUMP PRICES AND CRUDE SEP 2015 VS SEP 2014



Source: Platts

GASOLINE PUMP PRICES AND CRUDE SEP 2015 VS SEP 2014



Source: Platts

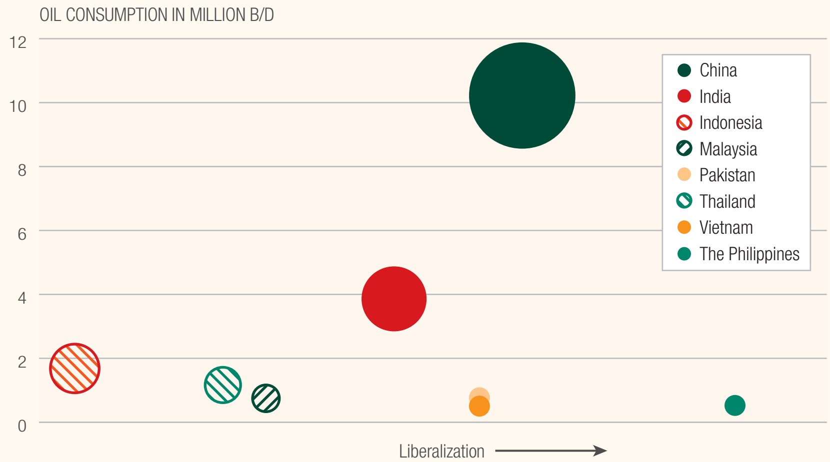
■ Crude, as measured by the average of Platts Dated Brent and Dubai – the most commonly used benchmark for refiner feedstock costs in Asia – plunged 52% in September from a year ago.

■ In that period, gasoline prices slumped the most – 30%-32% – in Thailand, Taiwan and Pakistan.

■ Gasoil slid the most – 35%-40% – in The Philippines, Taiwan and Vietnam.

■ Indonesia and Malaysia stand out as the countries with the least pass-through effect, with 88 RON gasoline prices in Indonesia, which began tracking the Singapore market starting January this year, actually rising compared with a year ago.

ASIA'S PROGRESSIVE 7, RANKED AND COMPARED TO THE PHILIPPINES, WHICH IS FULLY LIBERALIZED



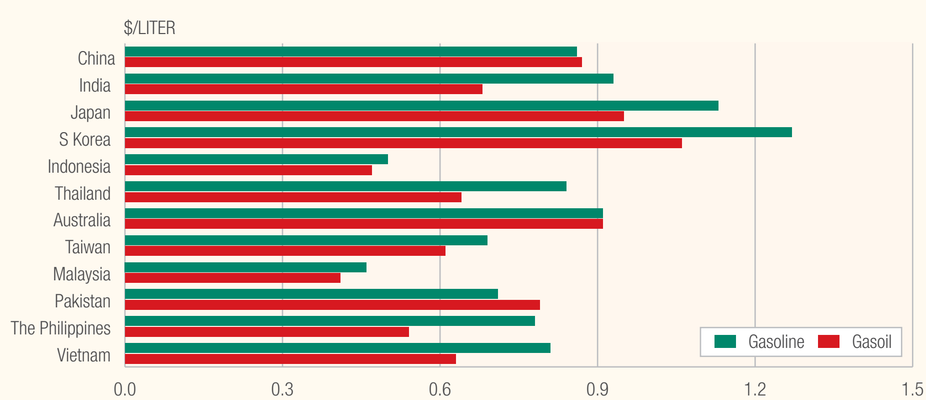
Source: Platts

■ The chart shows the countries scored on their level of liberalization in the retail pricing of gasoline, gasoil, LPG and kerosene.

■ The highest points were accorded to fully liberalized products, where the marketers are free to set retail prices without any government intervention or approval, followed by those that follow market pricing but with some degree of government control, and negative points accorded for fully or partially subsidized products. The greatest weightage was given to gasoil, being the largest part of the barrel sold in the region, followed by gasoline and LPG with equal points and kerosene at the bottom of the rung.

■ Indonesia lags way behind its peers on account of having fully deregulated only 92 and 95 RON gasoline, which occupy only a small proportion of the gasoline market, and having the most products on the opposite end of the scale, with gasoil and LPG partially subsidized and kerosene fully subsidized.

TRANSPORT FUEL PRICES

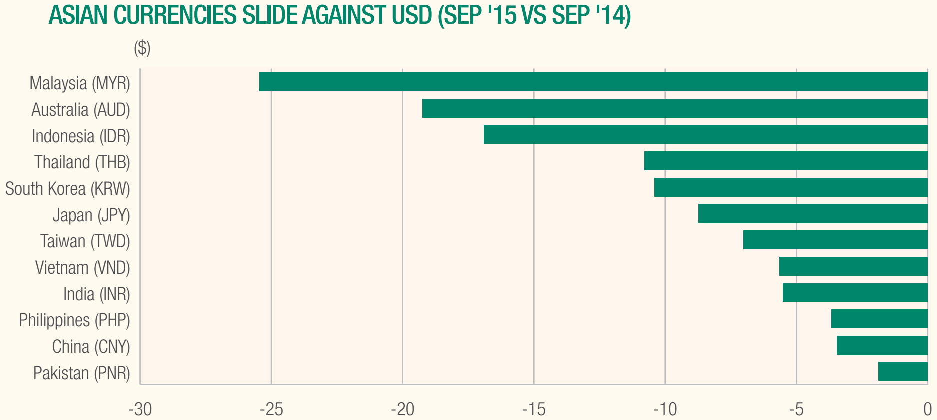


Source: Platts

■ Wide variation in transport fuel prices in the top 12 biggest oil consumers of Asia, with South Korean prices being nearly 2.5 to 3 times those in Malaysia, the lowest priced.

■ Fuel price as measured in US dollars is the cheapest in Malaysia, followed by Indonesia, despite both countries having adopted market pricing for gasoline and gasoil, which would explain the much smaller magnitude drop on-year in response to crude's plunge.

ASIAN CURRENCIES SLIDE AGAINST USD (SEP '15 VS SEP '14)



Source: www.xe.com

■ The Malaysian ringgit and the Indonesian rupiah, coincidentally, were among the most battered currencies over the 12 months to September 2015, depreciating by around 25% and 17% respectively against the US dollar.

■ A weaker home currency makes the country's crude imports costlier.

INDONESIA

Mriganka Jaipuriyar

Associate Editorial Director, Asia Oil News

JOKOWI'S REPORT CARD

Just over a year has passed since Indonesia brought Joko Widodo to power, making him the first Indonesian president with no ties to the military or political elite. It was his humble background that the common Indonesian, weary of corruption and bureaucracy, bought into.

Jokowi, as he is commonly known, came with a lot of promise to establish a pro-business administration, and Indonesia's embattled oil industry was filled with hope. But progress has been erratic to say the least.

Courtesy: iStock

A presidential election sticker for winning candidate Jokowi on the tank of a motorcycle in Ubud, Bali Indonesia.

The retail fuel price reform has veered off course, policies to kick start exploration and production have been sporadic, and the country is yet to get an oil and gas law.

Indonesia has substantial undiscovered resources and urgently needs clear policy direction to push through energy sector development and curtail its reliance on expensive imports.

Fuel subsidies

Jokowi clinched power when oil was firmly above $100/barrel and fuel subsidies were eating into government coffers. Subsidies consume valuable budget funds, but also lead to higher oil imports and a widening current account deficit, by artificially propping up demand for cheap fuels.

In 2014, the country spent Rupiah 229 trillion ($16 billion at current exchange rates) on subsidies. This compares with just Rupiah 67.9 trillion spent on healthcare.

Jokowi came with the pledge to reform retail fuel pricing and barely two months after being sworn in, implemented a 30-35% increase in prices of 88 RON gasoline and gasoil. This was a bold move, given Indonesians' sensitivity to fuel price hikes, which had sparked unrest and toppled governments.

The higher gasoline grades – 92 and 95 RON – are sold at market prices in the country.

Emboldened by Indonesians' muted reaction to the price rise and aided by the drop in global crude oil prices, the president took an even bolder step of eliminating gasoline subsidies and fixing the subsidy for gasoil, or diesel, at Rupiah 1,000/liter in January this year.

The government kept a strong hold on prices, but linked them to market levels and said it would set them on a monthly basis.

With this new pricing regime in place, the government said it expected to slash spending on fuel subsidies to Rupiah 64.6 trillion in 2015 – a considerable feat, or is it?

Politics eventually played a heavier hand and Jokowi in mid-2015 succumbed to demands that fuel prices be adjusted every three to six months instead.

What used to be a subsidy burden for the government has turned into losses for state-owned oil and gas company Pertamina, which has a near monopoly on 88 RON gasoline and gasoil sales in the country.

A senior Pertamina official told Platts in September the company has suffered losses of Rupiah 15 trillion ($1.1 billion) on fuel sales over January-August this year. Pertamina also posted a 50% drop in net profit to $570 million in the first half of 2015 due to losses suffered on fuel sales.

"The parliament has to be serious about speeding up the amendment of the oil and gas law. It is really important. Investors have been waiting for so long," said Komaidi Notonegoro, vice chairman at local think tank ReforMiner Institute."

The government last adjusted pump prices on March 28, when 88 RON gasoline was set at Rupiah 7,300/liter and of gasoil at Rupiah 6,900/liter.

Based on the government's pricing formula, gasoline prices should have been set to Rupiah 8,150/liter in April and May, at Rupiah 9,200/liter in June, Rupiah 9,350/liter in July, Rupiah 8,500/liter in August and Rupiah 7,700/liter in September, said I Gusti Wiratmaja Puja, oil and gas director general at the energy and mines ministry.

Puja said the government has realized that oil prices have increased since late March, but Jakarta "does not want to hike the price to maintain economic stability." Pertamina is bearing the cost burden, as prices have not been raised and since 88 RON gasoline is technically no longer subsidized, the firm does not get a pay out from the government. ▶

Upstream policy

With domestic oil and gas production dwindling – Indonesia is expected to miss its crude oil output yet again this year – Jokowi promised massive reforms to spur exploration and production work.

Some measures have been taken, but the overall pace of reforms has been slow and with no sign of a new oil and gas law getting passed soon, the country is unlikely to see an uptick in investment anytime soon. This is underscored by the level of upstream activity, or lack thereof, in the first half of this year.

Data from upstream regulator SKK Migas showed that only 26 wells were drilled in first-half 2015, representing 17% of the original target of 157. There were only 12 new seismic surveys carried out, down from a plan of 46.

This could partly be due to low oil prices, but SKK Migas communications chief Elan Biantoro attributes it to permits and land acquisition problems, issues that have long plagued the upstream industry. "The government's efforts to simplify the permit process have not been effective yet. Oil companies are still finding it difficult to carry out exploration work," he said in July.

The Jokowi government in mid-2015 announced it had cut the number of permits needed from the Ministry of Energy and Mines to 42 from 52. But that still leaves 289 more permits that need to be taken from other ministries such as transport, forestry, environment and from regional governments where the asset is located. Progress on streamlining these has been close to nil.

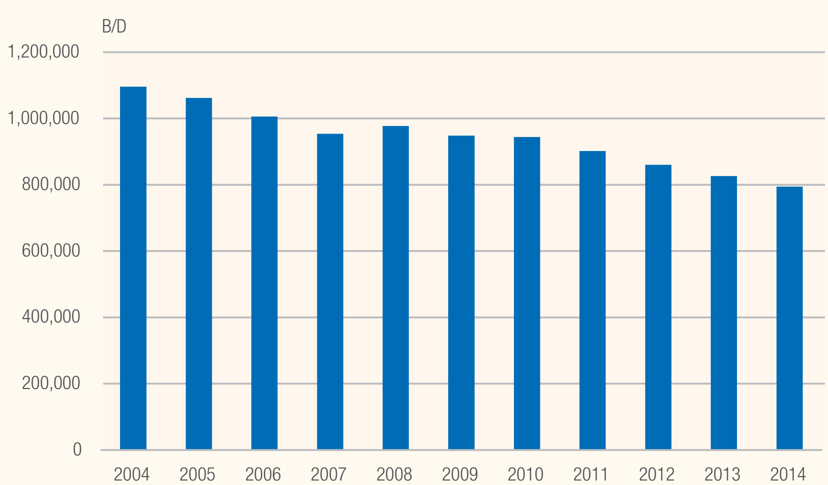
Biantoro said that if the situation does not improve, Indonesia will soon run out of oil.

Indonesia's last significant oil discovery was the Banyu Urip field in the onshore Cepu block in 2001. The country has not seen a new project come onstream since 2008 with the Cepu field, and that too at rates far below the original target.

Other initiatives have been taken such as bringing oil and gas investments under the purview of the investment coordinating board to remove unnecessary delays and setting up a national exploration team with the sole aim of identifying and tackling the problems plaguing the upstream industry.

But Lukman Mahfoedz, chairman of Indonesia's largest private upstream firm Medco Energi Internasional, said these initiatives are not enough.

INDONESIA'S CRUDE AND CONDENSATE PRODUCTION



Source: SKK Migas

"The main problem is how to make the energy and mines ministry the focal point of the industry. We [would like] the energy and mines ministry to be the focal point," Mahfoedz said, adding if this is achieved, it will be a huge incentive for investors.

"Currently energy and mines sectors are every ministries' business including finance, forestry, transportation and trade ... It's complicated."

Oil and gas law

Government failure to speed up passing the oil and gas law has been another drag on the country's upstream investment.

Indonesia's 2001 Oil & Gas Law was annulled in November 2012, when the constitutional court disbanded the then upstream regulator BPMigas. Though the government soon after set up a temporary regulator, SKKMigas, to take over BPMigas' functions, investment has since suffered due to the lack of certainty in the absence of a law and a permanent regulator.

The government in August eventually formulated the draft oil and gas law. The final draft and its conversion into a law could take some time as the parliament's energy commission is still in the process of drafting its own version. The two versions will then be debated before the law is finalized and passed.

A senior government official said they are hopeful it can be passed next year.

"The parliament has to be serious about speeding up the amendment of the oil and gas law. It is really important. Investors have been waiting for so long," said Komaidi Notonegoro, vice chairman at local think tank ReforMiner Institute.

OPEC re-entry

Even if Jokowi does not go down in history as the president who revamped Indonesia's energy sector, he may emerge as the one who was at the helm when Indonesia re-entered OPEC after exiting the group seven years back when the country became a net oil importer.

This move is aimed at cementing Indonesia's relationship with leading producers and to ensure that it gets crude on better terms to meet growing domestic demand. But industry watchers are skeptical.

"OPEC is a group of net oil exporting countries and Indonesia is a net oil importer. So it's really ridiculous," Kardaya Warnika, chairman of Commission VII on energy Issues told Platts in September. Commission VII is a special parliamentary committee that focuses on energy and mining issues.

Warnika added that Indonesia would have to pay Eur2 million on an annual basis as membership fee but cannot expect to get much in return.

"We have no bargaining power. We stand in the lowest level in OPEC," he said.

ReforMiner Institute's Notonegoro agreed. "I am afraid that the annual membership fee that Indonesia has to pay is high compared with the savings that we can make if we buy crude directly from OPEC countries. In fact, we can buy crude from anywhere, not only OPEC members," he said. ■

STEPHANIE WILSON
Managing Editor
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ASIA LNG
ABACHE ABREU
Editor
Asia LNG

LNG CENTER STAGE

After years of calling the shots, the balance of power is beginning to shift away from sellers in the LNG market. Increasing supply, low term contract prices and a fleet of new, uncommitted carriers have conspired to swing the market back in favor of buyers, at least for the time being.

The LNG spot market is experiencing a rapid change, the timing of which has taken most by surprise.

"There's a succession of new projects coming onstream from the US and Australia; all of us were prepared for that. What we may not have expected was that the timing coincides with a decline of the oil price and much weaker-than-expected demand in Asia," Jean-Pierre Mateille, Total Gas & Power's vice president for trading, told an industry event in September.

The entrance of new buyers who have yet to lock into term contracts, mainly in Pakistan and the Middle East, has potentially offered a new, lucrative market for traders with a large risk appetite. These factors are forming the perfect conditions for increased spot trading in the space of around 18 months.

"The number of participants in the LNG market has dramatically increased," Tetsuro Toyoda, LNG Trading Manager at BP, said in September. "In the past, LNG ships were there to move from point A to point B and that was all. Now, many of these ships are not dedicated to [specific projects], but to find optimal shipping movements, depending on the market, the arbitrage, and contractual agreements."

Liquidity is already beginning to build as trading activity, which was not expected to kick off in earnest until the slew of new projects due in 2016 came on stream, is ramping up.

"We believe that the physical spot market will develop to a larger extent than what we could have foreseen only a few years ago, and it will become more important," Mateille said.

For now, end users are largely on the sidelines of this new, more liquid spot market, despite the attractive prices.

Japan and South Korea have reduced their LNG intake by a total of 4.17 million mt in the first eight months of 2015, year on year, according to Eclipse data, as the world's two largest LNG importers battle with high inventories following temperate winters and faltering economies.

Similarly, Chinese imports are 500,000 mt lower over the same period, as government-set domestic gas prices remain much higher than the costs of competing fuels which face less regulation.

Advent of tenders

Waning demand from legacy buyers has freed up cargoes from existing facilities in Australia, Russia, Indonesia and Malaysia, while new production from Papua New Guinea and Australia has added to the overhang. This in turn has created one of the increasingly prominent features in LNG trading in 2015: supply tenders.

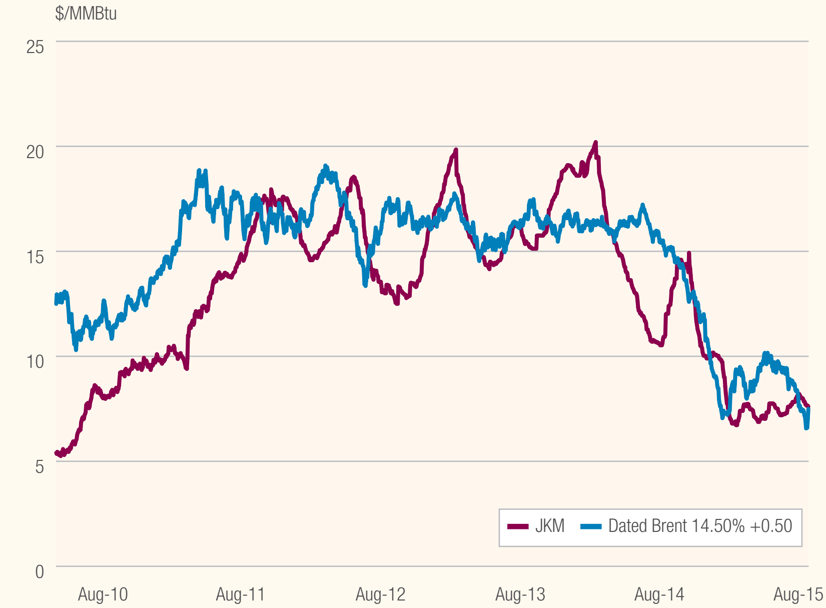
Just why projects are choosing to market via tender rather than through direct, bilateral negotiations is a topic for debate. For consortium suppliers, such as the Woodside-led North West Shelf LNG facility, a tender has historically been considered the fairest way to market volumes. For state-owned facilities, such as Indonesia, tenders provide a transparent approval and pricing process necessary for regulators.

For others, tenders are likely a function of the low spot price. In the past year, Platts' JKMTM has lost more than 65% of its value in a downslide that far preceded the decline of long term crude oil-linked prices. According to Platts tender data, by late September, almost 100 excess cargoes had been offered via tenders for loading or delivery in the second half of 2015, showing the trend will continue.

An analysis of previous awards also shows that most cargoes have been absorbed by portfolio suppliers and traders; those looking to optimize their fleet or backfill short positions, sometimes to other traders. This effectively creates a churn rate for the cargoes, creating more links in the same purchasing chain.

"We have noticed an increase in liquidity over the year," Ann Collins, BG Group Vice President, LNG Supply & Optimisation, Global Energy Marketing and Shipping said. "We have seen more cargoes tendered… The liquidity has also seen a growth of the trading companies."

JKM VS LNG TERM PRICE



Source: Platts

LNG EXPORT PROJECTS TO START UP BY MID-2016

	First LNG	Capacity (mt/year)
Gladstone LNG (train 1)	Q3 2015	3.9
Australia Pacific LNG (train 1)	Q4 2015	3.8
Sabine Pass (train 1)	Q4 2015	4.5
Gorgon LNG (train 1)	Q1 2016	5.2
Petronas Bintulu 9	Q1 2016	3.6
Petronas floating LNG	Q1 2016	1.2
Angola LNG (train 1)	Q1 2016	5.3
Total volumes		27.5

When end buyers eventually return to the spot market, it may not be just in a purchasing capacity.

China's top buyer CNOOC launched its first supply tender for October and November delivery from the recently commissioned Queensland Curtis LNG facility in Australia. The state-owned buyer has a 50% equity interest in QCLNG Train 1 and a contract with BG Group for the procurement of 5 million mt/year of LNG from the seller's portfolio.

It is unclear whether the volumes are available through its equity offtake, or from the BG portfolio. Either way, the tender further served to highlight that the radical shift in the supply and demand balance is underway.

An increasing reliance on spot?

Further along the curve, the oversupply is set to worsen into 2016. Seven LNG trains are set to start production by early next year, five of which in the Pacific basin.

This will add a total of around 25 million mt of LNG/year of plateau output to the global market. However, demand from the key northeast Asian markets shows no sign of recovery.

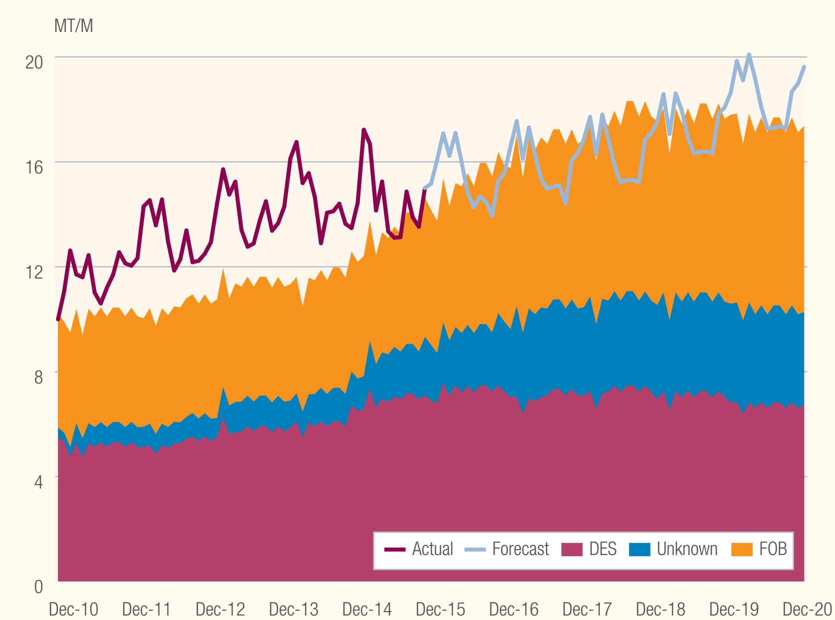
"There will be a supply overhang between now and 2025, but that gap looks like its tightening as we see economic recovery and projects face delays," said Demus King, General Manager, Offshore Resources Branch, Department of Industry and Science, Australia, at a recent industry event.

Many buyers are attempting to follow in CNOOC's footsteps in order to manage inventories where they can, although this is currently limited to selling cargoes from offtake positions in the US. These were largely concluded on a tolling, FOB basis, without destination restrictions, or take-or-pay clauses; the hallmarks of traditional LNG term contracts.

Ultimately though, buyers will likely require the ability to sell volumes from their term contracts, if they are to deal with the looming glut. This will mean the removal of destination clauses, take-or-pay terms and the use of more upward and downward quantity tolerance in contracts.

"[Buyers] face difficulties in managing supply as the demand decreases. In this regard, I am sure more flexible take or pay, or destination clauses, will go a long way to increasing the trade," South Korea's vice minister for trade, industry and energy, told a recent industry conference in Tokyo. "We need to take

LNG IMPORT CONTRACTS



Source: Platts

recent changes in the market as a chance to do away with the destination clause once and for all. The result will be a fairer and sounder LNG trading relationship for all parties."

Although sellers show strong resistance to any suggestion that such terms could be removed from contracts – citing the need for long-term security in order to finance new projects – behind the scenes, negotiations are already underway.

Several are beginning to concede some ground on new and even existing contracts, understanding that they must be flexible to stay competitive against the emerging wave of US exports.

"Contracts are becoming shorter. The US is FOB, so you have that flexibility of destination, and we see the traditional link between producer of gas and buyer of LNG has been broken up by this new business model. The contractual terms are changing," Mateille of Total Gas said.

In May, an agreement was announced between supplier BP and buyer Kansai Electric, which allows the Japanese utility to resell volumes to third parties, or ask BP to find alternative buyers by mutual consent.

The buyer had also agreed to cooperate on LNG procurement, marketing and shipping optimization with France's Engie in an agreement that will see the trader, formally GDF Suez, purchase 400,000 mt/year from Kansai's US volumes and sell an equivalent amount to Kansai from elsewhere in its portfolio, depending on market conditions. If the Japanese utility does not need the LNG it gets from Engie, it can also resell to a third party.

NEW VESSELS

	Existing	On Order	Total by 2020
Gas capacity over 120k	379	142	521
FSRU	22	9	31

More recently, several sources reported that renegotiations for existing contracts and those due for renewal with Japanese buyers had seen increased flexibility written in, with traditionally restrictive destination clauses widened to include other buyers' receiving terminals in Japan. However, this could not be confirmed.

Elsewhere in Asia, China's Sinopec is awaiting management approval to sell part of its 7.6 million mt/year long-term contract with the new ConocoPhillips-led Asia Pacific LNG facility in Australia, while trading sources said Petrochina has been marketing cargoes from Algeria since 2014.

Deeper supply/demand cycle looms?

Indeed as the glut becomes the focus, even the great indexation debate – whether contracts are linked to crude, gas hubs, hybrids or the Platts JKM -- appears to have been put on the backburner, with sellers now realizing that flexibility around delivery terms is worth more at the negotiation table.

"Buyers are being more fussy than they previously were," Elena Sidorochkina, Director of Long-Term LNG Supply and Marketing, Gazprom, said at a recent conference. "They are looking for much more flexibility in their contracts, and shorter term flexibility, which costs more. They are looking for softer credit terms, even though financing did not get any easier for the projects"

Term negotiations for new sales and purchase agreements have largely stalled as a result and new projects are not being sanctioned, despite increased warnings of an even deeper supply/demand cycle looming after 2025. Low prices lead to a lack of investment, which will ultimately tip the market back into a shortfall, triggering demand destruction when prices invariably increase. A cycle we're all too familiar with.

ExxonMobil's President of Gas & Power Marketing Company Robert Franklin acknowledges that securing new final investment decisions in the current environment will not be easy, and will likely remain challenging as more supply capacity comes on stream.

The International Energy Agency's recently appointed Executive Director, Fatih Birol, also cautioned there are growing risks of 'short term-ism' in the LNG market, which could become more costly in the long term.

"There is no doubt that a golden age of gas remains possible. In the US, it's already a reality. In this part of the world, we need to move faster and with more determination," he said. ■

AUSTRALIA

CHRISTINE FORSTER
Senior Writer
Asia Oil News

HEADWINDS FOR AUSTRALIA LNG

Australia's giant LNG industry is in an unprecedented transition from the construction boom seen since 2009 into its A$450 billion operational phase lasting 25 to 40 years, which would catapult it to the top of the producers list.

The shift comes against a backdrop of lower oil prices which could test the profitability of the new LNG projects, but it is still set to deliver a massive windfall for the country, provided the industry improves in a number of key areas.

Up to 2015, Australia's LNG industry was made up of the Woodside Petroleum–operated North West Shelf and Pluto projects, and ConocoPhillips' Darwin facility. The industry's total capacity then was just over 24 million mt/year.

At the start of this year, however, a wave of new startups began to break, with the BG-operated Queensland Curtis LNG making the first shipment from its 4.25 million mt/year train one. QCLNG has subsequently started up its second production train, loading its first cargo in July.

In total, another five new onshore LNG projects, including 11 more production trains, plus the Prelude floating LNG facility, are expected to begin operations between now and 2018. The single-train Prelude facility will be located in the Browse Basin off northwestern Australia and is slated to start producing in 2017.

Further south, the Chevron-operated Gorgon project is under construction on

AUSTRALIAN LNG PROJECTS

Project Name	Operator	Capacity (Million mt/year)	Cost (Billion US$[1])	Startup
North West Shelf	Woodside	16.3	23.7	1989
Darwin LNG	ConocoPhillips	3.7	3.3	2006
Pluto	Woodside	4.3	10.4	2012
Queensland Curtis LNG	BG Group	8.5	20.4	2015
Gladstone LNG[2]	Santos	7.8	18.5	2015
Australia Pacific LNG[2]	ConocoPhillips/ Origin	9	17.2	2015
Gorgon[2]	Chevron	15.6	54	2016
Wheatstone[2]	Chevron	8.9	29	2016
Ichthys[2]	Inpex	8.9	34	2017
Prelude[2]	Shell	3.6	12	2017
Total		**86.6**	**222.5**	

[1]At today's A$/US$ exchange rate. [2]Forecast cost and startup

Source:Platts

AUSTRALIAN LNG PROJECTS

Source: Platts

Barrow Island, off the coast. Chevron is also building the Wheatstone project near Onslow on the Western Australian mainland.

Gorgon was originally due to start in 2014, but weather and construction delays are now likely to push the first cargo into early 2016. Wheatstone has kept to schedule and is expected to produce first LNG at the end of that year.

In the northern city of Darwin, Japanese exploration company Inpex is building its first operated LNG project to process gas from the Ichthys field in the Browse Basin. Ichthys is expected to start up in the third quarter of 2017.

On Australia's east coast, QCLNG is the world's first coalseam gas-to-LNG project to begin producing at its facility on Curtis Island in Gladstone harbor. Two adjacent plants – Gladstone LNG and Australia Pacific LNG – are set to begin loading cargoes over the next few months.

The Santos-operated GLNG facility is scheduled to start up around end-September. The Australia Pacific LNG project, operated by Origin Energy and ConocoPhillips, is slated for first output before year-end.

The seven new plants represent an extraordinary investment of around $190 billion and will boost Australia's LNG capacity to a total of more 86 million mt/year, toppling Qatar as the world's biggest producer.

LNG can add $38 billion to GDP in 2020

Ultimately the benefits from the massive investments of the past six years will hinge on the success of the industry's move into production phase, according to a recent study by global consultancy Accenture, commissioned by the Australian Petroleum Production & Exploration Association.

Accenture found that the domestic LNG industry has the potential to add more than A$55 billion ($38 billion) to national gross domestic product in 2020. But to tap that benefit it must improve its international competitiveness, remove regulatory constraints and introduce a more flexible labor relations regime.

Accenture estimated that over the next five years, Australia's natural gas production would increase by more than 90%, the number of wells in production would jump by 400% and pipeline infrastructure would expand by 45%.

Total cumulative capital investment and operating expenses will reach around A$360 billion by 2020, 40% more ▶

than the A$250 billion spent during the construction boom.

"While the investment to date has been massive, this will be overshadowed by the A$450 billion of ongoing investment required to sustain the industry for the next 25 years," Accenture said. "The operations phase offers a remarkable, long–term opportunity and it provides a platform upon which Australia can be recognized as the world's center of excellence in LNG production."

To achieve that, greater industry and regulatory collaboration, accelerated workforce retraining and further investment in digital and automation will be required, Accenture said.

"If operators, the service sector and government can work together to get the transition right, we estimate the industry could collectively realize an additional A$50 billion to A$70 billion of shareholder value over the next 25 years – and this will have a positive impact on the whole economy," Bernadette Cullinane, Asia Pacific managing director for Accenture's energy industry group, said when releasing the report. "The speed, scale and scope of the transition are unprecedented."

Based on Accenture's survey of the top LNG operators and the companies that service them, Australia's industry is well prepared in several areas for the transition. Its biggest strengths are workforce capacity and capability, as well as tuning and adapting business models for production.

On a scale up to 1, Australia's workforce capacity and capability were rated at 0.58 and 0.68 respectively. Areas needing improvement were competitiveness, rated at 0.37, and regulatory framework, at 0.40. The industrial relations framework was rated as the biggest weakness at 0.32.

"The research overwhelmingly highlighted that there is room for more collaboration on key services such as turnarounds and logistics, with many stating the industry hadn't done enough sharing during the construction phase," Cullinane said.

Industry observers had lamented the lack of cooperation between the three coalseam gas-based LNG projects in Queensland, pointing to missed opportunities for shared infrastructure and services. Instead of collaborating, the Curtis Island projects have spent billions of dollars on duplicated infrastructure such as pipelines, jetties and loading facilities.

Accenture concluded that although operators and services companies had been busy preparing for the operational phase, this had been done in isolation.

"What is striking is that these readiness activities have mainly taken place within industry siloes and not in a collaborative or coordinated fashion," the consultancy said. "To date, operators and service providers have not had sufficient dialogue regarding their preparations."

Accenture added there was a lack of insight into what each party needs from the other to succeed. "Operators and service providers must improve their dialogue to help ensure the industry maximizes productivity in this new phase," it said.

Turnaround management was clearly identified as a critical area for industry collaboration, given the significant opportunities to reduce risk and improve the overall efficiency and safety performance of turnarounds. Cullinane said if operators cooperate and coordinate turnarounds, they can share the peaks of demand but also improve schedules and budgets.

One of the report's specific recommendations for cooperation was the introduction of a services sector-to-operator collaboration forum, based on the "shared objectives of overall industry improvement."

"Accelerating industry collaboration and embracing innovation and digital technologies will help drive global competitiveness, attract the next wave of capital investment and transform Australia into the world's largest and leading LNG industry," Cullinane said.

Lower oil prices, uncertain LNG demand

There is also the challenge of lower crude oil prices, the contractual benchmark for most Australian LNG exports. The Australian Financial Review, in a recent report quoting the International Energy Agency's senior gas expert Costanza Jacazio, forecast a difficult time for the new LNG projects.

"In a $60 oil environment the Australian projects will continue, but you are probably not breaking even," the AFR quoted Jacazio as saying. "Will anything else in Australia proceed beyond this next portion of projects? I think in this environment it is very unlikely," she added.

"Many of these projects were sanctioned in an environment of $100/b oil, so clearly the impact on your earnings and profits has dramatically changed," Jacazio said, adding that while operating costs might be recovered, the billions of dollars of sunk costs on the projects will take much longer to make back.

Downside risks also appear to be growing on the demand side. Cheap spot LNG has resulted in increased gas consumption in Japan, but competition from pipeline gas imports in China and coal in South Korea are stymying growth in those countries, according to the latest quarterly review by the Office of the Chief Economist in the Australian government's Department of Industry and Science.

> "If operators, the service sector and government can work together to get the transition right, we estimate the industry could collectively realize an additional A$50 billion to A$70 billion of shareholder value over the next 25 years – and this will have a positive impact on the whole economy," Bernadette Cullinane, Asia Pacific managing director for Accenture's energy industry group, said when releasing the report. "The speed, scale and scope of the transition are unprecedented."

To generate cash flow, operators of the new LNG projects are expected to maximize output regardless of whether buyers take contracted volumes. This is likely to promote spot market competition and underpin growing imports of uncontracted LNG into Europe and emerging regions such as ASEAN and India.

The Australian government forecast global LNG imports would balloon to 271 million mt in 2016 from 239 million mt in 2014, but not enough to prevent a short-term oversupply. ■

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THERMAL COAL STRUGGLES

Plunging oil markets may help regional coal miners to slash production costs, but sagging Chinese demand has dampened thermal coal prices, with no respite seen till at least 2017.

The industry looks to some relief from rising demand in India and emerging economies, which will intensify competition for these markets, as Indian imports are set to outpace China's this year.

Courtesy: Shutterstock

A coal-fired power plant in China.

Coal also faces threats from renewable energy amid mounting concerns over global warming, as well as cheap oil and gas.

China is reducing thermal coal imports as it confronts a slowing economy, oversupply in its giant coal industry and a break in the link between GDP/power consumption growth and coal usage.

China's National Energy Administration data in July showed that while electricity demand grew 1.3% in first-half 2015 versus a year ago, coal consumption shrank 5%, extending the 3% drop in full-year 2014, said US-based Institute for Energy Economics and Financial Analysis, or IEEFA.

"What it comes down to is that China has decoupled its economic growth from its coal usage," Tim Buckley, director of energy finance studies said in the IEEFA report in mid-July.

"These new figures starkly demonstrate that while electricity demand continues to rise and GDP growth remains at a level that would turn any Western treasury green with envy, coal consumption is rapidly declining as the country focuses on shifting to an 'everything but coal' energy mix."

Chinese domestic thermal coal prices had been sliding since last year, after its economy grew at the slowest clip in 24 years at 7.4%, and heavy rains damp demand. Worsening pollution in the capital, Beijing, also had the government on its toes.

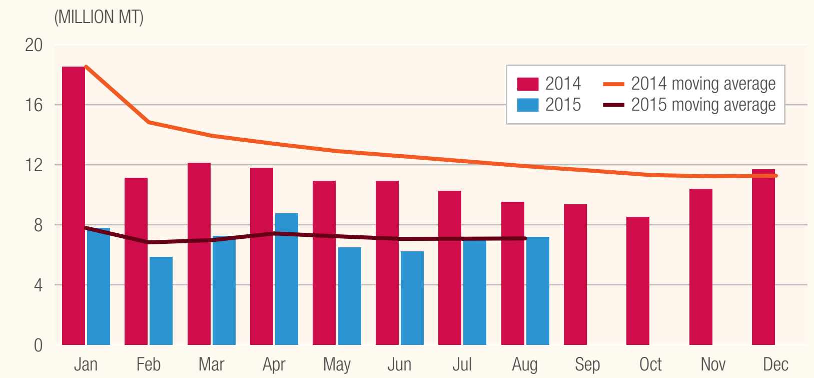
China implemented several policies that made seaborne-traded thermal coal imports less attractive to buyers, particularly utilities with coal-fired generation capacity on the southern and eastern coasts. These include a 6% import tariff on Australian thermal coal, a reduction in the acceptable level of ash to 16% in cargoes of imported thermal coal and instructions to state power firms to slash imports.

So far in 2015, Chinese thermal coal imports have dropped more than 40% year on year. Australia and Indonesia account for the bulk of imports.

"Improved logistics (rail & port) have improved the flow of domestic coal from coal mines in the North, Central and Western provinces to the main demand market in the southeastern coastal provinces," said Matthew Boyle of London-headquartered commodities consultancy CRU.

"In the current market price environment, with domestic prices at low levels, the only incentive for coastal power stations and industry to take seaborne thermal coal imports would be

CHINA THERMAL COAL IMPORTS 2014-2015



Source: Platts, China Customs Statistics

if they can purchase it cheaper than domestically sourced coal."

Emerging markets might be unable to help support prices in the short term, Boyle said. But their demand is set to rise on new coal-fired power projects built after 2020, when these markets will play a bigger role in seaborne thermal coal markets.

Chinese thermal coal imports are expected to reach 135 million mt in 2015, down from 200 million mt last year, while imports of East Asian emerging economies could rise to up to 113.6 million mt by 2021, matching Japan's imports in 2014, said Guillaume Perret of UK-based consulting and market research firm Perret Associates.

"Indonesian coal producers have been most affected by the reduction in Chinese imports of thermal seaborne coal during the first half of 2015," PT Harum Energy, an Indonesian miner of high-grade coal, said in its half-yearly report.

Indonesia, the world's top thermal coal exporter, produces about 425 ▶

million mt/year. But China has massive production of more than 3.5 billion mt/year and is among the leading producers with rich coal reserves, so the 203 million mt year-on-year output drop during July 2014-June 2015 is deemed insufficient to ease the current glut.

> "What it comes down to is that China has decoupled its economic growth from its coal usage," Tim Buckley, director of energy finance studies said in the IEEFA report."

Cash costs down

Harum Energy said FOB vessel cash costs – including mining, hauling, barging and transshipment – fell nearly 14% in first-half 2015 from a year ago, aided by a 40% drop in average fuel price.

"Indonesia coal companies are among the lowest-cost coal producers in the world," analysts at Credit Suisse said. "The decline in oil price has helped miners to reduce cost as they operate open pit mining in which mining cost accounts for around 50% of the total cost, and 40% of which is fuel related."

Yet, profits for Indonesian miners remain low, as prices have continued falling this year. Not many are optimistic about the coming year.

"The market remains oversupplied, with few cuts in output by producers outside of North America," Harum said. "Thermal coal prices remain at 8-year lows."

Pandu Sjahrir, chairman of the Indonesian Coal Mining Association, said at a conference in June that sustainability of many small and mid-sized miners could become difficult due to weak coal prices. He estimated Indonesia's total production for 2015 to range about 350-400 million mt, down from 425 million mt last year.

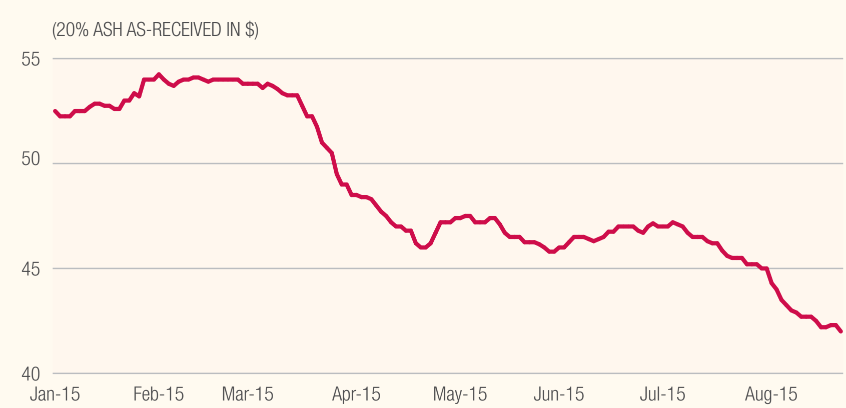
"I would expect that Indonesian exports would need to reduce by at least 100 million mt for any meaningful price increases of more than $10/mt to take effect," Stuart Murray of Asian Commodity Consultants Ltd. said.

"Most governments are under pressure to reduce coal consumption/pollution and emissions, so there may be some short-term increased demand to meet local shortfalls but cannot see long-term demand that would lead to any significant increase in prices."

India demand to the rescue?

Demand in India is set to keep growing steadily in coming years, as the country generates about 60% of total electricity from coal-fired plants.

FOB NEWCASTLE 5,500 KCAL/KG NAR THERMAL COAL SPOT PRICES

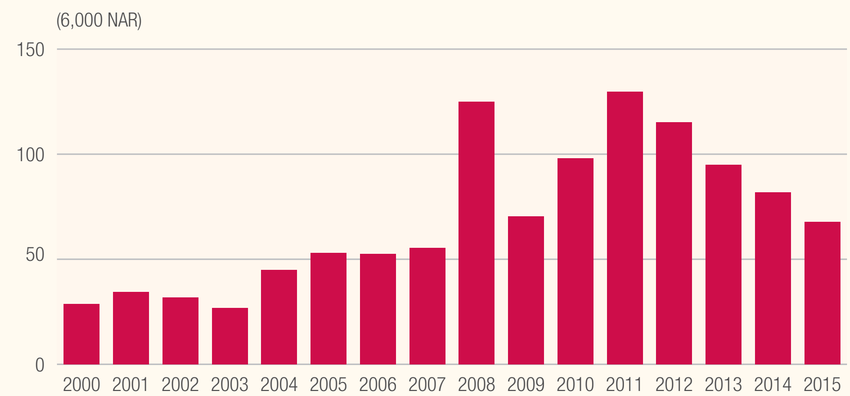


Source: Platts

The government aims for 1 billion mt of production for Coal India Ltd. – which supplies more than 80% of the country's coal needs – by 2019-2020, nearly double current levels. Coal India has missed its target by 12.77 million mt for fiscal 2014-15 and by about 20 million in 2013-14.

India is likely to import about 210 million mt of thermal coal in 2015-2016, up from 180 million mt in 2014-2015, to cover the shortfall.

JAPAN FY SETTLEMENT PRICES FOR AUSTRALIAN THERMAL COAL CONTRACTS



Source: Platts/Industry sources

While several overseas suppliers are rushing for a slice of the market, which could lead to oversupply and pressure prices, India's additional procurement has been restricted by the weak rupee against the dollar, lack of railway rakes to move coal from ports to power plants, a credit crunch and weak industrial growth.

Demand from South East Asia offers scant support to the market. "Vietnam is well supplied with the state-owned company Vinacomin, and I don't see much seaborne trade going there," said Xavier Jean of Standard & Poor's, a unit of McGraw Hill Financial.

"The Philippines, Thailand and Malaysian markets are also growing and could provide for a few million tons. But even if they pick up, that even a small 1-2% decline in demand from China for seaborne production would mute this."

Major Indonesian miner Adaro said in its half-yearly report the coal market remains challenging in the near-term. "The market condition was particularly tough for low-calorific value coal, as supply for 4,000 kcal/kg [GAR] type coal was plentiful," said the firm, which posted a 7% year-on-year production drop in the first-half.

China accounted for 18% of Adaro's total sales in H1 2015, while India made up 10%.

"No one expects any recovery in prices till 2017," said an Indonesia-based trader, who regularly supplies thermal coal to China.

But Calum Austin, assistant vice-president at Caravel Carbons, a unit of Hong Kong-based trading group Caravel Resources, is cautiously upbeat: "China's market is massively oversupplied, but over time there will be a better balanced market for Asia and we should not lose sight of that."

Markets oversupplied

Miners in Australia, the largest shipper of thermal coal to China, have changed their operating strategy towards boosting production to reduce unit costs and offset falling thermal coal prices.

Australian maximum 23% ash product has captured the lion's share of the ▶

niche market for import-grade 5,500 kcal/kg NAR thermal coal. Indonesia provides China with lower calorific value coal of mostly 4,700 kcal/kg NAR product.

The reduction in acceptable ash content for imported cargoes in China has hit Australian mines that have been shipping unprocessed high-ash thermal coal to China in recent years.

Beijing's ash-reduction move could affect up to 32 million mt of Australian thermal coal production, ANZ bank analysts said in a report.

“No one expects any recovery in prices till 2017,” said an Indonesia-based trader, who regularly supplies thermal coal to China.”

FOB prices for Australian 5,500 kcal/kg NAR thermal coal have dropped 20% so far this year to about $42/mt, on a 20% ash as-received basis.

“Both thermal and metallurgical coal prices have fallen dramatically since 2011. While we believe that current prices are below sustainable long-run levels, we do not expect a return to prices anywhere near the levels seen a few years ago,” Citi analysts wrote in a research note earlier this year.

Australian prices for thermal coal sold to Japan have declined over the past four years, after spiking to $129.85/mt FOB Newcastle basis 6,300 kcal/kg GAR (6,000 kcal/kg NAR) in the April 2011 term contract, shortly after the Japan earthquake and tsunami a month earlier.

The expected uplift to Japanese coal demand in the aftermath of the disaster that crippled its nuclear industry never quite materialized, and prices in the key April contract benchmark over the past few years have fallen steadily to date.

In the latest negotiation for year-contracts starting April 1, 2015, the agreed price was $67.80/mt FOB Newcastle, down from $81.80/mt in April 2014, $95/mt in April 2013 and $115.25/mt in April 2012.

The restart of some nuclear generation in Japan – the largest buyer of coal out of Newcastle port – could hit the Australian thermal coal export market, sources said.

Threat from renewables

A surge in renewable energy capacity additions might threaten long-term coal demand. “Global thermal coal demand is suffering from increasing environmental pressure and competition from natural gas and renewable energy,” Citi analysts said.

Japan's energy mix for 2030 calls for nuclear to make up 20-22% of total power generation and renewables accounting for 22-24%. Coal's share in the mix is expected to fall to 26% by 2030 from about 30% now.

China is also seeking to cut coal's share to 59% by 2020 from 69%, while India is targeting renewables to total 35% in its energy mix by 2050.

But falling oil prices pose limited threat to coal or other renewable energy. “With only 5% of global power generation provided by oil, major renewables like wind and solar are rarely in direct competition with oil,” Citi analysts said. ■

INDIA COAL

SUDIP SURAL

Senior Director
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COAL CONCERNS

India's coal crisis could ease after 2018 on adroit policy measures

India's coal shortage has impacted 13,000 megawatt of thermal power capacities in recent times, putting $15 billion worth of investments at risk.

The situation has been a long time coming because India's coal production had increased at an annual rate of just 4% between 2009 and 2014 (fiscal years April 1 to March 31), even as demand rose faster and new power plants were built encouraged by GDP growth of around 7% in the period.

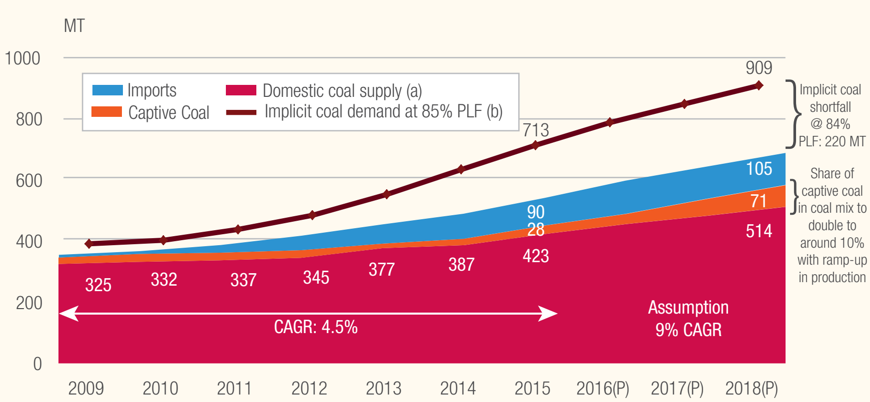
Prime Minister Narendra Modi's government, which took reins in late May 2014, has responded by speeding up environment and land approvals, clearing more mining projects and auctioning coal blocks.

Consequently supply of domestic coal to power companies increased to 10.7% in fiscal 2015 from 4% in fiscal 2014 as Coal India, one of the world's biggest miners, dug out more.

However, the full benefit of these initiatives is unlikely to kick in before 2018. That's because mining more coal alone is not enough, the infrastructure to ship it needs to improve considerably if the requirements of new thermal power plants are to be met.

A study by CRISIL, the global analytical company that's majority-owned by McGraw Hill Financial (NYSE:MHFI) – the parent of Platts – shows India's thermal power plants required about 713 million mt/year of coal to operate at an 85% 'plant load factor', or actual energy produced compared with the maximum

IMPROVING PRODUCTION FROM COAL INDIA AND CAPTIVE BLOCKS



(a) Domestic coal supply includes coal from Coal India Ltd, Singareni Collieries Company Ltd

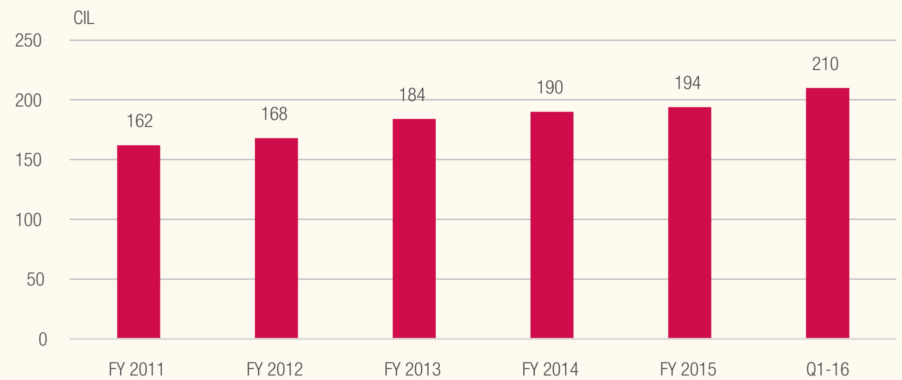
(b) Implicit coal demand for each year is the coal requirement at 85% PLF for the installed capacity at the end of that year

Source: CRISIL Ratings, Coal India Ltd, Central Electricity Authority possible, in fiscal year ended March 31, 2015.

But domestic coal supply was just 451 million mt and imports another 90 million mt – or 76% of what was required. Not surprisingly, India's plant load factor declined to a decade-low of 65% in 2014.

On its part, Coal India, which mines more than 80% of India's coal, has kickstarted 129 new projects that can potentially produce 452 million mt over the next five years.

COAL OFF-TAKE IMPACTED ON ACCOUNT OF RAKE AVAILABILITY CHALLENGES



Source: Coal India Ltd

So far, 60 small mining projects have received land and environment approvals. Potentially, these mines can together produce 88 million mt/year, and output is expected to begin in the fiscal year starting April 1, 2016.

Production from new coal mines is expected to grow at a moderate rate till 2017 and then increase to 10% as larger projects stabilize.

Mammoth task ahead

India's coal sector was thrown into a crisis in September 2014 when the country's Supreme Court retrospectively cancelled 204 mines allotted to various companies, including some government-owned ones, citing impropriety in allocation between 1993 and 2010.

The Modi government quickly responded by going for transparent auction of coal mines. In the first three rounds of the auctions, 32 mines – including 17 already in operation – were auctioned for $45 billion. The government would earn the money over the next 30 years.

After the auctions, the government quickly gave environment clearances and transferred 19 coal mines from earlier allottees to the bid winners.

Coal India is also improving its coal shipping ecosystem, with three critical railway lines being constructed in the major coal-producing states of Chhattisgarh, Jharkhand and Odisha. But progress has been slow because of poor co-ordination between state and central governments. There have also been inordinate delays in land and environmental clearances.

As a result, incremental coal shipments are likely to be only 105 million mt till 2020, against three times more possible if the railway lines were fully functional.

Availability of railway rakes to transport coal, which had been inadequate, improved sharply this year but a lot more would be required if Coal India is to increase shipments.

Given the initiatives and issues, we expect coal production to grow at 9% annually in the next three years.

But even as these problems are being solved, another one has cropped up: energy producers desperate for coal, bid so aggressively at the auctions that some even agreed to pay money to the government to extract coal, or offer the so-called 'forward premiums'.

The upshot is that power producers who won at the auction are now exposed to under-recovery in variable charges since mining costs and forward premiums are not recoverable in the tariffs to be charged to the distribution companies.

Currently, the plant load factor for 87,000 Mw of projects set up between 2009 and 2015 – including the 13,000 Mw at risk – hovers at a very sub-optimal 41%. CRISIL's calculations show this number will rise only up to 49% in 2018 – despite the increase in coal supplies expected.

Clearly, India's coal and electricity sectors are in a quagmire and pulling them out will be a herculean task. ■

ASIA-PACIFIC

LAWRENCE LU

Senior Director
Standard & Poor's Ratings Services

ENERGY GIANTS AWAKE

Asia-Pacific's giant energy companies will come off the merger and acquisition sidelines

Asia-Pacific's oil and gas giants are hunkered down. To cut costs while energy prices are freefalling, up to 20% of the region's oil rigs now stand idle. Merger and acquisition activities had almost crawled to halt until Australia's two largest players recently announced their proposed merger.

Standard & Poor's Ratings Services believes the industry's "big sleep" is more like a power nap than a coma. We expect more major players to hit the acquisition trail as soon as visibility improves over a pricing recovery.

In the meantime, the industry's focus on strengthening efficiency and slashing costs should help many to protect their credit health. For smaller players and select segments, the pain could deepen – increasing the risk of downgrades.

Much of Asia Pacific is struggling to balance robust underlying demand with limited natural resources. For years, China and India have been gobbling up global oil and gas assets like a 1980s video game. But the recent energy agreements with Russia have been the only notable deals for China so far in 2015; and these have been incubating for years and timed to coincide with President Putin's visit to Beijing. The agreements include several investments by China's state-owned players in Russian companies.

Other thirsty markets in Asia Pacific remained on the sidelines, until Australia's Woodside Petroleum Ltd. announced its all-share offer for Oil Search Ltd.

As low fuel prices exacerbate high costs and heavy debts, more acquisition targets are likely to emerge.

Overview

- Asia-Pacific oil and gas majors are riding out the currently tough industry conditions by cutting costs and largely suspending M&A activity.

- The pain is unevenly spread across the industry. Refineries are benefitting from increased margins, but capex cuts from E&P players are squeezing the downstream segment, including oilfield service providers and drillers.

■ Our industry outlook for Asia-Pacific remains stable with a negative bias.

■ M&A remains a key test of financial discipline, especially for some national oil companies.

Oil prices are currently hovering at just $50/barrel for Brent, a slump of more than 60% year over year. We don't believe industry fundamentals support a price higher than our current assumption of $50/b for the rest of 2015. The futures market points to only a marginal increase in prices this year.

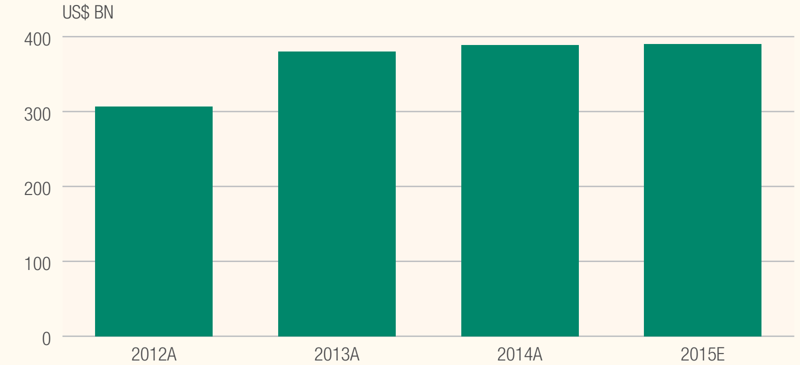
Currently, the futures price of oil is higher than the spot price, a situation known as "contango." Much of the pressure on prices stems from continuing oversupplies, with 2 million surplus barrels/day. Production isn't slowing despite the reduced rigs in operation, and that's partly because of efficiency gains.

So when are prices likely to recover? Standard & Poor's assumes that Brent oil price will be at $55/b for 2016, rising to $65 for 2017, and $70 for 2018 onwards. We assume WTI price to be $5 lower than Brent. Our Henry Hub natural gas price assumption is $2.75/ million British thermal units in 2015, $3.00 for 2016, $3.25 for 2017 and $3.5 for 2018 and beyond.

Engine check

Asia-Pacific oil and gas companies have pumped up their debt levels over the past few years in the hunt for secure energy supplies. We estimate total debts in the sector at $370 billion in 2015, compared with $300 billion in 2012.

APAC OIL AND GAS COMPANIES' AGGREGATE DEBTS



Source: Standard & Poor's Rating Services

Total debt levels in Asia Pacific are unlikely to drop, as cash flow from operations sharply reduce. The aggressive acquisition appetites of Asia-Pacific energy companies led capital expenditure in the sector to top $200 billion in 2013.

But the industry is tightening its belt. To preserve cash, capex is likely to drop by 9% in 2015 to about $160 billion, having already fallen by 12% to $175 billion in 2014. We base our estimates on the midpoint of producers' 2015 budgets.

Investment-grade companies (i.e., those rated 'BBB-' and above) represent only about 70% of rated oil companies in Asia-Pacific. These companies account for 80% of the sector's budgeted spending in 2015.

Lower-rated entities recorded the largest cuts in capex, not that surprisingly. These companies tend to be less diverse and have more limited liquidity, so they need to take drastic action during industry downturns.

For exploration and production (E&P) players, the removal from service of expensive but inefficient rigs has helped to reduce costs. Some rigs can cost hundreds of thousands of dollars to operate a day, and a prolonged period of inactivity translates into heavy cost savings. Additional savings have come from company restructurings, layoffs, and tighter controls over selling, general and administrative expenses.

Conditions are most difficult in the oilfield service sector. Low prices and capex cuts by E&P players are squeezing contract drillers and oilfield service companies. Service rates remain under pressure as service volumes decline and because E&P companies are pushing to renegotiate contracts. For example, Norway-based Statoil Petroleum AS recently canceled the service contract before the expiry date of COSL Pioneer, a semi-submersible drilling rig of China Oilfield Service Co. Ltd.

In the downstream segment, refineries were net beneficiaries of the low oil prices for the first half of the year. China Petroleum & Chemical Corp, the largest refiner in China, reported a 16% increase in gross refining margin in the first half of 2015, at $7.72/ b , compared with $6.66/b in the same period of 2014. ▶

Gross refining margin of South Korea's three refiners also significantly improved in the first half of 2015 compared with a year ago. But the second half of 2015 should prove difficult for the refiners, as the recent correction in crude oil prices will increase their inventory loss, while demand for refined products is softening as the economic recovery slows, particularly in China.

Demand-supply dynamics

China remains Asia-Pacific's economic dynamo and demand for crude is likely to hold up, given the country's high reliance on imports. Preliminary estimates from the International Energy Agency, or IEA, suggest demand rose to 11 million barrels/s/ day (mbpd) in April 2015, up 500,000 b/dyear over year. The IEA attributes the stronger-than-expected demand to heavy inventory clearances, a surprisingly strong uptick in refinery throughput and strengthened consumer confidence.

Demand remains flat in India, the world's third-largest oil consumer. Demand fell by 110,000 b/d in March but rose 105,000 b/d in April 2015, with the decline largely due to heavy rains that constrained agricultural demand.

Asia Pacific remains a net importer of oil. Indonesia is one producer whose domestic supplies fail perennially to keep pace with internal demand. But that may soon change. A joint venture between ExxonMobil and Indonesia's state-owned Pertamina has finally ramped up production at its Banyu Urip oil field. As a result, the IEA suggests the country could soon record its first annual growth in production for 20 years.

A credit cushion, or cliff edge?

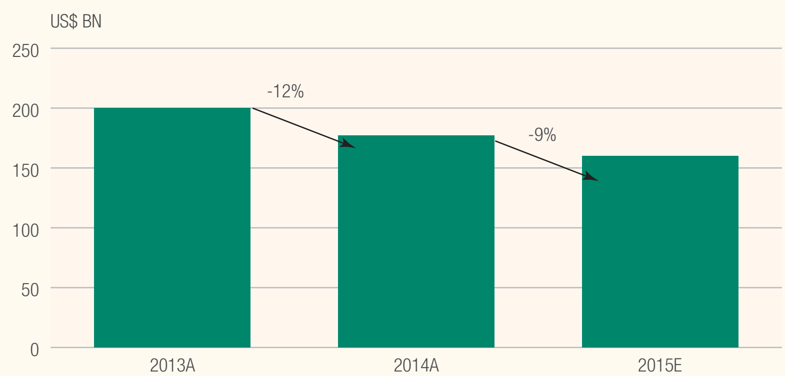
Our industry outlook for Asia Pacific remains stable with a negative bias. About 74% of our ratings have a stable outlook, compared with 19% negative and 7% positive. We believe the high cash holdings in the Asia-Pacific industry constrain short-term credit risks for oil and gas companies.

Generally, these players have good access to funding, which suggests the immediate pressure on liquidity will be low. Of the companies that Standard & Poor's rates in Asia Pacific, we assess 23% as having "strong" liquidity, 73% as "adequate," and just 4% as "less than adequate."

Difficult conditions for oil companies can also have implications for sovereign creditworthiness. Standard & Poor's recently affirmed the ratings on Malaysia (foreign currency A-/ Stable/A-2; local currency A/ Stable/A-1), but pointed out that high subsidy spending and heavy dependence on energy-related revenues weigh on the country's fiscal position. That was particularly the case prior to the removal of oil subsidies in December 2014.

Overall, we believe M&A remains a key test of financial discipline, especially for some national oil companies. ■

APAC OIL AND GAS COMPANIES' AGGREGATE CAPEX



Source: Standard & Poor's Rating Services

MICHELLE CHEONG
Director
Market Development
S&P Capital IQ

CLEMENS THYM
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S&P Capital IQ

SURVIVING THE DOWNTURN

The dramatic fall in global oil prices has put the spotlight on credit risk in energy sectors around the world, with the cost of a barrel of WTI crude dropping by half compared to this time last year. However, it is the sustained nature of the price drop that is really worrying from a credit perspective, particularly if China's economy continues to slow and global demand for energy sags. Figure 1 tracks the growth in default risk in the Asia-Pacific energy sector (rising orange line) versus other sectors and the broader Asia-Pacific market (stable black dotted line) over the last 18 months.

In this environment, corporations and financial institutions exposed to energy sector companies need to work out if key counterparties are likely to survive a prolonged fall in energy prices.

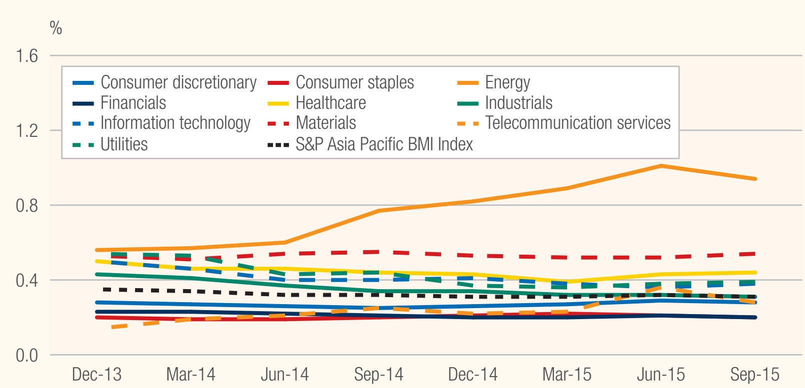
An easy task to get wrong

Unfortunately, managing credit risk in the energy sector as the economic cycle turns is a tricky exercise.

One approach is to set credit limits for energy firms by using financial ratio analysis to rank companies and establish cut-off points that divide the relatively "good" from "bad" risks. This works when the economic weather is fine.

However, such cut-off points are arbitrary and the rankings do not attach an absolute level of default risk to the "good" credits. As macroeconomic clouds gather, what risk managers really want to know is whether the "good" companies in strongly cyclical industry sectors such as energy exploration and production (E&P) will survive the storm. ▶

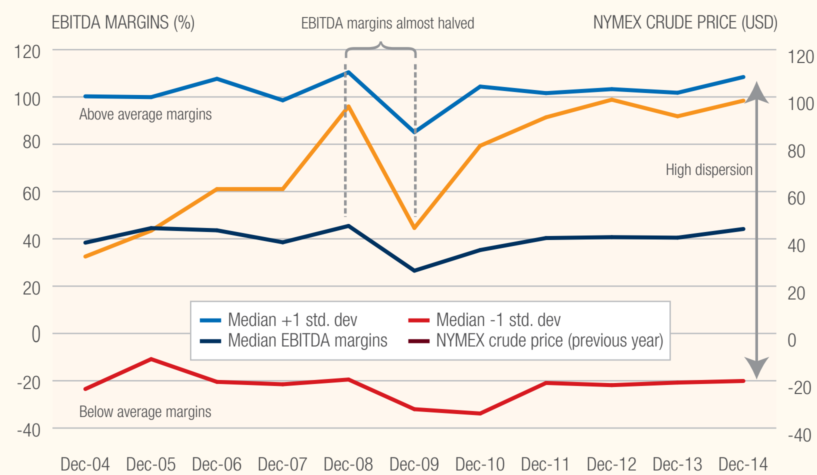
S&P ASIA PACIFIC BMI INDEX GICS SECTOR PD FUNDAMENTALS CHART



GICS® = Global Industry Classification Standard. PD = Probability of Default.
Source: Credit Market Pulse template on S&P Capital IQ's Credit Analytics, as of 31 July 2015. For illustrative purposes only.

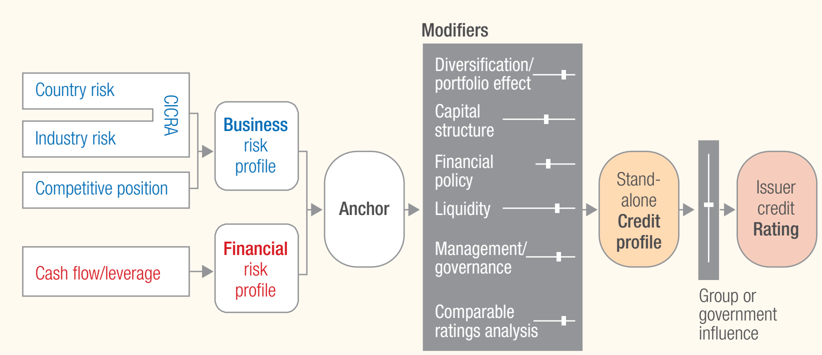
Other firms use default risk models that use statistical modelling to link historical default data to a range of fundamental obligor attributes, e.g., interest coverage. Whilst statistical approaches offer an efficient way to conduct large volumes of credit analyses, they do not usually consider entity-level qualitative factors that make a difference in turbulent times, e.g., management experience, availability of liquidity buffers, and effectiveness of risk management practices.

ENERGY SECTOR EBITDA MARGINS



Source: Fundamental data from S&P Capital IQ. Commodity price data from CMA on S&P Capital IQ, as of January 2014. For illustrative purposes only.

STANDARD & POOR'S RATINGS SERVICES RATINGS METHODOLOGY FOR CORPORATIONS



Source: RatingsDirect on S&P Capital IQ [add date]. Credit ratings are provided by Standard & Poor's Ratings Services, which is analytically and editorially independent from any other analytical group at McGraw Hill Financial. For illustrative purposes only.

Furthermore, the availability of high quality data to build and implement statistical models can be a problem in some emerging markets, including China and India. Worse, the inputs for the model – financial statement data – tend to be backward looking, and users struggle to forecast key ratios, e.g., EBITDA margins, to make the output forward looking.

This is a problem in the energy industries, where profit margins at the entity level vary significantly between companies and are highly unpredictable as the cycle turns (Figure 2), potentially leading to large errors in credit risk assessments using these fundamental inputs.

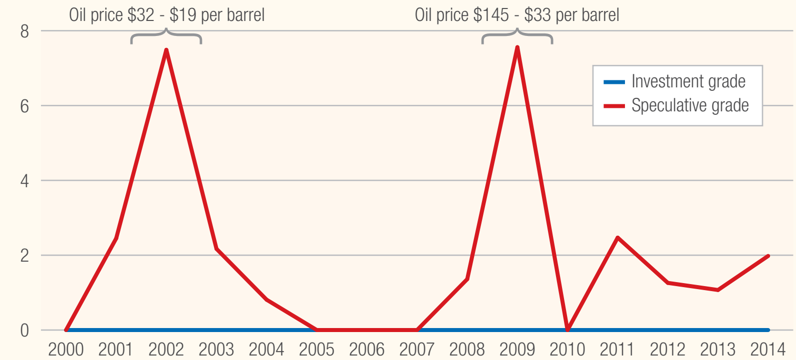
Resilience is key

So how can firms identify the bedrock resilience that can withstand the stress of economic cycles? It is precisely this problem – the provision of a "a forward-looking opinion about an obligor's overall creditworthiness" – that the Standard & Poor's Ratings Services' issuer credit ratings methodology is designed to tackle. Specifically, credit is assessed according to how well an entity can weather differing levels of deterioration in economic, business and industry conditions.

The approach begins with assessments of country and industry risks borne by a company as well as its competitive position within its market (Figure 3). For example, industries whose revenues and profits fall by a relatively large extent during industry downturns are deemed to have higher industry risk, all things being equal.

However, industry leaders are often more resilient during downturns, and the

INVESTMENT GRADE ENTITIES IN THE ENERGY SECTOR WEATHER DOWNTURNS BETTER THAN SPECULATIVE GRADE ENTITIES



Source: S&P Capital IQ's CreditPro®, as of 2014 Credit ratings are provided by Standard & Poor's Ratings Services, which is analytically and editorially independent from any other analytical group at McGraw Hill Financial.
For illustrative purposes only. For this slide, investment grade comprises ratings range 'AAA' – BBB-' and speculative grade" comprises all ratings levels below 'BBB-'.

impact of such market leadership on credit risk must also be factored in through measuring a firm's "competitive position." This delivers each firm's business risk profile.

Firms with strong cash flows relative to debt obligations and low financial leverage clearly also gain in terms of resilience, so the methodology analyses key financial ratios to generate a financial risk profile, benchmarked to industry peers. But it is the interaction of this financial risk profile with the firm's fundamental business risk profile that really determines the key "anchor" score, shown at the center of Figure 3.

Figure 4 shows how effectively the methodology discriminates between firms. During the last two periods of oil price correction (2001-2002 and 2008-2009) there were negligible defaults of energy and natural resource entities rated investment grade by Standard & Poor's Ratings Services, but the default rate leapt up for speculative grade credits.

The Standard & Poor's Ratings Services methodology was developed to deliver public ratings, but the fundamental approach can now be replicated to assess credit for a much larger universe of unrated firms through the application of S&P Capital IQ's expert judgment scorecards. Let's look at what this can deliver in the Asia-Pacific oil and gas exploration and production (E&P) industry using a real but anonymous case study.

Hunting for resilience in the real world

Company A, based in China, has a relatively weak country risk score under the approach – driven by a range of factors such as institutional effectiveness and payment culture – somewhat offset by the fact that Company A has operations in multiple countries. Company B, based in Indonesia, has an even weaker score.

Both companies are in the E&P industry, so their industry risk is assessed as intermediate. Key risk factors for the industry include its cyclicality, competitiveness as a commodity sector, tendency to overbuild production capacity, and regulatory regime risk.

However, the key differentiator between the companies in terms of business risk is their competitive position, determined by factors such as competitive advantage, diversification of operations, and operating efficiency.

Company A, for example, is a large-scale operator and a market leader, concentrated on China but with a geographically diversified reserve base. These reserves are in basins with a well-established performance history, and are relatively cheap to exploit, allowing Company A to ▶

demonstrate higher margins, e.g., an EBITDA margin of over 50%.

Company B is a much smaller concern, with high geographic business and project concentrations and declining production from maturing fields that have higher exploration costs and a weaker track record of exploration. It has EBITDA margins of about 30%.

In terms of financial risk profile, Company A is relatively cash rich and has a low ratio of debt to EBITDA, comparable to the score of an "a+" obligor with regard to this particular financial attribute, while Company B has a much higher ratio, comparable to the score of a "bb" obligor. (The letter-based credit scores in this article are expressed in lower case nomenclature to distinguish them clearly from Standard & Poor's Ratings Services credit ratings.)

The combined result of the business risk profile and the financial risk profile results in an anchor score of "b" for Company B, compared to "a+" for Company A.

The methodology then applies a series of modifiers to the anchor score – see Figure 3 for the full list – to account for risks not fully captured by the earlier analyses, e.g., some companies pursue aggressive liquidity strategies while others would remain liquid even if earnings were cut in half.

The final assessment of the methodology – whether the obligor might benefit from government or group (e.g., parent) influence in times of trouble – has particular significance. Company A is a large state-owned enterprise and plays a critical role in supplying the country's energy needs. It would likely be supported by the government, and the credit score from our scoring model is notched up to "aa-". Company B is not in such a favored position and its score remains at "b".

The different credit scores of the two companies have implications for their credit stability.

Figure 5 sets out the likelihood of a ratings transition for E&P firms with various Standard & Poor's Ratings Service credit ratings, as evidenced during the turbulent period of 2007-2012.

For example, entities with a credit ratings of AA+ to AA- were downgraded 4.9% of the time on average each year within the five-year period; with the lowest credit rating from BBB+ to BBB-. Entities with a credit ratings of B+ to B- were downgraded 10.1% of the time on average each year, amongst which 3.7% of these were given the default rating (i.e. "D").

As well as considering credit stability, firms can apply the through-the-cycle

HISTORICAL STANDARD & POOR'S RATINGS SERVICES RATINGS TRANSITIONS OF E&P ENTITIES (2007-2012)

Rating	AAA	AA	A	BBB	BB	B	CCC	CC	C	D
AAA	93.18	6.82	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AA	2.44	92.68	3.66	1.22	0.00	0.00	0.00	0.00	0.00	0.00
A	0.00	1.05	89.12	9.82	0.00	0.00	0.00	0.00	0.00	0.00
BBB	0.19	0.97	2.52	93.22	3.10	0.00	0.00	0.00	0.00	0.00
BB	0.00	0.00	0.00	5.67	88.92	4.93	0.49	0.00	0.00	0.00
B	0.00	0.00	0.22	0.22	5.82	83.62	6.25	0.22	0.00	3.66
CCC	0.00	0.00	2.53	0.00	0.00	17.72	64.56	1.27	0.00	13.92
CC	0.00	0.00	0.00	0.00	0.00	33.33	0.00	66.67	0.00	0.00
C	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

4.9% of 'AA'-rated entities downgraded, lowest rating category 'BBB'

10.1% of 'B'-rated entities downgraded, lowest rating category 'D'

Source: S&P Capital IQ's CreditPro database as of 2012. Credit ratings are provided by Standard & Poor's Ratings Services, which is analytically and editorially independent from any other analytical group at McGraw Hill Financial. For illustrative purposes only.

methodology to stress test the base case credit score by:

- Using S&P Capital IQ's research to understand what happens to median E&P company revenues and margins in the event of plausible "worse-case" falls in the price of oil; or

- Feeding analyst predictions for future individual company earnings into the credit scorecard to reveal a company's sensitivity to price shocks, etc.

Conclusion

In commodities sectors, users of quantitative credit models must forecast financial ratios at the turn of the cycle, just when the sector's fundamentals are at their most volatile and unpredictable.

At such a turning point, a rigorous and properly calibrated through-the-cycle expert judgment approach may be a better way to identify resilient companies because it is specifically designed to measure if an entity can weather downturns.

For many users, the optimum approach may be to apply quantitative models for risk management at the portfolio level, but then supplement these with expert judgment models for major energy counterparties, particularly as the economic cycle begins to turn. ■

JONTY RUSHFORTH
Global Editorial Director
Oil and Shipping Price
Group

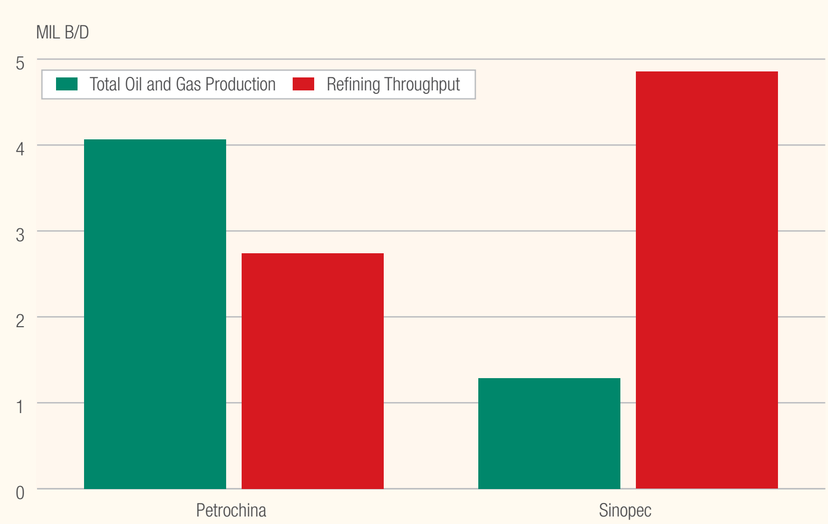
ASIAN MAJORS EMERGE

In many ways the history of the commodities markets in the last 10 years has been the history of emerging markets. The rapid growth of the middle class in the world's most populous nations inevitably led to a surge in demand for 'stuff': for new homes, new cars, travel and consumer goods. The volatility in prices for energy, metals, petrochemicals and food has in large part reflected the attempts of these markets to rebalance around the new reality of a multipolar global economy.

So it should be no surprise that the largest participants in the oil markets today are not European traders or US majors, but are in fact the new Asian majors. The biggest refinery in the world today is of course Reliance's Jamnagar in India. The most actively traded commodities futures contract in the world today is the Steel Rebar Futures contract on the Shanghai Futures Exchange. And the world's most active traders of spot crude oil are Singapore-based Chinaoil and Hong Kong-based Unipec Asia.

Over the last few years these two companies have steadily built a presence in global crude markets, and most actively in the Middle East sour crude market. The basic reasons why are fairly clear: the two corporate families of which they are part each have the largest crude throughput of any company in Asia; China as a whole has been building strategic and commercial petroleum storage that needs to be filled; and Asian companies in general have been disintermediating their price exposure management, moving into

CHINA MAJORS H1 2015 PRODUCTION AND THROUGHPUT



Source: Platts

the roles that were previously filled by western majors, traders and banks.

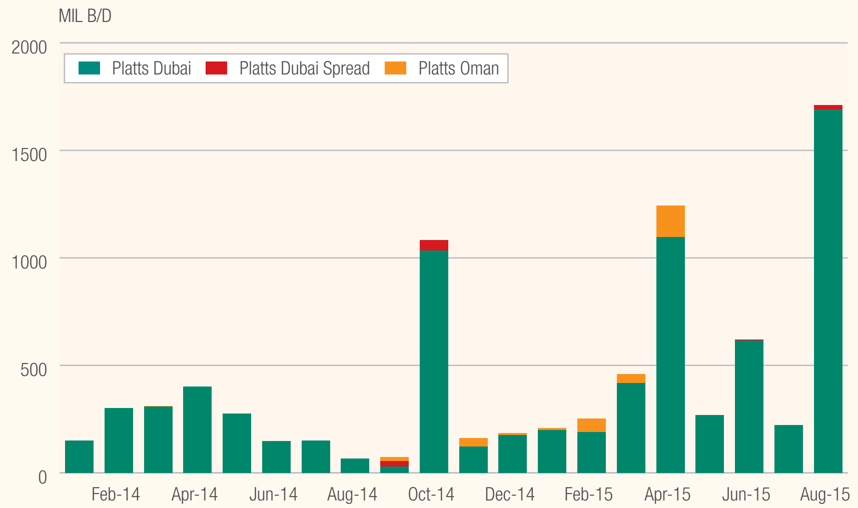
Sinopec, the ultimate parent of Unipec Asia, is a Chinese state-owned company that independently runs the largest refinery portfolio in Asia, and in the first half of this year refined 4.85 million barrels/day of crude oil. Meanwhile China National Petroleum Corporation, in turn the state-owned parent of Chinaoil, is one of the world's largest oil producers and had total oil and gas production of 4.07 million b/d in that period, in addition to refinery throughput of 2.74 million b/d.

In the latest round of active trading, in August of this year, trading volume during the Platts Market on Close assessment process for Dubai crude hit a monthly record high of 78 cargoes (1.26 million b/d) and a record 1,710 cash partial and spread trades during the month. That was more than three times higher than the average monthly volume for the previous seven months, and about 8 times higher than July volumes. Of those trades, Chinaoil (bought 86% of partials) and Unipec Asia (sold 68% of partials) represented the vast majority of activity.

Beyond mere historical interest, this activity represents a challenge for crude markets around the world. The sheer size of the two Chinese corporations means that their physical positions in markets are often orders of magnitude larger than most competitors. That in turn means that traditional crude benchmarks need to be robust enough to reflect fair market value at all times, including periods of significant activity from the new Asian majors.

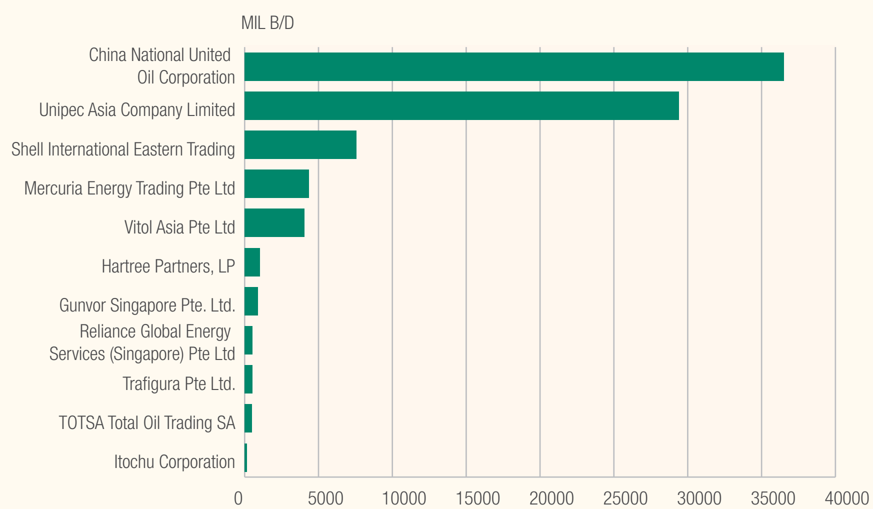
Platts Dubai and Oman benchmark assessments are together used to price more than 15 million b/d of physical crude oil contracts, as well as 20 million b/d of derivatives contracts. Dubai itself represents the lowest of three grades of crude in the Middle East: Dubai, Upper Zakum and Oman. Together these three grades represent about 1.6 million barrels/day of crude production, with Oman having around 1 million b/d of production within that.

LIQUIDITY IN PLATTS MIDDLE EAST CRUDE OIL MARKET ON CLOSE PROCESS



Source: Platts

PARTICIPATION IN PLATTS MIDDLE EAST CRUDE MOC AUGUST 2015



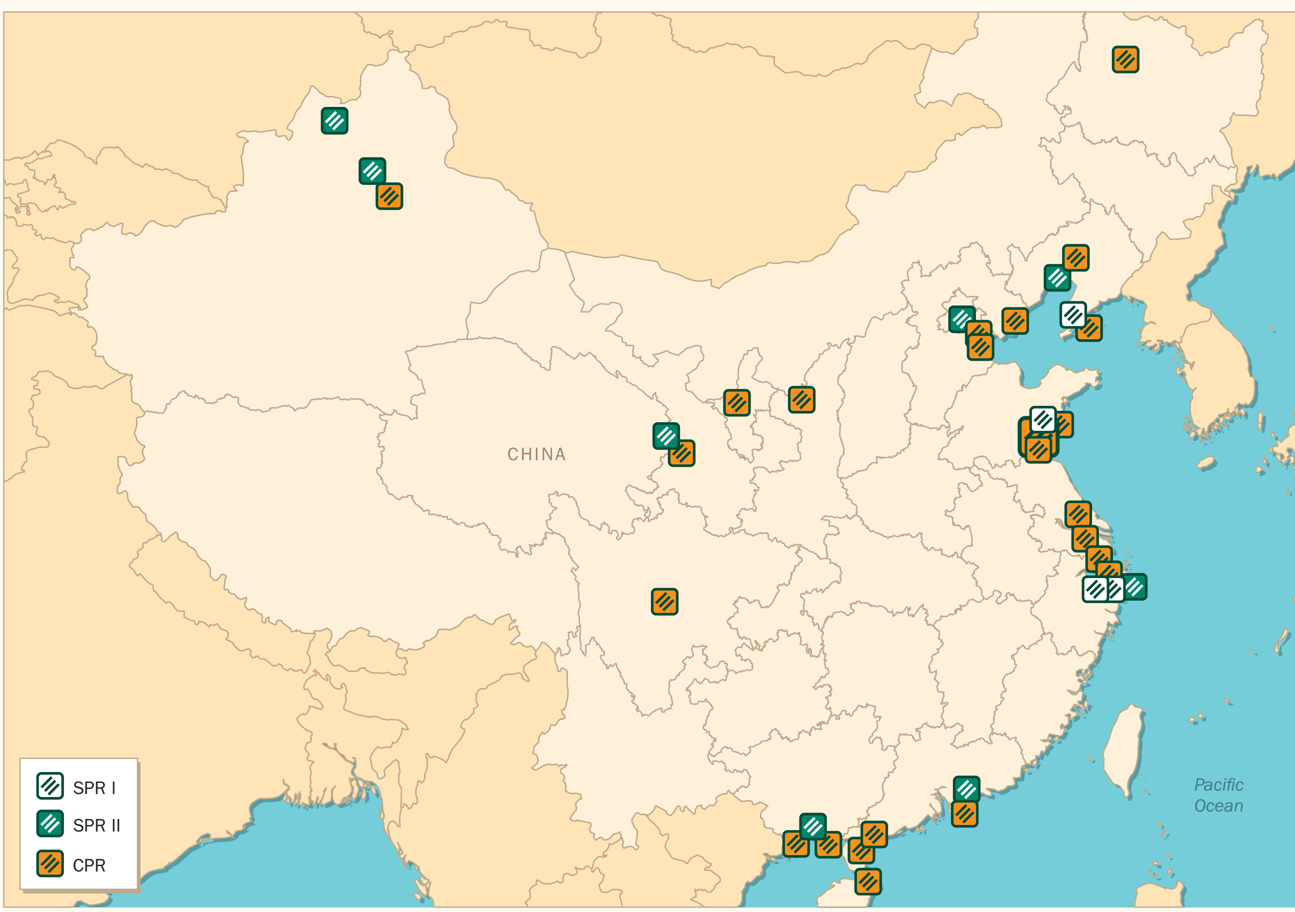
Source: Platts

Platts has long discussed with the market how these assessments could evolve to ensure they remain robust through the most liquid periods of market activity. In August, Platts opened up a consultation on adding new grades to the Dubai and Oman baskets: Al Shaheen (300,000 b/d) for Dubai and Murban (1.6 million b/d) for Oman (and by extension Dubai). Platts is also considering the addition of North Sea-style "Quality Premiums" for Murban. The consultation runs until the end of October and will likely lead into fairly prompt proposals for change to the benchmarks.

This is one step in the long evolution of these benchmarks, which has included the move to a 'partials' contract mechanism, the addition of new grades and most recently (from the start of August) the reflection of loadings via ship-to-ship transfer. And this will likely not be the final step. The industry is already actively discussing the role of STS more broadly within the Middle East crude market and the future of storage within the complex as well.

But it is worth noting that the challenge of new Asian majors extends well beyond these two benchmarks. The fact is that global oil markets everywhere will have to continue to rebalance around the world's largest energy companies taking a more active role within them. ■

CHINA PETROLEUM RESERVES



considered to drive a cleaner and more sustainable energy infrastructure to power the region's economic growth going forward. As we approach the ASEAN Economic Community Post 2015 vision, a more dynamic and resilient energy sector is needed to meet the emerging challenges.

The ASEAN framework and willingness among countries to cooperate creates opportunities for advancing energy efficiency, enhancing infrastructure and physical connectivity, deploying renewable and alternative energy and ensuring individual and regional energy security.

The ASEAN Plan of Action for Energy Cooperation (APAEC) 2010-2015 has served to advance cooperation towards energy security over the past 5 years. The region has made good progress on several of its goals, including on major energy infrastructure projects, namely the ASEAN Power Grid (APG) and Trans ASEAN Gas Pipeline (TAGP).

To date, six of the 16 planned APG interconnections have been built with 3,489 MW power purchase achieved. Similarly, the TAGP has commissioned a total of 12 bilateral gas pipeline interconnection projects with a total length of 3,377 km. Given the gas developments globally, ASEAN will also look to liquefied natural gas (LNG) as a key strategy to meet the region's energy demand going forward.

By the end of 2015, a new plan – the APAEC 2016-2025 – will kick in. Under the theme "Enhancing Energy Connectivity and Market Integration in ASEAN to Achieve Energy Security, Accessibility, Affordability and Sustainability for All", it will provide enhanced goals and targets for the region.

APAEC 2016-2025 will serve as the next blueprint of how ASEAN plans to drive its energy landscape in advancing regional integration towards a global ASEAN in seven key areas, namely the (1) ASEAN Power Grid, (2) Trans-ASEAN Gas Pipeline, (3) Coal & Clean Coal Technology, (4) Energy Efficiency and Conservation, (5) Renewable Energy, (6) Regional Energy Policy and Planning, and (7) Civilian Nuclear Energy.

Much work still needs to be done to implement these initiatives. For example, to achieve the APG and TAGP, technical standards, codes and guidelines should be harmonized; legal and regulatory frameworks for bilateral and cross-border interconnection and trade created; and financial modalities and investment interconnection identified and developed. In this aspect the ASEAN Centre for Energy envisions itself as becoming a regional centre of excellence which facilitates to build a coherent, coordinated, focused and robust energy policy agenda and strategy for the integration of the energy sector in ASEAN.

Therefore the conversation must evolve from cooperation to integration. At this stage, we need to take the bull by the horns to truly integrate and make these initiatives realities. ■

Dr. Sanjayan Velautham is the new Executive Director of the ASEAN Centre for Energy. He will be sharing more about the energy opportunities and implications of ASEAN integration at Singapore International Energy Week (SIEW) 2015 from 26-30 October.

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Power in Europe

A GAME-CHANGER YEAR

PLATTS | TOP 250

For many in the energy industry, 2014 will be remembered as a pivotal year marked by an abrupt upending of $100 oil and further seismic shifts in world energy production and consumption.

By year-end, oil prices had dropped by over 40% to trade below $60/b before hitting a temporary low of $45/b in early 2015. The supply glut that triggered the price fall, and remains with us, was caused by buoyant shale oil, slowing demand growth and a radical new policy tack by OPEC producers.

Dated Brent averaged $98.95 per barrel in 2014, a decline of $9.71 per barrel from the 2013 level and the first annual average below $100 since 2010.

The price rout heightened concern over market volatility and exacerbated energy pricing differentials between regions.

Gas prices saw regional gas pricing disparities continue to guide markets last year, with Japanese natural gas trading more than $16/MMBtu in August while Henry Hub values were around $4/MMBtu.

According to the World Energy Council, uncertainty over energy prices became the biggest concern for energy leaders for the first time last year, surpassing anxieties over the outcome of global climate change talks.

Far from overshadowing the US' shale oil and gas miracle, the price slump only brought the phenomenon under greater scrutiny as markets picked over clues to the pace of the supply response of US tight oil.

The US' move to energy independence – at least temporarily – continued to drive widespread and deep-felt repercussions across global energy markets last year. The upheaval in global trade flows and energy mix remained a dominant theme and underpinned many of the stand-out shifts in the rankings this year.

This year's Platts Top 250 Global Energy Company Rankings™ indicate a brighter outlook for the US' energy revolution with the region's producers and suppliers gaining ground on their global peers.

Ongoing coal-to-gas substitution in the US' electricity mix continued to push cheap coal from the US to Europe, where some modern gas plants stand idle. At the same time, global coal demand stalled and was the only fuel to see supplies contract.

In Asia, the oil price drop has been a boon to the world's biggest energy importing countries, with regional markets the main beneficiaries of lower energy costs. While the oil price windfall for Asian Pacific economies may have helped support growth, the region's oil and gas producers have seen little benefit from increased demand and revenues so far.

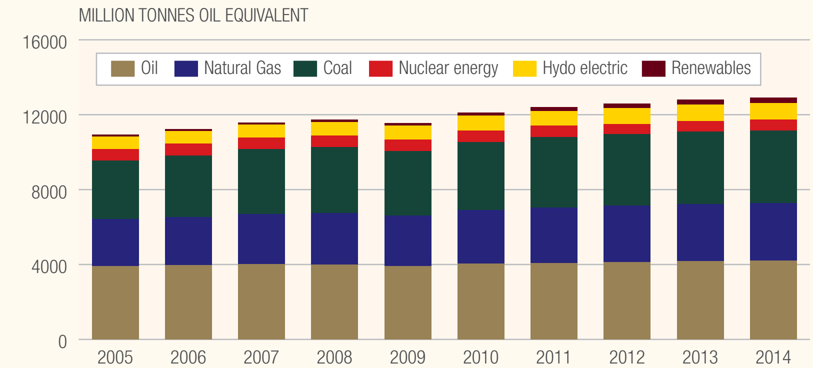
Chinese demand growth slowed last year to its lowest level since 1998 as its economy begins to rebalance away from energy-intensive sectors. Despite a slowdown in the pace of growth, China remained the world's demand center pulling in more energy per capita over the year than anywhere else. In 2014, China's economy grew by 7.4%, its slowest growth in 24 years, down from 7.7% in 2013.

Geopolitics also played a more pivotal role in 2014, with the turmoil over the Ukraine crisis and Western sanctions on Russia, accelerating moves by the world's top crude producer to forge new supply links to less hostile Asian consumers. The ruble also lost 40% of its value against the dollar last year, hobbling the fortunes of its biggest energy players.

The Top 10

This year's top 10 sees the big oil majors still dominating the rankings, but also a major shakeup in the traditional running order, with a few surprises thrown in on the back on the commodity price rout.

THE GLOBAL PRIMARY ENERGY MIX



Source: BP statistical review

Collectively, the world's 10 biggest energy companies posted combined earnings of $119.8 billion last year on revenues of $1.87 trillion, a significant slide of more than a third from the year-before totals.

First off, Exxon holds on to its top spot for the eleventh consecutive year, again outpacing its peers with sector-leading earnings and returns. Joined by Chevron and Shell near the top, the similarities with rankings in recent years ends there, however.

Integrated oil majors make up only half the leaderboard this year, with the sector's weaker placings overall making way for two refiners – Valero and Phillips 66 – and China's largest coal miner for the first time.

Valero, the world's biggest independent refiner, went from strength to strength with its mostly US Gulf Coast based operations continuing to benefit from the glut of US crudes in the region. Despite weaker coal markets, China Shenhua Energy jumps into the ▶

PLATTS RANK 2015	COMPANY	STATE OR COUNTRY	REGION	ASSETS $ MILLION	RANK	REVENUES $ MILLION	RANK	PROFITS $ MILLION	RANK	RETURN ON INVESTED CAPITAL ROIC%	RANK	3-YEAR CGR%	INDUSTRY CODE
1	**Exxon Mobil Corp**	Texas	Americas	349493	3	369431	3	32520	1	16	9	-5.5	IOG
2	**Chevron Corp**	California	Americas	266026	7	192308	7	19241	2	10	25	-6.6	IOG
3	**Royal Dutch Shell plc**	Netherlands	EMEA	353116	2	421105	2	14874	5	7	60	-3.6	IOG
4	**CNOOC Ltd**	Hong Kong	Asia/Pacific Rim	106930	22	44249	34	9711	6	12	21	4.4	E&P
5	**PetroChina Co Ltd**	China	Asia/Pacific Rim	388042	1	368279	4	17289	3	6	79	4.4	IOG
6	**Phillips 66**	Texas	Americas	48741	57	146593	8	4049	15	13	16	-7	R&M
7	**ConocoPhillips**	Texas	Americas	116539	19	55336	27	5738	11	8	46	-5.4	E&P
8	**Valero Energy Corp**	Texas	Americas	45550	64	130844	10	3692	18	13	15	1.3	R&M
9	**China Shenhua Energy Co Ltd**	China	Asia/Pacific Rim	86933	25	40065	38	6241	10	8	37	5.9	C&CF
10	**OJSC Rosneft Oil Co**	Russia	EMEA	163380	13	100541	15	6508	9	6	86	26.6	IOG
11	**China Petroleum & Chemical Corp**	China	Asia/Pacific Rim	234129	9	455759	1	7496	8	5	114	4.1	IOG
12	**OJSC Surgutneftegas**	Russia	EMEA	61830	37	16357	88	15365	4	28	3	3.7	IOG
13	**OJSC LUKOIL Oil Co**	Russia	EMEA	111800	21	144167	9	4746	12	5	98	2.6	IOG
14	**Reliance Industries Ltd**	India	Asia/Pacific Rim	79291	30	59007	25	3704	17	6	70	1.6	R&M
15	**Marathon Petroleum Corp**	Ohio	Americas	30460	97	91254	16	2520	33	14	14	7.4	R&M
16	**Tokyo Electric Power Co, Inc**	Japan	Asia/Pacific Rim	114021	20	54573	28	3623	19	5	98	8.3	EU
17	**Oil & Natural Gas Corp Ltd**	India	Asia/Pacific Rim	53074	49	25002	57	2882	28	8	43	2.6	E&P
18	**Enterprise Products Partners LP**	Texas	Americas	47101	59	47951	32	2782	29	7	60	2.7	S&T
19	**Ecopetrol SA**	Colombia	Americas	55860	46	27079	53	2951	26	7	57	1.5	IOG
20	**Canadian Natural Resources Ltd**	Canada	Americas	47938	58	15021	95	3129	23	9	31	11	E&P
21	**National Grid plc**	United Kingdom	EMEA	83588	28	23065	63	3064	24	5	98	3.2	DU
22	**EOG Resources, Inc**	Texas	Americas	34763	88	16693	85	2915	27	12	20	22.8	E&P
23	**Suncor Energy Inc**	Canada	Americas	63442	34	31742	46	2149	40	5	109	1.3	IOG
24	**RWE AG**	Germany	EMEA	94031	24	50526	30	1460	55	4	125	-2.1	DU
25	**Electricite de France SA**	France	EMEA	291943	4	79388	21	3609	20	3	192	3.7	EU
26	**TOTAL SA**	France	EMEA	229798	10	212018	6	4244	13	3	209	1.7	IOG
27	**Statoil ASA**	Norway	EMEA	123603	17	76036	22	2744	30	4	172	-2	IOG
28	**NextEra Energy, Inc**	Florida	Americas	74929	31	17021	82	2465	34	5	98	3.5	EU
29	**BP p.l.c.**	United Kingdom	EMEA	284305	5	353568	5	3778	16	2	224	-2	IOG
30	**Sasol Ltd**	South Africa	EMEA	22814	118	16499	86	2408	38	15	12	12.5	IOG
31	**PTT Plc**	Thailand	Asia/Pacific Rim	52802	50	84129	18	1639	46	4	151	5.3	IOG
32	**Iberdrola, SA**	Spain	EMEA	102153	23	32717	45	2558	32	4	168	-1.7	EU
33	**ENGIE SA**	France	EMEA	180081	12	81362	19	2585	31	2	218	-6.3	DU
34	**Encana Corp**	Canada	Americas	24621	111	8019	148	3392	22	19	5	-1.8	E&P
35	**Southern Co**	Georgia	Americas	70923	32	18467	74	1963	42	4	146	1.5	EU
36	**Tenaga Nasional Berhad**	Malaysia	Asia/Pacific Rim	30052	99	11620	116	1756	43	8	37	9.9	EU
37	**Edison International**	California	Americas	50186	54	13413	104	1426	58	6	81	8.2	EU
38	**Coal India Ltd**	India	Asia/Pacific Rim	17374	138	11319	120	2157	39	34	2	4.9	C&CF
39	**Exelon Corp**	Illinois	Americas	86814	26	27429	51	1623	49	4	175	12.9	EU
40	**PG&E Corp**	California	Americas	60127	39	17090	81	1436	57	4	125	4.5	DU
41	**Korea Electric Power Corp**	South Korea	Asia/Pacific Rim	147160	15	51349	29	2415	36	2	224	9.8	EU
42	**American Electric Power Co, Inc**	Ohio	Americas	59633	40	17020	83	1634	48	4	134	4	EU
43	**OJSC Gazprom**	Russia	EMEA	283848	6	102436	14	2974	25	1	261	6.4	IOG
44	**Huaneng Power International, Inc**	China	Asia/Pacific Rim	43905	68	20230	67	1701	45	4	134	-1.9	IPP
45	**Duke Energy Corp**	North Carolina	Americas	120709	18	23427	62	2446	35	3	203	18.1	EU
46	**Gas Natural SDG SA**	Spain	EMEA	54827	47	26954	54	1593	50	4	168	5.5	GU
47	**Tesoro Corp**	Texas	Americas	16584	143	40052	39	872	96	8	43	14.3	R&M
48	**Public Service Enterprise Group Inc**	New Jersey	Americas	35333	87	10886	127	1518	54	7	56	-0.6	DU
49	**Fortum Oyj**	Finland	EMEA	23286	115	5238	182	3436	21	17	6	-8.2	EU
50	**Woodside Petroleum Ltd**	Australia	Asia/Pacific Rim	24082	112	7435	157	2414	37	12	19	15.7	E&P

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51	**Devon Energy Corp**	Oklahoma	Americas	50637	52	17577	77	1590	51	4	146	18.5	E&P
52	**CLP Holdings Ltd**	Hong Kong	Asia/Pacific Rim	27674	104	11894	114	1447	56	7	57	0.2	EU
53	**Hess Corp**	New York	Americas	38578	77	10659	129	1635	47	6	79	-20.8	E&P
54	**Eni SpA**	Italy	EMEA	159276	14	119666	12	1406	59	2	248	0.5	IOG
55	**YPF SA**	Argentina	Americas	23170	117	15770	91	1000	76	7	50	36.2	IOG
56	**NTPC Ltd**	India	Asia/Pacific Rim	34511	89	12565	107	1570	53	6	86	6.7	IPP
57	**Chesapeake Energy Corp**	Oklahoma	Americas	40751	71	20951	66	1273	63	4	141	21.7	E&P
58	**SSE plc**	United Kingdom	EMEA	35347	86	48030	31	824	99	4	125	-0.1	EU
59	**Bharat Petroleum Corp Ltd**	India	Asia/Pacific Rim	13667	172	38101	41	755	106	11	24	4.5	R&M
60	**Williams Companies, Inc**	Oklahoma	Americas	50563	53	7637	152	2110	41	5	98	-1.2	S&T
61	**PPL Corp**	Pennsylvania	Americas	48864	55	11499	117	1575	52	4	134	-3.4	EU
62	**Husky Energy Inc**	Canada	Americas	30935	96	19185	73	991	77	5	114	3.1	IOG
63	**Plains All American Pipeline, LP**	Texas	Americas	22256	121	43464	35	878	95	5	114	8.2	S&T
64	**OAO Tatneft**	Russia	EMEA	13707	171	8909	142	1725	44	15	10	4.5	E&P
65	**Repsol, SA**	Spain	EMEA	56527	43	43319	37	1106	68	2	220	-7.9	IOG
66	**Indian Oil Corp Ltd**	India	Asia/Pacific Rim	36730	83	70462	23	772	104	4	164	3.1	R&M
67	**Consolidated Edison, Inc**	New York	Americas	44308	67	12919	106	1092	70	4	141	0.1	DU
68	**Empresas Copec SA**	Chile	Americas	21891	123	23841	61	856	97	5	109	4.1	R&M
69	**EDP-Energias de Portugal, SA**	Portugal	EMEA	46705	61	17750	76	1133	67	3	192	2.5	EU
70	**Sempra Energy**	California	Americas	39732	73	11035	124	1161	66	4	134	3.2	DU
71	**DTE Energy Co**	Michigan	Americas	27974	102	12301	110	904	91	5	95	11.6	DU
72	**Dominion Resources, Inc**	Virginia	Americas	54327	48	12436	109	1310	61	3	184	-3.3	DU
73	**Xcel Energy Inc**	Minnesota	Americas	36958	82	11686	115	1021	74	4	134	3.1	EU
74	**Tokyo Gas Co Ltd**	Japan	Asia/Pacific Rim	18112	133	18392	75	769	105	5	93	9.3	GU
75	**China Resources Power Holdings Co Ltd**	Hong Kong	Asia/Pacific Rim	29090	101	9112	140	1188	65	5	109	5.2	IPP
76	**Entergy Corp**	Louisiana	Americas	46528	62	12495	108	941	87	4	160	3.6	EU
77	**Enbridge Inc**	Canada	Americas	58016	42	29974	47	882	94	2	236	12	S&T
78	**Noble Energy, Inc**	Texas	Americas	22553	120	4931	190	1214	64	7	50	15.4	E&P
79	**Polska Grupa Energetyczna SA**	Poland	EMEA	17498	137	7437	156	962	84	7	52	0	EU
80	**Murphy Oil Corp**	Arkansas	Americas	16742	142	5289	181	1025	73	9	34	7.8	E&P
81	**Calpine Corp**	Texas	Americas	18378	132	7611	153	946	86	6	67	4	IPP
82	**TransCanada Corp**	Canada	Americas	46940	60	8110	147	1388	60	4	172	9.1	S&T
83	**Oil Transporting JSC Transneft**	Russia	EMEA	46275	63	14482	98	1099	69	3	211	4.9	S&T
84	**Enel SpA**	Italy	EMEA	181528	11	80814	20	563	130	0	285	-1.9	EU
85	**CEZ, a.s.**	Czech Republic	EMEA	24930	108	7854	150	890	93	5	98	-1	EU
86	**Kinder Morgan, Inc**	Texas	Americas	83198	29	16226	89	1015	75	1	257	26.9	S&T
87	**Zhejiang Zheneng Electric Power Co, Ltd**	China	Asia/Pacific Rim	16810	141	7127	160	962	82	6	67	0.4	IPP
88	**Energy Transfer Equity, LP**	Texas	Americas	64469	33	55691	26	567	128	1	264	89.5	S&T
89	**Snam S.p.A.**	Italy	EMEA	27132	105	4175	205	1305	62	6	81	2.3	GU
90	**Cenovus Energy Inc**	Canada	Americas	19665	129	15641	92	592	124	5	114	7.8	IOG
91	**Pioneer Natural Resources Co**	Texas	Americas	14926	158	4309	200	1031	72	9	31	26.9	E&P
92	**Saudi Electricity Co**	Saudi Arabia	EMEA	84769	27	10222	132	962	83	2	220	7.9	EU
93	**The AES Corp**	Virginia	Americas	38966	76	17146	80	789	102	3	209	2.1	IPP
94	**Marathon Oil Corp**	Texas	Americas	36011	85	10924	126	969	81	4	175	-9.5	E&P
95	**Polskie Gornictwo Naftowe I Gazownictwo SA**	Poland	EMEA	12932	180	9067	141	746	107	8	43	14.2	IOG
96	**Continental Resources, Inc**	Oklahoma	Americas	15145	156	4242	204	977	80	9	34	36.2	E&P
97	**Companhia Energética de Minas Gerais SA**	Brazil	Americas	11014	209	6149	169	987	78	13	18	7.5	EU
98	**Spectra Energy Corp**	Texas	Americas	34040	91	5903	172	1082	71	4	141	3.3	S&T
99	**Huadian Power International Corp Ltd**	Hong Kong	Asia/Pacific Rim	30370	98	11034	125	952	85	4	168	8.1	IPP
100	**GD Power Development Co, Ltd**	China	Asia/Pacific Rim	39725	74	9917	133	980	79	3	203	6.5	IPP

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101	**JSOC Bashneft**	Russia	EMEA	9794	228	11206	121	681	113	10	27	7.2	E&P
102	**Power Assets Holdings Ltd**	Hong Kong	Asia/Pacific Rim	17568	136	275	352	7865	7	46	1	-40.7	EU
103	**Osaka Gas Co, Ltd**	Japan	Asia/Pacific Rim	14939	157	12260	111	615	121	5	109	5.7	GU
104	**CenterPoint Energy, Inc**	Texas	Americas	23200	116	9226	139	611	123	5	122	3	DU
105	**Southwestern Energy Co**	Texas	Americas	14925	159	4038	211	924	88	8	42	11	E&P
106	**Eversource Energy**	Massachusetts	Americas	29778	100	7742	151	820	100	4	151	20.1	EU
107	**The Hong Kong & China Gas Co Ltd**	Hong Kong	Asia/Pacific Rim	14750	161	4076	210	917	90	8	49	12.1	GU
108	**Tohoku Electric Power Co Inc**	Japan	Asia/Pacific Rim	33143	93	17506	78	614	122	2	220	9	EU
109	**Cheung Kong Infrastructure Holdings Ltd**	Hong Kong	Asia/Pacific Rim	16253	150	823	345	4097	14	26	4	16.1	EU
110	**Türkiye Petrol Rafinerileri A.S.**	Turkey	EMEA	8176	262	14809	96	544	133	10	26	-0.9	R&M
111	**Kunlun Energy Co Ltd**	Hong Kong	Asia/Pacific Rim	15175	154	6194	168	723	109	6	89	22.8	E&P
112	**OMV Aktiengesellschaft**	Austria	EMEA	36972	81	39123	40	388	163	2	237	1.8	IOG
113	**JSC NOVATEK**	Russia	EMEA	13075	179	6689	162	698	112	6	76	26.8	E&P
114	**Korea Gas Corp**	South Korea	Asia/Pacific Rim	42044	69	33516	44	401	157	1	264	9.5	GU
115	**AGL Resources Inc**	Georgia	Americas	14909	160	5385	177	562	131	6	67	32.7	GU
116	**Wisconsin Energy Corp**	Wisconsin	Americas	15163	155	4997	185	588	125	6	72	3.7	DU
117	**ONEOK Partners, LP**	Oklahoma	Americas	14635	162	12192	113	566	129	4	141	2.5	S&T
118	**SDIC Power Holdings Co, Ltd**	China	Asia/Pacific Rim	27846	103	5317	180	903	92	4	175	11.8	IPP
119	**Ameren Corp**	Missouri	Americas	22676	119	5838	174	587	126	4	141	-0.7	DU
120	**GAIL (India) Ltd**	India	Asia/Pacific Rim	10946	212	9511	137	497	140	6	72	11	GU
121	**Inpex Corp**	Japan	Asia/Pacific Rim	36094	84	9396	138	624	119	2	233	-0.4	E&P
122	**Chubu Electric Power Co, Inc**	Japan	Asia/Pacific Rim	45182	66	24899	58	311	185	1	270	8.2	EU
123	**CGN Power Co, Ltd**	China	Asia/Pacific Rim	25315	106	3305	233	922	89	4	151	9.4	IPP
124	**Western Refining, Inc**	Texas	Americas	5683	339	15154	93	560	132	13	17	18.7	R&M
125	**SCA Corp**	South Carolina	Americas	16852	140	4951	186	538	134	4	125	3.9	DU
126	**Ultrapar Holdings Inc**	Brazil	Americas	6130	320	21315	65	391	161	8	46	11.7	S&T
127	**CMS Energy Corp**	Michigan	Americas	19185	130	7179	159	477	144	4	164	3.4	DU
128	**NiSource Inc**	Indiana	Americas	24866	110	6471	165	531	136	3	189	4	DU
129	**Power Grid Corp of India Ltd**	India	Asia/Pacific Rim	25267	107	2775	251	793	101	4	160	19.1	EU
130	**AGL Energy Ltd**	Australia	Asia/Pacific Rim	10627	217	7257	158	433	147	5	98	10.5	DU
131	**Veolia Environnement SA**	France	EMEA	37828	79	26014	55	218	220	1	267	2	DU
132	**Formosa Petrochemical Corp**	Taiwan	Asia/Pacific Rim	15334	152	29598	48	294	192	2	231	4.5	R&M
133	**Hindustan Petroleum Corp Ltd**	India	Asia/Pacific Rim	13477	174	34042	43	236	214	3	192	5.3	R&M
134	**Origin Energy Ltd**	Australia	Asia/Pacific Rim	23679	114	11040	123	403	156	2	231	12	IOG
135	**Denbury Resources Inc**	Texas	Americas	12728	181	2417	270	635	118	7	57	1.8	E&P
136	**Red Eléctrica Corporación S A.**	Spain	EMEA	11502	196	2031	292	782	103	8	37	4	EU
137	**OJSC Federal Hydro-Generating Co - RusHydro**	Russia	EMEA	16528	145	6396	166	479	142	3	189	-2.7	EU
138	**Datang International Power Generation Co, Ltd**	China	Asia/Pacific Rim	48787	56	11323	119	290	193	1	278	-1	IPP
139	**Cairn India Ltd**	India	Asia/Pacific Rim	10504	218	2302	274	704	111	8	48	7.3	E&P
140	**Newfield Exploration Co**	Texas	Americas	9598	231	2288	275	650	116	10	29	9.5	E&P
141	**FirstEnergy Corp**	Ohio	Americas	52166	51	14629	97	213	222	1	283	-2.1	EU
142	**Pinnacle West Capital Corp**	Arizona	Americas	14314	167	3492	222	398	158	5	109	2.5	EU
143	**Concho Resources, Inc**	Texas	Americas	11800	193	2660	254	532	135	6	75	18	E&P
144	**Manila Electric Co**	Philippines	Asia/Pacific Rim	6043	324	5982	171	406	154	16	8	1.2	EU
145	**EP Energy Corp**	Texas	Americas	10219	222	2099	287	727	108	8	41	12.6	E&P
146	**Essar Oil Ltd**	India	Asia/Pacific Rim	9126	243	13043	105	240	212	5	98	12.5	R&M
147	**ENN Energy Holdings Ltd**	China	Asia/Pacific Rim	6942	293	4692	195	479	143	10	27	24.5	GU
148	**Guangdong Electric Power Development Co Ltd**	China	Asia/Pacific Rim	11145	205	4686	196	485	141	5	119	2.8	IPP
149	**ONEOK Inc**	Oklahoma	Americas	15305	153	12195	112	320	181	3	217	-6.3	S&T
150	**HollyFrontier Corp**	Texas	Americas	9231	237	19764	69	280	197	4	160	8.6	R&M

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151	PT Perusahaan Gas Negara (Persero) TBK	Indonesia	Asia/Pacific Rim	6216	316	3409	227	723	110	15	11	15.2	GU
152	UGI Corp	Pennsylvania	Americas	10093	226	8277	146	337	172	5	122	10.8	GU
153	Antero Resources Corp	Colorado	Americas	11574	195	1812	301	671	114	7	60	110.1	E&P
154	Enable Midstream Partners, LP	Oklahoma	Americas	11837	192	3367	228	530	137	5	119	53.4	S&T
155	Alliant Energy Corp	Wisconsin	Americas	12086	186	3350	230	386	165	5	96	1.3	DU
156	YTL Corp Berhad	Malaysia	Asia/Pacific Rim	16576	144	5233	183	422	148	3	203	1.6	DU
157	Range Resources Corp	Texas	Americas	8747	247	2043	291	624	120	10	29	19.8	E&P
158	The Chugoku Electric Power Co, Inc	Japan	Asia/Pacific Rim	24920	109	10426	130	272	200	1	257	3.2	EU
159	Cimarex Energy Co	Colorado	Americas	8725	249	2424	269	497	139	8	40	11.3	E&P
160	TER SpA	Italy	EMEA	16405	149	2096	288	581	127	4	134	6.4	EU
161	Petróleo Brasileiro SA - Petrobras	Brazil	Americas	249654	8	106127	13	-6793	354	-3	324	11.4	IOG
162	SM Energy Co	Colorado	Americas	6517	307	2511	264	666	115	14	13	21.4	E&P
163	Companhia Paranaense de Energia - COPEL	Brazil	Americas	8061	264	4380	199	379	167	6	72	21.4	EU
164	Electric Power Development Co, Ltd	Japan	Asia/Pacific Rim	21333	125	6022	170	347	171	2	237	4.7	IPP
165	Volga Territorial Generation Co	Russia	EMEA	7037	289	2178	282	649	117	12	22	26.7	EU
166	E.ON SE	Germany	EMEA	136925	16	121903	11	-3252	352	-6	335	-0.5	DU
167	Plains GP Holdings, LP	Texas	Americas	23983	113	43464	35	70	278	0	289	8.2	S&T
168	China Power International Development Ltd	Hong Kong	Asia/Pacific Rim	13195	176	3316	232	446	145	4	164	8.3	IPP
169	Magellan Midstream Partners LP	Oklahoma	Americas	5517	340	2304	273	840	98	17	7	9.6	S&T
170	OGE Energy Corp	Oklahoma	Americas	9528	232	2453	267	396	159	6	66	-14.4	EU
171	Targa Resources Partners LP	Texas	Americas	6377	314	8616	143	319	182	6	86	7.2	S&T
172	Occidental Petroleum Corp	Texas	Americas	56259	44	19312	71	-144	313	0	298	-6.9	IOG
173	NRG Energy, Inc	New Jersey	Americas	40665	72	15868	90	78	275	0	292	20.5	IPP
174	Atmos Energy Corp	Texas	Americas	8595	250	4941	188	289	194	5	98	4.9	GU
175	China Coal Energy Co Ltd	China	Asia/Pacific Rim	39152	75	11399	118	124	252	0	286	-8	C&CF
176	Canadian Oil Sands Ltd	Canada	Americas	7974	266	2939	245	366	168	7	53	-1.6	E&P
177	Buckeye Partners, LP	Texas	Americas	8086	263	6620	164	333	174	4	134	12.1	S&T
178	JX Holdings, Inc	Japan	Asia/Pacific Rim	59554	41	87304	17	-2224	351	-6	333	0.5	R&M
179	Tauron Polska Energia SA	Poland	EMEA	9135	242	4874	192	312	184	4	125	-3.9	EU
180	Crescent Point Energy Corp	Canada	Americas	13113	178	2755	252	405	155	4	160	23.8	E&P
181	China Resources Gas Group Ltd	Hong Kong	Asia/Pacific Rim	7415	284	3702	217	320	180	7	65	26.4	GU
182	China Longyuan Power Group Corp Ltd	China	Asia/Pacific Rim	19925	127	2937	246	413	150	2	224	3.2	IPP
183	The Kansai Electric Power Co, Inc	Japan	Asia/Pacific Rim	62121	35	27325	52	-1190	343	-3	320	6.6	EU
184	MDU Resources Group Inc	North Dakota	Americas	7810	273	4671	197	294	191	6	89	4.9	DU
185	BKW Inc	Switzerland	EMEA	8376	258	2924	247	304	186	7	60	2.8	EU
186	Enbridge Energy Partners, LP	Texas	Americas	17747	134	7965	149	218	219	1	254	-4.4	S&T
187	ATCO Ltd	Canada	Americas	14086	168	3626	219	334	173	3	197	4.5	DU
188	Integrys Energy Group, Inc	Illinois	Americas	11282	200	4144	207	275	199	4	151	-4	DU
189	CPFL Energia SA	Brazil	Americas	11045	207	5446	176	299	190	3	184	10.9	EU
190	Acciona, SA	Spain	EMEA	17586	135	7476	154	201	225	2	244	-2.5	EU
191	SK Innovation Co, Ltd	South Korea	Asia/Pacific Rim	31553	94	59207	24	-474	328	-2	314	-1.2	R&M
192	Inner Mongolia Yitai Coal Co Ltd	China	Asia/Pacific Rim	9476	233	4002	212	363	169	4	146	-2.8	C&CF
193	BG Group plc	United Kingdom	EMEA	61846	36	19289	72	-1051	341	-2	316	3	IOG
194	EQT Corp	Pennsylvania	Americas	12065	187	2470	266	386	164	4	151	23.1	E&P
195	Rabigh Refining & Petrochemical Co	Saudi Arabia	EMEA	10915	213	14462	99	182	230	2	228	0.5	R&M
196	Shenergy Co Ltd	China	Asia/Pacific Rim	6853	296	4099	208	333	175	5	91	3.6	IPP
197	Pepco Holdings, Inc	District of Columbia	Americas	15667	151	4878	191	242	210	2	220	-0.6	EU
198	Fortis Inc	Canada	Americas	21204	126	4301	201	248	207	2	248	13.1	EU
199	YTL Power International Berhad	Malaysia	Asia/Pacific Rim	10885	214	3920	215	327	178	4	175	-0.5	DU
200	Westar Energy, Inc	Kansas	Americas	10347	221	2602	257	312	183	4	125	6.2	EU

Notes: C&CF = coal and consumable fuels, DNR = data not reported, DU = diversified utility, E&P = exploration and production, EU = electric utility, GU = gas utility, IOG = integrated oil and gas, IPP = independent power producer and energy trader, R&M = refining and marketing, S&T = storage and transfer. All rankings are computed from data collected and translated into USD 6/1/2015.

Source: S&P Capital IQ/Platts

PLATTS RANK 2015	COMPANY	STATE OR COUNTRY	REGION	ASSETS $ MILLION	ASSETS RANK	REVENUES $ MILLION	REVENUES RANK	PROFITS $ MILLION	PROFITS RANK	RETURN ON INVESTED CAPITAL ROIC%	RETURN ON INVESTED CAPITAL RANK	3-YEAR CGR%	INDUSTRY CODE
201	Yanzhou Coal Mining Co Ltd	China	Asia/Pacific Rim	21471	124	9739	135	129	251	1	278	8.7	C&CF
202	EnBW Energie Baden-Wuerttemberg AG	Germany	EMEA	41737	70	22965	64	-491	329	-4	327	3.9	EU
203	China Gas Holdings Ltd	Hong Kong	Asia/Pacific Rim	5835	329	3353	229	332	176	7	60	17.9	GU
204	Pembina Pipeline Corp	Canada	Americas	8968	244	4833	193	277	198	4	164	53.6	S&T
205	Hawaiian Electric Industries Inc	Hawaii	Americas	11184	204	3240	234	168	238	4	125	0	EU
206	Enagás, SA	Spain	EMEA	8401	257	1314	322	443	146	6	76	2.5	GU
207	OJSC INTER RAO UES	Russia	EMEA	10950	211	13860	102	147	245	2	244	11.4	EU
208	Beijing Jingneng Power Co, Ltd	China	Asia/Pacific Rim	6455	309	2091	289	412	151	7	53	14.9	IPP
209	Anadarko Petroleum Corp	Texas	Americas	61689	38	16375	87	-1754	350	-4	330	5.7	E&P
210	JSC ROSSETI	Russia	EMEA	37106	80	14206	101	-287	320	-1	304	6.2	EU
211	Oasis Petroleum Inc	Texas	Americas	5938	325	1390	319	507	138	11	23	61.4	E&P
212	Centrica plc	United Kingdom	EMEA	34431	90	44622	33	-1536	347	-10	344	8.8	DU
213	Emera Incorporated	Canada	Americas	7839	271	2367	272	324	179	5	93	12.9	EU
214	MOL Hungarian Oil & Gas Co	Hungary	EMEA	16406	148	17172	79	-12	297	0	296	-3.1	IOG
215	HK Electric Investments & HK Electric Investments Ltd	Hong Kong	Asia/Pacific Rim	14544	164	1354	320	413	149	3	189	1	EU
216	Shaanxi Coal Industry Co Ltd	China	Asia/Pacific Rim	14522	165	6638	163	153	243	1	254	-1.4	C&CF
217	DCP Midstream Partners LP	Colorado	Americas	5739	335	3488	223	303	187	6	81	-1.9	S&T
218	National Fuel Gas Co	New York	Americas	6740	300	2113	286	299	189	7	53	5.9	GU
219	Reliance Infrastructure Ltd	India	Asia/Pacific Rim	11134	206	2661	253	283	195	4	175	-11.2	EU
220	Kyushu Electric Power Co, Inc	Japan	Asia/Pacific Rim	38385	78	15030	94	-920	338	-3	321	7.5	EU
221	NHPC Ltd	India	Asia/Pacific Rim	9944	227	1274	326	392	160	5	119	3.9	IPP
222	Oil India Ltd	India	Asia/Pacific Rim	5826	331	1489	314	410	152	9	36	-1.3	E&P
223	Public Power Corp SA	Greece	EMEA	18926	131	6388	167	99	264	1	274	2.1	EU
224	JSC KazMunaiGas Exploration Production	Kazakhstan	EMEA	7984	265	4551	198	253	206	4	175	5.5	E&P
225	Idemitsu Kosan Co Ltd	Japan	Asia/Pacific Rim	21909	122	37142	42	-1107	342	-8	340	2.4	R&M
226	Apache Corp	Texas	Americas	55952	45	13478	103	-4886	353	-12	346	-6.8	E&P
227	Huadian Fuxin Energy Corp Ltd	China	Asia/Pacific Rim	13863	170	2243	278	301	188	3	211	24.1	IPP
228	Breitburn Energy Partners LP	California	Americas	7638	276	863	341	406	153	6	81	29.5	E&P
229	Shenzhen Energy Group Co, Ltd	China	Asia/Pacific Rim	6201	318	2017	293	328	177	6	70	-4.6	IPP
230	Galp Energia SGPS SA	Portugal	EMEA	14397	166	19713	70	-189	314	-2	311	2.3	IOG
231	Centrais Elétricas Brasileiras SA - Eletrobras	Brazil	Americas	45512	65	9517	136	-954	339	-3	322	1.2	EU
232	Oil Search Ltd	Papua New Guinea	Asia/Pacific Rim	10727	216	1610	308	353	170	4	168	30	E&P
233	Empresa de Energia de Bogotá SA ESP	Colombia	Americas	7432	283	906	340	385	166	6	76	17.5	GU
234	Hera S.p.A.	Italy	EMEA	9186	240	4811	194	180	232	3	211	1.2	DU
235	Tourmaline Oil Corp	Canada	Americas	5273	347	1017	337	389	162	9	33	57.8	E&P
236	TonenGeneral Sekiyu KK	Japan	Asia/Pacific Rim	11041	208	27686	50	-112	310	-2	315	8.8	R&M
237	CONSOL Energy Inc	Pennsylvania	Americas	11760	194	3498	221	169	237	2	233	-5	C&CF
238	Great Plains Energy Incorporated	Missouri	Americas	10476	219	2568	261	241	211	3	197	3.5	EU
239	Delek Group Ltd	Israel	EMEA	33860	92	4936	189	-82	307	-1	306	-17	R&M
240	Abu Dhabi National Energy Co PJSC	UAE	EMEA	31320	95	7439	155	-819	336	-3	324	4.2	DU
241	Showa Shell Sekiyu KK	Japan	Asia/Pacific Rim	9437	234	24051	60	-78	306	-2	313	2.7	R&M
242	Shikoku Electric Power Co Inc	Japan	Asia/Pacific Rim	11241	202	5329	179	83	272	1	267	3.9	EU
243	Japan Petroleum Exploration Co, Ltd	Japan	Asia/Pacific Rim	5911	326	2446	268	237	213	5	114	9.8	E&P
244	Hokkaido Electric Power Co Inc	Japan	Asia/Pacific Rim	14566	163	5559	175	24	292	0	292	3	EU
245	ACEA S.p.A.	Italy	EMEA	7529	279	3219	235	177	234	4	175	-2.9	DU
246	Royal Vopak NV	Netherlands	EMEA	5892	327	1441	315	269	201	6	81	4.1	S&T
247	TECO Energy, Inc	Florida	Americas	8726	248	2566	262	206	223	3	192	-7.2	DU
248	Neste Oil Corp	Finland	EMEA	7074	287	14237	100	62	282	1	257	-2.8	R&M
249	Cosmo Oil Co, Ltd	Japan	Asia/Pacific Rim	11461	197	24355	59	-624	333	-9	341	-0.8	R&M
250	VERBUND AG	Austria	EMEA	13342	175	3080	238	110	257	1	264	-2.2	EU

Notes: C&CF = coal and consumable fuels, DNR = data not reported, DU = diversified utility, E&P = exploration and production, EU = electric utility, GU = gas utility, IOG = integrated oil and gas, IPP = independent power producer and energy trader, R&M = refining and marketing, S&T = storage and transfer. All rankings are computed from data collected and translated into USD 6/1/2015.

Source: S&P Capital IQ/Platts

leaderboard at #9 from 15th place the year before, as shrinking earnings from leading oil producers gave it a relative boost.

BP's mid-top 10 placement for revenue and assets was upended by its weaker profits and very poor ROIC turnaround for the year. BP's 2% return on investment capital, a measure of how well a company generates cash flow relative to the capital it has invested in its business, fell to just 25 places from the bottom.

Last year's turnout was hit by an $8.9 billion impairment and losses on the sale of businesses and lower prices, a multi-year high.

Fluctuations in a company's earnings or business cycles do affect the ratio drastically, however, and BP's ROIC over the previous three years has averaged over 15%, beating Shell's over the same period.

Other casualties this year are France's Total and Russian gas giant Gazprom. The state gas supplier, which placed 4th overall last year with the world's biggest energy profits, dove nearly 40 places after the ruble's collapse triggered huge foreign exchange losses.

Total, a regular top 10 fixture, tumbles to 27th 26th place this year as its earnings and returns faltered.

Regional shifts

The radical rebalancing of global energy markets towards Asia has played a key theme across the rankings in recent years, with state-backed giants such as PetroChina growing to rival established Big Oil. But this year we see the acceleration of a more recent counter-current as the Asia's growth slows and the US shale revolution continues to transform global energy markets and trade. ▶

FASTEST GROWING ASIA COMPANIES

Rank	Company	Country	Industry	3-year CGR %	Platts Rank
1	Oil Search Ltd	Papua New Guinea	E&P	30	232
2	China Resources Gas Group Ltd	Hong Kong	GU	26.4	181
3	ENN Energy Holdings Ltd	China	GU	24.5	147
4	Huadian Fuxin Energy Corp Ltd	China	IPP	24.1	227
5	Kunlun Energy Co Ltd	Hong Kong	E&P	22.8	111
6	Power Grid Corp of India Ltd	India	EU	19.1	129
7	China Gas Holdings Ltd	Hong Kong	GU	17.9	203
8	Cheung Kong Infrastructure Holdings Ltd	Hong Kong	EU	16.1	109
9	Woodside Petroleum Ltd	Australia	E&P	15.7	50
10	PT Perusahaan Gas Negara (Persero) TBK	Indonesia	GU	15.2	151
11	Beijing Jingneng Power Co, Ltd	China	IPP	14.9	208
12	Essar Oil Ltd	India	R&M	12.5	146
13	The Hong Kong & China Gas Co Ltd	Hong Kong	GU	12.1	107
14	Origin Energy Ltd	Australia	IOG	12	134
15	SDIC Power Holdings Co, Ltd	China	IPP	11.8	118
16	GAIL (India) Ltd	India	GU	11	120
17	AGL Energy Ltd	Australia	DU	10.5	130
18	Tenaga Nasional Berhad	Malaysia	EU	9.9	36
19	Korea Electric Power Corp	South Korea	EU	9.8	41
20	Japan Petroleum Exploration Co, Ltd	Japan	E&P	9.8	243

Fastest Growing is based on a three year compound growth rate (CGR) for revenues. The compound growth rate (CGR) is based on the companies revenue numbers for the past four years (current year included). If only three years of data was available then it is a two year CGR. All rankings are computed from data collected and translated into USD 6/1/2015.

Source: S&P Capital IQ/Platts

FASTEST GROWING AMERICAS COMPANIES

Rank	Company	State or Country	Industry	3-year CGR %	Platts Rank
1	Antero Resources Corp	Colorado	E&P	110.1	153
2	Energy Transfer Equity, LP	Texas	S&T	89.5	88
3	Oasis Petroleum Inc	Texas	E&P	61.4	211
4	Tourmaline Oil Corp	Canada	E&P	57.8	235
5	Pembina Pipeline Corp	Canada	S&T	53.6	204
6	Enable Midstream Partners, LP	Oklahoma	S&T	53.4	154
7	YPF SA	Argentina	IOG	36.2	55
8	Continental Resources, Inc	Oklahoma	E&P	36.2	96
9	AGL Resources Inc	Georgia	GU	32.7	115
10	Breitburn Energy Partners LP	California	E&P	29.5	228

Fastest Growing is based on a three year compound growth rate (CGR) for revenues. The compound growth rate (CGR) is based on the companies revenue numbers for the past four years (current year included). If only three years of data was available then it is a two year CGR. All rankings are computed from data collected and translated into USD 6/1/2015.

Source: S&P Capital IQ/Platts

ASIA/PACIFIC RIM COMPANIES IN 2015 TOP 250

TOP ASIA	PLATTS RANK 2015	COMPANY	STATE OR COUNTRY	ASSETS $ MILLION	RANK	REVENUES $ MILLION	RANK	PROFITS $ MILLION	RANK	RETURN ON INVESTED CAPITAL ROIC%	RANK	INDUSTRY CODE
1	4	**CNOOC Ltd**	Hong Kong	106930	22	44249	34	9711	6	12	21	E&P
2	5	**PetroChina Co Ltd**	China	388042	1	368279	4	17289	3	6	79	IOG
3	9	**China Shenhua Energy Co Ltd**	China	86933	25	40065	38	6241	10	8	37	C&CF
4	11	**China Petroleum & Chemical Corp**	China	234129	9	455759	1	7496	8	5	114	IOG
5	14	**Reliance Industries Ltd**	India	79291	30	59007	25	3704	17	6	70	R&M
6	16	**Tokyo Electric Power Co, Incorporated**	Japan	114021	20	54573	28	3623	19	5	98	EU
7	17	**Oil & Natural Gas Corp Ltd**	India	53074	49	25002	57	2882	28	8	43	E&P
8	31	**PTT Plc**	Thailand	52802	50	84129	18	1639	46	4	151	IOG
9	36	**Tenaga Nasional Berhad**	Malaysia	30052	99	11620	116	1756	43	8	37	EU
10	38	**Coal India Ltd**	India	17374	138	11319	120	2157	39	34	2	C&CF
11	41	**Korea Electric Power Corp**	South Korea	147160	15	51349	29	2415	36	2	224	EU
12	44	**Huaneng Power International, Inc**	China	43905	68	20230	67	1701	45	4	134	IPP
13	50	**Woodside Petroleum Ltd**	Australia	24082	112	7435	157	2414	37	12	19	E&P
14	52	**CLP Holdings Ltd**	Hong Kong	27674	104	11894	114	1447	56	7	57	EU
15	56	**NTPC Ltd**	India	34511	89	12565	107	1570	53	6	86	IPP
16	59	**Bharat Petroleum Corp Ltd**	India	13667	172	38101	41	755	106	11	24	R&M
17	66	**Indian Oil Corp Ltd**	India	36730	83	70462	23	772	104	4	164	R&M
18	74	**Tokyo Gas Co Ltd**	Japan	18112	133	18392	75	769	105	5	93	GU
19	75	**China Resources Power Holdings Co Ltd**	Hong Kong	29090	101	9112	140	1188	65	5	109	IPP
20	87	**Zhejiang Zheneng Electric Power Co, Ltd**	China	16810	141	7127	160	962	82	6	67	IPP
21	99	**Huadian Power International Corp Ltd**	Hong Kong	30370	98	11034	125	952	85	4	168	IPP
22	100	**GD Power Development Co, Ltd**	China	39725	74	9917	133	980	79	3	203	IPP
23	102	**Power Assets Holdings Ltd**	Hong Kong	17568	136	275	352	7865	7	46	1	EU
24	103	**Osaka Gas Co, Ltd**	Japan	14939	157	12260	111	615	121	5	109	GU
25	107	**The Hong Kong & China Gas Co Ltd**	Hong Kong	14750	161	4076	210	917	90	8	49	GU
26	108	**Tohoku Electric Power Co Inc**	Japan	33143	93	17506	78	614	122	2	220	EU
27	109	**Cheung Kong Infrastructure Holdings Ltd**	Hong Kong	16253	150	823	345	4097	14	26	4	EU
28	111	**Kunlun Energy Co Ltd**	Hong Kong	15175	154	6194	168	723	109	6	89	E&P
29	114	**Korea Gas Corp**	South Korea	42044	69	33516	44	401	157	1	264	GU
30	118	**SDIC Power Holdings Co, Ltd**	China	27846	103	5317	180	903	92	4	175	IPP
31	120	**GAIL (India) Ltd**	India	10946	212	9511	137	497	140	6	72	GU
32	121	**Inpex Corp**	Japan	36094	84	9396	138	624	119	2	233	E&P
33	122	**Chubu Electric Power Co, Incorporated**	Japan	45182	66	24899	58	311	185	1	270	EU
34	123	**CGN Power Co, Ltd**	China	25315	106	3305	233	922	89	4	151	IPP
35	129	**Power Grid Corp of India Ltd**	India	25267	107	2775	251	793	101	4	160	EU
36	130	**AGL Energy Ltd**	Australia	10627	217	7257	158	433	147	5	98	DU
37	132	**Formosa Petrochemical Corp**	Taiwan	15334	152	29598	48	294	192	2	231	R&M
38	133	**Hindustan Petroleum Corp Ltd**	India	13477	174	34042	43	236	214	3	192	R&M
39	134	**Origin Energy Ltd**	Australia	23679	114	11040	123	403	156	2	231	IOG

Notes: C&CF = coal and consumable fuels, DNR = data not reported, DU = diversified utility, E&P = exploration and production, EU = electric utility, GU = gas utility, IOG = integrated oil and gas, IPP = independent power producer and energy trader, R&M = refining and marketing, S&T = storage and transfer. All rankings are computed from data collected and translated into USD 6/1/2015.

Source: S&P Capital IQ/Platts

Simply put, the rising tide of North American unconventionals has grown at the expense of energy rivals in Asia Pacific and more acutely in the low-growth EMEA region.

The America's again moved up the regional rankings with its top 10 energy companies placing 12 overall from 15.5 the year before. Taken together, American energy firms now make up 45% of the Top 250 list, with 11 more regional entries this year pushing out rival players from Asia and Europe.

ASIA/PACIFIC RIM COMPANIES IN 2015 TOP 250

TOP ASIA	PLATTS RANK 2015	COMPANY	STATE OR COUNTRY	ASSETS $ MILLION	RANK	REVENUES $ MILLION	RANK	PROFITS $ MILLION	RANK	RETURN ON INVESTED CAPITAL ROIC%	RANK	INDUSTRY CODE
40	138	Datang International Power Generation Co, Ltd	China	48787	56	11323	119	290	193	1	278	IPP
41	139	Cairn India Ltd	India	10504	218	2302	274	704	111	8	48	E&P
42	144	Manila Electric Co	Philippines	6043	324	5982	171	406	154	16	8	EU
43	146	Essar Oil Ltd	India	9126	243	13043	105	240	212	5	98	R&M
44	147	ENN Energy Holdings Ltd	China	6942	293	4692	195	479	143	10	27	GU
45	148	Guangdong Electric Power Development Co Ltd	China	11145	205	4686	196	485	141	5	119	IPP
46	151	PT Perusahaan Gas Negara (Persero) TBK	Indonesia	6216	316	3409	227	723	110	15	11	GU
47	156	YTL Corp Berhad	Malaysia	16576	144	5233	183	422	148	3	203	DU
48	158	The Chugoku Electric Power Co,Inc	Japan	24920	109	10426	130	272	200	1	257	EU
49	164	Electric Power Development Co, Ltd	Japan	21333	125	6022	170	347	171	2	237	IPP
50	168	China Power International Development Ltd	Hong Kong	13195	176	3316	232	446	145	4	164	IPP
51	175	China Coal Energy Co Ltd	China	39152	75	11399	118	124	252	0	286	C&CF
52	178	JX Holdings, Inc	Japan	59554	41	87304	17	-2224	351	-6	333	R&M
53	181	China Resources Gas Group Ltd	Hong Kong	7415	284	3702	217	320	180	7	65	GU
54	182	China Longyuan Power Group Corp Ltd	China	19925	127	2937	246	413	150	2	224	IPP
55	183	The Kansai Electric Power Co, Incorporated	Japan	62121	35	27325	52	-1190	343	-3	320	EU
56	191	SK Innovation Co, Ltd	South Korea	31553	94	59207	24	-474	328	-2	314	R&M
57	192	Inner Mongolia Yitai Coal Co Ltd	China	9476	233	4002	212	363	169	4	146	C&CF
58	196	Shenergy Co Ltd	China	6853	296	4099	208	333	175	5	91	IPP
59	199	YTL Power International Berhad	Malaysia	10885	214	3920	215	327	178	4	175	DU
60	201	Yanzhou Coal Mining Co Ltd	China	21471	124	9739	135	129	251	1	278	C&CF
61	203	China Gas Holdings Ltd	Hong Kong	5835	329	3353	229	332	176	7	60	GU
62	208	Beijing Jingneng Power Co, Ltd	China	6455	309	2091	289	412	151	7	53	IPP
63	215	HK Electric Investments & HK Electric Investments Ltd	Hong Kong	14544	164	1354	320	413	149	3	189	EU
64	216	Shaanxi Coal Industry Co Ltd	China	14522	165	6638	163	153	243	1	254	C&CF
65	219	Reliance Infrastructure Ltd	India	11134	206	2661	253	283	195	4	175	EU
66	220	Kyushu Electric Power Co, Incorporated	Japan	38385	78	15030	94	-920	338	-3	321	EU
67	221	NHPC Ltd	India	9944	227	1274	326	392	160	5	119	IPP
68	222	Oil India Ltd	India	5826	331	1489	314	410	152	9	36	E&P
69	225	Idemitsu Kosan Co Ltd	Japan	21909	122	37142	42	-1107	342	-8	340	R&M
70	227	Huadian Fuxin Energy Corp Ltd	China	13863	170	2243	278	301	188	3	211	IPP
71	229	Shenzhen Energy Group Co, Ltd	China	6201	318	2017	293	328	177	6	70	IPP
72	232	Oil Search Ltd	Papua New Guinea	10727	216	1610	308	353	170	4	168	E&P
73	236	TonenGeneral Sekiyu KK	Japan	11041	208	27686	50	-112	310	-2	315	R&M
74	241	Showa Shell Sekiyu KK	Japan	9437	234	24051	60	-78	306	-2	313	R&M
75	242	Shikoku Electric Power Co Inc	Japan	11241	202	5329	179	83	272	1	267	EU
76	243	Japan Petroleum Exploration Co, Ltd	Japan	5911	326	2446	268	237	213	5	114	E&P
77	244	Hokkaido Electric Power Co Inc	Japan	14566	163	5559	175	24	292	0	292	EU
78	249	Cosmo Oil Co, Ltd	Japan	11461	197	24355	59	-624	333	-9	341	R&M

Notes: C&CF = coal and consumable fuels, DNR = data not reported, DU = diversified utility, E&P = exploration and production, EU = electric utility, GU = gas utility, IOG = integrated oil and gas, IPP = independent power producer and energy trader, R&M = refining and marketing, S&T = storage and transfer. All rankings are computed from data collected and translated into USD 6/1/2015.

Source: S&P Capital IQ/Platts

The changes also mark a key inflection point for Asia's energy sector, which for years has seen its overall standing in the Platts rankings edge higher and higher. While Asia's emerging economies, led by China, continue to pull in the biggest share of incremental global commodity demand growth, the pace of growth is now clearly slowing.

Asian slowdown

This year saw the total number of regional Asian players slip by four to 78 from the previous year and their average ▶

rankings dipped from 134th to 137th place. That contrasts with last year's rankings, when Asia and Pacific Rim energy firms where still the only regional sectors to see total numbers swell.

Asia's biggest energy companies fared much better overall, however. This year, the top 10 Asian firms saw their average rankings rise to 18th from 26th, while the European average fell from 11.6 from 19th.

Indeed, despite a slowdown in growth, China alone accounted for almost a quarter of global energy consumption and over 60% of net energy consumption growth in 2014. China also remained the world's largest energy producer, accounting for some 19% of global energy supply. Notably CNOOC, China's biggest offshore oil and gas company, leaped into this year's top 5 at #4 from 12 last year, while Petrochina moved up two spots to rank 5th overall.

India, the second Asian demand power house, saw its energy consumption hit an all-time high with the fastest growth for the last five years, requiring more coal, LNG and oil. But even here energy companies saw their growth rates ebb. Only two Indian energy firms – Power Grid Corp and Essar Oil – placed on the list of top 50 fastest growing companies this year, down from seven a year ago.

Despite the price shock, the US shale revolution continued apace in 2014. Depending on who's counting, the US surpassed Saudi Arabia and Russia to become the world's largest producer of oil in 2014 and remained the biggest consumer of gas.

A total of 113 Americas companies made the list this year and ranked 119th overall as a region, up from 103 the year before when the region's players averaged 126th.

Europe, Russia

Once again energy players in the EMEA region labored under weak demand, regulatory impacts, and in the case of its top utilities, milder than average winters in both 2013 and 2014.

The European region alone suffered the biggest primary energy decline out of any region in the world, according to BP, falling to its lowest level in three decades by on outright volumes.

#1 IN ASIA BY INDUSTRY

Industry	Company	Country	Platts Rank
E&P	CNOOC Ltd	Hong Kong	4
IOG	PetroChina Co Ltd	China	5
C&CF	China Shenhua Energy Co Ltd	China	9
R&M	Reliance Industries Ltd	India	14
EU	Tokyo Electric Power Co, Incorporated	Japan	16
IPP	Huaneng Power International, Inc	China	44
GU	Tokyo Gas Co Ltd	Japan	74
DU	AGL Energy Ltd	Australia	130

All rankings are computed from data collected and translated into USD 6/1/2015.

Source: S&P Capital IQ/Platts

FASTEST GROWING EMEA COMPANIES

Rank	Company	Country	Industry	3-year CGR %	Platts Rank
1	JSC NOVATEK	Russia	E&P	26.8	113
2	Volga Territorial Generation Co	Russia	EU	26.7	165
3	OJSC Rosneft Oil Co	Russia	IOG	26.6	10
4	Polskie Gornictwo Naftowe I Gazownictwo SA	Poland	IOG	14.2	95
5	Sasol Ltd	South Africa	IOG	12.5	30
6	OJSC INTER RAO UES	Russia	EU	11.4	207
7	Centrica plc	United Kingdom	DU	8.8	212
8	Saudi Electricity Co	Saudi Arabia	EU	7.9	92
9	JSOC Bashneft	Russia	E&P	7.2	101
10	OJSC Gazprom	Russia	IOG	6.4	43

Fastest Growing is based on a three year compound growth rate (CGR) for revenues. The compound growth rate (CGR) is based on the companies revenue numbers for the past four years (current year included). If only three years of data was available then it is a two year CGR. All rankings are computed from data collected and translated into USD 6/1/2015.

Source: S&P Capital IQ/Platts

Overall, the number of EMEA entries on the list continues to slide this year with 59 companies holding an average ranking placement of 123rd, down from last year when the region fielded 65 energy firms averaging a position of 113th.

Growth rates in the region were again at the bottom of the pack, with average 3-year CGR of just 2.8%, less than half that of Asia/Pacific region (6%) and less than a third of the Americas' area (10.4%). Of the top 50 fastest growing energy firms, only four are based in the EMEA region and three of those are Russian.

Among companies losing the most ground in the rankings this year are Russia's biggest independent gas firm Novatek and its oil transport monopoly Transneft after their dollar results and debt payments were hit by the sharp depreciation of the ruble.

Austria's OMV was also one of the biggest fallers outright this year, slipping from 38 to 112th after selling down its refining assets and suffering the impact of security issues in Libya and Yemen on production volumes.

Fastest growing

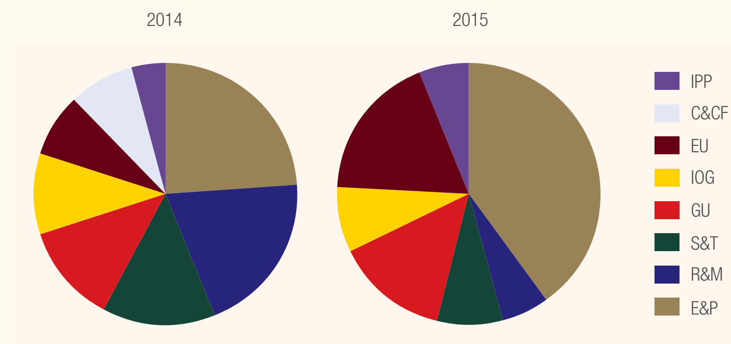
Overall, corporate growth rates slowed slightly in 2014, with average 3-year compound rates at 7.3%, down from 10% the year before.

But the world's top 50 fastest growers remain dominated by US shale players and there is no slow down for this sector. America's top players continued to post stellar gains, enjoying compound growth of 56% over the last three years, an acceleration from 46.8% in 2013. Exploration and production companies made up biggest group with almost half the list.

North American energy companies now hold 29 positions or almost 60% of the growth leaderboard, a remarkable change of fortunes from just the six in the 2012 rankings. US and Canadian tight and shale oil producers and mid-stream companies carrying their increasing volumes, now make up eight of the world's top 10 fastest growing energy company stories.

In the US, companies with advantaged, oil-rich shale acreage have been able to outperform the sector's average ▶

TOP 50 FASTEST GROWING BY SECTOR



Source: Platts Top 250

FASTEST GROWING ASIAN COMPANIES BY INDUSTRY

Industry	Company	Country	3-year CGR %	Platts Rank
E&P	Oil Search Ltd	Papua New Guinea	30	232
GU	China Resources Gas Group Ltd	Hong Kong	26.4	181
IPP	Huadian Fuxin Energy Corp Ltd	China	24.1	227
EU	Power Grid Corp of India Ltd	India	19.1	129
R&M	Essar Oil Ltd	India	12.5	146
IOG	Origin Energy Ltd	Australia	12	134
MU	AGL Energy Ltd	Australia	10.5	130
C&CF	Yanzhou Coal Mining Co Ltd	China	8.7	201
RE	NHPC Ltd	India	3.9	221

Fastest Growing is based on a 3 year compound growth rate (CGR) for revenues. All rankings are computed from data collected and translated into USD 6/1/2015.

Source: S&P Capital IQ/Platts

TOP 50 FASTEST GROWING COMPANIES

	Company	3-year CGR%	Platts Rank
1	Antero Resources Corp	110.1	153
2	Energy Transfer Equity, LP	89.5	88
3	Oasis Petroleum Inc	61.4	211
4	Tourmaline Oil Corp	57.8	235
5	Pembina Pipeline Corp	53.6	204
6	Enable Midstream Partners, LP	53.4	154
7	YPF SA	36.2	55
8	Continental Resources, Inc	36.2	96
9	AGL Resources Inc	32.7	115
10	Oil Search Ltd	30	232
11	Breitburn Energy Partners LP	29.5	228
12	Kinder Morgan, Inc	26.9	86
13	Pioneer Natural Resources Co	26.9	91
14	JSC NOVATEK	26.8	113
15	Volga Territorial Generation Co	26.7	165
16	OJSC Rosneft Oil Co	26.6	10
17	China Resources Gas Group Ltd	26.4	181
18	ENN Energy Holdings Ltd	24.5	147
19	Huadian Fuxin Energy Corp Ltd	24.1	227
20	Crescent Point Energy Corp	23.8	180
21	EQT Corp	23.1	194
22	EOG Resources, Inc	22.8	22
23	Kunlun Energy Co Ltd	22.8	111
24	Chesapeake Energy Corp	21.7	57
25	Companhia Paranaense de Energia - COPEL	21.4	163
26	SM Energy Co	21.4	162
27	NRG Energy, Inc	20.5	173
28	Eversource Energy	20.1	106
29	Range Resources Corp	19.8	157
30	Power Grid Corp of India Ltd	19.1	129
31	Western Refining, Inc	18.7	124
32	Devon Energy Corp	18.5	51
33	Duke Energy Corp	18.1	45
34	Concho Resources, Inc	18	143
35	China Gas Holdings Ltd	17.9	203
36	Empresa de Energia de Bogotá SA ESP	17.5	233
37	Cheung Kong Infrastructure Holdings Ltd	16.1	109
38	Woodside Petroleum Ltd	15.7	50
39	Noble Energy, Inc	15.4	78
40	PT Perusahaan Gas Negara (Persero) TBK	15.2	151
41	Beijing Jingneng Power Co, Ltd	14.9	208
42	Tesoro Corp	14.3	47
43	Polskie Gornictwo Naftowe I Gazownictwo SA	14.2	95
44	Fortis Inc	13.1	198
45	Exelon Corp	12.9	39
46	Emera Incorporated	12.9	213
47	EP Energy Corp	12.6	145
48	Sasol Ltd	12.5	30
49	Essar Oil Ltd	12.5	146
50	The Hong Kong & China Gas Co Ltd	12.1	107

Fastest Growing is based on a 3 year compound growth rate (CGR) for revenues. All rankings are computed from data collected and translated into USD 6/1/2015.

Source: S&P Capital IQ/Platts

growth by operating at lower costs than the shale industry average.

Leading the pack this year is Colorado-based shale gas player Antero Resources which makes the Top 250 for the first time with a stellar 110% 3-year CGR.

Antero holds around 400,000 acres in the Marcellus Shale and 150,000 acres in the Attica Shale, two of the lowest-cost shale plays in the US. Its robust hedging and low costs have helped the producers stave off the impact of low gas prices.

Another fast-growing shale player, Texas-based Oasis Petroleum, at second place, is also new to the list at #211.

Tourmaline, the third-largest Canadian natural gas producer, also makes their debut this year, rocketing to fourth place on the fastest growing list from their 2013 ranking of 235.

Growth rates at refining and mid-stream companies have ebbed and the world's fastest growing energy companies are now populated by more electric and gas utilities. Combined with exploration and production, the top three growth sectors made up almost two thirds of the top 50 fastest growing companies.

Asia's leaders' average growth slowed to 21% in 2014, down from 27.3% in 2013. Europe slumped to 14.8% from 22.4%.

With global coal consumption slowing, it's not surprising that China's three coal producers on the fastest growing list last year have now dropped out of contention (China Shenhua Energy, Shanxi Xishan Coal & Electricity Power, and Yanzhou Coal Mining).

SECTORS: Oil producers, refiners, storage

This year's rankings reflect a radical change of fortunes in the mix of companies enjoying growth rates above their energy sector peers.

Although E&P sector growth rates averaged 15.8% in 2014, on par with the previous year, the sector's dominant US oil players saw their numbers jump on the list of top growers relative to the rest of the energy sectors. Eight more E&P companies sit in the Top 250 this year and the sector now makes up 40% of the top 50 fastest growing list, up from 24% the year before.

Standout US E&P stories this year include Devon, Chesapeake, Concho Resources, EOG Resources, and Pioneer Natural Resources, all tight oil players marching through the ranks despite the oil price rout in the latter half of the year. Encana Corp, Canada's biggest natural gas producer which had seen its ranking hit by dire US gas prices, has now surged back up the list placing 34th after a corporate overhaul which included cutting upstream exposure to cheap regional gas prices.

Some US players fared less well. Anadarko dropped 118 places to 209th after its earnings were hit by its $5.15 billion settlement over its ill-fated acquisition of Tronox. Apache fell the furthest in rankings, from 45 in 2014 to 226th following a major downsizing to focus on US oil.

If the US E&P sector put in the strongest growth showing, the sector to suffer most last year was refining and marketing. In 2014, global refining margins remained under pressure due mainly to industry overcapacity amid sluggish demand, particular in developing nations such as China. Global average refinery utilization remained at below 80%, the lowest since 1987.

The number of refiners in the rankings this year fell by 7 from 30 to 23 and the sectors' average ROIC dipped to 4.2% from 5.3% the year before. In terms of growth, refiners filled just 3 slots on the fastest growing list this year, down from 10 the year before.

For a second year, however, it was North American refiners that retained their advantage over competitors elsewhere with access to cheaper crude and natural gas prices. US refiners with export-potential, based on the Gulf Coast, benefited the most.

Phillips 66 not only retained its top spot as the world's biggest refiner but moved up into 6th place overall, a significant climb from 13th place ranking previously. Valero followed Phillips 66 into the Top 10 list, rising 11 places to 8th overall. The US' Western Refining and Tesoro both stood out with 3-year CGRs of 18.7% and 14.3% respectively, pushing them into the top quintile for growth.

Bucking the trend, however, was US refiner HollyFrontier which slide 65 places in to 151st overall as it's mostly mid-continent refineries were unable to capture the price advantages of US oil supply growth last year.

The US dominated storage and transport space experienced a marked slowdown in growth relative to other sectors. Average 3-year CGR for the sector was 14.2% in 2014, down from 21% the year before ▶

Top 250 Methodology

This annual survey of global energy companies by 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 billion. The fundamental and market data comes from a database compiled and maintained by S&P Capital IQ, a business unit of McGraw Hill Financial.

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.

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 U.S. companies came from Securities and Exchange Commission (SEC) Form 10K.

The company rankings are derived using a special 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.

when margins from transporting booming tight oil and oil sands volumes were higher.

Integrated oil majors continued to see their profits squeezed by rising costs and project delays, while the price slump hit those most exposed through an oil production mix and fewer projects under production sharing contracts.

Last year, a 10% increase in revenues in 2014 was outweighed by increases in costs and the recording of significant impairments, resulting in a 13% decline in after-tax profits, according to Ernst & Young.

Utilities, gas utilities, coal

Utilities continue to play second fiddle to global oil and gas companies in Platts' Top 250, but weak fossil fuel prices have seen a relatively stronger showing from power generators, energy suppliers and network operators this year.

The proviso is that a high placing in the Top 250 does not necessarily denote good health or rosy prospects. Impairment charges, asset write-offs and plant closures are still a regular occurrence in European electricity markets. Owners of conventional power stations are facing falling wholesale prices, falling or stagnant demand and the disruptive influence of renewables. The emergence of the 'prosumer' household with solar panels and a battery may have been over-egged by commentators, but the direction of travel is away from centralized fossil-fired generation and utilities are scrambling to re-invent themselves.

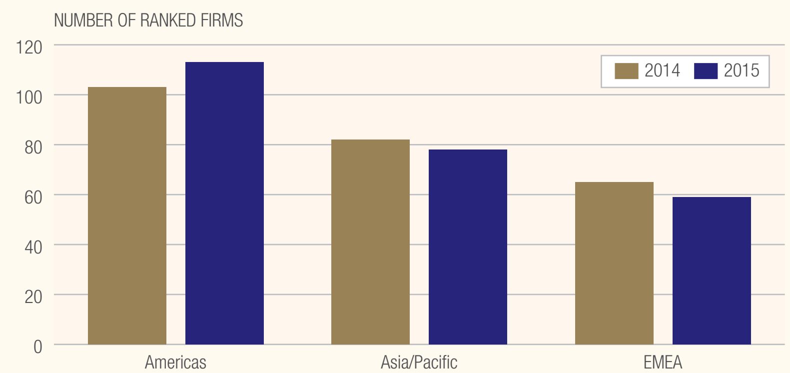
North American utilities are making a much better fist of adapting to these structural shifts than their European counterparts, not least because of the financial breather offered by the shale gas revolution. The alacrity of US management to respond to 21st century generation and network challenges, however, also has to be acknowledged.

All 10 of the highest-placed utilities have climbed the Top 250 rankings this year versus last year, indicating the reduced exposure to pure commodity price risk that these diversified (often partly regulated) companies face compared to mid-cap oil and gas concerns. When your wholesale price is going through the floor, it's nice to have a regulated network or two to fall back on.

In detail for the utilities bracket, Tokyo Electric Power Corporation has risen to 16th from 26th in 2014 , National Grid from 30th to 21st, RWE from 169th to 24th, EDF at 25th from 32nd and NextEra from 58th to 28th. Engie has risen from 164th to 33rd, Southern Company from 56th to 35th, Tenaga from 60th to 36th and Edison International from 77th to 37th.

The trend continues down to Fortum in 49th place, up from 71st. The Finnish

REGIONAL SHIFTS



Source: Platts Top 250

utility has been suffering as much as any company from plummeting wholesale power prices, and in 2014 saw sales decline by 11%, but was able to post improved financials for the most recent year because of significant cost cutting and asset divestments.

The main conclusion must be that the relative improvement in utility rankings is more a reflection of harsher conditions facing integrated oil and gas concerns, rather than any fundamental upturn in power player fortunes. In addition, utility restructuring is a few years ahead of oil and gas restructuring, and in some cases that has had a radical influence on Platts' 250 rankings.

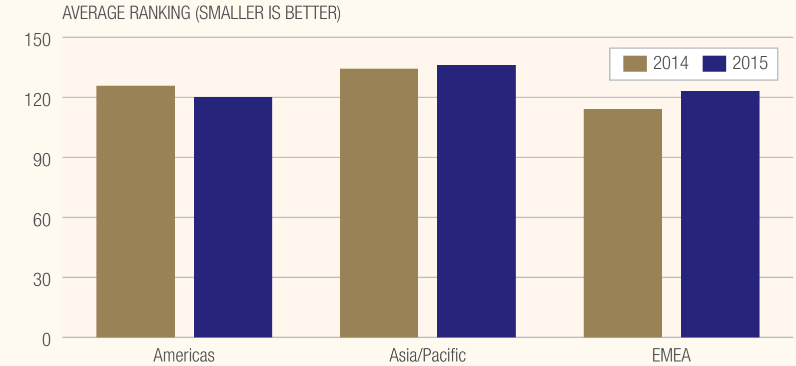
RWE – up 145 places . . .

The most startling example of a misleading bounce is that of German utility RWE, the Top 250's highest climber but facing a meltdown in its share price in 2015, down from around €30/share October 1, 2014 to €10/share October 1, 2015.

In 2013 RWE booked a €4.8 billion impairment and posted a net loss for the first time in decades. The crisis in German conventional electricity generation had seen prices drop from €42 per megawatt hour in February, 2013 to €37/MWh by the end of that year, prompting RWE to mothball 3,800 MW of gas-fired power station capacity and press on with a huge cost cutting program.

By the end of 2014 RWE was back in profit and storming up the Top 250 – even though prices had dropped to €32/MWh and the renewables boom had reached new heights, accounting for 26% of total German supply for the year.

REGIONAL STRENGTHS



Source: Platts Top 250

The roller-coaster ride has continued into 2015, with nuclear provisioning fears further undermining confidence in the utility's value.

If German electricity forward prices remain in the low €30s, "sooner or later RWE Generation will end up with an operating loss, despite the great number of efficiency improvements," company chief executive Peter Terium said in RWE's 2014 annual report.

"I am of the opinion that, as in the UK, the introduction of a technology-neutral capacity market is a good solution," he said. "However, we will not wait for politicians to make decisions. We will take matters into our own hands."

RWE will need to. There is little or no prospect of a significant capacity market in Germany's new market model. The concept is for an energy-only market backed by a small capacity reserve focused on lignite-fired plant. As lignite plant owners this is going to offer some relief to RWE and Vattenfall, but gas and hard coal plants remain at the mercy of the wholesale price. ▶

Engie's early move

French utility Engie (formerly GDF Suez)'s early cost cutting has seen a similar unlikely bounce in the rankings. In 2013 the then GDF Suez was among the sector's front runners in recognizing massive impairment losses (nearly €15 billion) relating to goodwill, property, plant and equipment. At the time it acknowledged a "major shift in Europe's energy sector, in which entire asset categories are moving towards new uses aimed at guaranteeing the electricity and gas supply" – one way of saying 'our assets are often surplus to requirements'.

Having made a net loss of over €9 billion in 2013, the company bounced back in 2014 with net income of €2.44 billion - but revenue was down 6.6% to €74.7 billion. At 2%, it also chalked up the lowest Return on Invested Capital of any company in the top 50 of the 2014 Platts listing bar Gazprom (1%). Rightly recognizing the threat from declining gas and oil prices at the end of last year, GDF Suez launched a snap 'operational reaction plan' in addition to its Perform 2015 cost cutting program, reducing opex and delaying capex.

Nuclear boost for KEPCO

The third big utility bounce to report is that of state-owned integrated utility Korea Electric Power Corporation, up from 127th in 2014 to 41st this year, reflecting operating income up 281% between 2013 and 2014 to KRW5.8 trillion ($4.9 billion) on revenue up 6.4% to KRW57.5 trillion.

The impressive results flowed from greater output from three nuclear power stations that returned to service in early 2014, lower fossil fuel generation input costs and a 5.4% tariff hike in November 2013. KEPCO generated around 84% of the country's power in 2014. With oil prices falling further since the beginning of this year, the company is set to improve on these results in 2015 as it commissions further new generating capacity.

Tepco looks ahead

With 29 million customers, Tokyo Electric Power Co continues to top the utility segment, rising to 16th place overall in the Top 250 this year. Tepco's high rank is something of an anomaly, however, given that the government bailed it out following the Fukushima disaster of March, 2011, when three reactors at the Fukushima Daiichi site suffered a meltdown following a 9.0 magnitude earthquake and tsunami. The disaster led to closure of Tepco's entire nuclear fleet and an overnight switch of generation to conventional thermal sources, more than doubling Tepco's annual fuel bill.

On the face of it, Tepco's march up the rankings mirrors a net income swing from a $6.8 billion loss in 2012 to a $3.2 billion gain in 2013 and a $3.64 billion gain in 2014, helped by a steep decline in LNG prices. A net income gain of 2.9% in 2014 annual accounts, however, includes over $7 billion in grants-in-aid from the Nuclear Damage Compensation and Decommissioning Facilitation Corporation as extraordinary income, and $4.97 billion in Nuclear Damage Compensation costs as extraordinary losses.

Looking ahead, the Japanese government wants to reduce its involvement in Tepco and ultimately sell its 51% stake in the company. With this in mind, Tepco plans to restructure in April 2016, placing its nuclear and decommissioning operations in a new holding company while its non-nuclear businesses are spun off into three subsidiaries. "Based on this business management system, Tepco Group will establish a sustainable revenue base for corporate revival and fulfil its responsibilities for the Fukushima nuclear accident as it generates resources for Fukushima's revitalization," it said in August.

'Clean power' US utilities thrive

The highest-placed US utility in the ranking is NextEra Energy of Florida, up a full 30 places year-on-year to 38th this year.

This is a 'clean energy' success story, NextEra is benefiting from the US' shale gas revolution via its large fleet of gas-fired power stations, and installing an impressive 1,600 MW of wind and solar in 2014.

The company owns and operates 17% of US wind and 11% of US solar capacity, claiming to produce more clean power from these sources than any other utility in the world. Together with wholly-owned subsidiary Florida Power and Light Company (FPL), NextEra's 45-GW of total generating capacity makes it second-largest in the US and its nuclear fleet remains one of the nation's largest, comprising eight reactors at five sites in four states.

FPL's early-mover decision to phase out older power plants and replace them with combined cycle units has had a beneficial impact on end user bills. The company's investments since 2001 in gas-fired power alone have produced $7.5 billion in fuel savings, it says. These efficiency savings are in addition to savings from low market prices for gas in recent years. The utility's typical bill in 2016 will be more than 10% lower than it was 10 years ago, FPL said September 2, 2015. A typical FPL residential customer pays about 30% less for electricity than the US national average.

Two other North American utility climbers are Southern Company, up to 35th place this year from 56th last year, and Edison International in 37th this year, up from 77th in 2014.

Southern Co is another utility riding the US gas wave, pumping some of the proceeds into new combined cycle gas and nuclear capacity at Kemper and Vogtle respectively. With 45% of its 50-GW portfolio gas-fired, the utility is now on the verge of boosting its exposure to the fast-growing natural gas market from New Jersey to Florida with agreement to buy gas utility AGL Resources for $12 billion.

Meanwhile, its renewables portfolio of 1,450 MW either in operation or under development has just received a boost from acquisition of a controlling interest in the 300-MW Desert Stateline Facility in California from First Solar Inc. The solar farm, now in construction and heading for full operation in the third quarter of 2016, will cover 1,685 acres in San Bernardino County and consist of 3.2 million thin-film photovoltaic modules.

Edison International's improved position, meanwhile, follows a successful year of housekeeping and the start of several major grid enhancement projects.

The housekeeping involved resolution of settlement issues surrounding the decommissioning of the San Onofre nuclear plant, and reorganization of ▶

bankrupt subsidiary Edison Mission Energy, with the sale of assets to NRG Energy.

Now the company can focus its attention on its core goal to modernize the distribution system into a flexible smart grid capable of two-way electrical flows "to better integrate distributed energy sources". Investments of over $4 billion per year are aimed at growing subsidiary Southern California Edison's rate base by up to 9%/year through 2017.

> "China's currency devaluation, weak buying interest and lower domestic prices due to discounting by Chinese producers has drastically weakened the market for imported thermal coal."

Gas utilities – mixed bag

Companies in the 'gas utility' bracket had a patchy 2014, reflected in Top 250 declines for Spain's Gas Natural (to 46th from 40th last year), Tokyo Gas Co Ltd (to 74th from 64th) and Gail (India) Ltd (to 120th from 97th).

Gas Natural saw its European gas sales down 10% to 175 TWh due to an unusually warm year. Sales in Latin America, however, were up 9.5% to 249 TWh, with demand growth coming from industrials in Colombia and power generators in Brazil. Looking ahead, Gas Natural is banking on emerging markets to drive demand for liquefied natural gas, and has signed a 2 billion cu m LNG supply contract with Cheniere for deliveries starting in 2019.

Meanwhile Tokyo Gas Co saw sales in the 12 months to end-March 2015 climb 8.5%, while operating income rose 3.4%. A 9% hike in operating expenses to Yen 2,120.7 billion, however, contributed to a net income decline of 11.6%, to Yen 95.8 billion.

In comparison, Osaka Gas Co fared better, rising in the Top 250 from 133rd last year to 103rd, on net income up 35% to Yen 77 billion. It warned, however, that it expected net revenue for the year to end-March 2016 to fall over 10% on the assumption that the unit selling price of city gas would decline on the back of falling LNG prices. First quarter results to end-June 2015 confirmed the expectation, with net sales down nearly 6% – but income up due to a fall in raw material (LNG) costs.

Coal glut

Coal mining represents a segment in the Top 250 where high flyers are confronting headwinds. Notable among these is Chinese coal miner-to-power generator China Shenhua Energy Co Ltd, rising to 9th this year from 15th last year and 58th back in 2008.

China Shenhua is facing an oversupplied market with falling prices. The trend has accelerated into 2015, with China Shenhua reporting Q1 coal sales down 33.5%. As of August 19, Platts reported seaborne cargoes of thermal coal for delivery to South China tumbling below $50 per metric tonne, a new low for the grade. China's currency devaluation, weak buying interest and lower domestic prices due to discounting by Chinese producers has drastically weakened the market for imported thermal coal.

In response China Shenhua has been targeting efficiencies in its power generation business. While total output was down 5% at 214 TWh in 2014, that power was generated at improved load factors. Average utilization hours of Shenhua's coal-fired power stations rose to 5,174 hours for the year, exceeding the national average by 468 hours. Unit production costs were also improved, down 3.3% year-on-year to RMB 132/tonne ($20.75/tonne) of self-produced coal, while unit cost of power output dispatch fell by 6.7%.

Meanwhile, the largest pure coal mining company in the world, Coal India, has climbed to 38th place in the rankings this year from 47th place last year. The state miner's challenge is keeping up with strong internal demand and hitting the coal ministry's ambitious extraction targets.

It fared rather well in 2014, with the ministry acknowledging that a 7.3% year-on-year increase in production to 342.4 million metric tonnes was "a remarkable feature of the year", even if the company still undershot the ministry's goal by 164 million mt. Deliveries to utility power producers were up 9.5% at 256 million mt.

A shortfall in new production drilling last year was due to several reasons, the ministry said, including "serious law and order problems in many coal blocks", slow forest clearance and a lack of skilled manpower. Again, however, Coal India posted impressive growth year-on-year, with a 14% improvement in drilling in 2014 on 2013 levels. ■