Challenges loom for China’s teapots

Shandong refiners confident of survival despite major headwinds

Shandong—China’s teapot refineries are facing some major challenges these days, with a confluence of slumping domestic demand, tightening credit and government mandates for consolidation threatening survival.

But refiners in the eastern coastal province of Shandong—the location of 80% of the country’s small refineries—remain confident that their contribution to the province’s economy will hold them in good stead.

To the western world, they are known as “teapot” or “tea kettle” refineries, because of their relatively small size, from 20,000 b/d to 100,000 b/d, as well as the perception that they are inefficient and unsophisticated. They have accounted for roughly a fifth of the country’s overall refining capacity, although expansions in recent years has pushed this proportion closer to 30%.

The landscape for these refiners has been changing, as they now have to grapple with shrinking credit, slowing growth in oil products demand, and weak margins. But like the tireless Mao era oil worker ‘Iron Man’ Wang Jinxi, long held up as a model worker-hero by the Communist Party, teapot refiners have arguably beaten huge odds to exist today.

They are on the cusp of revolutionary change in China, as the government involves more private sector participation in the economy. A widening in crude oil import rights seems likely to be the first visible concession to independent refiners. At the same time, those refiners are facing threat of further consolidation by a central government that has placed considerable emphasis on cleaning up pollution and getting rid of excess capacity in various energy-intensive sectors.

In the 1980s a wave of consolidation occurred in the refining sector when PetroChina and Sinopec were established as state (continued on page 2)
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oil companies and the government rolled out an intensive refinery upgrading program to enable the production of high-value products such as gasoil, jet fuel/kerosene and gasoline. By 2000, the government had ordered 60% of China’s 200 odd independent refineries to be culled, allowing only 82 to remain.

Oil is one of the most important industries in Shandong. Through the decades, teapot refineries in Shandong received strong local government support, both in terms of financial incentives such as tax breaks as well as favorable operating conditions like cheap access to land, which is why the province currently has the largest concentration of these refineries.

Small capacity, huge role

Unlike the state-owned companies, teapot refineries have no rights to export their oil products, so their fortunes are tied to domestic conditions. In the last decade the teapot refineries acted as swing suppliers and were able to ease some regional supply deficits in eastern and central China when fuel shortages emerged.

Teapot refineries are not saddled with the responsibilities of wholly state-owned enterprises and are the only purely profit-oriented refineries in China so their performance is often a barometer of how well the country’s overall refining sector is faring.

Like their state-owned peers, teapot refineries’ production today is dominated by gasoil and gasoline, which account for the majority of China’s total consumption. They have no jet/kerosene output, but do churn out some fuel oil, petrol coke, LPG and a small amount of off-specification naphtha.

There are roughly 10,000 retail fuel stations in Shandong, yet only 300 belong to the teapot refineries, while over a third are owned by Sinopec and PetroChina. This explains why teapot refineries have little bargaining power when selling their refined products to retailers.

Teapot refineries in Shandong fall into two categories—privately-owned companies and those in which state-owned enterprises have a stake.

Private refineries account for 60% of Shandong’s total refining capacity of 189 million mt/year (3.8 million b/d). Last year they generated Yuan 336 billion ($54.9 billion) in revenue, Yuan 5 billion in profit and paid Yuan 37 billion to the state and central governments in taxes.

Teapot refineries that are partly owned by state-owned companies have a combined capacity of 39.5 million mt/year, bringing overall teapot refining capacity in Shandong to 152.15 million mt/year.

Pressure to modernize

Late last month, the Shandong government issued a policy paper outlining an ambitious vision for the sector, but offered little in terms of how it expects to achieve those targets. The basic thrust of the policy is for teapot refiners to modernize, increase scale, and upgrade in order to stay relevant and efficient, and be able to compete with the large state-owned behemoths.

Shandong government’s targets for its private teapot refineries include:

- Capacity to be cut and capped at 100 million mt/year by the end of 2017 from 112.65 million mt/year currently.
- Average capacity of each refiner to be raised from the current 2.3 million mt/year to 4.5 million mt/year by 2017, and 5 million mt/year by 2020.
- Utilization rate to be raised to 60% by 2017 and 75% by 2020, from under 40% today. The teapot refineries have until now been running at between 30% to 40% rates due to poor refining economics and difficulties in securing feedstock.
- Gasoline and gasoil yield to be raised 40% by 2020 from around 30% currently.
- Petrochemicals to contribute over 30% of refiners’ total income by 2020, with ethylene and aromatics production targeted to reach 1 million mt/year.

To achieve this, the government says the ideal tactic would be to get rid of more than 20 refineries—Shandong currently has 49 refineries—translating into 12 million mt/year of capacity. But it has not revealed which companies it is targeting, the criteria it will use to select them or how it intends to implement the closures.

These targets do not apply to teapot refineries affiliated with state-owned companies.

Government mandates not new

In an effort to cool overheated growth and promote efficient use of resources, the central government has long mandated the closure of small plants.

It originally wanted refineries with under 1 million mt/year of topping capacity to shut by the end of 2011, and later raised the limit to 2 million mt/year and delayed the deadline to end 2013. A few years back, the central government also suspended construction of new refineries with crude distillation capacity of under 10 million mt/year, as well as set minimum limits on secondary units.

In response, the teapot refineries did the opposite—expanded their capacities in order to stay operational. Compared with 2000, the scale of Shandong’s independent refineries had risen by more than 25-fold by late last year.

There are conflicting aims between the central and local government officials. The strategies they have adopted to ensure their survival.

Next: A look at three teapot refiners and the strategies they have adopted to ensure their survival.
China’s apparent oil demand rises 3.5%

Growth improves in H2 2014 after sluggish start to the year

Singapore—China’s apparent oil demand in November spiked by a relatively robust 3.5% from the same month last year to 42.18 million mt, or an average 10.31 million b/d, according to Platts estimates Friday based on recently released preliminary government data.

This is the third-highest monthly pace of growth in 2014, behind August and September.

China’s apparent oil demand has improved in the second half of the year after a sluggish start to 2014, with absolute demand since September exceeding 10 million b/d.

Over January-November, apparent oil demand totaled 455.34 million mt, or an average 9.99 million b/d, rising by 2.3% year on year. This was an acceleration from the 2% growth seen over January-October.

Despite the improvement, apparent oil demand growth this year still lags the 2.6% growth seen over January-October 2013 and the high single digits of 2012.

China does not release official data on oil demand, or commercial and strategic oil inventories. Platts calculates apparent oil demand based on data on refiners’ crude throughput and net oil product imports, as reported by the government.

Bearish macroeconomic data

There was some bearishness in the latest macroeconomic data released this week.

The NBS data showed November industrial demand grew 7.2% versus the same month last year, slipping from 7.7% growth in October and below consensus estimates of 7.5%. Fixed asset investment growth for the first 11 months of this year was 15.8%, slipping from 15.9% over January to October. However, retail sales growth, a key indicator of consumer spending, rose 11.7% year over year in November, improving from 11.5% in October.

In a reflection of weaker external demand, China’s total export growth slowed to just 4.7% year on year last month, sliding from 11.6% in October and far below analysts’ estimates of around 8%, according to data from the General Administration of Customs on Monday.

On the other hand, overall imports into the country contracted by 6.7% year on year in November compared with positive growth of 4.6% in October.

Commodity imports in particular, slumped by 21.9% compared with a 6% contraction in October.

Muted growth to remain

The weak trade growth data continues to support the view that China’s growth momentum remained weak in November, Nomura Research noted on Tuesday.

In its latest Oil Market Report released Friday, the International Energy Agency said: “Overall, the Chinese oil demand forecast remains relatively muted, with 2.5% gains foreseen in both 2014 and 2015, as modest Chinese forecast gains in transport fuels and petrochemical feedstocks continue to offset declines/weakness in gasoil/diesel and residual fuel oil.”

While China’s crude oil imports rose 8% year on year last month to 6.21 million b/d, oil product inflows plunged 16% over the same period to 2.37 million mt.

Oil product exports jumped 15.6% year on year in November to 2.44 million mt.

So far this year, China has turned an overall marginal net exporter of oil products, with imports falling 26.1% year on year to 26.78 million mt and exports rising 3.8% to 26.85 million mt over the January-November period.

Detailed November production and trade data for individual oil products is scheduled to be released later this month.

Domestic refinery throughput recorded a robust 5.5% expansion to 42.25 million mt, or an average 10.32 million b/d in November, the second-highest on record.

The country’s refineries processed 9.99 million b/d of crude over January-November, rising 4.7%, or 448,000 b/d, year on year, although the net oil product exports suggests refinery output likely exceeded demand. — Song Yen Ling

Thai refiner Bangchak consolidates upstream move

Sydney—Thai refiner Bangchak Petroleum has moved to shore up its presence in the upstream oil and gas sector by topping an earlier offer from Risco Energy Investments for Australian Otto Energy’s 33% stake in the Philippines’ Galoc oil field.

Bangchak’s 81.41%-held Australian subsidiary Nido Petroleum has offered $108 million for the stake, which Otto agreed to sell to Singapore-based Risco in September for $104 million. Risco has waived its right to match Nido’s offer for the asset, held by Galoc Production Company.

Nido will pay a $10.8 million deposit and assume all production rights and liabilities associated with the Galoc stake with effect from July 1, 2014. Nido already owns 22.9% of the Galoc field.

Nido said it planned to fund the acquisition through a combination of cash reserves and debt, to be provided by Bangchak. The acquisition is set to boost Nido’s production base to more than 4,000 b/d.

“Nido has provided Bangchak with a platform to grow our upstream capability,” Bangchak President Vichien Usanachote said. “This is therefore the initial step in using Nido as a vehicle to aggregate production and exploration opportunities in the region. I expect that this will be the first of many opportunities that we will capture going forward.”

Nido Managing Director Philip Byrne said the acquisition fitted with the strategy Bangchak outlined when it took its majority stake in the company earlier this year and put Nido in a controlling position for a potential expansion of the Galoc field.

The Galoc field, which lies off Palawan, has produced more than 2 million barrels since the start-up of a phase-two development in December 2013. The project cost about $204 million and began producing at around 10,000-12,000 b/d. — Christine Forster
Draft commodity law drops code of conduct requirement

Brussels—The European Commission’s plan to require contributors to commodity price benchmarks to sign binding codes of conduct is facing opposition in both the European Parliament and the EU Council, it emerged Friday.

“Imposing extensive binding requirements on non-critical indices would risk creating unnecessary, substantial costs,” the parliament’s lead negotiator on the EC’s proposals, Cora van Nieuwenhuizen, said in her draft report available on the parliament’s website Friday.

Such costs could “significantly reduce the supply of benchmarks,” she said.

The EC included the plan in its September 2013 proposals for a detailed EU regulation to govern all benchmarks used to price financial instruments, including commodity price benchmarks, in the wake of the Libor and Euribor interest rate scandals.

The rules as proposed by the EC would affect commodity price reporting agencies, such as Platts.

Van Nieuwenhuizen said commodity benchmarks needed “tailored arrangements” in line with “relevant international standards.”

The International Organization of Securities Commissions published principles for oil price reporting agencies in October 2012 and for financial benchmarks in July 2013.

The IOSCO price reporting principles do not include a submitter code of conduct.

Code of conduct

Meanwhile, the EU’s Italian presidency’s latest compromise text, drops the code of conduct requirement entirely for all commodity benchmarks except those based on regulated data or on contributions mainly from financial institutions.

The presidency coordinates the views of the EU’s 28 national governments, acting in the EU Council.

The presidency text includes a specific annex for commodity benchmarks setting out rules to govern the benchmark methodologies and the quality and integrity of calculations, the reporting process and assessors.

These rules require benchmark administrators to “employ a system of appropriate measures so as to ensure that contributors comply with the administrator’s applicable quality and integrity standards for market data.”

The rules also govern audit trails, conflicts of interest and complaints.

The latest presidency text includes a requirement for commodity benchmark administrators to organize an external independent audit every year on their compliance with their stated methodologies and with the proposed EU rules.

The parliament, council and the EC have to agree a common text before the benchmark proposals can become binding.

The parliament’s economic affairs committee is scheduled to debate van Nieuwenhuizen’s draft report on January 8, with a final committee vote scheduled for March 5.

EU diplomats were scheduled to meet Friday in Brussels to discuss the latest presidency text. — Siobhan Hall

Turkey begins talks with Russia on pipeline proposal

Istanbul —Turkey and Russia have begun talks on the possibility of building an offshore gas pipeline from Russia to Turkey through the Black Sea, Turkish energy minister Taner Yildiz said Thursday.

Speaking during a press conference broadcast live on Turkish TV, Yildiz confirmed that Russian officials had already visited Ankara for discussions on the proposed 63 Bcm/year project.

On December 1, Russia’s president Vladimir Putin said Gazprom was abandoning the idea of routing the long planned South Stream pipeline through the Black Sea and across Bulgaria due to continuing opposition from the EU.

Putin proposed that by re-routing the line, it could supply Turkey with the 14 Bcm/year of Russian gas it currently receives via its western Trans Balkan import line, which carries gas arriving via Ukraine. The bulk of the gas would be supplied to a proposed new gas hub on the Turkish-Greek border, according to Putin.

Commenting on the proposed pipeline, Yildiz referred to it as “Turkish Stream” and suggested construction could be completed in 2019-2020.

“All these proposals have to be evaluated—at the moment we are still at the evaluation stage,” he said.

However, he also warned that Turkey had to be careful not to “put all its eggs in one basket,” adding that Turkey does not regard it as “purely a transit project” and has suggested the project could also involve the development of an LNG export terminal on the coast of Turkey’s European province of Thrace.

Yildiz also confirmed that Turkey remains committed to realizing the planned 31 Bcm/year TANAP pipeline project it is developing in partnership with Azerbaijan.

“We would not be involved in a project that would affect TANAP—we are a partner in that project,” he said.

Separately, an official at formal EU gas transmission system operator body Entsog said draft EU rules to harmonize natural gas transmission tariffs look set to apply from mid-2018.

“The earliest we think these rules will be implemented is June 2018,” Entsog’s tariff subject manager Malcolm Arthur told an Entsog workshop in Brussels.

The new rules are intended to increase transparency in how EU gas TSOs determine their transmission tariffs.

The draft code includes requirements that all EU gas TSOs not only publish the same information about their tariffs in an agreed format, but also publish expected tariff trends for the next four to five years, Arthur said.

The current draft also includes a requirement for TSOs to hold public consultations at least every four years on the tariff setting methodology chosen and the dedicated service costs, for example, he said. — David O’Byrne with Siobhan Hall in Brussels

UK urges ban on jet fuel exports to Syria after EU move

London—The United Kingdom has called on “all nations” to ban the export of jet fuel to Syria after the EU Council on Friday signed off on Brussels’ ban on supplying jet fuel to the regime of President Bashar al-Assad.

EU foreign ministers agreed in late October to impose the export ban on jet fuel and relevant additives to Syria as part of a wider package of new sanctions against Damascus, and the legal acts were agreed Friday.

“This measure will ensure that no EU people or companies will be involved in jet fuel going to Syria,” the UK minister for the Middle East, Tobias Ellwood, said in a statement. “I urge all nations to ban jet fuel going to the Assad regime.”

The UK had led the EU move to impose the ban “as jet fuel enables the Syrian regime’s air force to kill its own people, including with barrel bombs.”

Traders have said the ban is likely a token gesture, as Syrian imports of EU jet fuel are negligible.

The EU’s own statistics service Eurostat shows negligible exports of jet fuel from Europe to the Middle Eastern country in 2013.

The EU is a net importer of jet fuel to the tune of around 12 million mt/year, so the ban will also likely have very little impact on flows.

Typically, Turkey and North African countries such as Egypt and Libya supply jet fuel to the eastern Mediterranean region, including to Syria.

Traders said product can also make its way into Syria via truck or train.

The US had led the way on oil sanctions against Syria in August 2011, with President Barack Obama signing an executive order banning all dealings, including investment, by US citizens with the country’s oil sector.

Syrian oil exports to the EU had been running at around 150,000 b/d, with overall production seen at around 350,000 b/d before 2011. — Stuart Elliott
E&P operators ready to face low oil prices

Hedges, cost cuts, disciplined capex to help brave turbulence

Houston—Amid the turbulent waters of sinking oil prices, US upstream operators are finding that years of financial and operational discipline has paid off for them with the ability to weather the cyclone of even $60/b oil.

- Newfield nets over $80/b in $65/b world
- Sanchez focuses on higher margin
- Pioneer says 85% of oil hedged in 2014-2015

Managers of large independent oil companies Newfield Exploration, Concho Resources, Pioneer Natural Resources, and small-cap Sanchez Energy all insist their hedging programs, capital discipline and cost-shaving efforts have put them in good fiscal shape even as oil prices droop to levels not seen in years. NYMEX front-month crude oil closed at $57.10/b on Friday.

Executives claim many of their unconventional oil plays can earn decent even if not spectacular returns at current prices.

With what he characterized as a “very strong” hedge book, Newfield Exploration’s Chief Operating Officer Gary Packer said his company knows “how to behave in the environment we’re currently in.”

“We’ll only drill wells that make sense with the current prevailing commodity price, whatever that may be.”

This year, Newfield will spend just shy of $1.8 billion on its capital program. At $75/b oil, it would probably map out a $1.6 billion plan for 2015 and at current prices, possibly $1.4 billion, he said, although the company will not release its budget until February.

“We’re particularly well positioned because in every one of the four areas we’re in, we operate [and] we have good core positions we can retreat to,” Packer said.

Newfield operates in the Eagle Ford, the Bakken Shale in North Dakota and Uinta Basin in Utah. But its prize asset is in Oklahoma where it pioneered the STACK play and the underlying Meramec formation, and also was an early mover in the both the South Central Oklahoma Oil Province (SCOOP) and Springer Shale plays there.

Sanchez flexible on capex

The company—which operates in the Eagle Ford Shale play in south Texas and the emerging Tuscaloosa Marine Shale in Louisiana—was one of the first to release a lower 2015 capital spending plan of around $875 million, down from $1.1 billion it had earlier guided.

And that capex level could be taken down another 25-30% to $650 million, and still have flat to 10% year-over-year production growth, CEO Tony Sanchez said at the Capital One gathering on last week.

As a result, Sanchez is “where we need... to be in a $60/b world,” Sanchez said, adding he believes that price level “might [stay around] for awhile.”

Although most of its operations can at least break even around that price, if oil does indeed remain at current levels the company will likely focus on higher-margin Eagle Ford fields such as Marquis which can generate mid-teens return rates at $60/b, the CEO said.

Some areas of the Eagle Ford’s Catarina field, which Sanchez acquired earlier this year from Shell, can generate return rates in the 20%-30% as rig dayrates and service costs come down, he said.

Knocking down costs and drilling days per well has been a big focus of unconventional oil players even during the boom times of recent years. That has led to a paradox which now characterizes the modern oil industry: it can eke out more wells with fewer rigs.

Sanchez, for example, has driven its total operating cost down to $24.05/barrel of oil equivalent in the third quarter, from $45.06/barrel in 2011.

Concho poised for growth

Concho’s Matt Hyde, senior vice president of exploration, is also big on increasing efficiencies. Well completion optimization is “one of the huge levers we have to grow our resource,” said Hyde at the Capital One conference.

Concho was one of the first upstream companies to announce its 2015 capital spending program of $3 billion last month, up from $2.6 billion this year, at a time when oil was in the high $70s/b.

Hyde hinted that could change, saying the company will make “appropriate adjustments” according to oil price behavior in the weeks and months ahead. For example, the rig count might go down from the 39 rigs earlier envisioned for 2015, and higher-risk projects might be placed on hold.

“At $75/b oil we could continue to grow, and potentially grow down into the $60/b price frame,” Hyde said.

The company has 45% of its projected 2015 oil production hedged at $87.73/b.

Pioneer in the Permian

Pioneer is one of the most-hedged companies in the industry, its chief operating officer said at the Capital One conference. Pioneer’s oil production is hedged at 85% for both this year and next year and 45% for 2016, Tim Dove said.

The company was a first-mover in unconventional oil in the West Texas Permian Basin, and is exploring several geologic horizons of the Permian’s Midland sub-basin where it is one of the biggest producers at 186,000 boe/d in Q3.

“We still have a large number of economic wells” in the play,” Dove said. “Returns are still good in the $62/b range.”

Pioneer also was the first producer in the US to export its Eagle Ford Shale condensate along with Enterprise Products Partners after reclassifying approval from the US Commerce Department earlier this year.

And in a low oil-price environment, exports of both condensate and also crude oil—exports of which are still legally banned—are even “more important” than at higher oil prices, Dove said, because the value of those commodities in world markets are greater than the price they now fetch in the US. —Starr Spencer

US rig count falls by 27

Houston—The US rig count was 1,893 for the week ended December 12, down by 27 from the prior week, according to Baker Hughes.

The latest count includes 1,833 land and 60 offshore, with 346 assigned to gas, 1,546 to oil and 1 to miscellaneous drilling. The rigs were drilling 330 vertical, 196 directional and 1,367 horizontal wells.

Here are Baker Hughes’ latest figures for the total number of active rigs in the US (with selected states) and Canada. Plus comparable figures for a week ago and a year ago:

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Ecopetrol to export diesel from Reficar

Revamped Cartagena refinery to start up in June

Bogota—Colombia’s state-owned Ecopetrol next year will enter the regional products market, changing from an importer to exporter of diesel fuels, with the June inauguration of its $6.5 billion ultramodern refinery near Cartagena.

The capacity to sell up to 50,000 b/d of clean burning diesel in hemispheric markets once the refinery, known as Reficar, begins ramping up production in June represents the biggest external impact of the facility’s completion, said Federico Maya Molina, refining and petrochemicals vice president at Bogota-based Ecopetrol, in an interview.

“We will be entering this diesel products market with strong competitors including refiners on the US Gulf Coast, but we are confident our high quality diesel can compete,” Maya said.

The new 165,000 b/d refinery will produce diesel with less than 10 ppm of sulfur, he said.

In comparison, Colombia’s other major refinery, the 230,000 b/d Barrancabermeja facility, produces diesel at less than 50 ppm sulfur, even after undergoing a $1 billion upgrade in 2010. That facility is also owned by Ecopetrol.

The new refinery will have a utilization rate of 97%, up from the 76% rate of the old 80,000 b/d Cartagena refinery, which is being partially mothballed.

Once the new Reficar refinery is commissioned in June, Ecopetrol’s low sulfur diesel will immediately hit the market, as it will be the first product that the complex will produce. Demand for diesel is rising quickly in Colombia as more heavy vehicles and buses are added to the nation’s fleet amid its economy development.

“The new facility will have the possibility of producing gasoline, but its main purpose is to make diesel,” Maya said. He said the Reficar refinery will refine at “triple or quadruple the margins of the old Cartagena refinery.”

Ecopetrol said the most appealing markets for Reficar’s diesel will be Caribbean nations, Brazil, and Colombia’s Andean neighbors Ecuador, Peru and Chile.

Caribbean refining margins strong

The fact remains that Reficar will have to compete with the powerhouse export refining center on the US Gulf Coast. In order to do this, Ecopetrol—also a major exporter of crude oil—will likely have to discount its own crude stream.

This presents a tremendous opportunity for Colombia, as many other regional refiners in the Caribbean lack access to discountable crude.

Reficar is designed specifically to process Colombian heavy crudes which now represent more than half of Colombia’s supply. Those crudes originate mostly in the eastern Llanos region, which has been the main source of Colombia’s near-doubling of crude output since 2005 to 1 million b/d.

But Ecopetrol will also have the option of importing cheap heavy crudes and adding significant value by refining them with Reficar’s modern technology, Maya said.

Of course lower crude prices globally play into Ecopetrol’s refining plans as uneconomic netbacks for its crude could be absorbed, partially, by running more barrels internally at Reficar.

Plummeting crude prices—as well as a burgeoning glut of refining products on the US Gulf Coast, which has pushed down yields—have begun to favor Caribbean refining economics.

For example, over the past 30 days Angolan Cabinda coking/cracking margins on the US Gulf Coast have averaged between $3.50-$5/b, Platts data shows. Caribbean margins over the same period are nearly twice as strong.

Cabinda is useful to illustrate this point as it is a widely traded spot market grade available in both the Gulf Coast and the Caribbean, as well as Europe and Asia.

Platts margin data reflects the difference between a crude’s netback and its spot price. Netbacks are based on crude yields, which are calculated by applying Platts product price assessments to yield formulas designed by Turner, Mason & Co.

Currently Colombia imports 50,000 b/d of diesel that meets the country’s strict pollution control requirements. Once the new refinery is fully operational, it will process 80,000 b/d, with up to 50,000 b/d destined for domestic use and the remainder to be sold on the open market.

Another major impact of the new refinery is that Colombia will no longer import 60,000 mt/year, or half of the 120,000 mt of propane it consumes each year, because the new facility will produce at least enough to meet domestic supply. The refinery will also produce hydrated coking fuel and sulfur for export, Maya Molina said.

Barrancabermeja upgrade

The Ecopetrol board of directors has for the time been rejected the idea of building a $1.5 billion petrochemicals plant on a site adjacent to Reficar’s location about 20 miles southwest of Cartagena, Maya also said.

Rather, the board is considering another multi-million dollar upgrade of the Barrancabermeja refinery, where capacity is slowly being degraded as the profile of the nation’s crude output includes more and more heavy oils and less light to medium grades.

If such an upgrade is carried out, the Barrancabermeja facility’s capacity could rise to 250,000 b/d, whereas if no upgrade is performed, throughput will decline to 200,000 b/d from the current 230,000 b/d level, Maya said. Maya declined to estimate the cost and timing of such an upgrade.

“The plan to renovate Barrancabermeja is going forward but it has not been finally approved,” Maya said. He said the conversion or utilization rate at Barrancabermeja is a low 76%, which would rise to 95% with the planned renovation.

The Barrancabermeja complex currently produces 60,000 b/d of diesel, which would rise to 105,000 b/d with the renovation, “but that would be many years into the future,” he said.

Most of the country’s gasoline will continue to be produced at the Barrancabermeja refinery. Reficar will also produce jet fuel for use at Caribbean airports. — Chris Kraul, with James Bambino in New York

White House vetting US blowout preventer rule

Washington—US offshore safety regulators have sent a long-awaited proposed rule on next-generation blowout preventers to the White House for review.

The US Department of Interior expects to unveil the proposal in February after the White House office of Management and Budget notice issued Friday. Final action on the rule is expected in July.

The long-delayed rule, which is being developed in response to BP’s 2010 Macondo disaster in the Gulf of Mexico, reflects numerous recommendations as well industry best practices, standards and specifications for controlling a well, according to Nicholas Pardi, a BSEE spokesman.

In a statement, Pardi said the rule requires: new, stricter design requirements for well control safety system equipment; traceability standards for blowout prevent systems and other control equipment; new tests for equipment operations; and more monitoring of operations.

Development of the rule was complicated in June when the US Chemical Safety Board released a report which offered an alternative view on the role the blowout preventer played in the disaster.

That report argued that the drill pipe in the blowout preventer aboard the Deepwater Horizon drillship was buckled and moved off center by a phenomenon known as “effective compression.”

This conclusion differed from previous findings which said the disaster was largely caused by the blowout preventer getting jammed. — Brian Scheid
North Dakota output falls for first time in 11 months

Houston—Low oil prices and regulations for flaring and oil conditioning combined to suppress North Dakota’s crude oil production in October, the first time the monthly total has fallen since November 2013, data released Friday by the state’s Department of Mineral Resources showed.

Crude output in October was 1.182 million b/d, a 4,054 b/d decline from September, the agency said.

“We’ve really got three majors forces at play here and all of them are working to restrict production...or hold it flat,” said Lynn Helms, director of North Dakota’s Department of Mineral Resources.

Helms said this marked the first time in eight months the state did not set a production record and said it was “very unusual” to not see an increase in production from September to October.

Helms pointed to flaring reductions, conditioning and falling oil prices as the likely explanation.

On Tuesday, the state’s three-person Industrial Commission approved an order requiring Bakken crude oil to be conditioned before it is shipped by rail. Once the rule takes effect April 1, crude oil cannot have a vapor pressure that exceeds 13.7 psi, 1 psi below the national standard of 14.7.

Helms said that while the order does not go into effect until April 1, producers may have scaled back some production plans in anticipation of the new rules.

Helms said his agency estimates the rule will cost industry a total of $20 million, adding about 10 cents/b for Bakken crude, due largely to vapor recovery systems which could cost operators as much as $100,000 to install. Helms said these costs were “pretty significant” amid current low prices.

Additionally, the commission earlier this year set a series of benchmarks that require operators to limit flaring to 26% by October 1, 23% by January 1, 15% within two years and 10% by 2020.

Statewide flaring rates were 22% in October and 60 of the state’s 68 operators were in compliance with flaring reduction rules, Helms said.

The number of producing wells hit another all-time high in October, climbing 134 to 11,892, the agency said. At the same, about 650 wells remain uncompleted as producers attempt to wait out low prices, Helms said.

Helms said the state’s rig count was at 183 rigs on Friday, down 16% from the high of 218 on May 29, 2012. He said he expected that count to fall by as much as 50 more rigs by mid-2015, due mainly to prices. — Joshua Brown with Brian Scheid in Houston

At the Wellhead

T he statistics are glaring—of the 209 discoveries made since India launched the New Exploration Licensing Policy in 1999, only 30 have been put into production.

India last saw a major hydrocarbon discovery in the early 2000 when Reliance Industries discovered the deepwater KG-D6 gas block and Cairn India discovered the Rajasthan oil block.

Furthermore, India has seen a 25% drop in gas production between fiscal year 2009-10 (April-March) and 2013-14 to 3.42 Bcf/day, though one can say that this drop has been partly offset by a 12% rise in crude oil production over the same period to 37.79 million mt (760,000 b/d).

In light of these facts, one would have expected the action-oriented and pro-investment government led by Prime Minister Narendra Modi to have taken some decisive steps to spur the E&P engine and deliver on its commitment of gradually boosting India’s energy security and make it less import dependent.

India relies on imports to meet 85% of its crude needs and recently had the privilege of overtaking Japan to become Asia’s number two crude oil importer.

It is against this backdrop that the terms and conditions laid out by the government in its model revenue sharing contract come as a surprise. The onerous clauses will drive investors away when the need of the hour is to get the best oil and gas companies to come in and uncover the country’s hydrocarbon potential.

To give the government some benefit of doubt, it has said that the model contract was just that—a model—and officials are working on parts of the contract that have raised the most concern in the industry.

India has for the last several years debated whether it should completely do away with the decades-old production sharing contract, where a contractor is allowed to fully recover costs before sharing revenue with the government, or move to a revenue sharing model, where the government gets a share of revenue from the moment production begins on a block.

It was the controversies surrounding the KG-D6 block and allegations by the federal audit agency that operator Reliance had inflated costs to cut the government’s share of profit petroleum that led to the start of the debate.

A committee set up by the previous government had recommended in 2012 that India move to a revenue sharing model. The recommendation, adopted by the new government, was based on the premise that a focus on costs has been a major bottleneck in exploration with the contractor and the government often disagreeing on the actual cost and delaying progress of a project.

But some of the clauses in the Modi-led government’s model revenue sharing contract have raised serious concerns in the industry, according to K. Ravichandran, senior vice president at ratings agency ICRA.

These include asking the contractor to set up an escrow account where all revenues earned from the asset will be deposited so that the government can protect its share of the revenue and, in certain circumstances, restrict the contractors’ access to the revenue; penalties if the actual volume deviates from the committed volume by more than 25%; and no scope to lower the government’s share of revenue if the actual capital expenditure on a block is higher than initial estimates.

The conditions set in the contract won’t work in India where the risks are high for deep and ultra-deepwater projects, and the probability of time and cost overruns are high, Ravichandran said. Also, in unexplored basins, if actual production is lower than the initial estimates, the industry could end up paying large penalties, he said.

“The government seems very focused on maximizing revenue for itself rather than maximizing production. They are looking at it from an audit point of view and not a business perspective,” Ravichandran said.

A similar view was echoed by P. Elango in an editorial published in local daily The Hindu, where he said that the spirit of partnership and trust completely goes missing under the escrow clause.

On the penalty for low production, Elango wrote: “The data from seismic surveys using the best of technology cannot tell with certainty whether the fluid seen is oil or water. To put such penal provisions is a sure way to put off serious investors who have multiple investment options across the globe.”

The key difference between the production sharing contract and the revenue sharing model is that the PSC model would encourage investors to take higher exploration risks, and in the event of success, the costs could be recovered, Elango wrote. Since only one-third of our sedimentary basins have been fully explored, a contract model that encourages intensified exploration activities should have been preferred, he said. — Mriganka Jaipuriyar in Singapore
Oil slips further as IEA slashes forecasts

No let-up in bearish market fundamentals into 2015

London—Oil prices slumped to fresh multi-year lows Friday after the International Energy Agency made a new set of bearish oil market forecasts, slashing its estimate for global oil demand growth and cutting its estimate of the need for OPEC’s oil next year.

- Demand growth under 1 million b/d in 2015
- Supply surplus could reach 2 million b/d

In its latest monthly oil market report, the IEA also said that while non-OPEC supply growth would slow next year compared with 2014, there would likely be no short-term impact of falling oil prices on US light, tight oil production.

Global oil prices have plunged by more than 40% since mid-June due to slower demand growth and market oversupply, though the IEA said lower prices would not necessarily translate into increased demand growth.

In fact, the agency reduced its forecast for global demand growth by 230,000 b/d compared with its previous report to 900,000 b/d on lower expectations for countries in the former Soviet Union and other oil-exporting nations.

World oil demand is now seen reaching 93.3 million b/d next year compared with 92.4 million b/d in 2014, it said.

“While demand growth is still expected to gain momentum in 2015, from 2014, the acceleration is now looking more modest than previously foreseen, in line with the ever more tentative pace of the global economic recovery,” the IEA said.

“The adverse impact of the oil price rout on oil-exporting economies looks likely to offset, if not exceed, the stimulus it could provide for oil importing countries against a backdrop of weak economic growth and low inflation,” it added.

Oil prices continued their steep declines after the report was published Friday with Brent trading below $62/b for the first time since mid 2009.

The agency maintained its global demand growth estimate for 2014 unchanged at 700,000 b/d compared with last month’s report.

The IEA said its forecast for Russian oil demand in 2015 had been sharply reduced because of the oil price fall.

“The Russian forecast has been hit particularly hard by the market sell-off, with the forecast for 2015 revised down by 195,000 b/d to 3.4 million b/d, attributable to the darker macroeconomic outlook and with heightened associated risks skewed towards the downside,” it said, a reference to international sanctions against Moscow’s oil sector.

Demand for OPEC oil

As a result of slowing demand growth and oversupply on the market, the IEA slashed its forecast “call” on OPEC output by 300,000 b/d to 28.9 million b/d for 2015.

It cut the “call” for every quarter by between 200,000 b/d and 400,000 b/d, and reduced the estimate for the second quarter to just 28.1 million b/d, almost 2 million b/d below OPEC’s current production ceiling of 30 million b/d.

The revisions, the IEA said, were “due to a lower demand forecast and upward revisions to historical estimates and projections of North American and biofuels supply.”

The “call” is expected to decline seasonally by 1.2 million b/d from the fourth quarter of this year to the first of 2015, in line with its previous report.

OPEC crude supply declined by 315,000 b/d in November to 30.32 million b/d, the IEA said, after Libya’s recent production recovery stumbled.

But, it said, OPEC output remained in excess of the group’s production ceiling for a seventh straight month.

Supply from Saudi Arabia eased by 70,000 b/d in November to 9.61 million b/d “apparently due to the extended closure of the Khafji oil field shared with Kuwait and reduced need for crude to fuel domestic power plants.”

Global production fell by 340,000 b/d in November to 94.1 million b/d on lower OPEC supplies.

“Surging US light tight oil supply looks set to push total non-OPEC production to record growth of 1.9 million b/d this year, but the pace is expected to slow to 1.3 million b/d in 2015,” the IEA said.

Price effect

The IEA also noted that in an apparent bid to remain competitive in a well-supplied market, Saudi Aramco cut its official selling prices to the US for a fifth straight month and made sharp reductions in differentials to the core Asian market.

Despite the plunging oil price, the IEA said any effect on production would only be felt after a number of years given the long lead time of oil projects.

“Barring a disorderly production response, it may well take some time for supply and demand to respond to the price rout,” the IEA said.

The IEA said that, although producers are cutting spending due to the lower oil price, the effect will more likely be on medium- and long-term output than short-term supplies.

“So long is the lead of oil projects that price swings can take time to work their way through to supply. Projects that have already been funded will for the most part go on,” the IEA said.

It said that, while non-OPEC supply growth for 2015 would not “come close” to its 2014 record, prices have little to do with it as things stand now.

“The short-term outlook for US light tight oil production remains unchanged at current prices as long as producers maintain access to financing,” it said.

“Only in Russia is oil’s plunge, along with sanctions and a collapsing currency, likely to trim 2015 production plans.”

On the demand side, the IEA said that, in oil-importing countries, price effects are “asymmetrical.”

“Demand lost to substitution or efficiency gains during prolonged periods of high prices will not come back in a selloff,” it said. — Stuart Elliott, Robert Perkins

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### IEA Supply/Demand Highlights (December)

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*(Figures in million b/d)*

Source: IEA
MARKETS & DATA

Crude supply glut may test global storage

As capacity fills up in developed countries

London—Global oil markets may find it increasingly difficult to cash in on low oil prices by absorbing a growing surplus of crude as storage capacity fills up in developed countries, the International Energy Agency said Friday.

In its latest monthly report, the IEA said it sees world demand for OPEC’s oil falling to a low of 28.1 million b/d in early 2015, more than 2 million b/d less than the cartel’s current production.

Assuming OPEC continues to produce at current levels and demand remains steady, global oil inventories would notionally build by almost 300 million barrels in the first half of 2015, the IEA estimated.

OECD crude stocks already stand at 98% of their maximum recorded levels since 2000 and could build to 2.87 billion barrels by mid-2015 if current demand and supply fundamentals hold, the IEA said.

If half the expected stock build in early 2015 takes place in the OECD, inventories could “bump against storage capacity limits”, the IEA said.

The Paris-based agency said, however, that accurate estimates of global storage capacity were complicated by the lack of widespread stock data and detailed information on commercial and strategic storage capacities.

An “imperfect proxy” on storage capacity can be gathered from comparing current inventories with recent historical highs, the IEA said, estimating total OECD crude and product stocks stand at 97% of previous highs.

“While this measure might be used as a guide, it does not reveal how full storage capacity was when inventories reached their peak, nor does it account for such mothballing or expansion of capacity as might have occurred since the highs,” the IEA said.

Relative to historical highs, industry stock holdings are fullest in OECD Americas where they stand at 99% of previous records, the IEA said.

It noted new storage infrastructure was continuously being built in North America to keep up with fast-growing shale oil output.

Indeed, US oil stocks are only at 60% of working capacity, which has been estimated at 2 billion barrels by the US Energy Information Administration, the IEA noted.

In Asia and Europe, some shuttered refineries have been turned into storage terminals and independent product storage at terminals expansion projects have seen significant investments. — Robert Perkins

Dakota Plains raises guidance on Bakken crude use

New York—Dakota Plains, operator of Bakken crude oil offtake services, expects transloaded volumes of crude running through its Pioneer Terminal in New Town, North Dakota, could reach 80,000 b/d by the summer of 2015 when its third storage tank there becomes operational, despite a fall-off in crude oil prices which threatens to stem some production in the region.

Between December 1-10, 52,000 b/d of light, sweet Bakken crude has run through the Pioneer Terminal, the highest rate ever for the facility, a company presentation showed Friday.

November throughput rates were 36,000 b/d.

The company said construction of a third, 90,000-barrel storage tank is on schedule to come online in August, bringing the amount of crude at the facility available for loading on unit trains to 270,000 barrels and supporting the higher guidance.

However, while latest data shows North Dakota posted a record 1.184 million b/d of oil production in September, rig counts have fallen “dramatically” amid low crude oil prices, Lynn Helms, director of the state’s Department of Mineral Resources, said in November.

The price of Bakken crude ex-Clearbrook, Minnesota, which takes into account higher rail transportation costs needed to move the crude to refineries, has averaged $88.93/

Pemex cuts the constant in its crude price formula

Houston—Mexico’s Pemex will cut the constant term—or “k factor” —for its price formula for January deliveries of Maya crude to the Americas, Europe and Asia, PMI, the state-owned company’s trading arm, said Friday.

The differential for Maya deliveries in the Americas in January was reduced by 90 cents to minus $3.70/barrel, PMI said.

Pemex’s exports of Maya crude to the Americas, apart from the US West Coast, are usually priced at a premium or discount to a formula based on the values of similar regional crudes. The US Gulf Coast and European formulas for Maya also reflect fuel oil values, due to Maya’s sizable fuel oil yield.

Maya has a 22 API gravity and 3.3% sulfur content.

The Maya differential for January-loading cargoes to Europe was reduced by $1.90 to a discount of $7.55/b to PMI’s European regional formula.

For Asian deliveries, the Maya differential was cut by $1.55/b to a discount of $12.30/b to the PMI formula for the region.

The Isthmus crude differential for deliveries to the Americas was decreased $1.05 to a discount of $1.60/b. For deliveries to the US West Coast, the differential was down $1.10 to a discount of $1.40/b to the Pemex price formula.

For European deliveries, the differential for Isthmus decreased $1.90 to a discount of $3.00/b to the Pemex price formula for Europe.

The Isthmus differential for Asian deliveries also fell $1.90 to a discount of $6.35/b to the formula.

Pemex decreased the differential for Olmeca crude deliveries to the Americas by $1.15 to a discount of 15 cents/b to the applicable formula in the region. For European deliveries, the differential for Olmeca fell $1.90 to a discount of $4.05/b to the Pemex price formula. — Richard Capuchino

MARKETS & DATA

http://plts.co/capitol-crude-120814

Platts Podcast

Podcast — The Butterfly Effect: Will the winds of change hit US oil policy?

Platts senior editors Brian Scheid and Herman Wang explain how the long-term effects of OPEC’s production decision will be better understood as companies announce their capital expenditures, which will have an impact on US crude oil production and issues like possible exports and domestic refining. Listen to the latest episode of Capitol Crude: The US Oil Policy Podcast now: http://plts.co/capitol-crude-120814

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Oil futures sink, settling lower on bearish IEA report

New York—Oil futures settled lower Friday after the International Energy Agency cut its estimate for 2015 global oil demand growth and said US crude production is not poised to drop anytime soon.

One day after eclipsing the $60/b threshold for the first time since July 2009, prompt NYMEX crude had further room to fall. The January futures contract settled down $2.14 at $57.81/b.

ICE January Brent ended the session $1.83 lower at $61.85/b.

In refined products action, NYMEX January ULSD closed down 4.54 cents at $2.0160/gal. Prompt NYMEX RBOB settled 2.71 cents lower at $1.5973/gal.

“The tipping point came today when the IEA joined [the US Energy Information Administration] and OPEC in saying there will be reduction in global demand growth, which seemed to bring sellers out of the woodwork again,” Tradition Energy senior analyst Gene McGillian said.

Traders are keeping a close eye on North American crude producers for signs supply is starting to respond to lower prices.

“Although falling oil prices may be a stimulus to the demand side of the market over the intermediate to longer term in standard Economics 101 fashion, the IEA makes an interesting point that in the near term lower prices may hurt demand from important growth markets such as Russia, where the drop in crude oil has contributed to a developing recession,” Citi Futures and OTC Clearing analyst Tim Evans said in a client note.

ULSD crack spread

One development of late has been the relative strength of NYMEX ULSD in the face of falling crude prices. The difference between the value of NYMEX ULSD and ICE Brent closed Friday at $22.82/b, compared with $19.30/b December 4 when the upward trend began.

NYMEX ULSD’s resilience reflects conditions specific to the futures contract’s delivery point, New York Harbor. Demand for ULSD rises in the winter because the US Northeast uses the fuel to heat homes.

On the Gulf Coast, stockpiles could be used to ship ULSD to the Atlantic Coast. Moreover, a financial incentive exists. On Friday, for example, US Atlantic Coast ULSD was assessed at a 36.25 cents/gal premium over the USGC.

But the options for shipping more ULSD from the Gulf Coast are limited. The Houston-to-New Jersey Colonial Pipeline Line 2, with a capacity of 1.16 million b/d, is fully allocated. And moving products via barge is unlikely due to the shortage of Jones Act vessels. — Geoffrey Craig

PDVSA, PetroVietnam in talks over Orinoco Belt

Caracas—The presidents of state-owned PDVSA of Venezuela and PetroVietnam of Vietnam reviewed plans last week to jointly develop the Junin 2 block in the Orinoco Belt in which they hope to be producing 50,000 b/d by 2016.

“The managers agreed to concentrate on finishing the profiling of the reserves and construction production capacity with drilling and surface installations,” PDVSA said in a statement in which it disclosed the private meeting of the two heads.

PDVSA and PetroVietnam formed the mixed venture Petromacareo in 2012, with 60% and 40% equity stakes, respectively. They plan to develop the 225 square km (87 square mile) block in south-central Venezuela in Guarico state.

“Petromacareo completed the acquisition and seismic studies of the entire block in 2013 and 2014 and constructed the first elements of production facilities,” PDVSA said in the statement.

Petromacareo plans to build a heavy crude (8.5 API) upgrader with a capacity of 200,000 b/d to produce 183,000 b/d of upgraded crude at 32 API. According to previously released information from PDVSA, Petromacareo is two years behind schedule in its plans to develop Junin 2.

PDVSA has heavy oil reserves in the Orinoco Belt estimated at 295 billion barrels. — Meru Magollon