S&P Global
Platts

OILGRAM NEWS

Volume 96 / Issue 124 / Tuesday, June 26, 2018

UAE's Sharjah launches first onshore round

Emirate offers 30-year contracts to explore gas-rich plays

Dubai—The UAE's Sharjah Petroleum Council launched its first onshore acreage licensing round Monday, offering 30-year contracts for three exploration blocks as it looks to develop its own gas resources to meet growing power demand.

- Three blocks cover a total 2,185 sq km
- Looking for more gas to meet power demand
- Round follows similar plans by other emirates

The blocks, covering a total 2,185 sq km, are located in the "producing Thrust Zone play trend, including an un-appraised deeper gas discovery below the Sajaa gas-condensate field in Area A," state-owned Sharjah National Oil Co. said in a statement.

The company is currently preparing to drill a well in Area B.

SNOC is owned by the government of Sharjah, one of the seven emirates that make up the UAE. It owns the 700 MMcf/d Sajaa gas plant, Sharjah's largest producing gas development, handling gas from the onshore Sajaa, Moveyeid and Kahaif gas and condensate fields.

"Significant capacity is available in existing SNOC field infrastructure, gas-condensate processing and export facilities and all suitable field discoveries can be tied into the existing plant in order to generate early cash flow at lower capex, with SNOC to purchase the hydrocarbons," the company said.

Commercial and technical data will be available from July 4, with bids due to close November 18.

The announcement of the bid round follows the award of major concession agreements by Abu Dhabi National Oil Co., the UAE's largest oil producer at more than 3 million b/d, for its offshore fields.

Ras al-Khaimah, another emirate, launched its own inaugural offshore and onshore licensing round in April, offering seven onshore and offshore blocks. Bids are due in August, with the winners of any exploration and

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IEnova joins auction to build, operate Mexico terminal

Mexico City—IEnova is looking to build and operate a marine fuel terminal at the port of Topolobampo in the northwestern Mexican state of Sinaloa with plans to import refined products into the region.

- IEnova only company to announce project bid
- Terminal to give access to northwest Mexico
- Port authority to award contract July 29

IEnova, the Mexican subsidiary of Sempra Energy, said late Friday it has submitted a bid to the Federal Port Authority of Topolobampo to construct and operate the terminal. The port authority will award the contract July 29.

IEnova is the only company to publicly announce it has bid on the project, which is the only marine terminal being developed in Sinaloa.

Whoever gains access to the terminal will have an advantage competing with Mexico's Pemex for market share in the region.

Andeavor and Chevron have said separately they would be interested in contracting the terminal from the developer that wins the auction. Chevron currently has a deal to contract half of IEnova's 1 million-barrel terminal near Ensenada in the state of Baja California.

Other companies, such as Repsol and BP, have also expressed interest in gaining market share in Mexico's northwestern region.

Mexico's northwestern region, which includes the states of Baja California, Baja Sur, Sonora and Sinaloa, is a net importer of refined products. According to Mexico's Energy Secretariat (SENER), the region consumed 96,500 b/d of gasoline and 60,500 b/d of diesel in April.

Pemex sold 26,270 b/d of gasoline and 17,150 b/d of diesel in Sinaloa on average over January to April, according to SENER. In the adjacent state of Sonora, Pemex sold 21,000 b/d of gasoline and 18,700 b/d of diesel over the same period.

Lack of access to infrastructure has become a significant challenge for major oil companies entering Mexico's fuel wholesale market.

Although Mexico allowed the private import of motor fuels in April 2016, Pemex still controls 97% of gasoline imports into the country.

IEnova growing

IEnova is becoming one of the largest private midstream developers and operators in Mexico's opening fuel market. The company is

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TOP STORIES

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ADNOC joins India mega-refinery project

Buys 25% stake from Saudi Aramco in $44 billion venture

New Delhi—Abu Dhabi National Oil Company (ADNOC) on Monday signed an agreement to pick up a 25% stake from Saudi Aramco in the proposed $44 billion refinery and petrochemical project at Ratnagiri expected to start production by 2022.

- **Five companies now part of venture**
- **Project to start production by 2022**
- **Aramco, ADNOC to supply crude**

ADNOC joins Saudi Aramco, which will hold 25%, and Indian state refiners IOC, BPCL and HPCL, which hold the remaining 50%, in the Ratnagiri Refinery & Petrochemicals (RRPCL).

Saudi Aramco signed an agreement in April to take a 50% stake in the 60 million mt/year (1.2 million b/d) refinery project in the western state of Maharashtra with a promise it would sell a portion of the stake to a strategic investor.

"This project itself will be a catalyst at many levels," Amin Nasser, CEO of Saudi Aramco, said.

As per the initial agreement in April, Aramco will supply half of the crude oil required for processing at the refinery. ADNOC will also now supply crude to the proposed refinery.

"The strategic partnership brings together crude supply, resources, technologies, experience and expertise of these multiple oil companies with an established commercial presence around the world," India oil minister Dharmendra Pradhan said.

Pradhan said the refinery will produce a wide range of refined petroleum products, including gasoline and diesel meeting Euro 6 fuel standards.

The refinery will also have 18 million mt/year processing capacity for petrochemical products.

"It can be a role model not just in the field of energy but also in a variety of fields," Nasser said.

He also termed India to be "a key element" in the company's global downstream business.

"We are looking at all options," Nasser said in response to a question about whether Saudi Aramco would take steps into India's fuel retailing market alone or with India partners.

Saudi Arabia is India's second-biggest supplier of crude at around 35 million -37 million mt after Iraq, while UAE is the sixth-biggest supplier, sharing 7%-8% of total annual imports of around 216 million mt.

India's total annual refining capacity stands at around 232 million mt/year (4.6 million b/d), exceeding its annual demand of 200 million mt/year and is expected to reach 458 million mt by 2040, according to the International Energy Agency.

India will require around 10 million b/d of refining capacity to meet its annual demand in 2040, according to the oil ministry.

—*Ratnajyoti Dutta with Staff Reports*

Australian energy IPO helps Vitol build cash pile

ANALYSIS *Singapore*—The proposed listing of Vitol's Australian energy business allows the trading major to monetize its fuel marketing and refining assets in the country and build a hefty cash pile for itself at the same time.

- **Could raise $2.3 billion from Viva Energy listing**
- **Australia relying heavily on fuel imports**
- **2017 crude trades averaged over 7 million b/d**

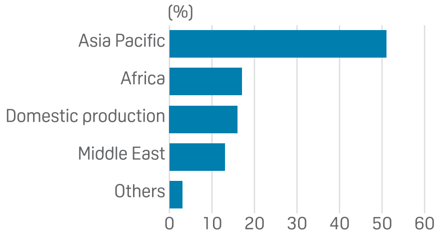
Vitol plans to raise up to A$3.1 billion ($2.3 billion) from the listing of Viva Energy on the Australian Stock Exchange by mid-July, at a market capitalization of A$5.2 billion.

Viva Energy owns the Geelong refinery in Victoria and supplies around 25% of Australia's fuel demand through its gasoline stations that previously belonged to Royal Dutch Shell.

The listing comes at a time when Australia has shut around 40% of its refineries, forcing it to rely heavily on fuel imports. Vitol expects to retain a 40%-50% ownership in the new company through Vitol Investment Partnership, allowing it to benefit from fuel supply agreements into Australia.

More importantly, the dependence on fuel imports has raised energy security concerns in government circles that triggered an official review in May. This has raised the net worth of existing oil and refining assets in the country, and is a great time for Vitol to cash-in on its position, according to analysts.

AUSTRALIA'S CRUDE OIL SUPPLY BY SOURCE IN 2017



Source: Australian Petroleum Statistics, Viva Energy Australia

"What a trading house is after is access to long and shorts, and they will always do what they have to do to lock both in," Jean-François Lambert, head of Lambert Commodities, said.

Trading houses constantly evaluate opportunities to free capital, and if the opportunity arises and the price is right, they will not hesitate to sell, providing they can keep their access to the shorts, he said.

"Vitol has a strong capital base and has demonstrated this in several markets," Lambert said. "I do not believe Vitol is selling because of the current [difficult] market conditions. This is not a defensive move, this is simply a smart, timely move."

Cash rich

With a turnover of $181 billion in 2017, Vitol is among the world's largest independent commodity traders. Like its peers, Vitol faced challenging market conditions last year amid declining trading margins.

For 2017, its crude and product trading volumes, excluding LNG and LPG, slipped to 349 million mt from 351 million mt in 2016, but Vitol still maintained an average of over 7 million b/d, or roughly 7% of global trading.

The $2.2 billion Vitol raises in Australia will add to around $2.7 billion raised from the listing of Vivo Energy, its Africa business, on the London Stock Exchange earlier this year.

"Current market conditions are not easy and trading houses require a lot of cash to churn more volume to keep margins afloat," Lambert said. "So, I would think they are not in a hurry to lock cash in very large investment just yet unless this proves to be the right opportunity."

While trade finance has been getting tighter, Vitol has several options to deploy its cash pile.

In some ways, Vitol's move resembles fellow commodity trader Trafigura, whose logistics and fuel distribution businesses are housed in separate joint venture or subsidiary companies like Puma Energy and Impala Terminals. This helps to focus on the core trading business, reduce exposure to fixed assets, and helps generate downstream demand for traded commodities.

Growing trades like LNG and battery metals require new investment and deals with new counterparties, like Trafigura's 15-year deal with Cheniere Energy for US LNG and Gunvor's long-term LNG deal with Russia's Yamal LNG. —*Eric Yep*

UAE's Sharjah launches first onshore round

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production sharing contracts to be announced in November.

The emirate currently has no upstream oil and gas production of its own, relying on imported gas from Oman and the neighboring emirate of Umm al-Quwain.

LPG plans

Separately, SNOC said it is diversifying into the LPG marketing business, with the launch of a new blending and loading complex in the UAE, and expects to begin importing LPG to meet domestic demand.

Previously a small exporter, SNOC will begin importing LPG for its blending plant at the Sajaa complex at the Hamriyah port on the UAE's Persian Gulf coast.

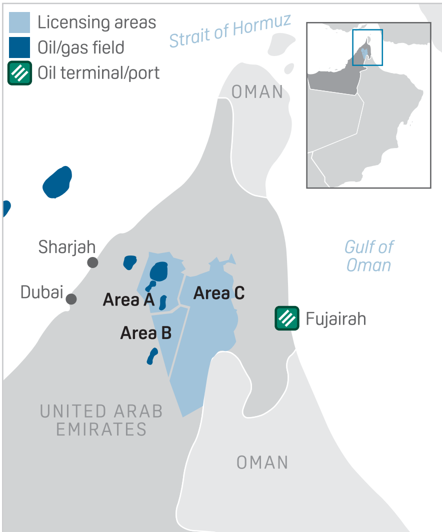
Although the plant is ready, the company did not say when it would accept its first shipment.

The emirate had been exporting LPG since the 1980s, with most of its shipments bound for a single buyer in Japan. That term agreement expired at the end of 2016 and has not been renewed, leaving only spot sales.

With its LPG production down to just 150 mt/d, SNOC has now even stopped spot sales.

Instead, it is looking at importing around 1,500 mt/d of LPG for its new blending plant and trucking facility to meet rising domestic demand in the UAE's northern emirates. SNOC officials have previously said they would also look at re-exports, to countries that do not have refrigerated LPG facilities, such as Bangladesh. —*Adal Mirza*

UAE'S SHARJAH LICENSING ROUND



Source: S&P Global Platts

Shell makes second North Sea investment decision of 2018

London—Shell has approved a plan to develop the Fram gas and condensate field in the UK North Sea, its second North Sea investment decision of the year, saying it envisaged further projects there thanks to cost cuts.

The decision revives a project abandoned in 2013 due to what Shell called "unexpected" drilling results.

Fram will start producing gas in mid-2020 and condensate in 2021, Shell said in an emailed comment.

Two wells will be drilled and natural gas liquids from the field will be transported via a new pipeline to the Starling field and then on to the Shearwater platform, which has had a troubled history, but is expected to become more viable thanks to new investments. Shearwater in turn feeds the Forties crude stream, with gas transported via the SEAL pipeline to Bacton.

Fram is expected to produce 41 million cu feet/d of gas and 5,300 b/d of condensate, making for total production of 12,400 b/d of oil equivalent, Shell said.

"Fram is a simplified and cost-effective project that will allow us to develop this field profitably," Shell upstream director Andy Brown said in a statement. "Through our ongoing work with partners to maximize the economic recovery of the North Sea, we've been able to transform and revitalize Shell's UK Upstream business by focusing on competitive projects and cost effective operations."

Shell is operator of Fram despite holding the lesser stake, of 32%, alongside ExxonMobil with 68%.

The high-pressure, high-temperature Shearwater field had to be shut in 2012 until 2015 due to well integrity issues unearthed following a gas leak at Total's nearby Elgin-Franklin complex, also characterized by high pressure, high-temperature wells.

The Fram development plan published last October estimated total condensate production from Shearwater, including Fram, would be 17,000 b/d in 2022, also to be supplemented by Dana Petroleum's proposed Arran field development, in which Shell holds a 24% stake.

The new investment follows Shell's decision to sell a swathe of other North Sea assets that accounted for more than half its UK oil and gas production in 2016, to private equity-backed Chrysaor.

In January Shell and ExxonMobil approved a redevelopment of the Penguins oil project.

Norway's Equinor operates another field of the same name in Norwegian North Sea waters, for which new investment was also announced in May. —*Nick Coleman*

Eni makes new oil find at Angola's Kalimba prospect

London—Eni has made a new oil discovery in a gas-prone part of Angola's prolific deepwater offshore Block 15/06, the Italian oil major said Monday.

- **Up to 300 million barrels of light crude in place**
- **Opens oil opportunities in gas-heavy block**

Drilling at the Kalimba prospect in the southern part of the block found an estimated 230million-300 million barrels of light crude in place, Eni said.

The discovery well, drilled some 50 km from the Armada Olombendo FPSO (East Hub), found 23 meters of net pay holding of 33 API crude with an estimated production capacity of more than 5,000 b/d, Eni said.

"The discovery opens new opportunities for oil exploration in the southern part of Block 15/06, so far considered mainly gas prone, thus creating new chances for additional potential value in the block," Eni said.

It said it will now work to further appraise the discovery and begin studies to fast-track development.

Eni operates Block 15/6 with a 36.84% stake, alongside state-owned Sonangol (36.84%) and SSI Fifteen 26.32%.

The block's two oil developments, West Hub and East Hub, are producing about 150,000 b/d. Eni is also the operator of Cabinda Norte Block, located onshore Angola.

The next start-ups in block 15/06 this year will be the Upper Miocene, in the East Hub, and the Subsea Boosting System for the Mpungi field, while the Vandumbu field, that will be connected to the West Hub, will start production at the end of 2018, ahead of plan, Eni said.

Eni said the start-ups will add further 30,000 b/d to the overall production from Block 15/06, which in 2019 will exceed 170,000 b/d gross.

With the Eni-operated Ochigufu field in Block 15/06 ramping up and the Total-operated giant deepwater Kaombo field beginning production in August, Angola hopes to boost production to 1.65 million b/d at the end of this year, up from about 1.55 million b/d in recent months. —*Robert Perkins*

PDVSA run rates likely to fall again in July

To buy at least of 19,000 b/d of imported crude equal to Mesa 30 quality

Caracas—Venezuelan state-owned oil company PDVSA will try to put the brakes on the collapse of its refining network by incorporating imported crude and diluted crude oil in the throughput of its four operating local refineries, according to a internal PDVSA report reviewed by S&P Global Platts Monday.

- **July crude output to average 1.347 million b/d**
- **439,000 b/d to be processed in local refineries**
- **Mesa 30 production expected to decline**

PDVSA estimates July crude production will average 1.347 million b/d, of which 439,000 b/d will be processed in local refineries, according to the report by the office of the company's refining vice president.

"These processing rates in Venezuelan refineries are estimates that can change according to international commitments," said a PDVSA official who spoke on condition of anonymity.

The volume of crude expected to be refined in July represents 27.4% of the PDVSA refining system's total capacity, and is a processing rate that is less than was expected for June, according to a previous report

PDVSA targeted a June processing volume of an average 499,000 b/d, or 30.9% of its total capacity, a decrease of 144,000 b/d, or 22.4%, from the crude processing rate recorded in 2017.

This volume includes for the first time 55,000 b/d of diluted crude oil, called DCO, which will be used to complete the month's refining at the Cardon facility.

Additionally, PDVSA said that to complete its programmed refining for July at the El Palito refinery, the company will have to buy a minimum of 19,000 b/d of imported crude equal in quality to local Mesa 30 crude.

The low rate of processing is attributable to a shortage of crude oil for processing, a lack of supplies and the large number of plants that have been shut due to delays in maintenance and unscheduled shutdowns due to accidents.

However, PDVSA depends on agreements with international companies for the exchange of DCO crude for light crude, due to the financial problems of the Venezuelan state company.

PDVSA's refinery system is comprised of five refineries: 645, 000 b/d Amuay; 310,000 b /d Cardon; 140,000 b/d El Palito; 187,000 b/d Puerto La Cruz, and 335,000 b/d Isla, in Curacao. PDVSA has a total refining capacity of 1.6 million b/d.

According to the PDVSA report, the supply of crude to the Isla refinery in Curacao island, operated by PDVSA via a lease agreement with the Curacao government, is not forecast for July. PDVSA suspended its shipments of crude to Curacao on May 7 after US-based ConocoPhillips began legal proceedings against PDVSA to collect a claim awarded by International Trade Court.

Insufficient production at Mesa 30

According to the report , the availability of Mesa 30 crude is key to maintaining the El Palito and Puerto La Cruz refineries in operation.

Mesa 30 is a sweet crude (29.1 degrees API with 1.08% sulfur content) that PDVSA produces in the El Furrial oil field in Monagas state in eastern Venezuela. It was the most plentiful and profitable of Venezuelan crudes during the 1980s. It is important for the throughput requirements of El Palito and Puerto La Cruz refineries, which are conventional refineries with no deep conversion units.

Additionally, PDVSA uses Mesa 30 crude to dilute extra heavy crudes produced in the Orinoco Belt to make a mixed crude called Merey 16.

PDVSA estimates production of Mesa 30 during July at 118,000 b/d, less than the estimates for June of 132,000 b/d. In its most recent annual report, PDVSA listed full year 2016 production of Mesa 30 at 156,000 b/d. Figures for 2017 are not yet available.

In its refining plan for July, PDVSA contemplates processing levels of 90,000 b/d at El Palito, of which 51,000 b/d corresponds to Mesa 30 and 19,000 b/d to imported crudes. For the Puerto La Cruz refinery, PDVSA projects processing 83,000 b/d of which 55,000 b/d are attributable to Mesa 30 crudes.

According to figures in the report, the availability of the 106,000 b/d of Mesa 30 for the El Palito and Puerto La Cruz refineries is uncertain, "since PDVSA has promised part of this volume to others customers," said the report.

If the other customers decide to take this crude, the lack of crude will impact one or both of the refineries. "To halt the collapse, it will be necessary to look for crudes on the international market to cover the deficit," the report said.

DCO in Cardon and condensate in Amuay

According to previous reports, PDVSA projected processing 50,000 b/d of Leona 22 crude (a blend of the medium TJL and heavy Merey 16), as part of the feedstock for the Amuay refinery to complete minimum throughput. However, for July, this crude was replaced in those plans with 16,000 b/d of condensate coming from the Cardon IV offshore block.

PDVSA is planning for a July processing rate of 197,000 b/d at the Amuay refinery, or 30.5% of its capacity, which is 85,000 b/d less than was projected for June.

At the Cardon refinery, PDVSA expects to process an average 83,000 b/d in July the report said, of which 55,000 b/d will be DCO, although the facilities were not designed to process this type of crude, according to refinery operator who spoke on condition of anonymity.

PDVSA did not immediately respond to a request for comment. —*Mery Mogollon*

Derailed tank cars were shipping Canada crude to US Midwest

Houston—Thirty-two tank cars that derailed Friday in Iowa were shipping Canadian crude to the US Midwest and spilled 230,000 gallons, or roughly 5,475 barrels, officials said over the weekend.

A total of 14 tanks cars were "compromised" and a BNSF investigation is underway, railroad spokeswoman Amy Casas said Sunday. The rail cars went off the track near Doon in Lyon County, Iowa, spilling crude into the nearby Little Rock River.

The train was carrying Canadian crude produced by ConocoPhillips and the cargo was destined for Stroud, Oklahoma, company spokesman Daren Beaudo said in an email Saturday.

There were no reported injuries to the train crew or nearby residents, he said.

ConocoPhillips is a 50% owner and operator of the Surmont oil sands facility in Alberta, Western Canada, with a current gross capacity of 140,000 b/d, according to information on the company website.

Total E&P Canada owns the remaining 50% in the project that produces raw bitumen and is Alberta's single-largest in the steam-assisted gravity drainage facility.

Beaudo did say if the Western Canadian heavy barrels were destined for the Phillips 66-operated 220,000 b/d Ponca City refinery in Oklahoma. The refinery processes a mix of light, medium and heavy crude that is received from Oklahoma and Canada, information on Phillips 66 website said.

BNSF said Saturday hazardous materials and environmental experts are containing spilled oil with booms and recovering it with skimmers and vacuum trucks. An estimated 100,000 gallons (2,380 barrels) or 44% of the total volume was contained.

With pipelines running full from Alberta to refineries in the US Midwest and the US Gulf Coast, Western Canadian producers are relying increasingly on crude-by-rail to move heavy barrels.

CBR volumes out of Western Canada were estimated at 170,622 b/d in March, the latest National Energy Board report showed, compared with 134,075 b/d in February. —*Ashok Dutta*

US exports in focus as prices shift

ICE Brent's premium to WTI has nearly halved since late May

New York—With stocks at Cushing, Oklahoma, falling steadily of late, the ICE Brent/WTI spread has closed sharply, lessening the incentive for US producers to ship crude overseas in pursuit of higher prices.

- **Crude stocks expected to draw**
- **NYMEX crude backwardation steepens**
- **Syncrude production closed**

Market observers will be watching US export figures in the coming weeks to gauge whether the price signals have had an impact.

While ICE Brent's premium to WTI has nearly halved since late May, it remains within the $3/b-$7/b range seen from August until mid-May, when US crude exports hit record highs on several occasions.

The ICE Brent/WTI spread was $6.65/b Monday at the market close, in from $6.97/b Friday and more than $10/b earlier last week.

Greater exports have helped tighten US crude inventories, offsetting the fact that domestic production has climbed to 10.9 million b/d. US crude stocks were 1.2% below the five-year average at 426.527 million barrels the week ending June 15.

Analysts surveyed Monday by S&P Global Platts expect crude stocks fell 2.3 million barrels last week. If confirmed, that would further grow the size of the deficit to the five-year average.

Stocks actually saw a slight build of around 40,000 barrels on average for the same period from 2013-17, according to Energy Information Administration weekly inventory data.

US crude exports have averaged 2.074 million b/d over the last four weeks, versus 775,000 b/d over the same period a year ago. That is not surprising in light of the ICE Brent/WTI spread blowing open from less than $6/b in early May to more than $11/b a month later.

US crude exports averaged 1.959 million b/d last week, S&P Global Platts cFlow shiptracking data shows. EIA pegged exports at 2.374 million b/d the week ending June 15.

OPEC shifts strategy

The commitment by OPEC and its 10 allies outside OPEC to keep a lid on production since the start of 2017 provided a tailwind for US crude exports needed to fill any supply voids.

However, that premise has begun to falter after the OPEC/non-OPEC coalition agreed to an increase of 1 million b/d of supply.

Saudi Arabia's energy minister, Khalid al-Falih, noted Saturday that overcompliance averaged 983,000 b/d the last three months, so the additional supply would actually place overall conformity at 100%.

Still, the fact that Saudi Arabia pushed for additional supply at last week's meeting in Vienna marks a significant step demonstrating Riyadh's willingness to adjust policy in response to higher oil prices.

"Saudi Arabia and Russia were keen to raise output and overcame earlier opposition by Iran and others," Citi Research said in a note.

ICE Brent topped $80/b in late May for the first time since late 2014. NYMEX crude reached its own three-year high around the same time, in the low-$70s, trailing far behind Brent.

Last week saw NYMEX crude shed its status as the laggard across the oil complex. A contributor to NYMEX crude's relative strength has been US crude inventories, especially at Cushing, Oklahoma.

Stocks at Cushing —the delivery point for the NYMEX crude contract —have fallen five straight weeks by 4.6 million barrels to 32.6 million barrels, the lowest amount since the week ending March 23.

Syncrude shutdown

Another issue that will likely exacerbate these trends is the loss of Canada's Syncrude possibly through the end of July or longer after a power outage last week caused the closure of an upgrader.

This development has been supportive for prompt NYMEX crude, causing the term structure to strengthen and the Brent/WTI spread to narrow.

NYMEX crude's front-month/second-month spread was $1.04/b Monday, out from 16 cents/b a week ago. The front-month/12th month spread was $5.07/b Monday, versus $3.34/b a week earlier.

"The WTI-Brent spread continues to contract as the Syncrude disruption and subsequent blowout in the WTI prompt spreads force reductions of long Brent/short WTI trades," Ole Hansen, head of commodity strategy at Saxo Bank, said Monday in a tweet.

In the physical market, the same message has been conveyed to traders, urging them to move barrels to Cushing.

WTI crude at Cushing jumped $5.54/b Friday, the largest single-day price increase since June 2012, according to Platts data.

Brisk refinery activity is also pulling barrels from the Midwest. Gulf Coast crude runs averaged 9.32 million b/d the week ending June 15, up from 9.13 million b/d a year ago and 868,000 b/d above the five-year average.

Analysts are looking for the total refinery utilization rate to have fallen 0.7 percentage point last week to 96% of capacity. That compares with an average of 92.5% a year ago.

Gasoline stocks are expected to have risen by 160,000 barrels, while distillate stocks likely built by 500,000 barrels.

One side effect of crude strength of late has been the decline in NYMEX product crack spreads against WTI.

The RBOB crack fell under $16/b at one point Monday, down from more than $20/b last week. The ULSD crack crossed below $19/b Monday, compared with above $24/b last week.

—*Geoffrey Craig*

IEnova joins auction to build, operate Mexico terminal

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currently developing four terminals with a combined capacity of nearly 4.5 million barrels of storage, representing nearly 14% of motor fuel storage capacity under development in Mexico, according to SENER.

IEnova's strategy is to build integral supply systems anchored by marine terminals connected to new inland terminals at significant demand centers. For instance, the company is building such a system with Valero, which includes a 2.1 million-barrel storage terminal at the Port of Veracruz and inland terminals in the cities of Puebla and Mexico City each with a storage capacity of 640,000 barrels.

CFEnergia also has two fuel oil terminals in Sinaloa: one 326,000-barrel terminal in Topolobampo, and one 580,000-barrel terminal in Mazatlan.

The fuel marketing subsidiary of Mexico's power utility CFE, CFEnergia plans to reconfigure its fuel oil facilities to unload and store motor fuel products or even export crude oil.

Andeavor announced in early June it signed a contract to reconfigure CFEnergia's 450,000-barrel fuel oil terminal at Rosarito in Baja California.

The Federal Port Authority of Baja California Sur is also auctioning a new marine terminal at the port of Pichilingue at the city of La Paz in the state of Baja Sur.

The total area of the terminal will be near to 45,000 sq. meters and it will be awarded on November 26, according to the participation rules released by the port authority on June 21.

During its first-quarter earnings call, IEnova said it was following closely the auction for a new marine terminal at La Paz.

IEnova could not be reached for comment.

—*Daniel Rodriguez*

Banks maintain oil price forecasts

Demand amid lower supply to support pricing despite OPEC output hike

London—Oil market watchers largely maintained their price forecasts Monday, saying OPEC's move to raise production from the second half is required to help balance the market over the coming year.

- **Merrill Lynch sees Brent at $90 in Q2 2019**
- **Danske Bank holds forecast at $72/b in H2**
- **OPEC spare output capacity set to shrink**

OPEC and its oil producer allies led by Russia agreed at a key meeting on Friday to boost oil supplies by around 1 million b/d from July. The decision was short on specifics but the actual increase will be closer to 700,000 b/d, according to members, because some producers are already pumping flat out.

Bank of America Merrill Lynch said OPEC's move was roughly in line with its expectations, and maintained its Brent price forecast for 2018 at $70/b. It also retained a Brent forecast of $90/b for Q2 2019, citing expectations of a tighter market balance.

Global spare production capacity is dwindling due to a lack of new investment, meaning the oil market will likely remain in deficit next year, the bank said.

"Plus we see the Trump administration taking advantage of any dip in oil prices to put additional pressure on Tehran, likely reducing downside risks to oil prices in the absence of a full-blown trade war," Merrill Lynch said in a note.

The International Energy Agency estimates OPEC's spare capacity at roughly 3.41 million b/d, with Saudi Arabia holding 60% of the total. With Iran and Venezuela sidelined, the group's spare capacity could drop to just 2.5 million b/d by mid-2019, the IEA believes, the lowest level since the end of 2016.

Indeed, Jefferies said it expects Brent will trade above $80/b in the second half of 2018 as spare capacity falls to 2% of global demand, its lowest level since at least 1984.

"Despite the OPEC agreement we believe that tight supply is likely to drive oil prices higher during 2018," the bank said in a note Monday.

Swedish bank SEB maintained its oil price forecast for 2018 at $75/b assuming a 200,000 b/d ramp-up per month from OPEC and its producer allies to reach a combined 50.1 million b/d in September.

"A ramp-up of close to 1 million b/d from OPEC+ in H2 will clearly temper the upside price risk and significantly reduce the risk for a price spike to $100/b during the second half of this year," the bank said, adding it believes Saudi Arabia is keen to keep oil prices above $70/b.

Further out, SEB also maintained its price forecast of $85/b for 2019 and 2020.

Venezuela, Iran sanction key

OPEC produced 31.90 million b/d in May, according to the latest S&P Global Platts OPEC survey. Output of the 12 members with hard quotas was 710,000 b/d below their combined caps. Venezuela, which is seeing its production slide due to country's economic crisis, accounts for some 610,000 b/d of that.

According to an analysis of key market forecasts by Platts, OPEC would need to boost its crude production by more than 1 million b/d in order to balance the global market over the coming 18 months faced with robust demand and an expected slide in volumes from Iran and Venezuela.

Even on its own estimates, OPEC expects global demand to average 2 million b/d higher in the second half of 2018 than in first six months of the year. As a result, OPEC's figures suggest the market needs more than 33 million b/d of its crude to balance the market in H2, compared with current levels of 31.7 million b/d.

The IEA is also expecting a gradual slide in Venezuelan output from current levels of 1.36 million b/d to 800,000 b/d by the end of 2019. It also sees US sanctions on Iran, due to begin in November, causing the loss of 900,000 b/d of Iranian crude output next year.

Following the OPEC deal, Danske Bank maintained its forecast for Brent to average $72/b in H2 and $73/b in 2019.

Commerzbank said it believes a production increase of 1 million b/d in the second half "should be sufficient to rebalance the oil market," adding that it expects prices to fall to $70/b in the third quarter.

Front-month Brent crude was trading around $74.30/b Monday after giving up almost 2% of the gains from Friday ahead of the OPEC decision. —Robert Perkins

Libya extinguishes Ras Lanuf fires, saves two oil storage tanks

Dubai—Libya's National Oil Corp. has extinguished fires at its oil storage tanks at the Ras Lanuf export terminal, saving two of the remaining tanks from destruction, the company said Sunday.

The National Oil Corp. declared *force majeure* on crude oil loadings out of the eastern oil terminals of Es Sider and Ras Lanuf on June 14 due to attacks on the oil facilities by militant groups. The so-called Libyan National Army retook Ras Lanuf and Es Sider, two of the country's key eastern oil terminals, last Thursday. They were captured by militias from the former Petroleum Facilities Guards a week earlier.

"Despite the severity of the fire damage to storage tanks 2 and 12, tanks 5 and 6 were saved thanks to the exemplary work of personnel on site, thus ensuring the continuity of export operations," NOC said in a statement.

The *force majeure* issued on Libya's Es Sider and Ras Lanuf crude loadings has had a limited impact on Mediterranean light sweet crude complex pricing so far, except for Azerbaijan's Azeri Light, which has seen a boost in differentials for July cargoes, trading sources said Monday.

NOC has carried out an initial damage assessment, but did not say when operations at the oil port could resume.

Before the latest attacks on the port, Ras Lanuf was exporting at around 130,000 b/d. Ras Lanuf had five operational storage tanks, storing up to 950,000 barrels. The loss of tanks 2 and 12 due to fire reduced total capacity by 400,000 barrels to just 550,000 barrels.

Tank 6 was heard to have caught fire as the LNA attempted to retake the port. With only tanks 1 and 3 left operational, the port has around 350,000 to 400,000 barrels of operational storage capacity, sources in Libya said.

The larger Es Sider terminal was shipping around 260,000 b/d. There was no damage to its infrastructure from the attacks. The port should be able to resume operations once NOC's workers return, the sources said.

NOC Chairman Mustafa Sanalla said Friday the country's output had been cut by 450,000 b/d, and he hoped it would restart in a "couple of days." Libyan output was 950,000 b/d in May, according to the latest S&P Global Platts OPEC survey. —Adal Mirza, with Gillian Carr in London

Brazil's Petrobras pumps first oil from Tartaruga Verde Field

Rio de Janeiro—Brazilian state-led oil producer Petrobras pumped first oil from the offshore Tartaruga Verde Field, completing installation of the company's second new floating production unit to enter service in 2018, Petrobras said in a statement Monday.

The Cidade de Campos dos Goytacazes floating production, storage and offloading vessel, or FPSO, started production on Friday, Petrobras said. The FPSO is capable of pumping 150,000 b/d of oil and processing up to 3.5 million cu m/d of natural gas, according to Petrobras. Natural gas compression capacity, which is used to reinject gas in order to increase oil-recovery rates, is 5 million cu m/d, Petrobras said.

"This is the second platform to enter operation this year and will contribute to Petrobras' increase in production under the horizon of the 2018-2022 strategic business plan," Petrobras said. Petrobras set its annual production target at 2.1 million b/d in 2018, down slightly from the 2.154 million b/d produced in 2017. The company expects output to fall because of planned sales of existing production assets under Petrobras' $21 billion divestment plan for 2017-2018.

Tartaruga Verde is part of a two-reservoir development that also includes the Tartaruga Mestica Field, with output from both of the deposits eventually expected to be handled by the FPSO Cidade de Campos dos Goytacazes, Petrobras said. Tartaruga Verde is located about 127 kilometers off the coast of Rio de Janeiro state, with the vessel anchored in waters 765 meters deep.

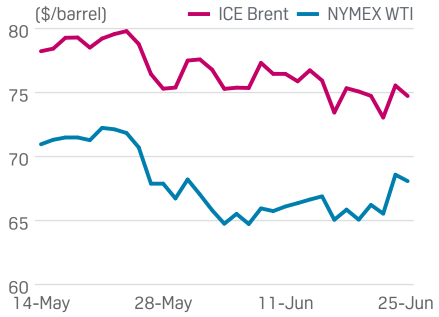
Petrobras owns 100% of Tartaruga Verde, while the Tartaruga Mestica reservoir extends beyond the borders of the existing concession into acreage owned by Brazil's government. Petrobras owns 69.35% of Tartaruga Mestica and government subsalt management company Pre-Sal Petroleo SA, or PPSA, retains the remaining 30.65%.

Tartaruga Verde and Tartaruga Mestica will also need to be unitized with the Sudoeste de Tartaruga Verde area, which will be sold at Brazil's fifth subsalt production-sharing bid round scheduled for September 28. The area was also available for bid at Brazil's second subsalt production-sharing auction held in September 2017, but generated no offers.

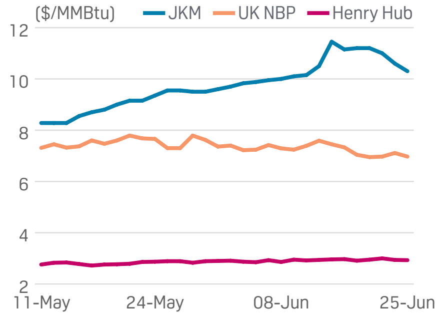
Brazil's National Petroleum Agency, or ANP, estimated last year that Sudoeste de Tartaruga Verde held 160 million barrels of crude in place.

Petrobras, which holds preferential rights to take a 30% operating stake in any area offered at the subsalt sales, exercised its rights to operate the Sudoeste de Tartaruga Verde area in early June. The minimum profit-oil guarantee to the government was set at 10.01% for the area, with the signing bonus fixed at Real 70 million, according to Brazil's National Energy Policy Council, or CNPE.—Jeff Fick

NYMEX WTI, ICE BRENT CRUDE OIL FRONT MONTH DAILY SETTLES



GLOBAL GAS PRICE COMPARISON



Source: Platts, prices are rounded

S&P Global Platts

OILGRAM NEWS

Volume 96 / Issue 124 / Tuesday, June 26, 2018

ISSN: 0163-1284

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Oilgram News is published every business day in New York and Houston by Platts, a division of S&P Global, registered office: Two Penn Plaza, 25th Floor, New York, N.Y. 10121-2298.

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