Energy Intelligence

PETROLEUM INTELLIGENCE WEEKLY®

Vol. 60, No. 36 www.energyintel.com September 10, 2021

Will Iraq Deal Be New Model for Megaprojects?

Could the multibillion-dollar integrated energy deal that TotalEnergies signed with Iraq this week become a model for future oil megaprojects? While some aspects make it a special fit for Total, the deal's structure provides medium-term production growth while satisfying environmental demands with gas capture and solar components. Such a model could have broad appeal for international oil companies (IOC) facing investor pressure to deliver strong returns in the near term while shifting greater investment to cleaner energy technologies over the long term. IOCs have long chafed at Iraq's harsh operating environment. And its carbon-intensive oil — related to the large volumes of gas it flares — have become a growing source of concern for investors (PIW Oct.23'20). But Total appears to have found a profitable solution — combining an expansion of oil production capacity with the capture of gas that was previously flared, and also throwing a big chunk of solar power into the mix. The deal could prove to be a pivotal project for both Iraq's struggling oil sector and the French major's energy transition strategy (PIW Sep.3'21). The project's initial capital expenditure is estimated at $10 billion-$11 billion while total spend, covering both operating expenditure and capex over the next 25 years, is pegged at $27 billion. At a $50 per barrel oil price, total profits over the project's lifetime are projected at $96 billion, Iraq's oil ministry says. Experts say Total has secured better terms than those offered in Iraq's licensing rounds. The deal involves gas capture, covering a 600 million cubic foot per day project at Ratawi; the expansion of oil output at Ratawi from 85,000 barrels per day to 210,000 b/d; a 1 gigawatt solar project; and a 5 million b/d water injection project to provide treated seawater needed to maintain reservoir pressure at key southern oil fields.

(Please turn to p.4)

All Hands on Deck in Abu Dhabi's Transition

Abu Dhabi has moved faster than other producers in the Middle East to respond to the challenges posed by the energy transition. Abu Dhabi National Oil Co. (Adnoc) has been at the center of the effort, pushing its advantage as low-cost, low-carbon producer as peak oil demand nears (PIW May7'21). But other players in the emirate are also making contributions, even if they sometimes come in under the radar. Abu Dhabi National Energy Co. (Taqa) and state fund Mubadala Investment Co. have been quietly shifting more investment into electricity and clean energy projects after spending years making moves in oil and gas markets. The repercussions of both Covid-19 and the accelerating energy transition mean that hydrocarbon producers must adapt to a new energy landscape characterized by a changing demand picture and lower oil and gas revenues. Abu Dhabi, which produces almost all the oil and gas in Opec member United Arab Emirates, has moved relatively swiftly to respond to the changes taking place and begun to prepare the emirate, in line with the UAE's 2050 energy strategy. It is pursuing greater economic diversification and preparing for a changing energy system, both at home and internationally. This includes placing a greater focus on streamlining oil and gas production, electricity and water — including desalinated — generation and renewables, while driving collaboration among the relevant state entities where possible, for example in areas such as hydrogen.

Adnoc's strategy is clear: it is moving to produce more oil in a shorter time frame, aiming to boost oil production capacity by 1 million barrels per day to 5 million b/d by by 2030, while also

seeking self-sufficiency in gas production by the end of the decade (PIW Feb.5'21). It is also keeping downstream expansion plans on track, bolstering marketing and trading capabilities — including through this year's launch of the Murban crude futures contract — and pursuing the type of flexible financing strategy that has allowed it to raise around $25 billion since 2017 via the lease of key infrastructure and assets and stake sales in its listed retail fuel unit. This week's announcement that it would float a 7.5% stake in Adnoc Drilling on the Abu Dhabi Securities Exchange (ADX) is the latest case in point.

While Adnoc's role has always been focused on the development of Abu Dhabi's hydrocarbon reserves, the remits of quasi-state firms Taqa and Mubadala have been broader historically, both in terms of portfolios and geographies. Both have invested in international oil and gas — along with other energy — assets. But more recently, Abu Dhabi appears to be moving toward positioning them more clearly. Taqa is being turned primarily into a utility, with a strong national focus but also international assets. Last week, the majority Abu Dhabi government-owned and ADX-listed company said it might sell some or all oil and gas assets as part of a broader strategic review. Their reorientation reflects the pervasive change taking place in the emirate in response to the transtion. "Our future is as a utility business with a large, regulated asset base and long-term contracted generation plants at its core," Taqa CEO Jasim Husain Thabet told Energy Intelligence in July. Set up in 2005 at a time of rising oil prices, Taqa quickly began to expand across the globe, acquiring oil and gas assets in Canada, the US, the UK, Netherlands and Asia, along with power and water assets in Africa. But the spending spree left the company with a $24 billion debt pile 10 years later, forcing it to restructure and sell some oil assets.

Mubadala, the owner of local renewables firm Masdar, meanwhile continues to focus on renewables and clean energy technologies — and increasingly on gas and LNG. Through its Mubadala Petroleum unit, the company is seeking to decarbonize energy production and has identified lower-carbon gas and LNG as bridge fuels to the energy transition. Both gas and LNG are set to account for around 70% of its portfolio going forward, Bakheet al-Khateeri, head of UAE industries at Mubadala, recently told Energy Intelligence.

New Producers, New Pressures in South America

Newly found oil riches in Guyana and Suriname could drastically transform both countries economically, politically and socially. However, monetization of these resources will come amid heightened climate change concerns as the world and energy industry finally get serious about decarbonization and reducing emissions. Yet both South American nations are pushing to quickly move ahead with exploration and development plans at one of the world's final frontier oil basins. They are trying to head off environmental concerns by emphasizing the "advantaged" low-cost, low-carbon barrels from their huge offshore reserves, while noting the enormous "carbon sink" capacity of their vast forests. The Guyana-Suriname Basin has recoverable resources of around 11 billion barrels of oil equivalent. In Guyana, Exxon Mobil and partners Hess and China National Offshore Oil Corp. have found more than 9 billion boe in the offshore Stabroek Block (PIW Sep.27'19). Guyana could be producing around 1 million barrels per day by 2025-26 and well above that by 2030, Natural Resources Minister Vickram Bharrat said at last month's Offshore Technology Conference (OTC) in Houston. In Suriname, partners APA (formerly Apache) and TotalEnergies have found close to 2 billion boe in offshore Block 58. Production from the block could commence in 2025, Patrick Brunings, exploration manager at Suriname's state-run oil company Staatsolie told OTC. Consultancy Rystad Energy foresees total production from initial finds in Block 58 peaking at almost 550,000 b/d in the mid-2030s.

Guyana's new government has a pulse on the energy transition, but new oil revenues from deepwater developments are too tempting to turn down. Guyana has already launched a low-carbon development strategy in pursuit of a nonpolluting growth pathway given the enormous carbon sink capacity of its forests. It is also stepping up efforts to reduce emissions from oil operations using low-carbon technologies. "We realize ... we need to explore [our] resources to the fullest potential in the shortest possible time because we're working against a tight time frame to ensure that we do so," Bharrat said. Guyana is already a net-zero emitter and will likely remain that way despite the addition of Exxon's production, the country's Vice President Bharrat Jagdeo told OTC (PIW Apr.16'21). Guyana's forests, which cover more than 85% of the country, serve as a carbon sink for 19.5 gigatons of carbon dioxide equivalent, representing annual sequestration of 154 million tons of CO2. "Where the world is trying to get by 2050, Guyana is already there," Jagdeo said. Guyana's government remains committed to its resource development mandate despite calls to back off. "We cannot remain locked into a cycle of low-carbon emissions but low income," Jagdeo argued. "If we freeze all new investments now in [the] oil and gas sector, particularly in countries like Guyana ... what we are doing is locking this investment in for the incumbents. Why should we not want to displace some of the higher-cost producers in the world?"

Neighboring Suriname also plans to continue development in a sustainable manner. Onshore and near-shore production will get a much-needed boost from offshore developments over the short term (PIW Aug.28'20). APA and Total expect to sanction their first development in deepwater Block 58 as soon as 2022, with initial oil flowing around mid-decade. Suriname needs the economic boost from deepwater developments, but it also notes the role these projects will play in funding international oil companies' energy transition plans. "The focus now is on oil and gas production since revenues from those sectors will be needed to invest in green energies," Staatsolie's Brunings told OTC. Suriname is also a net-zero emitter, and "looks to stay carbon neutral and if possible even carbon negative," despite the addition of deepwater oil production, Brunings said. Suriname is also covered by large forests — part of the Guiana shield, a regional biodiversity hotspot that spans some 270 million hectares — that serve as a carbon sink. Suriname also benefits from hydropower, several solar projects, and is pondering a floating solar park in addition to options like wind, hydrogen and other green energies.

Ida Effects May Linger as Output Slow to Restart

Hurricane Ida, which tore through Louisiana almost two weeks ago, has had a muted impact on oil markets so far (PIW Sep.3'21). But with 1.4 million barrels per day of crude production still off line and no clear timeline for it to return, the effects could still be significant. The aftermath of the storm has been atypical for the US Gulf Coast oil industry, which typically sees upstream production return faster than area refineries. In all, some 20 million bbl of crude and 20 million bbl of refined products have gone unproduced thus far due to the storm. After slamming Louisiana, Ida continued northwards and eastwards, with its dregs flooding parts of New Jersey, Pennsylvania, and New York — a premier market for gasoline. And yet markets did not respond that strongly; global benchmark Brent is less than $1 above pre-storm levels while the Nymex gasoline contract has retreated. Offshore production remains under significant pressure. Energy Intelligence estimates almost 80% is still off line, amounting to some 1.4 million b/d — much of it the heavier, more sour grades that Gulf Coast refiners crave. As a result, Energy Intelligence now expects 2021 US production to come in 200,000 b/d below 2020 levels. Refiners have resumed operations more quickly. Ida sent some 2 million b/d in refining capacity off line ahead of landfall, but already roughly 1.3 million b/d of that is in some stage of the restart process. It will take more than a week from now for utilization to hit pre-storm levels, experts say.

Ida has also hampered port activities. A massive storm surge flooded Port Fourchon, the onshore counterpart to the Louisiana Offshore Oil Port (Loop), disrupting crude flows into the US. Operations at Fourchon and at Loop have yet to normalize, and it was only Monday that Fourchon said tenants could return (p8). Meanwhile, waterways and roads clogged with debris, as well as power outages, have interfered with assessments and restart operations. With inbound crude flows facing significant hurdles, the US government has stepped in. The Strategic Petroleum Reserve (SPR) has enacted several exchanges with refiners in the Baton Rouge, Louisiana area. Exxon Mobil's Baton Rouge facility, the first refiner to announce restart, accepted 1.5 million bbl of sour crude from the SPR — under the terms of exchange, an equivalent amount of crude must be returned with a premium added. The Environmental Protection Agency (EPA), meanwhile, has enacted a fuel waiver for vessels near Port Fourchon, effectively canceling International Maritime Organization (IMO) sulfur specifications for a brief period to smooth logistics and get feedstock flowing to refiners — and other goods to other markets. Petroleum exports, on the other hand, face fewer hurdles as they tend to be loaded at ports west of Ida's path in Texas.

The upstream outages and port havoc juxtaposed with the relatively quick downstream recovery have robbed refiners of one of the typical silver linings from storms. Offshore production usually resumes faster than refinery operations, leading to lower crude prices and higher margins for refiners still running once demand starts to recover. But Energy Intelligence data show Gulf Coast profits in a complex refinery against an incremental barrel of medium, sour Mars at $17.45 per barrel — down from over $19 just after Ida made landfall and only some $2 above the pre-storm levels. Several other factors are also at play; from a seasonal perspective, peak demand for gasoline has passed and margins typically descend. In addition, global demand remains under pressure from the Covid-19 pandemic, and the US is the world's largest exporter of refined products.

Ida's biggest impact could be on US natural gas markets, which were already experiencing higher prices due to growth in exports, strong domestic consumption, and relatively flat production (PIW Aug.27'21). As a result of Ida shut-ins, the U.S. Energy Information Administration now expects fourth-quarter Henry Hub spot prices to average $4 per million Btu, up 16% from its August forecast.

Will Iraq Deal Be New Model for Megaprojects?

(Continued from p.1)

To be sure, Total was uniquely positioned to make this deal. Unlike some rivals, its transition strategy keeps the door open to new, large investments in oil to maintain stable or even higher production volumes this decade, when global oil demand is expected to keep growing (PIW Aug.6'21). Total also brings significant solar power expertise. Royal Dutch Shell has shifted its fossil fuel growth focus squarely to gas and LNG, and BP's transition plan entails a 40% drop in upstream volumes by 2030 (PIW Feb.14'20). US majors Exxon Mobil and Chevron have no interest in renewable power projects because they say returns are too low. However, Total does not plan to shrink its upstream volumes in the coming years and is prioritizing lower-cost, shorter-cycle projects, making the Middle East a focal point. Total still aims to grow its oil and gas production to 3.3 million-3.4 million barrels per oil equivalent per day in 2025 from an expected 2.87 million boe/d this year, despite an acceleration in spending on renewable and low-carbon energy. Indeed, Total believes continued strong volumes and cash flows from its traditional upstream operations are needed to fund its long-term shift into greener energy (PIW Jun.12'20).

Total may enjoy more leeway from investors than rival IOCs because it has been a leader in setting and implementing a coherent transition strategy. This includes a 2050 net-zero target for operational emissions (Scope 1 and 2) and a less ambitious Scope 3 component for end use of its products. But investor attitudes are changing rapidly, and the French major invites greater scrutiny with every new oil project it commits to — particularly if Scope 3 demands intensify (PIW Aug.27'21). Earlier this year, the Climate Action 100+ investor consortium, which has over $54 trillion under management, asked Total to expand its emissions goals and commit to absolute reductions, saying its plans fall short of the Paris goals. Climate Action 100+ investors own more than 25% of Total's shares. More than 8% of Total's shareholders voted against the company's energy transition strategy in May, showing that even proactive IOCs remain vulnerable to mounting climate pressure.

It's unclear if other large producing countries will follow Iraq's lead and offer similar integrated deals, but pressure is building on producers to avoid stranded assets and diversify their economies beyond oil and gas. Further opportunities could arise in Iraq, where rampant gas flaring and electricity shortages beg for solutions, and elsewhere in the Middle East. Carbon capture and storage and solar power will be part of Qatar's LNG megaexpansion, where awards are due soon and Total is already involved on the solar side (PIW Feb.12'21). Saudi Arabia is looking to open its upstream gas sector; Iran could be in play again if US sanctions are lifted; and North Africa is eyeing green hydrogen opportunities.

Can North Africa Seize Green Hydrogen Chance?

As Europe seeks to decarbonize to achieve its climate change commitments, some European policymakers and industry bodies are pushing green hydrogen produced in North Africa as a viable solution (PIW Jun.11'21). Carbon-free green hydrogen made from renewable electricity and water could play a critical role for Europe, which cannot do this itself on the scale required given its limited land area and population density. North Africa's rich solar and wind resources offer Europe the chance of hydrogen imports via existing hydrocarbon infrastructure, which could be cost-effectively re-tasked. The opportunity could prove attractive to both sides. Europe could develop a low-carbon resource on its doorstep, while some politically unstable and economically fragile North African states could create new markets, replacing some oil and gas exports with hydrogen. Pilot projects are sprouting across Morocco, Algeria and Egypt. In late July, the $850 million Hevo Ammonia Morocco project was launched involving Dublin-based Fusion Fuel Green, Athens-based contractor CCC and Swiss trader Vitol, which would manage the offtake. A first phase could see a 183,000 ton green ammonia plant in Morocco, which could abate 280,000 tons of CO2 per year. In Egypt, Siemens signed a memorandum of understanding with Cairo last month to develop a hydrogen-based industry with export capability. In Algeria, the new Energy Transition and Renewable Energies Ministry, state Sonatrach, German development agency GIZ, and consultancy Tractebel are all looking into green hydrogen's potential.

But both sides have been here before, with little to show for it. In 2009, the Desertec Industrial Initiative (DII) sought to export solar power from the Sahara to meet 20% of Europe's electricity

demand by 2050 but was eventually abandoned. Now, some of the same public-private network has emerged as DII Desert Energy pursues zero-emission projects across the Middle East. Hydrogen's potential as a clean energy carrier continues to attract attention, but there is no consensus view on its future market size (PIW Aug.14'20). "Green hydrogen feels like solar 10 years ago and it feels unavoidable," argues Frank Wouters, chairman of DII's advisory board and currently at India's Reliance. The first DII, he says, was more of an idea than a project and a means to build dialogue. The original vision foundered on the costs of expanding an electricity grid between Africa and Europe.

Energy Intelligence believes much will depend on how hydrogen's costs evolve versus other sources of energy. Our levelized cost of hydrogen is based on our levelized cost of energy model, which is used to calculate the cost of generating electricity from different energy sources (NE Sep.2'21). Green hydrogen is expensive at around \$3-\$4 per kilogram, with power at \$40 per megawatt hour and available about 40% of the time, which is roughly what offshore wind or solar photovoltaic (PV) with batteries can deliver. Green hydrogen's key cost driver is electricity prices. It could reach \$1.50/kg if cheaper capital expenditure was possible; power fell to \$20/MWh — in line with recent Mideast PV tenders; and batteries enabled utilization rates of 50% or higher. A Europe-North Africa Hydrogen manifesto, co-authored by Wouters, argues that a green hydrogen market could emerge that produces hydrogen for €1/kg (\$1.19/kg). A report by McKinsey and the Hydrogen Council says Algeria could produce green hydrogen under \$2/kg.

The geopolitics around climate change and the investment landscape have changed dramatically over the past 12 years. Investor pressures are building momentum across the industry that could enable green hydrogen exports from North Africa to Europe to take off. But significant obstacles remain. Power subsidy reforms will be needed across North Africa for such a vision to become reality. Moreover, as with oil and gas developments, political instability could impact any transition to hydrogen. Algeria is targeting 15,000 MW of renewable power by 2035, with a growth rate of 1,000 MW per year (PIW Jul.23'21). Natural gas still accounts for some 96% of Algeria's current installed capacity, with solar, wind, hydro and oil accounting for the remaining 4%. "A clear strategy for renewables has to deal with subsidized electricity to clear the way for a sustainable renewable development in Algeria," says a former Algerian oil minister. However, Algeria remains locked in a political crisis since the fall of former President Abdelaziz Bouteflika in 2019 after a 20-year rule. "Dealing with subsidies is not a priority for the present government given the economic and political situation in the country," he says.

Demand Forecast Sees Return of Some Normalcy

Despite fresh outbreaks of the Covid-19 Delta variant, the rollout of vaccines is restoring some normalcy to oil markets, including a return to demand seasonality. With some exceptions, oil consumption patterns are acting more like before the pandemic started in early 2020, which should improve the reliability of demand forecasts going forward (PIW Jun.25'21). This year's demand recovery has shrouded the impact of seasonal fuel demand, perhaps except for US gasoline during the just concluded summer driving season. Covid-19 wiped an estimated 8.9 million barrels per day from oil consumption to 92.1 million b/d last year. Some 5.2 million b/d should return this year, Energy Intelligence reckons, but new outbreaks keep forcing tweaks to that estimate. Even in normal times, changes to forecasts can be large. The pandemic made forecasting harder as it knocked the base out of demand models. Supply had to adjust, mostly through Opec-plus cuts. In a regular year, 100 million b/d of demand for oil products is met roughly by 80 million b/d crude that is processed through refineries; 15 million b/d by natural gas liquids; 3 million b/d by biofuels; and 2 million b/d by refinery gains.

Seasonality brings a rhythm to demand and helps predict swings. In the coming Northern Hemisphere winter, Asia will burn much kerosene, Europe more heating oil, and the US more heating oil and propane. The pandemic disrupted many rhythms through lockdowns and other behavioral changes like working from home. As it lingers, it continues to affect fuel consumption, but greater clarity on the long-term effects is emerging. In a regular year, US gasoline demand is 1 million b/d lower in January than in the peak August month. But workers are still commuting less as many still work from home. Business travel, on land or by air, is down and might not recover since many meetings are now held on line. Leisure travel should return and might increase, helping gasoline and jet fuel over time. Shortening supply chains, the buzz at the start of the pandemic, seems overstated based on bumper international trade, but the local-is-reliable trend is taking root.

Swings to forecasts remain big. The Delta variant, combined with weaker data in emerging markets, shaved 480,000 barrels per day off Energy Intelligence's 2021 demand forecast in July alone (PIW Jul.23'21). Expectations that international flights and travel would resume this summer did not materialize due to Delta's spread in June. Demand growth for 2021 is now seen at 5.2 million

b/d — where the forecast started the year. Vaccine optimism had once upped that to 5.8 million b/d, with jet fuel accounting for most of the increase. Two-thirds of global oil products are consumed as transportation fuels. Lockdowns primarily impacted commuting, flying and shipping. Fuel-gulping international travel remains mostly out, although domestic travel is booming in the US, Europe, China and Russia. Gasoline demand is above pre-pandemic levels as people avoid public transportation or airplanes. The jet fuel impact is stark in global oil demand forecasts. December 2021 demand is expected to be 2.1 million b/d below December 2019, with jet fuel accounting for 1.9 million b/d of the shortfall.

A new disrupter is also taking hold with the energy transition, which will compound the challenge for forecasters. Transition impacts will be felt rapidly in transportation fuels — gasoline and diesel first, with the introduction of alternative power sources like electric and hydrogen. Covid-19 rendered 2020 baseless for 2021 oil consumption forecasts. Likewise, the transition could over time make GDP much less useful for assessing future demand (PIW Aug.6'21). Refinery output will remain helpful for measuring actual demand. Much of actual demand is measured by what refineries produce, which are the oil products that consumers burn. But this method also has flaws. When refiners plan maintenance, consumers do not stop driving, but delivered products go down, which shows up as lower demand — a quirk that can make global demand swing a few million b/d month on month, especially in May and September.

Kazakhstan Faces Up to Low-Carbon Era

Kazakhstan, once a magnet for Western majors eager to invest heavily in offshore oil and gas developments, is battling to stay relevant in the new low-carbon era. While the three giant fields of Tengiz, Kashagan and Karachaganak will continue to make up the bulk of its oil and gas production for years to come, the Kazakh government is shifting its focus to renewables (PIW Aug.13'21). A recent tie-up between national oil company Kazmunaigas and Eni to pursue a range of wind, solar and hydrogen projects across the country points to the way forward, and this model could be copied by some of the other majors. Eni, which played a central role in Kazakhstan's evolution as a major oil producer, believes the country has huge potential in renewables and has already invested in wind projects that the Kazakhs put out to tender several years ago.

Over the next three to four years, Opec-plus member Kazakhstan is hoping to increase its oil production capacity — including gas condensate — beyond the 2 million barrel per day mark. This will depend entirely on the timing of the ongoing expansion of the Chevron-operated Tengiz field, which already accounts for roughly one-third of current output of 1.8 million b/d (PIW Mar.26'21). Due to Covid-19-related disruptions, the planned completion of the project has been pushed back at least six months until mid-2024, although Chevron said in July that work was 84% done and making steady progress. If all goes to plan, Tengiz production will increase by some 30% to around 850,000 b/d, with all the incremental barrels to be pumped to the Russian Black Sea via the Caspian Pipeline Consortium (CPC) pipeline and marketed as CPC Blend to predominantly European buyers. The main snag for Chevron and its partners — Exxon Mobil, Kazmunaigas and Lukoil — is that the expansion would have cost them some $45 billion when all work is done, more than a quarter more than the original estimate. Even so, at current oil prices, the costs should be reimbursed long before the joint venture contract expires in 2033.

The reality is now dawning on Kazakhstan that the 9 billion barrel-plus offshore Kashagan oil field, which was supposed to become its largest single producer with output of over 1 million b/d, will fail to reach its full potential. Over two years ago, the North Caspian Operating Co. (NCOC), the seven-member consortium overseeing the project that includes Eni, Total, Royal Dutch Shell and Exxon, achieved the Phase 1 plateau of around 400,000 b/d. But the cost of a second development phase, estimated in the tens of billions of dollars, is prohibitive. With the production-sharing contract expiring in 2041, none of the partners is willing to commit that kind of capital, which they could deploy instead on much lower-cost, shorter-cycle projects. The best that NCOC and Kazakhstan can hope for is that production from Kashagan rises to around 500,000 b/d through a combination of extra gas reinjection and the debottlenecking of existing facilities.

As new offshore projects lose their attraction, Kazakhstan is trying to drum up interest in new exploration onshore. At the end of last year, the country sold rights to several blocks in its first-ever online auction, and a second one was held in April. The results, however, were disappointing: none of the established oil companies bothered taking part, and it was exclusively Kazakh-owned entities that snapped up the acreage. Kazakhstan has had more luck in auctioning rights to renewables projects, with a helping hand from the European Bank for Reconstruction and Development, and plans to hold more tenders in the months and years ahead. The country has set itself the ambitious goal to have 10% of domestic power produced from renewable energy by 2030, and 50% by 2050, as it phases out the use of locally produced coal.

What's New Around the World

CORPORATE — Chevron's upcoming strategy update outlining its low-carbon plans has taken on new significance following reports of potential activist shareholder interest in the US major. The Wall Street Journal reported that Engine No. 1 — the plucky activist upstart that successfully overhauled Exxon Mobil's board earlier this year (PIW May28'21) — has received queries from other investors about potentially launching an activist campaign against Chevron regarding its energy transition strategy. Citing unnamed people familiar with the matter, the Journal said Engine No. 1 hasn't decided whether it wants to pursue another campaign at a major oil company. The hedge fund also gave no indication of its plans with Chevron during recent talks with company executives. But how things proceed from here could weigh heavily on what Chevron delivers during its Sep. 14 strategy update. The company has couched the meeting as offering new insights into how Chevron aims to reduce its carbon intensity. But Chevron officials have declined to specify whether fresh targets are in play or if they will simply provide further details around existing plans. What is clear is that the boldest the US major is likely to go is embrace net-zero emissions targets exclusively around its operations

CORPORATE — Midstream giant Enbridge has acquired a major piece of export infrastructure along the US Gulf Coast in a big bet on the future of US oil production and exports. The Canada-based pipeline and logistics firm will acquire Moda Midstream's dock and associated assets at the Port of Corpus Christi for some $3 billion in cash. The asset can export some 1.5 million b/d of crude oil and includes roughly 15.6 million bbl of storage capacity. The facility has permits to expand to 21 million bbl of storage and 1.9 million b/d of export capacity. Enbridge is renaming the facility — the Enbridge Ingleside Energy Center — and said it has a long-term 925,000 b/d commitment underpinning the deal. The transaction includes a 20% stake in the 670,000 b/d Cactus II pipeline as well as 100% operating interest in the 300,000 b/d Viola pipeline and 350,000 b/d Taft terminal. Acquiring Moda's port facilities means Enbridge can offer shippers a direct and wholly owned path from oil sands wellheads in Alberta, the fields of the US Bakken Shale, and other regions nearly all the way to the point of loading for a tanker. But Enbridge is largely targeting light crude, such as that produced in the nearby Permian Basin. The transaction also highlights the dramatic emergence of North America as a crude exporter and confidence that those flows are here to stay.

Opec-Plus Compliance Soars in August

Technical issues in several countries kept oil production in Opec-plus largely flat in August. As a result, the compliance rate for the alliance came to 117%, Energy Intelligence caluculates, one of the highest levels in the 16 months the new agreement has been in force. For the first time compliance among the nine non-Opec members surpassed 100%, due mainly to a steep fall in Kazakhstan, where the Chevron-operated Tengiz field is undergoing maintenance.

Among the 10 Opec members with quotas, Nigeria was the standout again, its persistent terminal mishaps leading to a monthly output decline and compliance rate of 264%. Heavyweights Saudi Arabia and Iraq also produced below quota, giving the group of 10 Opec producers a rate of 125%.

All told, last month Opec-plus produced 922,000 b/d short of its collective ceiling of 36.74 million b/d. The trend of underproducing is poised to continue in September, and possibly into the autumn, as countries grapple with technical constraints (PIW Sep.3'21).

August 2021 Opec and Non-Opec Compliance

Opec	Base	Target	Aug	Compliance	
Saudi Arabia	11,000	1,400	9,413	1,587	113%
Iraq	4,653	593	4,008	645	109%
UAE	3,168	403	2,768	400	99%
Kuwait	2,809	357	2,443	366	103%
Nigeria	1,829	233	1,215	614	264%
Angola	1,528	194	1,198	330	170%
Algeria	1,057	135	919	138	102%
Congo (Br.)	325	41	224	101	NA
Gabon	187	24	171	16	NA
Eq. Guinea	127	16	84	43	269%
Opec 10	**26,683**	**3,396**	**22,443**	**4,240**	**125%**
Iran	3,296	0	2,510	0	NA
Venezuela	1,171	0	530	0	NA
Libya	1,114	0	1,190	0	NA
Opec 13	**32,264**		**26,673**	**4,240**	**125%**

Non-Opec	Base	Target	Aug	Compliance	
Russia	11,000	1,400	9,711	1,289	92%
Mexico	1,753	0	1,574	0	NA
Kazakhstan	1,709	218	1,329	380	174%
Oman	883	113	789	94	83%
Azerbaijan	718	91	618	100	110%
Malaysia	595	75	420	175	233%
Bahrain	205	26	178	27	104%
South Sudan	130	17	153	-23	NA
Brunei	102	13	98	4	31%
Sudan	75	9	81	-6	NA
Non-Opec 10	**17,170**	**1,962**	**14,951**	**2,040**	**104%**
Combined 20	**43,853**	**5,358**	**37,394**	**6,280**	**117%**

In '000 b/d. Opec and non-Opec compliance based on crude oil only. Mexico no longer has a quota but nominally is a member of the non-Opec alliance. Source: Opec, government data, Jodi, Energy Intelligence.

Big Boost for Global Oil Supply

Global liquids supply got an 839,000 barrel per day boost in August from both Opec-plus and non-aligned producers as they chased rising summer demand (PIW Aug.13'21). At 97 million b/d, global supply was 4.85 million b/d higher than August in 2020. Over the year, Opec-plus added 3.15 million b/d in crude output while non-Opec-plus grew by 1.2 million b/d, with the balance coming mostly from natural gas liquids. In August, key additions were seen in Brazil, Norway, China, Iraq, Angola and Russia. Hurricane Ida in the US will shave an expected 500,000 b/d from September crude supply in the US.

World Crude Oil and Other Liquids Supply

('000 b/d)	Jul '21	Aug '21	Chg.	Crude Aug	Other Aug
Non-Opec-Plus	**44,837**	**45,310**	**473**	**31,693**	**15,785**
US	18,034	17,983	-51	11,230	6,753
Canada	5,530	5,530	0	4,300	1,230
Brazil	4,215	4,484	269	3,100	1,384
Colombia	750	755	5	755	0
Norway	2,035	2,095	60	1,775	320
UK	950	957	7	857	100
Egypt	693	695	1	605	90
Qatar	2,077	2,075	-3	594	1,481
China	3,921	3,983	62	3,983	0
India	698	693	-5	585	109
Indonesia	705	708	3	667	41
Other Non-Opec-Plus	5,228	5,353	125	3,243	4,278
Opec-Plus	**49,119**	**49,517**	**398**	**41,625**	**7,892**
Opec	**31,524**	**31,921**	**397**	**26,673**	**5,248**
Saudi Arabia	11,783	11,769	-14	9,413	2,356
Iraq	3,975	4,076	102	4,008	68
Iran	3,245	3,253	8	2,510	743
UAE	3,782	3,830	48	2,768	1,062
Kuwait	2,592	2,607	16	2,443	164
Nigeria	1,446	1,427	-19	1,215	212
Libya	1,175	1,252	77	1,190	62
Algeria	1,302	1,346	44	919	427
Angola	1,009	1,216	207	1,198	18
Other Opec	1,216	1,145	-71	1,009	136
Non-Opec	**17,595**	**17,596**	**2**	**14,952**	**2,645**
Russia	11,221	11,379	158	9,711	1,668
Kazakhstan	1,788	1,630	-158	1,329	300
Azerbaijan	779	803	24	618	185
Mexico†	1,798	1,758	-40	1,574	184
Oman	1,044	990	-54	789	201
Malaysia	488	505	17	420	85
Other Non-Opec	477	532	55	510	22
World Supply	93,956	94,827	872	73,317	23,678
Refinery gains	2,200	2,168	-32	0	0
Total World	**96,156**	**96,995**	**839**	**73,317**	**23,678**

*Other liquids include natural gas liquids, biofuels, gas-to-liquids, coal-to-liquids, refinery additives. †Mexico nominally is a member of the Opec-plus alliance but has no production quota. Source: IEA, EIA, Jodi, government and trade data, Energy Intelligence.

Marketview

Life on Mars

The recent release of crude from the US Strategic Petroleum Reserve (SPR) put Saudi Aramco in a tricky spot in pricing its exports to Asia.

The 20 million barrels of SPR crude helped crack the US crude arbitrage window to Asia wide open. At least 12 million bbl of US crude, mostly heavy, sour Mars, ended up being sold to buyers in China, South Korea, Taiwan, Japan and India, and were expected to arrive from October to December (PIW Sep.3'21).

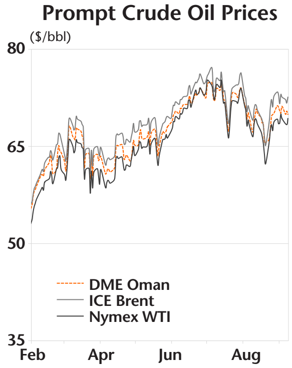
Those Mars cargoes were sold at very cheap prices, with many deals concluded at premiums ranging from 50¢ per barrel to around $1.70/bbl to the Dubai benchmark on a delivered basis into Asia, sources said.

This meant that they were very competitive with comparable Mideast crudes. When the deals were done, the most recent Saudi official formula prices were for September loaders, with Aramco in the process of setting its October formula prices.

September Saudi Arab Medium, whose API is very close to Mars but is more sour, was priced at a premium of $2.45/bbl to the Dubai and DME Oman benchmark price average. Add in freight of around 80¢/bbl from the Mideast to China, and September Arab Medium was pricing at a premium of $3.25/bbl when delivered into China from late September to October. This meant that Arab Medium was around $2/bbl more expensive than Mars, said a trader.

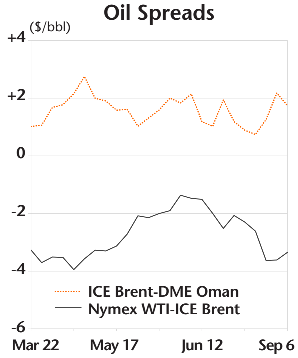
Some market players thought this dynamic would factor into Aramco's October prices — but they did not expect the Saudis to cut their prices as deeply as they did.

Prompt Crude Oil Prices



Source: Nymex, ICE, DME

Benchmark Crude Oil Spreads



Source: Nymex, ICE, and DME Prompt Settlements

When Aramco slashed the October Arab Medium formula price by $1.00/bbl, it sparked widespread surprise and shock in the market. Five Asian trading sources predicted that Aramco would only cut the October Arab Medium by 15¢/bbl to 40¢/bbl from September. One Asian refiner source even expected an increase of 15¢/bbl.

But if Aramco had followed through with these predicted cuts, October loading Arab Medium, which would arrive in Asia from late October to November, would still be much more expensive than Mars.

That would have meant unhappy Asian term lifters, some of whom could have have asked for less Saudi crude at a time when Aramco's production is rising due to the easing of Opec-plus supply cuts (PIW Sep.3'21).

With its position in the world's most important oil market possibly at risk, it appears that Aramco took the threat from Mars seriously.

But now comes a twist.

Hurricane Ida damaged a key transfer hub handling Mars crude, with production still offline more than a week later (p3). At least some of the Mars cargoes sold to Asia are affected, likely by loading delays — although force majeure is unlikely to be declared, Asian market players say.

The Louisiana Offshore Oil Port, the only US terminal capable of fully loading very large crude carriers, is also still off line, which hurts the economics of Mars crude heading to Asia, a trader noted.

Ironically, Mars' threat to Aramco's position in Asia has now receded somewhat.

Protesters Shut Key Libyan Oil Ports

Libya's reliability as a crude supplier was tested again this week when protesters shut down loading operations at the oil ports of Es Sider and Ras Lanuf on Wednesday, while a demonstration at the port of Marsa al-Hariga led to the closure of the main gate.

The twin terminals of Es Sider and Ras Lanuf have a combined export capacity of some 550,000 b/d while Hariga has a capacity of around 110,000 b/d. All three are located along the coastal crescent of eastern Libya's oil-rich Sirte Basin. A prolonged shutdown at Es Sider and Ras Lanuf would likely impact global oil supplies and prices (PIW Apr.16'21).

PIW Market Indicators

($/barrel)	Sep 6-Sep 8	Aug 30-Sep 3	Aug 9-Aug 13
Spot Crude			
Opec Basket	$71.28	$71.76	$70.71
UK Brent (Dtd.)	71.95	72.92	71.09
US WTI (Cushing)	68.91	69.13	68.27
Nigeria Bonny Lt.	72.01	72.62	70.81
Dubai Fateh	70.01	70.74	69.78
US Mars	69.91	68.51	66.60
Russia Urals (NWE)	71.21	71.32	68.74
Crude Futures			
Brent 1st (ICE)	72.17	72.73	70.60
Brent 2nd (ICE)	71.50	71.86	70.20
B-wave (ICE)	72.15	72.55	70.32
WTI 1st (Nymex)	68.83	69.12	68.31
WTI 2nd (Nymex)	68.59	68.86	68.10
Oman 1st (DME)	70.43	70.55	69.71
Oman 2nd (DME)	69.54	70.15	69.05
Murban 1st (ICE)	70.75	71.32	69.85
Murban 2nd (ICE)	70.11	70.70	68.91
Forward Spreads			
Brent (1st-Dtd.)	+$0.22	-$0.20	-$0.49
Brent (2nd-1st)	-0.67	-0.87	-0.40
WTI (2nd-1st)	-0.23	-0.25	-0.21
WTI (3rd-2nd)	-0.31	-0.32	-0.35
Oman (2nd-1st)	-0.89	-0.39	-0.66
Oman (3rd-2nd)	-1.27	-0.73	-0.82
Murban (2nd-1st)	-0.64	-0.62	-0.95
Murban (3rd-2nd)	-0.72	-0.71	-0.74
Grade Differentials			
WTI-Brent (1st)	-$3.56	-$3.76	-$2.50
WTI-LLS	-2.13	-1.71	-0.68
WTI-Mars	-1.00	+0.62	+1.67
Brent(Dtd)-Dubai	+1.95	+2.18	+1.31
Brent(Dtd.)-Urals	+0.74	+1.60	+2.35
Brent(Dtd.)-Bonny Lt.	-0.06	+0.30	+0.28
Term Crude Formulas			
Arab Lt.-US (c.i.f.)	$72.74	$71.34	$69.33
Arab Lt.-Europe (Med)	70.45	70.85	69.52
Arab Lt.-Far East (f.o.b.)	73.55	74.09	72.90
Nigeria Bonny Lt.	71.64	72.61	71.52
Arab Light Gross Product Worth			
Rotterdam	$71.98	$71.85	$71.09
US Gulf Coast	79.69	81.42	78.36
Singapore	71.24	70.56	69.27
Gross Product Worth & Margins			
Rotterdam			
UK Brent GPW	$76.79	$76.68	$69.92
UK Brent Margin	+3.73	+3.08	-1.77
US Gulf Coast			
Mars GPW	78.25	79.78	76.68
Mars Margin	+8.24	+11.17	+9.98
Singapore			
Oman GPW	72.36	71.18	69.50
Oman Margin	+0.81	-0.72	-1.51
US Nymex			
WTI 3-2-1 Crack	+$20.65	+$22.65	+$24.36
Refined Products			
Rotterdam ($/ton)			
Eurobob Gasoline	$720.93	$718.95	$709.32
Gasoil (0.1%)	595.92	597.50	571.90
Fuel Oil (0.5%)*	502.17	502.25	481.50
US Gulf Coast (¢/gal)			
RBOB Gasoline	213.61¢	223.12¢	223.84¢
ULS Diesel	208.93	209.83	202.71
Fuel Oil (0.5%, $/ton)	$510.67	$508.20	$498.60
Singapore ($/bbl)			
Naphtha	$72.53	$71.59	$72.59
Gasoil (0.05%)	76.29	75.81	74.28
Fuel Oil (0.5%, $/ton)	542.00	535.20	521.60

*ARA fuel oil prices for 1% sulfur fuel oil (LSFO) have been discontinued as the market becomes increasingly illiquid. The new 0.5% sulfur fuel oil (VLSFO) specs reflect the transition to new emissions standards set by the International Maritime Organization effective Jan. 1 2020. Latest week's data are preliminary. For GPW and margin calculations, see Refining Profitability Methodologies on the Energy Intelligence website in Reference Tools Publication Methodologies. Spot prices from Thomson Reuters. Opec basket source, Opecna. 3-2-1 crack spread for 3 parts crude, 2 parts gasoline, and 1 part heating oil. PIW Numerical Datasource subscribers can download all indicators in Excel worksheets.