Global capex growth to accelerate

Worldwide E&P spending is set to increase 16% in 2022, extending the 5.5% growth experienced in 2021. The first coordinated global upturn since 2018 will be led by North America, but ambitious capacity growth targets in the Middle East, Latin America and Africa will drive international capex gains.

JAMES WEST, Evercore ISI

Our initial take for 2022 is for global E&P capex spending to increase 16%, with North America (NAM) and international both rising for the first time since 2018, Fig. 1. International spending accounts for a near- record 80% of global capex, and growth is expected to accelerate from 7.4% in 2021 to 14.9% in 2022.

However, for the first time in four years, international growth is projected to lag NAM, which has contracted for three straight years. We believe spending in NAM is poised to increase 20.6% in 2022 and lead the global recovery, Table 1. The U.S. could see total E&P capital spending increase 23.5% in 2022, led by privates, +42%, and independents, +26.5%. Combined with Canada's 7.7% growth, North America leads all geographic regions.

International capex gains will be led by the Middle East, +19.5%, while Latin America and Africa come off a low base at more than 40% below their 2014 peak, Table 2. In contrast, spending in the Middle East has held up remarkably well and is only 13% from peak. Asia remains the largest international market at 27% of the mix, followed by Russia at 17%, while the Middle East and Latin America tie for third at 14%, each. However, this excludes spending by the majors, which account for 11% of all international capex while NAM independents are a modest 1%. For 2022, E&P spending is expected to increase in all regions and across all operator classes, although independents are trimming capex in select regions.

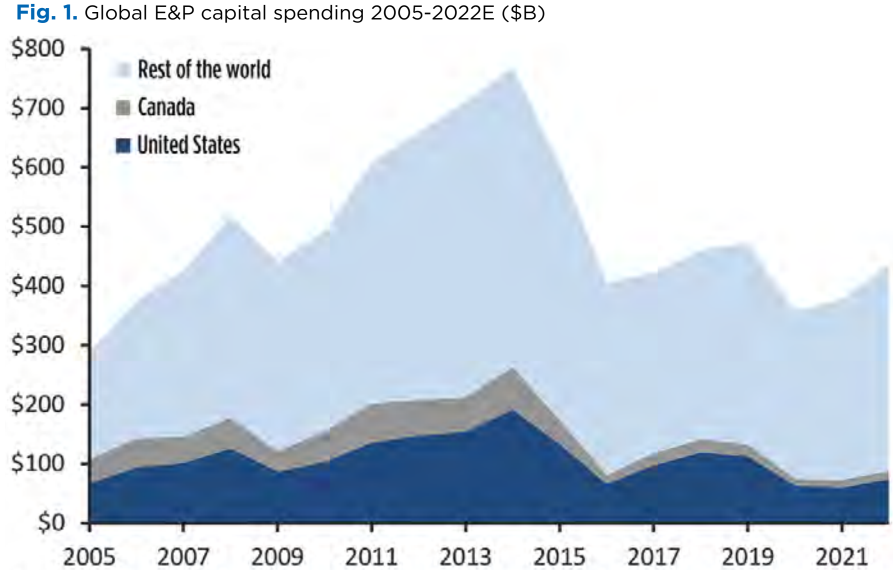
An improved outlook for 2022 is predicated on new Covid variants being contained, plus effective rollout of vaccines and boosters. It is also predicated on continued resurgence in global demand and restrained global supply growth. Cash flow and oil price remain dominant drivers of global E&P spending, and at current levels, commodity prices merit increased investments.

Offshore resurgence. Majors and NAM independents will increase focus on offshore prospects and projects in 2022. The supermajors were noticeably absent during the last mini-upcycle (2018-2019), having largely abstained from both international and the U.S. shale growth until near the end. While some supermajors became key players in the Permian basin, they have scaled down their North American aspirations. Shell is divesting its Permian assets to ConocoPhillips and stepping up buybacks, highlighting the shift in corporate strategies.

For 2022, international spending is accelerating for all operator types except independents, who will trim to 9.7%. Majors will accelerate spending 17.1%, while NOCs increase 15.5% and NAM independents jump 41.6%. We believe higher international spending reflects higher offshore activity, particularly in Latin America, as new projects progress offshore Brazil and Guyana.

Privates play oversized role. We have analyzed financial and strategic documents for approximately 270 oil and gas companies to assess the outlook for the industry. This figure is slightly larger than in past years, as we have sought out more private companies to participate in our survey. Private E&Ps make up 60% of the U.S. land rig count but only about 15% of our U.S. capex estimate, suggesting the U.S. market is larger than we may think. Directionally, our sample of private operators increased capex 20% in 2021, versus total U.S. spending of -6% and are poised to increase capex by more than 40% in 2022.

Fig. 1. Global E&P capital spending 2005-2022E ($B)



Source: Company Data, Salomon Brothers, Salomon Smith Barney, Lehman Brothers, Barclays Capital, Evercore ISI Research

Table 1. North American upstream spending. Source: Evercore ISI Research, company data.

	2022 Survey data, $ millions		2022 Year-on-year Change	
Region	2021E	2022F	$+/-	%
U.S. spending	$59,584	$73,585	$14,001	23.5%
Canadian spending	$13,202	$14,219	$1,017	7.7%
NAM spending	**$72,786**	**$87,804**	**$15,018**	**20.6%**

Digital transformation on hold. Operators have historically been slow to adopt new technologies, and this will likely remain true, with approximately 77% of respondents planning to retain their same decision process toward testing and adopting new technologies. Those more likely to try new digital solutions surprisingly dropped from 30% in 2020 to 22% in 2021. This highlights an eagerness to accelerate production, using tried and proven methods rather than risk delays in testing and deploying a novel approach. However, we expect advanced data analytics, AI/machine learning and remote operations technologies to increase in importance over the coming years.

Capex for renewables. The worldwide spending increases are encouraging, but will competition from renewables hamper oil and gas development in 2022? We are less concerned about the competition for upstream dollars from renewable energy, as it won't be the first time this has occurred. Europe has been investing in renewables for decades, and in the U.S., the DOE has distributed billions in clean energy stimulus over the past several decades. Some companies may be allocating 10% of their capex to renewables and low-carbon resources, but oil and gas are widely perceived as the primary fuels to power the economy. Moreover, we believe traditional oil and gas companies will be fundamental to the success of the energy transition and are encouraged by a confluence of events that are driving digitalization of the oil field and the energy transition.

Unprecedented growth. Evercore ISI economist Ed Hyman has tracked more than 600 stimulus initiatives from the beginning of the Covid outbreak and believes this massive and unprecedented amount of stimulus remains underappreciated. The U.S. economy may be stronger than any of us realize. The Fed's balance sheet has nearly doubled in less than two years and a near-$2 trillion reconciliation package might still follow the $1 trillion Infrastructure Bill. Evercore ISI forecasts GDP growth to remain elevated in 2022.

Demand at pre-pandemic levels. OECD crude and product inventories drew down in October, despite lower refining runs on the back of strong demand across geographies, driving oil prices to a seven-year high of $84.57/bbl on Nov. 9. Despite lagging jet fuel demand, which remains 1.5 MMbpd below the 2019 average, global oil demand is on track to return to pre-pandemic levels of about 100 MMbopd. We forecast global oil demand to increase by 3.8 MMbopd to 100.1 MMbopd in 2022.

Commodity prices. E&Ps are using $70/bbl WTI and $3.90/MMbtu Henry Hub decks for 2022 budgets. Commodity price expectations have generally improved since our mid-year 2021 update, but they then slipped with the emergence of the Omicron variant. As this latest variant has begun to subside, oil prices have jumped noticeably higher, to well above $80/bbl, which is in excess of the $75/bbl level, at which budgets would reset higher. Natural gas budgets are unlikely to be materially revised unless prices fall below $3/MMbtu or increase above $5.50/MMbtu.

Cash flow is king. For the sixth consecutive year and seventh time in eight years, cash flow leads as the key determinant of E&P spending for a near-record 77% of our survey recipients. The oil price and natural gas price continue to rank two and four, respectively, but the oil price slipped slightly while gas increased, suggesting a subtle shift in operators' hydrocarbon targets. Capital availability dropped to seven from three, reinforcing that E&P balance sheets have largely been repaired.

Exploration activity. Exploration spending increased unexpectedly by a three-to-one margin in 2021 versus initial plans for exploration spending to decrease on a net basis for a second consecutive year. Higher oil and gas prices throughout 2021 clearly improved the economics of exploration in the U.S., Canada and internationally, as one in four of our survey respondents plan to increase their exploration budgets for 2022.

OFS pricing. Having experienced broad pricing concessions in 2020, operators entered 2021 expecting oilfield services pricing to remain stable. The majority, 31%, detected no change in service costs, but 23% experienced a slight change in pricing for select product lines, such as completion and downhole tools. For 2022, the overwhelming majority (85%) expect service pricing to broadly increase, led by labor, tubulars and transportation, but also fracturing/stimulation, drilling and other services.

REGIONAL BREAKDOWN

North America. NAM E&P spending is expected to increase 20.6% in 2022, reversing the 1.7% decline in 2021 and part of the 44.1% collapse in 2020. At about $73 billion in 2021, NAM capex fell to its lowest level since 2003 and was about 72% below the 2014 peak and 49% below the 2018 high point.

The U.S. will lead NAM at 23.5%, while Canada decelerates from 21.4% to 7.7% growth. Efforts are underway to reduce emissions from Canadian oil sands production, but we believe Canada is likely permanently impaired, due to the rise of U.S. oil shale and an unfavorable political climate for oil and gas.

Meanwhile, despite the sharp three-year consecutive decline in spending, U.S. crude oil production averaged 11.2 MMbopd in 2021, down only 100,000 bopd, year-over-year, and down 1.7 MMbopd from the November 2019 peak of 12.9 MMbopd. We believe U.S. shale production has peaked, with declining well productivity and increasingly challenging geological conditions limiting production growth. With operators prioritizing capital discipline and limiting capex spending, we believe U.S. shale is also structurally impaired. Thus, U.S.-based E&Ps have shifted focus from production growth, as the rise of value-based management incentives has modified corporate strategies to de-leveraging balance sheets, boosting shareholder returns and creating value into the unfolding commodity upcycle.

Middle East. We expect spending by select Middle East companies will accelerate to 19% growth in 2022. **Abu Dhabi National Oil Co** increased its five-year plan for 2022-2026 to $127 billion. The company is working to increase oil production capacity to 5 MMbopd (from the current

4 MMbopd) by 2030 and has plans to double its LNG production capacity from 6 MMtpa to 12 MMtpa. Adnoc recently awarded $6 billion of service contracts to boost its drilling capacity, including $3.27 billion for wellheads over 10 years and $2.34 billion for downhole completion equipment over five years.

Saudi Arabia is targeting growth of 1 MMbopd by 2030. Having slashed its 2020 capex budget to $27 billion from $35 billion to $40 billion previously, the NOC expects to spend about $35 billion this year and grow 20% to 25% in 2022, as it strives to expand oil production capacity to 13 MMbopd by 2030. The Kingdom plans to produce and export about 4 MMtons of hydrogen by 2030, when gas and renewables are expected to make up 50% of the nation's energy mix.

Kuwait announced plans to invest $6.1 billion in exploration over the next five years to increase its oil production capacity to 4 MMbopd by 2040. About 31 oil rigs were contracted earlier this year to drill 700 new wells, as Kuwait Oil Co launched several new projects targeting a near-term production target of 3.2 MMbopd by 2025 from current production of 2.4 MMbopd in 2020. **Qatar Energy** is making progress on its massive North Field expansion plan, which will raise its LNG capacity from 77 MMtpa to 110 MMtpa by 2025 and 126 MMtpa by 2027. Meanwhile, expansion of Al-Shaheen oil field is being done in partnership with TotalEnergies.

Latin America. We estimate E&P spending by select Latin America companies will increase 19% in 2022, building on the 9% growth experienced in 2021. Overall spending in the region could be even higher, with the majors and NAM independents stepping up development offshore Guyana, Suriname and Brazil.

Mexican President Andres Manuel Lopez Obrador proposed an ambitious $32-billion budget for Pemex in 2022. While part of the funding is for downstream, $18 billlion has been allocated to hydrocarbons, representing a 26% increase to boost production 4.2% to 1.826 MMbopd. Having stemmed 15 years of production declines, the company is making progress on revitalizing its mature shallow-water plays and has plans to invest $100 million in exploration of the Upper Cretaceous region by 2023.

Brazil's Petrobras announced plans to invest $68B between 2022-2026, which includes $57.3B or 84% for exploration and production. About two-thirds of the budget will focus on pre-salt projects in both deep and ultra-deepwater, which is expected to increase from 70% of total output in 2022 to 80% by 2026. Petrobras' oil output is expected to increase from 2.1 MMbopd in 2022 to 2.6 MMbopd by 2026.

Table 2. Global upstream spending, excluding North America. Evercore ISI Research, company data.

	2022 Survey data, $ millions		2022 Year-on-year Change	
Region	**2021E**	**2022F**	**$+/-**	**%**
Middle East	$40,343	$48,200	$7,857	19.5%
Latin America	$39,889	$47,270	$7,381	18.5%
Russia/FSU	$56,283	$59,794	$3,511	6.2%
Europe	$24,096	$26,749	$2,653	11.0%
India, Asia, Australia	$82,843	$95,881	$13,038	15.7%
Majors, Int'l spending	$33,525	$39,242	$5,717	17.1%
Africa	$7,548	$8,914	$1,366	18.1%
NAM independents, int'l spending	$2,584	$3,659	$1,075	41.6%
Other	$17,583	$20,366	$2,783	15.8%
International spending	**$304,696**	**$350,074**	**$45,378**	**14.9%**

Africa. Spending by African companies is on track to accelerate 18% in 2022. Capex by Libya's National Oil Co. could increase from $1 billion to $1.6 billion in 2022. The Oil Ministry targeted oil production growth to 1.4 MMbopd by year-end 2021, and is striving for 1.6 MMbopd in 2022. TotalEnergies has plans to invest billions in Libya to boost oil production, reduce flaring and develop solar.

Egypt exported 1 MMt of LNG during third-quarter 2021, surpassing its North African neighbors. Spending could increase 20%, with multiple operators targeting growth in the Western Desert, where Cairn Energy and Chevron recently closed on their acquisition of Shell's assets, and Eni recently made three new discoveries that added 50 MMboe of reserves.

The **Algerian** government may boost state-owned Sonatrach's budget by 30% in 2022. The country is targeting growth of its production capacity from 187 MMt to 195.9 MMt. A major supplier of natural gas to Europe, Eni is also assessing Algeria for production of blue and green hydrogen, and recently signed an agreement with Sonatrach to accelerate cooperation.

Asia/Australia. We expect spending in this region to accelerate 16% during 2022, vaulting total regional spending 32% above the 2018 trough and 22% from the 2013 peak. On an absolute basis, Asia leads the industry at 27% of total international E&P spending and 22% of global capex. We forecast the region to account for almost 30% of 2022 international capex growth.

China has been busy preparing for the Beijing Winter Olympics, which is expected to showcase low-carbon development through use of renewable energy, sustainable venues and green transportation. However, that has not stopped CNPC, Sinopec and CNOOC from boosting both onshore and offshore investments. The country produced 20 Bcm of gas in 2020, short of its 30-Bcm target. New targets of 50 to 80 Bcm were established for 2025, and the city of Chongqing has plans to invest $30 billion in a new production zone for 20 Bcm by 2030, to feed new gas-fired power plants. Sinopec is on track to produce a record 7 Bcm of shale gas this year.

Europe. Spending by European companies should increase 11% during 2022. Companies in the North Sea are advancing offshore wind and other low-carbon solutions, but the majority of capital spending continues to target the upstream oil and gas sector. Rising commodity prices and fuel shortages are reinforcing the need to keep investing in oil and gas, with Equinor continuing to dedicate 90% of its budget to the upstream, including 10% for exploration. Turkish Petroleum is moving forward with its first deepwater development, sanctioning the August 2020 Sakarya gas discovery as a $3.6-billion, fast track greenfield development. It is due to go onstream in 2023.

Russia/FSU. Spending by Russian and FSU companies should grow 6% in 2022. Companies are slowly restoring production at legacy assets and increasingly shifting their focus to LNG and other low-carbon resources for European export. Although work offshore remains constrained by ongoing U.S. and European sanctions, Gazprom is moving forward with new exploration wells in the Barents Sea. WO

Oil and gas in the crosshairs

The upstream industry must play a defensive holding action until the U.S. mid-term elections.

ROGER BEZDEK, Contributing Editor

Joseph Biden campaigned against fossil fuels, recommended "throwing oil executives in jail," and wasted little time in following through as President, **Fig. 1.**

For example, thus far, he has recommitted the U.S. to the Paris Climate Agreement; rescinded the construction permit for the Keystone XL oil pipeline; and signed an Executive Order (EO) requiring that all electricity the federal government uses be "100% carbon-free" by 2030. In addition, he ordered federal agencies to reinstate over 100 environmental regulations rolled back by former President Trump; suspended oil leasing in Alaska; suspended permits to drill in oil and gas (O&G) leases on federal lands; asked the Federal Trade Commission to investigate whether O&G companies are responsible for increasing gasoline gas prices; and plans to block O&G leasing on 11 million acres of Alaska's North Slope—nearly half of a 23-million-acre reserve set aside for energy development decades ago.

Fig. 1. President Joe Biden has had a contentious, harmful relationship with the U.S. upstream industry since before he even took office. Image: The White House.

Biden's administration also planned to close the L5 pipeline, which carries O&G liquids from Canada to the U.S. but reversed itself in the face of intense criticism. The anti-energy policies may be working: Active U.S. rigs totaled 586 on Dec. 31, 2021—a 27% decrease from the Dec. 27, 2019, count of 805. The administration's war on the O&G industry continues with death by a thousand cuts.

Biden's senior environment and energy positions are populated by climate alarmists hostile to the O&G industry, **Fig. 2.** Interior Secretary Deb Haaland co-sponsored the Green New Deal (GND), opposes O&G production on federal lands, and supports a fracing ban. White House National Climate Advisor Gina McCarthy was architect of Obama greenhouse gas emissions (GHG) rules, which were repealed by the Trump EPA. John Kerry, former Obama Secretary of State, is Special Presidential Envoy for Climate—he drafted the 2016 Paris Climate Accord and has labeled climate change as "the most serious threat to mankind."

Transportation Secretary Pete Buttigieg labeled climate change a national emergency and advocates the GND. Treasury Secretary Janet Yellen advocates CO_2 emissions taxes and cap-and-trade; has labeled climate change an "existential threat;" and created a Treasury climate change team. Securities and Exchange Commission Chair Gary Gensler is imposing stringent ESG disclosures; increased corporate reporting on GHG emissions; and "evaluation and pricing of climate risk."

Meanwhile, Stanford University professor Sally Benson serves as deputy director for energy and "chief strategist for energy transition" at the White House Office of Science and Technology Policy. One of her top priorities is ensuring a swift transition to a "clean energy economy." She noted that President Biden's goals of 100% clean electricity by 2035, and eliminating CO_2 by 2050, will "require a total transformation of America's industrial and transportation systems."

However, industry dodged a bullet when Saule Omarova, under criticism, withdrew her nomination to be Comptroller of the Currency—the U.S. federal bank regulator. Dr. Omarova, who attended Moscow State University under a Lenin Scholarship, stated that fossil fuel producers should "go bankrupt, if we want to tackle climate change."

The administration can be tone-deaf and clueless; for example:

- In promoting his efforts to reduce gasoline prices, Biden stated that "Americans would save money on gas, if they owned electric cars"—electric vehicles (EVs) currently comprise 1% of U.S. vehicles.
- At a press conference, Energy Secretary Jennifer Granholm admitted that she did not know how much oil the U.S. consumes per day (answer is 18.2 MMbbl). At an energy conference, she stated "We have to add hundreds of gigawatts to the grid over the next four years. It's a huge amount. And there's so little time." U.S. installed electric generating capacity totals 1,100 GW. To claim that the U.S. should add "hundreds of gigawatts" to the grid in four years is ludicrous.

The administration's energy policies are embarrassing. Faced with politically damaging, increased gasoline prices in late 2021, officials implored OPEC to increase oil production. Is the administration upending five decades of U.S. energy policy and attempting to increase U.S. dependence on the OPEC cartel? At the same time, the administration is implementing policies to decrease U.S. oil production. It also initiated a "Buy American" program that will "support domestic production of products critical to our national and economic security." It is hard to imagine a product more important than oil to "U.S. national and economic security."

The administration wants companies to pay more to drill on federal lands and waters. The Interior Department recommends increasing the federal royalty rate from the current 12.5% and increasing the bond that companies must post before they start new wells. Raising the royalty rate to 18.75% for drilling in deep waters offshore would cost companies an additional $1 billion/yr., and a royalty rate of 25% for on- and offshore drilling would double the cost to $2 billion annually.

Interior officials also want to incorporate the "social cost of carbon" into the price of permits for new O&G extraction. The administration set this at $51/ton of CO_2 but suggested the estimate could go higher—the Interagency Working Group recommended a 2022 estimate of nearly $80/ton of CO_2.

This coincides with efforts from congressional Democrats to pass a suite of O&G leasing provisions in the Build Back Better budget deal, **Fig. 3.** The version passed by the House included provisions that would raise the minimum royalty rate for onshore drilling, for the first time in a century; shorten the length of leases from 10 to five years; and eliminate a program that allows sales of leases for as little as $1.50/acre. However, the bill did not pass the Senate. The Interior Department can increase royalty and bonding rates unilaterally but embedding higher rates in legislation would shield the policies from court challenges.

In June, the administration submitted a budget proposal that would have eliminated many fossil fuel "subsidies." That wish list of tax changes dwindled in subsequent months, but the Build Back Better proposal included two provisions that would cost industry dearly. One would eliminate an O&G exception to a 2017 law that taxes foreign profits of U.S. companies, and this could cost industry as much as $8.5 billion annually. The proposal also would have reinstated the tax on crude oil designed to support EPA's Superfund program clean-up efforts, which expired in 1995. This could cost industry an additional $4 billion annually.

As part of the Build Back Better (BBB) plan, a new tax starting in 2023 would be levied on natural gas production that would translate into higher heating bills. The fees depend on where the natural gas is produced and vary depending on methane releases. The Congressional Budget Office estimated that the new "methane fee" would cost industry nearly $1 billion annually, and the natural gas industry contends that the fee will be paid by consumers: "New fees or taxes on energy companies will raise costs for customers, creating a burden that will fall most heavily on lower-income Americans." The new fee could translate into a 17% increase in energy prices for homes utilizing natural gas.

DOE warned that U.S. households using natural gas would face cost increases of 30% to 50% in 2022. DOE estimated that the average family relying on natural gas heat would pay $746 between October and March, compared to an average $570 in 2021. The methane fee would add 17% to this cost. This is a regressive tax, since the energy burden for low-income families is three times higher than of more affluent households. Further, once the methane tax is enacted, it can be increased over time and, combined with new methane regulations, will continue to increase costs. The House bill was not passed in the Senate. It remains to be reintroduced, although Sen. Joe Manchin (D-WV) on Feb. 3 reiterated that as far as he was concerned, the BBB legislation was dead.

Under the guise of regulating GHGs, EPA announced new, more stringent fuel-efficiency standards for cars and light-duty trucks. The new standards begin with the 2023 model year, and 2026 vehicles will be required to achieve a fleet-wide average of 55 mpg, an increase of more than 35% from the 2021 standard. EPA intends to impose even more stringent standards beyond 2026. The action is the latest in the administration's efforts to force Americans to buy EVs, and manufacturers contend that the new standards cannot be met without "more generous government EV subsidies." However, the real purpose is to impose an EV mandate by regulatory fiat, since there is no chance that Congress will ban sales of internal-combustion vehicles.

Biden wants to ensure that 50% of new car sales are electric by 2030 and that all additions to the federal government's vehicle fleet are electric by 2035. Meeting the new standards will be difficult, because consumers do not want EVs. Through the first nine months of 2021, 460,000 EVs were sold in the U.S.—half of them in California. By comparison, Ford sold 535,000 pickup trucks during this same period.

Restriction of leasing and permitting for O&G drilling on federally owned lands and in federally owned waters will be a major 2022 court battle. The first drilling lease sale held under the administration, which offered 80 million acres for auction in the Gulf of Mexico, was contentious. The administration delayed that lease sale as part of its moratorium on new O&G leasing. However, after a court halted the moratorium, the sale went through, much to the chagrin of environ-

Fig. 2. Inside and outside The White House, the Biden administration is filled with climate alarmists, who are anti-the O&G industry. Image: Library of Congress Series in the Carol M. Highsmith Archive.

Fig. 3. Congressional Democrats tried to pass the Build Back Better budget package, which contains punitive measures against the O&G industry, but it failed to make its way through the Senate and may not be revived. Image: Library of Congress Series in the Carol M. Highsmith Archive.

mental groups. These groups oppose future sales, including a proposal to auction ocean parcels near Alaska's coast and an onshore lease sale in New Mexico.

But in yet another twist on Jan. 27, U.S. District Judge Rudolph Contreras in Washington, D.C., vacated the lease sale in a 67-page decision. He found that the Interior Department underestimated the climate impacts of the leases and conducting a further analysis wouldn't overly harm the companies seeking the leases. "The leases have not become effective, and no activity on them is taking place," the judge wrote. If the leases were to take effect, it would be much harder to cancel them, he added.

The issue, over which waters should be regulated, has been an intense partisan battle for years. In 2015, the Obama administration expanded coverage to small bodies of water, but this was repealed during the Trump administration. The Biden administration will propose to regulate more waters, but the specifics are unclear. Rule opponents will likely sue, and if environmentalists do not think the rule goes far enough, they will likely also challenge it.

During 2022, the battle over power plant emissions will ensue through regulations and at the Supreme Court. EPA is expected to propose rules regulating emissions from new and existing power plants, to be finalized in 2023. EPA was likely to have a relatively blank slate after a lower court struck down a Trump-era rule—the Affordable Clean Energy Rule (ACER). ACER gave states more time and authority, compared to the Obama administration's rule (the Clean Power Plan), to decide how to reduce emissions from fossil fuel plants.

But in October 2021, the Supreme Court agreed to consider EPA's authority to regulate CO_2 emissions under the Clean Air Act, a decision which, according to court observers, "is the equivalent of an earthquake. It could sharply curtail or eliminate the administration's ability to use the Clean Air Act to significantly limit GHGs." Petitioners asked the court to review the ruling, with North Dakota arguing that the court should reinstate the Trump-era rule. The Biden administration urged the justices not to hear the case.

There are two sleepers that require monitoring. First, Jerome Powell, the recently reappointed Federal Reserve chair, stated that climate stress tests for banks will "be a very important priority" in supervision—even though climate policy is not part of the Fed's mandate. This could have the Fed using stress tests to force banks to reduce and eventually eliminate O&G financing. Banks would have to adjust their balance sheets to account for the risks from government climate policies, such as mandates, regulations, and carbon taxes.

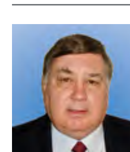
Accordingly, to pass the climate stress tests, banks would have to liquidate O&G assets. This is political allocation of capital, which also is not the Fed's job. Also at the Fed, Sarah Bloom Raskin was nominated to be vice chair of Supervision. She has stated that U.S. regulators should use their existing powers to mitigate climate risk and "has specifically called for the Fed to pressure banks to deny credit to traditional energy companies."

Second, federal spending is governed by Federal Acquisition Regulations (FAR). Responding to a Biden Executive Order, the FAR Council wants to determine how climate change should be factored into federal spending. The federal government spends over $6 trillion annually, so this could have a major impact.

The FAR Council has issued an Advanced Notice of Proposed Rule Making, "Federal Acquisition Regulation: Minimizing the Risk of Climate Change in Federal Acquisitions." It proposes that agencies give preference to bidders, who are reducing their GHG emissions, and require procurement officials to measure life cycle emissions of purchases. Suppliers would be required to report their GHGs and to reduce them.

The statutory authority for this is questionable, since Congress is supposed to enact legislation to do this—agencies cannot decide what to buy, based on a climate agenda. Trying to measure life cycle emissions for $6 trillion of procurement annually, and then basing procurement decisions on these measures, is absurd. However, that does not necessarily mean it will not happen.

It is likely that in November, Republicans will retake at least the House or Senate, and this will serve as a break on the administration's anti-fossil fuel policies. Until then, it is going to be a long year for the O&G industry. WO



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U.S. activity to jump as oil prices surge, companies adjust to energy transition

CRAIG FLEMING, Technical Editor, and KURT ABRAHAM, Editor-in-Chief/ Chief Forecaster

The U.S. oil and gas industry is recovering and adjusting its business models, as companies pursue net-zero goals. Approximately 50% of the world's population has received at least one dose of the Covid-19 vaccine, and many companies are finalizing their return-to-office plans. Oil demand is back to 95% of pre–Covid levels, and prices are remaining well above $80/bbl and beyond $90/bbl at times.

Despite higher oil prices, U.S. shale operators have resisted (until just recently) ramping-up drilling activity and remained disciplined with capital expenditures. The speed at which new rigs have been deployed to the field has mostly been less than in previous up-price cycles, although recent weeks have shown greater movement. Most U.S. shale companies have been conservative, as priorities remain focused on protecting balance sheets and generating free cash flow.

Capital investments in U.S. drilling projects should increase 15% to 20% in 2022 (**Fig. 1**), according to *The Wall Street Journal.* Investors have pressured oil companies to live within their means, pushing them to pay off debts and return cash to shareholders. Many of the larger companies are likely to increase spending less than 5%, according to IHS Markit. Meanwhile, the companies set to increase spending the most are the smaller, private producers that kept oil production growing in the major U.S shale plays.

Higher prices funding energy transition. The escalation in oil prices above the $40-to-$60/bbl range is significant. In the past, high oil prices encouraged companies to increase capital expenditures and focus on their core business, rather than on new sustainability opportunities. Accordingly, it is assumed that high oil prices could slow the energy transition.

However, a year-end survey by Deloitte shows that 76% of executives state that oil prices above $60/bbl will boost their energy transition in the near term. The current cycle of higher oil prices reveals two new trends, which will likely continue throughout 2022 and challenge conventional wisdom:

1. Oil companies are more disciplined with production and capital guidance, despite high oil prices. A significant reduction in the DUC inventory (37% decrease between December 2020 and December 2021), flat production levels (increase of 2.5% in 2021) and debt reduction (decrease of 4.5% in 2021) suggest that the industry is no longer just managing the cycle.
2. High oil prices are enabling companies to fund their net-zero commitments. Many U.S. companies joined the net-zero group in 2021.

Strong oil prices enable investment in riskier and expensive green energy projects, including carbon capture, utilization and storage (CCUS). Given that no single stakeholder can provide the necessary investment and absorb all commercial risks associated with building a CCUS industry, all participants in the oil and gas value chain (upstream, midstream and downstream) become important players, as they are involved in 50% of planned CCUS projects.

OFS transitioning. The OFS sector had slashed costs and optimized operations to remain profitable before the pandemic. Being traditionally dependent on upstream cycles, the sector is likely to see a permanent structural shift, as rapid energy transition alters the scales of oil and gas revenues and spending. Not surprisingly, spending in OFS, which declined during the pandemic, is expected to remain about 25% below 2019 levels until 2025. With margins at the mercy of another price cycle and reduced spending, many OFS companies are crafting new strategies for the future of energy.

With a broadening decarbonization

Fig. 1. The rebound in U.S. drilling is being supported by continued technical innovation, such as the Nabors PACE®-R801 (pictured here), the world's first fully automated land rig, which successfully drilled its first well on a test pad in Midland County, Texas, last October. Image: Nabors Industries.

mandate across industries, companies have an opportunity to lead the way by fully re-engineering OFS business models and solutions outside traditional oilfield services. Several companies have already diversified beyond core services. One company has restructured its business by making big bets on cloud and edge computing, whose rate of growth is expected to outpace that of their oil and gas business in a few years.

Similarly, Halliburton and Baker Hughes are partnering with start-ups and academic institutions, through Halliburton Labs and Baker Hughes Energy Innovation Center, to accelerate technology development for diverse energy and industrial applications. However, digitalization will only help to a certain extent. Providing integrated solutions for decarbonizing upstream projects, implementing subscription-based revenue models or diversifying into the low-carbon space could be key enablers of the future OFS strategy.

Schlumberger bets on traditional demand growth. Despite the green push, Schlumberger is gearing up for growth around the world, as the company expects recovering economies to ignite several years of crude demand expansion. Schlumberger will boost spending 18% to $2 billion, serving North American oil explorers that should dominate activity in the first half of the year, followed by international growth in the final six months. "Oil demand is expected to exceed pre-pandemic levels before the end of the year and to further strengthen in 2023," said CEO Olivier Le Peuch. "Resurgent global demand-led capital spending will result in an exceptional multi-year growth cycle."

Many OFS companies are experiencing a resurgence in profitability, as crude demand rebounds, due to underinvestment. The company expects North American clients, drilling on land and offshore, to increase spending 20% this year, while international customers should expand their budgets 12% to 16%.

Fig. 2. A drilling rebound and higher oil and gas prices should almost ensure better activity, further development and more new platforms in the Gulf of Mexico. Yet, the near future was thrown in doubt, when a federal judge in late January threw out the results of BOEM's federal lease sale 257. Image: Shell.

Table 1. Forecast of 2022 U.S. wells and footage to be drilled.

	Total wells			Total footage, 1,000 ft		
State or area	2022 forecast	2021 estimated[3]	% diff	2022 forecast	2021 estimated[3]	% diff
Texas[1]	6,876	5,646	21.8	104,459.5	85,481.0	22.2
Southeast[1,4]	590	528	11.7	8,610.4	7,751.4	11.1
Northeast[5]	1,286	1,128	14.0	20,649.2	18,804.9	9.8
Midwest[6]	551	453	21.6	1,375.0	1,111.0	23.8
Mid-continent[7]	2,967	2,500	18.7	33,687.8	29,257.0	15.1
Rocky Mountains[8]	2,206	1,794	23.0	33,707.0	27,337.2	23.3
West Coast[9]	891	736	21.1	2,899.4	2,142.3	35.3
Alaska-offshore[2]	11	9	22.2	74.1	60.6	22.3
California-offshore[2]	4	8	-50.0	16.0	28.0	-42.9
Gulf of Mexico[2]	122	109	11.9	2,141.1	1,912.7	11.9
Total U.S.	15,504	12,911	20.1	207,619.5	173,886.1	19.4

[1] Excludes state and federal offshore wells, which are included in the GOM total.
[2] Includes state and federal offshore wells.
[3] 2021 estimates are based on well counts furnished by state and federal regulatory agencies, and API.
[4] Includes Alabama, Arkansas, Florida, Louisiana, Mississippi and Tennessee.
[5] Includes New York, Ohio, Pennsylvania, Virginia and West Virginia.
[6] Includes Illinois, Indiana, Kentucky, Michigan and Missouri.
[7] Includes Kansas, Nebraska, North Dakota, Oklahoma and South Dakota.
[8] Includes Colorado, Idaho, Montana, Nevada, New Mexico, Utah and Wyoming.
[9] Includes Alaska-onshore, California-onshore and Oregon.

OPEC struggling to meet demand. Although the cartel pledged to add 400,000 bopd each month to reduce oil prices, actual production increases have fallen short, due to internal unrest and insufficient long-term investment. In December, OPEC increased output by just 90,000 bopd. UAE Energy Minister Suhail Al-Mazrouei said OPEC is increasing output, but he warned the cartel could not solve the global oil supply issues alone. "The industry needs investment, through the involvement of international oil companies, to provide adequate supplies. Failure to infuse sufficient capital may lead to future price hikes," Al-Mazrouei warned.

Inflationary pressure. If OPEC+ continues to fall short of production targets, there may be wider economic consequences. The recovery in oil demand has remained robust, as the Omicron variant has had a milder effect on the global economy than anticipated. Brent has jumped considerably since the start of the year and has gone as high as $95 recently.

Surging energy prices are a significant contributor to rising inflation, and the U.S. White House, led by President Joe Biden, has consistently applied pressure on OPEC+ to boost supply and help curb costs, rather than call on U.S. producers to increase output. Through most of 2021, Russia maintained fairly consistent monthly production increases, as it restored capacity idled in the initial stages of the pandemic. By November, the revival floundered; most idle and shut-down Russian wells were returned to production, indicating that the industry had essentially deployed its spare capacity.

The abovementioned factors, along

with *World Oil's* surveys of operators and state agencies, have all shaped this cycle's U.S. forecasting process. Accordingly, *World Oil's* editorial staff presents its 2022 E&P forecast, as follows:

- U.S. drilling will increase 20.1%, to 15,504 wells, **Table 1**
- U.S. footage will increase 19.4%, to 207.6 MMft of hole
- U.S. Gulf of Mexico activity should improve 11.9%, to 122 wells.

U.S. MARKET FACTORS

Although positive trends in commodity prices slowed in late December/early January, due to Omicron, Evercore ISI expected that this latest variant would have a limited impact on mobility and global demand. Companies have been using $70/bbl WTI and $3.90/MMbtu Henry Hub decks for 2022 budgets.

Commodity price expectations have improved noticeably since our mid-year 2021 forecast update and remained resilient despite the emergence of the Omicron variant. Oil prices have now gone above the sweet spot between where budgets will reset higher at $75 WTI and lower at $65 WTI, while gas budgets are unlikely to be materially revised unless prices fall below $3 or increase above $5.50. Cash flow remains the key determinant of spending, although y-o-y changes in oil and gas prices as determinants for spending plans suggest a subtle shift is underway in operators' hydrocarbon targets.

However, there is a sense that fundamental transformation is required, as the industry moves into 2022. Simply managing or riding oil price cycles is not an option anymore, and many companies are taking action to reinvent themselves by:

- Practicing capital discipline (global upstream capex increased only 4% in 2021)
- Focusing on financial health (debt reduction of 4% in 2021)
- Stronger financial commitment

Fig. 3. The Permian basin will lead the drilling rebound in Texas, with the region set to drill 22% more wells than in 2021. Image: Latshaw Drilling.

to addressing climate change
- Transforming business models. About 66% of industry executives said they are positive about the strategic changes made by their organizations.

Capex. NAM spending is expected to increase 20.6% in 2022, reversing the 1.7% decline in 2021 and part of the 44.1% collapse in 2020, says James West, senior managing director at the Evercore ISI investment firm (see page 19). At about $73 billion in 2021, NAM capex fell to its lowest level since 2003 and is about 72% below the 2014 peak and 49% below the 2018 level. With spending growing 20.6% in 2022, led by the U.S. at 23.5%, total NAM capex should recover slightly north of 2004 and 2016 levels. However, Capex remains 66.6% below the 2014 high point and 38% below the 2018 level.

Crude production. Despite the sharp three-year consecutive decline in spending, U.S. crude production averaged 11.2 MMbopd in 2021, down only about 130,000 bopd year-over-year and just 1.7 MMbopd from the annual record of 12.9 MMbopd averaged in 2019.

Analysts believe U.S. shale production has peaked, with declining well productivity and increasingly challenging geological conditions limiting growth. And with operators prioritizing capital discipline and limiting capex spend, it appears U.S. shale is structurally impaired.

Evercore ISI analyst Steve Richardson forecasts U.S. crude output to increase by 1.1 MMbopd in 2022, with a significant boost coming from new GOM projects. Although the U.S. land rig count has increased steadily from the August 2020 record low, Evercore believes the U.S. rig count and frac activity continue to operate at levels below that required to stave off broad production declines. The firm also believes it is materially below levels required to grow production, as forecasted by EIA, which foresees 12.0 MMbopd in 2022 and 12.6 MMbopd in 2023.

Fig. 4. The gas-dominated Northeast will see activity rise 14%, led by an 18% increase in West Virginia.

Natural gas production. The EIA estimates that the U.S. produced 93.5 Bcfd in 2021, up 2.0 Bcfd (2%) from 2020. Natural gas production fell in 2020 as a result of low prices that reduced drilling activity. Production grew in 2021, as drilling activity came back online, especially in the Permian basin, where associated gas production in that region contributed to the overall growth.

Fig. 5. Oil production in North Dakota should see a moderate gain during 2022, with drilling increasing about 6%. Image: ConocoPhillips.

We forecast dry natural gas production will increase by 2.5 to 3.0 Bcfd (2.7% to 3.2%) in 2022. Recent increases in oil and domestic natural gas prices will contribute to an overall increase in drilling activity in 2022, which will, in turn, lead to production growth from second-quarter 2022 onward.

LNG outlook. The EIA forecasts that U.S. natural gas exports will reach record highs in 2022 and continue to grow in 2023. Net gas exports averaged 10.7 Bcfd in 2021 and are forecast to increase to 13.4 Bcfd in 2022 and 14.3 Bcfd in 2023. A combination of rising LNG exports and increases in pipeline exports to Mexico will drive this increase. The U.S. exported 11.2 Bcfd of LNG in December 2021, an increase of 0.7 Bcfd over the previous record set in November. LNG export growth in 2021 was driven by rising natural gas demand and high LNG prices in Europe and Asia; reductions in global supply because of several unplanned outages at LNG export facilities worldwide; and cold weather in key LNG consumption markets, particularly in Asia.

Crude prices. Oil prices rose during much of 2021, with Brent spot prices averaging $71/bbl for the year, compared with $42/bbl in 2020. Rising prices reflected growth in global oil demand that outpaced near-term growth in oil production, resulting in falling global oil inventories. During 2021, Brent prices reached their highest monthly average of $84/bbl during October. Brent prices fell to an average of $74/bbl in December, which reflected concerns about how the Omicron variant and potential mitigation efforts might affect near-term oil demand. EIA expects Brent will average $82.87/bbl in 2022.

Natural gas prices. Henry Hub spot prices averaged $3.91/MMBtu in 2021. Natural gas prices were volatile throughout 2021. Early in 2021, volatility resulted from near record-high spot prices during the extreme winter weather in February. During the rest of the year, Henry Hub prices rose from $2.62/MMBtu in March to $5.51/MMBtu in October, before falling back to $3.76/MMBtu in December, amid a warmer-than-normal start to the heating season across most of the country. EIA forecasts HH spot price will average $4.07/MMBtu in 2022.

Drilled-but-uncompleted. In a surprising turn of events, U.S. operators have made considerable progress working down the DUC backlog over the last year. Clearly, the increase in oil prices has made these temporarily abandoned wells more attractive, as operators know the breakeven price from completing other wells on the lease (spoked or wine-racked). As of December 2021, the DUC total stood at 4,657, 36% less than reported by the EIA a year earlier. DUCs in the Permian dropped dramatically, with 1,444 tallied in December, 59% fewer than the year-ago figure of 3,524. The Bakken (-41%) , Eagle Ford (-27%) and Niobrara (-21%) round out the top four regions with inventory declines. And in January 2022, the U.S. DUC total fell another 191 wells, to 4,466.

U.S. FORECAST

In 2021, global oil and gas discoveries hit their lowest level in 75 years, with total volumes found calculated at 4.7 Bboe. This also represents a considerable decline from the 12.5 Bboe added in 2020 (Rystad Energy). Liquids continue to dominate the hydrocarbon mix, accounting for 66% of discoveries. The monthly average of discovered reserves in 2021 was 424 MMboe. The reduction in volume accentuates the absence of large individual finds.

Part of the reason that oil prices are reaching multi-year highs is an unexpected supply gap, caused by robust demand despite Omicron, outages and geopolitical unrest. A major contributor to the lack of surplus production capacity was caused by excessive pressure applied by short-sighted politicians, who caved into demands from environmental groups without considering the far-reaching consequences. This created an unprecedented reduction in investment in hydrocarbon-based energy, in favor of developing unreliable green resources. However, the price spike has been a boon for the U.S. shale industry.

Gulf of Mexico. As the Biden administration's move to scrap new oil and gas leases remains in unsettled legal territory, Democrats and Republicans on a U.S. House panel sharply disagreed about the merits of new energy development in the GOM. Democrats argue that reducing energy development off the Gulf Coast is one way to drive down emissions from fossil fuels. Republicans respond that reducing domestic production would not meaningfully lower global emissions, because the demand would be filled by other sources.

The situation was complicated further, when a federal judge in late January invalidated the results of BOEM lease sale 257, comprising 1.7 million acres, which was conducted last November, **Fig. 2.** The judge said that the Biden administration violated federal law by tying the sale to flawed analysis of the climate change impact of drilling in the Gulf. Now, a new analysis will have to be conducted before another sale can take place.

Despite the political wrangling, operators plan to increase drilling activity in the Gulf of Mexico. *World Oil* predicts an 11.9% increase in drilling (122 wells) and total footage in 2022.

U.S. REGIONAL ACTIVITY

World Oil projects nationwide drilling was up 12.7% in 2021, due to a sustained increase in commodity prices, caused by an unexpected supply gap, which was triggered by stout demand, outages and

Fig. 6. A somewhat calmer political climate, paired with operators' loyalty to the Niobrara shale, should generate 20% greater drilling in Colorado this year. Image: ConocoPhillips.

geopolitical uncertainty. With demand expected to exceed pre-Covid levels in 2022, coupled with a lack of surplus production capacity due to underinvestment, we forecast a 20.1% increase in 2022, **Table 1.**

Although 52% of U.S. drilling will be in the Texas and New Mexico oil-rich shale plays, operators also plan to increase their search for natural gas in 2022. We predict 46% and 5% increases in Texas Districts 10 and 6, respectively, and a 35% increase in District 4. The Texas District 8 portion of the Permian will remain the major target for companies seeking to add oil reserves, with 3,409 wells forecast for 2022, an increase of 21%. We also expect operators working other oil-rich shale plays in Oklahoma and New Mexico, to boost drilling by 24% and 19%, respectively. Kansas and Wyoming will be leading a rebound in gas-focused activity.

Texas. Shale drilling will continue to dominate the Lone Star State, but natural gas-producing regions will get more attention in 2022 than in previous years. In spite of the modest increase in drilling activity in 2021, operators still managed to increase production to 4.9 MMbopd in October 2021, 5.6% more than the year-ago figure of 4.64 MMbopd.

However, this significant amount of crude output in a remote area forces operators to flare vast quantities of casinghead gas to capture the liquids. To combat the wasteful practice, RRC Commissioner Jim Wright announced he will deny most requests for exceptions to Statewide Rule 32, governing flaring permits to gather more details on the need to flare, and to inquire about the timeline for sufficient infrastructure to take gas to market.

In spite of the state's stricter stance on flaring, Permian basin operators working in RRC District 8 plan to increase drilling activity 21.4%, with an accompanying boost in footage of 22.1% in 2022, **Fig. 3.** In District 7C, *World Oil* forecasts an 18% increase in well spuds and a 19% jump in total footage. In the heart of the Eagle Ford, in District 1, operators plan to ramp-up drilling 23% and total footage 24%.

With the demand for natural gas reaching all-time highs, and improvements in LNG production and transport capabilities, we predict Districts 10, 4 and 8A will enjoy 46%, 35% and 30% increases in drilling activity, respectively. Similarly, gassy Districts 5 and 9 also will increase, with gains of 20% and 20.7%, respectively. *World Oil* forecasts total combined activity in Texas will increase 21.8% during 2022, with footage up 22.2%.

Southeast. In northern **Louisiana,** a 19% y-o-y increase in the area's DUC inventory, coupled with an abundant supply of natural gas from other shale plays, will result in just a 10% increase in the Haynesville gas play during 2022. Activity by smaller companies will also increase in the state's mature shallow oil fields. In southern Louisiana, footage and total well spuds are forecast to increase 6.7%. Combined, Louisiana will enjoy a 9.5% increase in wells and a 9.7% jump in total footage during 2022. In **Alabama** and **Mississippi,** the volume of activity will remain relatively low compared to pre-2016 levels, but percentage gains will be noticeable in 2022 at 38.5% and 26.7%, respectively.

Northeast. After demand fell precipitously, due to Covid-19, LNG buyers around the world cancelled more than 100 U.S. cargoes, as prices for the fuel collapsed to record lows in Europe and Asia. However, the demand for U.S. LNG has recovered. It is estimated that the short-run marginal cost of U.S. LNG exports to the Asian market rose to $5.60/MMBtu, as of June 2021, up 65% from $3.4/MMBtu in mid-2020 and 30% higher than last year's average of $4.30 per MMBtu.

Although liquefaction and transportation costs have increased slightly, the EIA forecasts U.S. natural gas exports will reach record highs in 2022 and continue to grow in 2023. It is likely that demand for Marcellus-Utica gas and LNG export from the Cove Point LNG facility in Maryland will improve during 2022. Accordingly, gas-dominated activity in the Northeast will be up 14%, **Fig. 4.**

After impressive development during the shale boom, drilling activity in **Pennsylvania** has slowed and is forecast to improve just 8.5% with a footage increase of 7.7%. In **West Virginia,** *World Oil* forecasts a strong increase in activity, with spuds improving 18% and total footage projected to jump 18.2% in 2022. The average well should TD around 17,100 ft in the Mountain State. Apparently, relatively high drilling costs associated with wells in excess of 20,500 ft is suppressing activity in **Ohio.** We forecast the state's well activity will improve just 5%, but total footage is projected to climb 8.6% in 2022 as operators increase horizontal well lengths to improve ROI.

Midwest. *World Oil* predicts activity levels will experience a noticeable surge in this region. In **Illinois,** state officials project a 9.2% increase in spuds, with an 8% improvement in total footage in 2022. The increase is due to higher commodity prices and an increase in rig availability. In **Indiana,** where gas activity will improve, we are predicting an increase of 19% in drilling activity and a similar jump in footage.

Michigan continues to lag in overall volume, compared to its sister states, but recovering demand as Covid vaccines take hold is a factor driving new drilling projects. Because of this optimism, we forecast a 21% increase in spuds and 26% jump in total footage during 2022 in the Wolverine State.

Mid-continent. Although disappointing results in the SCOOP and STACK plays of **Oklahoma** continue, operators are expected to increase drilling operations in the state, to take advantage of updated technologies and completion practices. During 2022, we predict that Oklahoma's activity will increase 24% overall, with a 24.1% boost in total footage. Activity in the Sooner State continues to be dominated by Continental and Devon.

In the oil-rich Bakken shale of **North Dakota,** activity is forecast to remain relatively consistent in 2022. *World Oil* forecasts that drilling and footage will increase 5.6% and 6.7%, respectively, **Fig. 5.** We predict the trend to laterals approximately two miles long will continue through 2022, with some wells reaching a total MD in excess of 21,300 ft. Although the DUC count in the region has declined 41% y-o-y, there are still 458 wells waiting on completion. Oil transport from the remote location is still an issue, but the region's entrenched operators will continue to support their large drilling and completion investments.

In conventionally oriented **Kansas,** operators continue to drill relatively shallow oil and gas wells to maintain production. But with other shale plays waning, and gas prices surging, investors are starting to shift attention back to traditional prospects that don't require high-cost horizontal drilling and staged fracing techniques. Similar to last year's gains, we predict a 24.4% increase in total wells and a 24.9% jump in footage during 2022.

Rocky Mountain states. The pro-green political climate in **Colorado** is starting to fade, and the state's oil and gas industry is starting to recover. It's clear the established operators working the state are not willing to abandon their producing properties in search of more favorable drilling conditions in neighboring states. As such, we project 20% more wells and footage in 2022, **Fig. 6.** And despite the hostile environment, Colorado's crude production has remained stable. In October 2021, the Centennial State produced 411,000 bopd, up 4.1% from a year earlier.

Fig. 7. California's oil production is holding up fairly well, thanks to continued drilling in the venerable heavy oil fields of Kern County, pictured here in a 1938 photo. The area still accounts for 70% of California's oil production and 90% of gas output. Image: Library of Congress.

On the **Wyoming** side of the Niobrara shale, operators plan a 30.1% uptick in drilling activity, while making 32.2% more hole in 2022. The state is benefiting from the negative political climate in neighboring Colorado and a push is underway to drill on federal lands before leases expire. In spite of a 24% increase in drilling activity in 2021, production remained unchanged at 235,000 bopd last October, the same as the year-ago figure. In January, Canadian Overseas Petroleum announced it confirmed a conventional light oil discovery in Converse and Natrona Counties, Wyoming. COPL estimates total reservoir volume of 1.5 Bbbl of oil. Production has commenced from the Dakota sand at the BFU 14-30VF discovery well, with an output of 100-120 bopd.

In northeastern **Utah's** multi-horizon Uinta basin, a boom scenario is predicted, as operators expedite activity to lock in held-by-production rights on federal lands as leases expire. Approximately 67% of the state's mineral acreage is controlled by the U.S. BLM. Drilling activity is forecast to increase 41%, and footage should improve 45.5% in 2022. The 74% jump in drilling activity during 2021 increased oil output 28% (y-o-y) to 104,000 bopd in October 2021.

Although **New Mexico** was late to the Permian shale boom, the southeastern part of the state is now a full-fledged member of the exclusive Permian basin club. Operators will focus more attention on the prolific Bone Spring formation, with an 18.9% increase in drilling activity during 2022, as operators rush to drill federal lands before lease terms expire. We also forecast that operators will increase footage drilled 20.4% in 2022.

On the **West Coast, California's** production has been remarkably resilient over the past several years, especially considering there was practically no exploratory drilling for the past decade, **Fig 7.** However, this might change in 2022, with onshore operators expected to increase drilling 19.8%, with total footage up 35.0%. But compared to last year, we predict that 2022 will be a bust scenario for offshore drilling in the Golden State, with only four new wells projected for 2022, compared to eight drilled in 2021. As in previous years, most onshore drilling is conducted by just four companies. The erratic drilling activity is starting to take a toll on the state's production. In October 2021, operators managed to pump 365,000 bopd, 5.2% less than produced in October 2020.

Several factors have hampered the development of **Alaska's** offshore drilling industry, with no meaningful recovery in sight. However, offshore work in the Cook Inlet will increase 22.2% for 2022, with footage set to rise 22.3%. Furthermore, onshore drilling activity and total footage on the North Slope are both projected to boom, with a 36% increase forecast in 2022. WO

U.S. operators respond cautiously to higher crude prices

Despite oil hitting multi-year highs, many of the large, publicly traded companies remained cautious in 2021, electing to pay off debt and return cash to shareholders rather than ramping up drilling activity. According to IHS Markit, the larger companies held back in 2021, increasing spending by about 5%. The majority of the drilling activity was by smaller, private producers that kept oil production growing in the major U.S shale plays.

The average U.S. rig count for 2021 was 474.8 units, an 8.9% increase compared to the previous year's average of 435.9 During January 2021, the rig count averaged 374, and then it gained for 11 consecutive months, finishing with a monthly average of 579 in December.

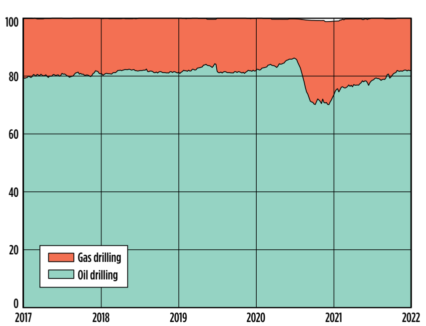
Four major oil-producing states enjoyed sizeable gains in activity, with Utah shooting up over 200%. Wyoming (+39%), Oklahoma (+31%), and Louisiana all experienced significant percentage gains. Continued interest in the Haynesville drove activity up 36%, as operators sought to take advantage of higher gas prices.

In Texas, nine of the 12 RRC districts experienced an increase in activity, with a statewide average gain of 18 rigs in 2021, an upturn of about 9%. In the Permian, RRC District 8 (+1.5%) and RRC District 7C (+31%) experienced gains in activity. In the Eagle Ford, District 1 broke even, averaging 14 rigs in 2020 and 2021. But gas-rich District 4 saw a 138% increase y-o-y. On the New Mexico side of the Permian, activity increased 7.4%. North Dakota suffered a major decline, losing 22% of its active rigs and dropping to an average 18 units in 2021.

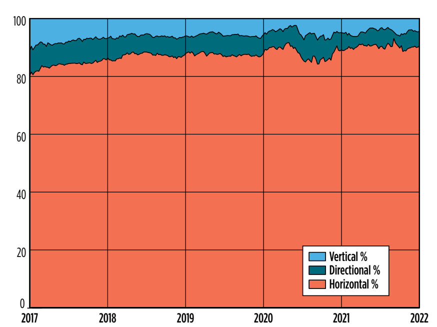
Despite escalating prices for natural gas in the second half of 2021, Pennsylvanian was down 15%, to average 18 rigs in 2021. However, West Virginia and Ohio increased rig utilization 13% and 29% respectively, in 2021.

Target/trajectory split. The spot price for natural gas averaged $3.91/MMBtu in 2021. However, the ratio of rigs targeting gas versus those drilling for crude declined steadily in 2021. In January, approximately 76% of rigs were targeting oil, with 23% drilling for gas. In 2021, the split between trajectories remained relatively stable. Similar to previous years, horizontal drilling accounted for the vast majority of wells drilled. WO

U.S. drilling split by target.



U.S. drilling split by trajectory.



Average number of U.S. rotary rigs in operation[1]

State Or Area	2020 Avg.	2021 Avg.	% Diff.
Alabama	0.1	0.0	-100.0
Alaska-Total	4.8	4.3	-10.4
Land	4.8	4.1	-14.6
Offshore	0.0	0.3	0.0
Arkansas	0.0	0.0	...
California-Total	7.0	7.0	0.0
Land	7.0	7.0	0.0
Offshore	0.0	0.0	...
Colorado	10.2	10.2	0.0
Florida	0.0	0.0	...
Illinois	0.0	0.6	...
Indiana	1.2	0.4	-66.7
Kansas	0.0	0.0	...
Kentucky	0.0	0.0	...
Louisiana-Total	40.2	48.0	19.4
North - Land	24.8	33.8	36.3
South - Inl. Water	0.6	1.0	66.7
South - Land	0.8	0.9	12.5
Offshore	14.3	12.3	-14.0
Michigan	0.0	0.4	...
Mississippi	0.3	0.2	-33.3
Montana	0.5	0.3	-40.0
Nebraska	0.0	0.0	...
Nevada	0.1	0.0	-100.0
New Mexico	70.1	75.3	7.4
North Dakota	23.4	18.3	-21.8
Ohio	7.6	9.8	28.9
Oklahoma	22.3	29.3	31.4
Pennsylvania	21.4	18.3	-14.5
Texas-Total	206.9	224.5	8.5
Offshore	1.4	1.2	-14.3
Inland Water	0.2	0.4	100.0
District 1	13.6	13.7	0.7
District 2	17.0	15.8	-7.1
District 3	5.1	3.6	-29.4
District 4	3.4	8.1	138.2
District 5	0.3	0.5	66.7
District 6	13.3	15.3	15.0
District 7B	0.8	2.3	187.5
District 7C	14.9	19.5	30.9
District 8	132.4	134.4	1.5
District 8A	4.3	8.8	104.7
District 9	0.8	0.0	-100.0
District 10	0.6	2.0	233.3
Utah	2.6	8.1	211.5
Virginia	0.0	0.0	...
W. Virginia	9.3	10.5	12.9
Wyoming	7.5	10.4	38.7
Others	0.1	0.0	-100.0
U.S. Offshore Total	15.7	13.8	-12.1
U.S. Grand Total	435.9	474.8	8.9

[1] Totals may not add due to rounding. * Others comprise Arizona, Hawaii, Idaho, New York, Oregon, South Dakota and Virginia.

U.S. crude output falls slightly, Natural gas rises

Despite a 12.7% y-o-y increase in drilling activity, U.S. oil production was down 1.13%, averaging 11.19 MMbopd in 2021. The loss in output could have been more drastic, but U.S. operators completed 2,682 DUC wells in 2021, with 2,078 of that total in the Permian basin. WTI started 2021 at $52.00/bbl and climbed steadily throughout the year, hitting a seven-year high of $81.48/bbl in October.

Crude and condensate. As noted, while U.S. oil production decreased mildly during 2021, there were significant declines in Oklahoma, Colorado, California and North Dakota. Of the nine major oil-producing states (>100,000 bopd), seven suffered losses, with the exception of New Mexico and the GOM. Texas oil production was down 2.4%, decreasing to a daily average of 5.07 MMbopd in 2021, despite booming DUC completions in the Permian and Eagle Ford plays (2,350 wells completed). On the New Mexico side of the Permian, production surged 22.5%, up to 1.263 MMbopd, the only onshore gain of the big-nine states/regions. Bakken production in North Dakota registered an 8.5% decrease, down to 1.081 MMbopd.

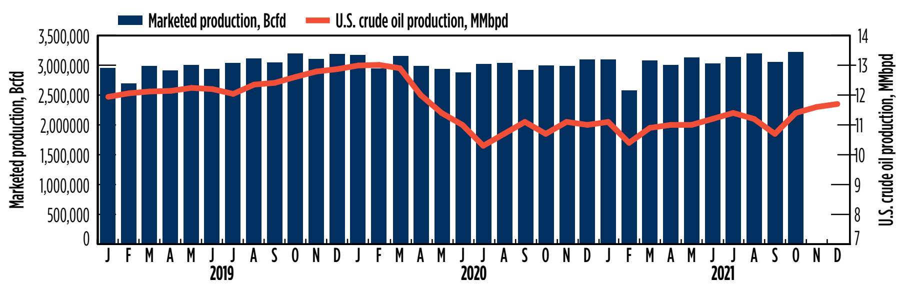
In the Western states, Colorado's green initiative caused a 12.8% decrease to 393,300 bopd, while Wyoming was down 4.6%, to 232,300 bopd. In California, waning drilling activity that started in 2015 continues to negatively impact the state's production, which dropped to 369,700 bopd in 2021, a loss of 9.1%. A 14.4% increase in Utah pushed that state up to 99,300 bopd from 86,800 bopd in 2020.

In the Mid-continent, production in Oklahoma was down a whopping 16.7%, with underperformance in the SCOOP and STACK plays causing the state's output to decline to 390,700 bopd. The Sooner state had already experienced a 19% loss of crude output between 2019 and 2020. Despite virtually no shale activity, Kansas dropped just 1.2%, to average 75,700 bopd. Alaska also declined moderately, dropping 2.4% to average 437,100 bopd. Louisiana and the federal offshore jumped 4.7%, up to 1.49 MMbopd, as production came back on-line after disruption from Hurricane Ida knocked out 80% of crude output in September.

Natural gas. Henry Hub gas prices averaged $3.91/MMBtu in 2021, up $1.88/MMBtu from 2020. HH prices averaged $3.62/MMbtu for the first nine months of 2021 bottoming at $2.62/MMBtu in March. Prices hit a yearly high of $5.51/MMBtu in October, but retreated back to $3.76/MMBtu by year's-end. The surge in gas prices during 2021 was influenced by increased demand despite Omicron, geopolitical unrest in Europe.

Monthly average marketed gas production fluctuated throughout 2021, hitting a low of 92.372 Bcfd in February, before climbing back up to 101.884 Bcfd in December. WO

U.S. oil and natural gas production.



U.S. crude and condensate production by state

	Daily, 1,000 bbl		Annually, 1,000 bbl	
STATE	2021[1]	2020[2]	2021[1]	2020[2]
Alabama	11.5	10.9	4,240	4,310
Alaska	437.1	447.8	159,018	163,852
Arkansas	11.6	11.3	4,159	4,143
California[3]	369.7	406.9	134,609	147,683
Colorado	393.3	451.1	143,191	167,832
Florida	4.0	3.8	1,506	1,488
Illinois	19.4	19.5	7,056	7,166
Kansas	75.7	76.6	27,587	28,260
Kentucky	6.1	6.2	2,175	2,265
Louisiana[3]	1,485.4	1,419.2	540,546	518,102
Michigan	12.3	11.4	4,476	4,197
Mississippi	36.3	39.2	13,253	14,166
Montana	51.3	52.4	18,705	18,985
Nebraska	4.3	4.7	1,593	1,674
New Mexico	1,263.3	1,031.4	460,359	370,402
North Dakota	1,081.3	1,182.3	393,619	434,889
Ohio	49.6	65.3	18,022	23,819
Oklahoma	390.7	469.3	142,380	171,740
Pennsylvania	17.8	15.1	6,457	5,532
Texas[3]	5,074.0	5,199.8	1,849,362	1,896,797
Utah	99.3	86.8	36,169	30,951
West Virginia	52.0	51.1	18,894	19,059
Wyoming	232.3	243.6	84,600	89,091
Others[4]	26.7	23.9	9,703	8,689
TOTAL U.S.	**11,186.9**	**11,314.7**	**4,075,364**	**4,129,563**

[1] Estimated using EIA data. Totals may not add due to rounding.
[2] Revised using EIA data.
[3] Includes state and federal offshore.
[4] Includes Arizona, Indiana, Missouri, Nevada, New York, South Dakota, Tennessee and Virginia.

U.S. proved reserves drop sharply

According to the U.S. Energy Information Administration (EIA), the price effects of the economic slowdown following the Covid event contributed to reductions in U.S. petroleum and natural gas reserves in 2020. Proved reserves of crude oil and lease condensate decreased 9 Bbbl in 2020, a decline of 19%. Proved reserves of natural gas decreased by approximately 22 Tcf, a drop of 4.5%.

The pandemic had a significant effect on U.S reserves. On March 13, 2020, then-President Trump declared a national emergency in the U.S. Many states imposed mandatory lockdowns and issued stay-at-home orders, and in addition to travel restrictions, people also voluntarily chose not to travel, to avoid exposure. Consequently, demand fell for transportation fuels, and commodity prices fell. Liquid fuel production also faced a critical shortage of available storage, which caused WTI to plummet 300%, to minus $37.63/bbl in April 2020. As a result, operators revised their proved reserves downward in 2020 and postponed development drilling.

Crude oil. The precipitous decline in drilling activity caused proved reserves of U.S. crude and lease condensate to decline 19%, from 47.2 Bbbl to 38.2 Bbbl at the end of 2020, **Table 1.** Proved reserves of crude decreased 8.4 Bbbl in 2020 and proved reserves of lease condensate (produced from natural gas wells) decreased 560 MMbbl. U.S. oil and lease condensate production decreased 7% in 2020.

Texas, the state with the largest volume of proved reserves of oil and lease condensate, had the largest net decrease in 2020, dropping 3.1 Bbbl, a 16% decline. **North Dakota** had the second-largest net decrease, losing 2.2 billion barrels (-38%). And the GOM experienced the third-largest decline, slipping 0.8 Bbbl (-16%). **Utah** had the largest net increase in proved crude/condensate reserves in 2020, adding 91 MMbbl (31%).

Tight oil. Meanwhile, U.S. tight oil reserves fell 15.4% during 2020, to 19.7 Bbbl, with every play experiencing a loss. The largest play, the Permian basin, fell 1.6% to 11.9 Bbbl. The greatest loss occurred in the Bakken shale, where reserves fell 37% to 3.7 Bbbl.

Table 1. Crude oil and lease condensate proved reserves, reserves changes, and production, 2020, MMbbl

State and subdivision	Proved Reserves 12/31/19	Changes in reserves during 2020: Adjustments (+,-)	Revision increases (+)	Revision decreases (–)	Sales (–)	Acquisitions (+)	Extensions & discoveries (+)	Estimated production (–)	Proved reserves 12/31/20
Alaska	2,680	387	3	568	1,369	1,353	101	162	2,425
Lower 48 States	**44,492**	**857**	**3,018**	**12,079**	**792**	**1,142**	**3,141**	**3,992**	**35,787**
Alabama	48	0	2	8	0	2	0	5	39
Arkansas	34	-1	8	7	0	0	0	4	30
California	2,213	-129	130	655	1	0	84	145	1,497
Colorado	1,557	-29	240	619	216	366	41	171	1,169
Kansas	327	-1	13	20	0	0	0	29	290
Kentucky	8	-4	0	1	0	1	0	0	4
Louisiana	449	26	67	142	13	15	10	37	375
Michigan	49	4	6	15	0	0	0	4	40
Mississippi	117	25	7	42	0	0	0	14	93
Montana	323	-7	81	115	0	0	2	22	262
Nebraska	12	0	2	0	0	0	0	2	12
New Mexico	3,738	190	82	802	33	41	694	371	3,539
North Dakota	5,899	133	574	2,719	2	0	219	432	3,672
Ohio	316	-55	31	42	7	29	31	24	279
Oklahoma	2,342	60	160	759	77	109	94	171	1,758
Pennsylvania	130	-5	2	30	0	0	6	6	97
Texas	19,797	559	1,135	4,954	389	542	1,787	1,788	16,689
Utah	298	133	75	158	5	5	92	31	389
West Virginia	233	-4	16	87	6	4	32	19	169
Wyoming	1,151	-30	52	308	34	20	33	89	795
Federal Offshore[a]	5,350	-17	330	551	9	8	15	621	4,505
Miscellaneous[b]	102	6	5	18	0	0	1	7	138
U.S. Total	**47,172**	**1,244**	**3,021**	**12,647**	**2,161**	**2,495**	**3,242**	**4,154**	**38,212**

[a] Includes Federal offshore Louisiana, Mississippi, Alabama and Florida. [b] Miscellaneous states include Arizona, Florida, Idaho, Illinois, Indiana, Maryland, Missouri, Nevada, New York, Oregon, South Dakota, Tennessee and Virginia. Note: The production estimates in this table are based on data reported on Form EIA-23L, *Annual Report of Domestic Oil and Gas Reserves.* Source: U.S. Energy Information Administration.

Natural gas. Proved reserves of natural gas decreased 4.5%, from 495.4 Tcf at year-end 2019 to 473.3 Tcf at year-end 2020. The decrease was the second, consecutive annual setback in proved reserves of natural gas in the U.S. However, producers in **Alaska** managed to add a substantial new volume of proved natural gas reserves in 2020. The annual total of proved gas reserves in Alaska increased in 2020 by 27 Tcf, quadrupling the state's total from 9 Tcf to 36 Tcf. Producers in **Texas** reported the largest decrease in proved gas reserves in 2020, losing 11 Tcf, a decline of 9%. **Pennsylvania** experienced the second-largest decrease of proved gas reserves, dropping 9.6 Tcf, a decrease of 9%.

Proved natural gas reserves nationwide were set to decline over 10%, but on May 21, 2020, the U.S. FERC approved the large-scale Alaskan LNG Project. The Alaska LNG Project will connect gas reserves and production in the Prudhoe Bay Unit of Alaska's North Slope with (via pipeline) liquefaction facilities on the Kenai Peninsula, allowing up to 20 MMmt/year of LNG exports. Project approval means that a large volume of previously stranded Alaskan gas resources are now "proved." Thus, Alaska's proved gas reserves increased in 2020 by the aforementioned 27 Tcf, boosting the state's total to 36 Tcf. Additional production facilities will add more reserves in future years.

Proved reserves are estimated volumes of hydrocarbon resources that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions. Reserve estimates change from year to year because of: 1) new discoveries; 2) appraisals of existing fields; 3) production of existing reserves; 4) changes in prices, costs, ownership or planned infrastructure; and 5) new and improved techniques and technologies. WO

Table 2. U.S. tight oil plays–production and proved reserves, 2019-2020, MMbbl

Basin	Play	State(s)	2019 production	2019 reserves	2020 production	2020 reserves	Change, 2019–2020 reserves
Permian	Wolfcamp/Bone Spring	NM, TX	1,209	12,069	1,322	11,870	-199
Williston	Bakken/Three Forks	ND, MT, SD	517	5,845	431	3,685	-2,160
Western Gulf	Eagle Ford	TX	451	4,297	399	3,246	-1,051
Anadarko, S. Okla.	Woodford	OK	53	524	46	378	-146
Appalachian	Marcellus	PA, WV	21	326	23	247	-79
Denver	Niobrara*	CO, KS, NE, WY	25	235	16	218	-17
Fort Worth	Barnett	TX	2	19	1	15	-4
U.S. tight oil totals			**2,278**	**23,240**	**2,238**	**19,659**	**-3,581**

Note: Includes lease condensate. Bakken/Three Forks tight oil includes fields reported as shale or low permeability on Form EIA-23L. *Other* includes fields reported as shale on Form EIA-23L, not assigned by EIA to the Eagle Ford, Bakken, Barnett, Marcellus, or Niobrara resource plays. * The Niobrara estimate may contain some reserves from the Codell sandstone. Source: U.S. Energy Information Administration, Form EIA-23L, *Annual Report of Domestic Oil and Gas Reserves,* 2019 and 2020

Table 3. Total natural gas proved reserves, reserves changes, and production, wet after lease separation, 2020, MMbbl

		Changes in reserves during 2020							
State and subdivision	Proved Reserves 12/31/19	Adjustments (+,–)	Revision increases (+)	Revision decreases (–)	Sales (–)	Acquisitions (+)	Extensions & discoveries (+)	Estimated production (–)	Proved reserves 12/31/20
Alaska	9,380	774	18	36,009	4,729	67,242	101	248	36,529
Lower 48 States	**486,000**	**4,396**	**35,044**	**97,289**	**15,654**	**21,345**	**39,728**	**36,814**	**436,756**
Alabama	1,423	184	156	127	0	9	0	115	1,530
Arkansas	5,836	88	143	599	0	0	0	485	4,983
California	1,369	120	71	326	2	0	43	153	1,122
Colorado	24,115	-819	3,163	6,065	3,476	4,885	553	1,944	20,412
Kansas	2,303	7	76	108	2	0	0	162	2,114
Kentucky	1,369	-47	21	61	0	28	0	61	1,249
Louisiana	36,779	951	6,502	8,685	1,063	1,152	5,176	3,242	37,570
Michigan	1,261	-118	81	190	80	1	0	64	891
Mississippi	227	-40	25	18	0	0	0	27	167
Montana	631	-32	160	148	0	0	1	42	570
New Mexico	24,305	2,808	1,158	2,963	1,097	434	3,457	1,973	26,129
New York	81	56	44	54	0	0	0	12	115
North Dakota	13,083	240	1,991	6,189	3	0	426	985	8,563
Ohio	34,748	-2,973	2,535	7,282	51	2,598	887	2,362	28,100
Oklahoma	35,823	3,703	3,059	11,724	1,400	2,228	1,105	2,703	30,091
Pennsylvania	107,392	-3,104	1,774	13,757	2,609	2,845	12,415	7,154	97,802
Texas	126,150	4,590	11,006	25,152	4,475	4,973	8,075	10,435	114,732
Utah	2,362	70	308	538	812	1,122	114	245	2,381
Virginia	2,298	-22	81	308	0	2	2	102	1,951
West Virginia	40,130	-1,123	1,428	7,161	469	909	7,212	2,564	38,462
Wyoming	18,325	-1	916	5,119	20	29	149	1,153	13,126
Federal Offshore[a]	5,939	-127	346	700	95	106	13	828	4,654
Miscellaneous[b]	49	-15	0	15	0	24	0	3	40
U.S. Total	**495,380**	**5,170**	**35,062**	**133,298**	**20,383**	**88,587**	**39,829**	**37,062**	**473,285**

[a] Includes Federal offshore Louisiana, Mississippi, Alabama and Florida. [b] Miscellaneous states include Arizona, Florida, Idaho, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota and Tennessee. Note: The production estimates in this table are based on data reported on Form EIA-23L, *Annual Report of Domestic Oil and Gas Reserves*. Source: U.S. Energy Information Administration.

Activity outside North America will lead global recovery

Every region will post an increase, led by the Middle East, the Americas, Africa and the FSU. Offshore activity will grow at about the same pace as onshore drilling.

WORLD OIL Staff

After experiencing an unusually low level of activity during 2020, sparked by the Covid pandemic, drilling outside the U.S. grew at an 8.0% pace during 2021. And given burgeoning oil and gas demand, coupled with much-improved commodity prices, the stage is set for a noticeably better drilling performance in 2022.

The number of wells drilled internationally increased from 35,918 in 2020 to 38,777 last year, **Table 1.** Five of eight regions worldwide posted gains last year, while three areas (Middle East, Africa and Eastern Europe/FSU) eroded further. For 2022, operators will have demand and commodity prices on their side, but they also will have to deal with supply chain issues and higher prices and/or spot shortages for oil and gas products and services. The situation for OCTG supplies will be a particular issue to keep an eye on.

Table 1. Forecast of 2022 drilling outside the U.S.*

Region or country	Wells forecast 2022	Wells drilled 2021	% diff.
North America[1]	5,676	4,882	16.2
South America[2]	1,524	1,299	17.3
Western Europe[3]	411	365	12.6
Eastern Europe/FSU[4]	11,493	9,916	15.9
Africa	840	722	16.3
Middle East	2,440	2,118	15.2
Far East/South Asia	21,592	19,216	12.4
South Pacific	280	259	8.1
World Total	**44,256**	**38,777**	**14.1**

* Some countries are estimated.
[1] Includes Canada, Cuba, Mexico and Others.
[2] Includes Argentina, Bolivia, Brazil, Chile, Colombia, Ecuador, Peru, Trinidad & Tobago, Venezuela and Others.
[3] Includes Austria, Denmark, France, Germany, Italy, Netherlands, Norway, UK and Others.
[4] Includes Albania, Croatia, Czech Republic, Hungary, Poland, Romania, Russia and Others.
[5] Includes Algeria, Angola, Congo, Egypt, Gabon, Libya, Nigeria, South Sudan, Sudan, Tunisia and Others.
[6] Includes Iran, Iraq, Kuwait, Neutral Zone, Oman, Qatar, Saudi Arabia, Syria, Turkey, UAE-Abu Dhabi, UAE-Dubai, Yemen and Others.
[7] Includes Brunei, China, India, Indonesia, Japan, Malaysia, Myanmar, Pakistan, Philippines, Thailand, Vietnam and Others.
[8] Includes Australia, East Timor, New Zealand and Papua New Guinea.

Given the aforementioned factors, along with *World Oil's* surveys of international petroleum ministries and departments, *World Oil's* editorial staff forecasts 2022 international E&P activity, as follows:

- Canadian wells will rise 16.1%, while Mexican drilling will jump 18.0% higher
- Global drilling, excluding the U.S., will increase 14.1%; **Table 1.**
- Global offshore drilling is forecast to gain 14.5%, with increases expected in every region, **Table 2.**

After dropping an unprecedented 7.0% during 2020, worldwide crude and condensate production rose 0.6% last year, to 77.1 MMbpd, **Table 3.** The increase was a response to growing demand worldwide, as effects of the Covid pandemic lessened.

NORTH AMERICA

Outside the U.S., North American drilling is expected to increase 16.2% during 2022, with double-digit growth featured in Canada and Mexico.

Canada. All basic indicators of oil patch activity are trending up in Canada, but not all is well. Politics continue to be the biggest wild card in the country. The Trudeau administration's anti-oil agenda continues to suppress optimism for a Canadian rebound.

Nevertheless, the Canadian oil and gas production outlook is positive for the near term, although the fate of the overall market is very much in the hands of the individual provinces. While the Albertan premier, Jason Kenney, continues his support for oil operations critical to the economy, the story is different on the Atlantic coast. In Newfoundland and Labrador, provincial premier Andrew Furey withdrew financing for offshore seismic operations, calling into question the government's commitment to the offshore oil and gas industry.

For 2022, the Canadian Association of Petroleum Producers expects drilling to increase 16.1%, **Fig. 1.** Please turn to page 42 for the full Canadian forecast article.

Mexico. President Andres Manuel Lopez Obrador (AMLO) will continue his focus on meeting domestic demand, going so far as to cut crude oil exports to help satisfy the country's need for gasoline and other refined products. As many as 300,000 bopd that would have been made available to the export market are now being dedicated to Mexico's refiners, who have been operating at less than 50% capacity for the past several years.

Finances remain a challenge for Mexico's Pemex, regardless of where the crude produced ends up. Mexico's president, AMLO, has announced a slate of tax breaks for the state-owned operator to keep E&P work moving. Third-party operators will continue to face regulatory uncertainty, souring interest in

Mexican prospects as well as individual asset performance. The future of Zama field, Mexico's largest offshore operation, looks uncertain, as Pemex struggles to fund the $2 billion necessary to develop the project after it was wrested from joint-partner Talos Energy.

Increased domestic demand, along with Mexico's skilled approach to price hedging, will help propel drilling growth. *World Oil* projects an 18% increase in Mexican drilling this year.

SOUTH AMERICA

Drilling across South America is expected to continue its strong upward trend from 2021, as high commodity prices and robust political agendas support new operations. In what's now a historic shift, Venezuela will add new wells for the first time in several years, and offshore growth will be strong across the board in South America. Accordingly, *World Oil* sees drilling activity increasing 17.3% in 2022, with 1,524 wells forecast to be drilled across the region.

Brazil. President Jair Bolsonaro is continuing his strong support of the oil and gas sector, recognizing its role in supporting the broader Brazilian economy. Domestic oil demand is roaring back, and major operators are taking advantage of the favorable business environment created by recent tax reforms and regulatory updates. Drilling is projected to increase 18.7% in Brazil this year.

On Feb. 1, 2022, Petrobras announced that the *FPSO Guanabara* had arrived at Mero field on the Libra Block, in the pre-salt Santos basin, offshore Brazil, **Fig. 2.** Mero is the third-largest pre-salt field. During first-half 2022, this FPSO will be connected to wells and subsea facilities. Pending hook-up and final testing, the vessel should realize first production in the first half of the year. The field's first production was postponed in April 2021, due to delays in constructing the FPSO, due to the Covid-19 pandemic. The *FPSO Guanabara* can produce up to 180,000 bopd and is the first of four platforms planned for Mero field.

Fig. 1. Canadian drilling of all kinds will be up this year and should result in a combined 16% increase. Image: Precision Drilling Corporation.

Argentina. The Argentine government is looking forward to starting work on several Atlantic exploration blocks, auctioned in 2019, as a supplement to the Vaca Muerta shale formation on land. Environmental activists may stand in the way, however. Coming off a significant victory against new silver mines, green groups in Argentina have set their sights on stopping new offshore drilling. The government has asserted that drilling is key to meeting the nation's economic needs. Yet, if history is any indication, the activists may tally another win. Nevertheless, drilling activity is expected to increase 12.1% in Argentina during 2022.

Venezuela. After years of battering by U.S. economic sanctions, Venezuela is taking advantage of the Biden administration turning a blind eye to the country's oil production activities. Partner-in-sanctions Iran has resumed trading refined products for raw crude, and China has begun openly accepting crude shipments from the Maduro regime. Global oil demand makes for strange bedfellows; Biden recently extended, for a year, certain financial protections to ensure Venezuela's Citgo retains ownership of oil refining facilities in the United States. With sanctions enforcement seeming to fall by the wayside, Venezuela is expected to drill its first new wells in nearly two years, later this year.

Colombia. With oil and coal accounting for half of the nation's export revenue, Colombia continues to be a stable E&P

Table 2. Forecast of 2022 offshore drilling worldwide*

Region or country	Wells forecast 2022	Wells drilled 2021	% diff.
North America[1]	245	215	14.0
South America[2]	94	85	10.6
Western Europe[3]	354	330	7.3
Eastern Europe/FSU[4]	124	102	21.6
Africa[5]	196	145	35.2
Middle East[6]	248	207	19.8
Far East[7]	898	802	12.0
South Pacific[8]	33	29	13.8
World Total	**2,192**	**1,915**	**14.5**

* Some countries are estimated.
[1] Includes Canada, Mexico, the U.S. and Others.
[2] Includes Brazil, Guyana, Suriname, Trinidad & Tobago and Others.
[3] Includes Denmark, Germany, Italy, the Netherlands, Norway, the UK and Others.
[4] Includes Croatia, Poland, Romania, Russia and Others.
[5] Includes Angola, Congo, Egypt, Gabon, Libya, Nigeria, South Africa, Tunisia and Others.
[6] Includes Neutral Zone, Oman, Qatar, Saudi Arabia, Turkey, UAE-Abu Dhabi, UAE-Dubai and Others.
[7] Includes Brunei, China, India, Indonesia, Japan, Malaysia, Myanmar, Thailand, Vietnam and Others.
[8] Includes Australia, East Timor, New Zealand and Papua New Guinea.

player in the region. Clouds may be forming on the horizon, however, as presidential favorite Gustavo Petro seeks to plot an eventual end to fossil fuel production in the region. For the time being, interest in oil, and its contribution to Colombia's coffers, remains strong. Drilling is expected to increase 49.6% in 2022.

Guyana and Suriname. The increasingly prolific Guyana-Suriname basin is coming into its own as the next frontier in offshore oil and gas development. ExxonMobil and Apache announced more significant discoveries, while offshore and oilfield service companies rapidly expand in-country operations to progress operations already underway.

WESTERN EUROPE

While renewable energy captures much of the attention of legacy players in Western Europe, the North Sea will continue its role as a key basin for future oil and gas development. Smaller players are both taking on assets from the majors and seeking new permits of their own, ensuring a robust market for oilfield services, for some years to come. Growth in Western Europe will be steady, increasing 12.6% in 2022.

Norway. Drilling activity on the Norwegian Shelf was flat last

Table 3. World crude/condensate production by countries, 2021 and 2020*

Region or country	Daily production (thousands of barrels) 2021	2020**	% Diff.	Region or country	Daily production (thousands of barrels) 2021	2020**	% Diff.
North America	**17,341.5**	**17,205.3**	**0.8**	Angola	1,130.8	1,267.7	-10.8
Canada[1]	4,398.5	4,154.6	5.9	Congo	277.5	292.2	-5.0
Cuba	42.0	43.0	-2.3	Egypt	562.2	573.7	-2.0
Mexico	1,735.7	1,710.4	1.5	Equatorial Guinea	135.2	147.6	-8.4
United States	11,157.5	11,289.0	-1.2	Gabon	187.5	190.2	-1.4
Others	7.8	8.3	-6.0	Libya	1,252.5	407.2	207.6
South America	**5,708.4**	**5,637.5**	**1.3**	Nigeria	1,539.0	1,754.3	-12.3
Argentina	495.3	506.1	-2.1	Sudan/South Sudan	224.2	227.1	-1.3
Bolivia	46.5	48.8	-4.7	Tunisia	37.6	32.1	17.1
Brazil	2,947.8	2,939.9	0.3	Others	405.3	452.3	-10.4
Colombia	768.7	799.1	-3.8	**Middle East**	**24,467.9**	**24,483.4**	**-0.1**
Ecuador	491.1	473.9	3.6	Iran	3,101.5	2,655.5	16.8
Guyana	121.0	74.3	62.9	Iraq	4,038.2	4,103.8	-1.6
Peru	108.0	124.6	-13.3	Kuwait	2,489.1	2,550.4	-2.4
Trinidad & Tobago	59.5	56.4	5.5	Neutral Zone	200.0	120.0	66.7
Venezuela	652.0	596.0	9.4	Oman	961.3	949.5	1.2
Others	18.5	18.4	0.5	Qatar	1,366.5	1,351.1	1.1
Western Europe	**2,864.9**	**2,950.1**	**-2.9**	Saudi Arabia	9,055.6	9,407.5	-3.7
Austria	12.0	11.8	1.7	Syria	36.0	35.0	2.9
Denmark	65.7	71.6	-8.2	Turkey	66.3	61.8	7.3
France	13.0	13.6	-4.4	UAE - Abu Dhabi	2,790.4	2,885.4	-3.3
Germany	35.5	38.0	-6.6	UAE - Dubai	212.5	219.8	-3.3
Italy	95.4	100.3	-4.9	Yemen	70.6	65.5	7.8
Netherlands	32.7	32.8	-0.3	Others	79.9	78.1	2.3
Norway	1,762.5	1,712.5	2.9	**Far East/South Asia**	**6,382.6**	**6,392.3**	**-0.2**
United Kingdom	845.0	965.8	-12.5	Brunei	99.1	100.1	-1.0
Others	3.1	3.7	-16.2	China	4,004.5	3,890.5	2.9
Eastern Europe	**13,063.1**	**13,119.4**	**-0.4**	India	614.1	628.5	-2.3
Albania	16.2	17.3	-6.4	Indonesia	665.8	711.2	-6.4
Bulgaria	0.4	0.4	0.0	Malaysia	510.7	548.3	-6.9
Croatia	11.3	11.9	-5.0	Myanmar	10.4	10.6	-1.9
Czech Republic	1.7	1.8	-5.6	Pakistan	82.1	76.7	7.0
Former Soviet Union	12,918.1	12,969.7	-0.4	Philippines	1.0	1.0	0.0
Russian Federation	10,204.6	10,185.9	0.2	Thailand	184.5	202.1	-8.7
FSU - Others	2,713.5	2,783.8	-2.5	Viet Nam	182.1	194.2	-6.2
Hungary	16.5	15.5	6.5	Others	28.3	29.1	-2.7
Poland	17.6	18.8	-6.4	**South Pacific**	**409.7**	**428.8**	**-4.5**
Romania	65.7	67.6	-2.8	Australia	337.4	353.6	-4.6
Serbia	15.5	16.3	-4.9	East Timor	13.9	14.2	-2.1
Others	0.1	0.1	0.0	New Zealand	20.2	21.6	-6.5
Africa	**6,871.2**	**6,467.1**	**6.2**	Papua New Guinea	38.2	39.4	-3.0
Algeria	1,119.4	1,122.7	-0.3	**World Total**	**77,109.3**	**76,683.9**	**0.6**

*Some countries are estimated. None contain NGLs or refinery gains. **Revised [1]Includes bitumen and synthetic oil output.
Sources: *World Oil*'s surveys of governments and companies, plus some third-party data.

year, as renewable energy projects gain traction. Climbing oil price forecasts, along with recovering demand and challenged production from OPEC, will make Norway's existing infrastructure all the more appealing for operators looking to add barrels. We project a fresh year of drilling growth offshore Norway, with the number of wells drilled to climb 4.4% in 2022.

In mid-February 2022, Sembcorp Marine announced completion of the *Johan Castberg* FPSO and its delivery to Equinor, **Fig. 3.** The FPSO then set off to Norway. Upon final completion in Norway, the FPSO is scheduled for deployment at Johan Castberg field in the Barents Sea, about 240 km from Hammerfest, Norway.

United Kingdom. The trend of supermajors selling legacy assets to smaller operators on the UK Continental Shelf continues, with ExxonMobil and Suncor leading the transition. The UK Oil and Gas Authority estimates that between 10 Bboe and 20 Bboe of recoverable petroleum reserves remain on the shelf, pointing to a long, albeit declining, future for offshore oil and gas production. Based upon the enthusiasm that smaller operators are showing for drilling the supermajors' legacy assets, *World Oil* anticipates a 16.2% increase in drilling in the United Kingdom.

EASTERN EUROPE

Dominated by Russian activity, Eastern Europe (including the former Soviet Union states) will see drilling increase 15.9% in 2022, a nearly four-fold increase from the year prior.

Russia. Deputy Premier Alexander Novak pushed hard for higher OPEC production quotas early in 2021, while falling behind those quotas late in the year and into 2022. Focus remains on expanding natural gas export infrastructure, including both the Nord Stream 2 pipeline and other assets for Chinese delivery. Drilling in Russia is expected to increase by 16.2% in 2022. Rosneft is expected to lead the way among Russian operators planning greater drilling.

Outside of Russia, in the former Soviet Union, higher commodity prices are spurring renewed interest in drilling programs, with new wells drilled increasing 13.2% this year. **Kazakhstan** and **Azerbaijan** will set the pace among FSU countries for greater activity.

AFRICA

After a moderate 6.5% decline in drilling during 2021, African nations are expected to accelerate operations in 2022. A stabilizing political environment in Libya, combined with more offshore activity across the West African region, will see drilling rates increase 16.3% this year.

Egypt will continue its exploration efforts offshore the Mediterranean Sea with Chevron and ExxonMobil, and onshore exploration is still underway following discoveries in the Western Desert. Recently, APA Corporation (Apache) modernized and consolidated its PSC in the country and will increase investment in Egypt, accordingly. *World Oil* projects Egyptian drilling rates will increase 9.3% this year.

Fig. 2. The *FPSO Guanabara,* operated by Petrobras, is now on station at Mero field in the pre-salt offshore Brazil. It is slated to begin producing during first-half 2022. Image: Petrobras.

Fig. 3. Once the *Johan Castberg* FPSO is completed in Norway and subsequently undergoes hook-up and final commissioning at Johan Castberg field, it should achieve first production in 2024. Image: Equinor, photo by Ong Tze Wei Justin and Chua Chee Hou.

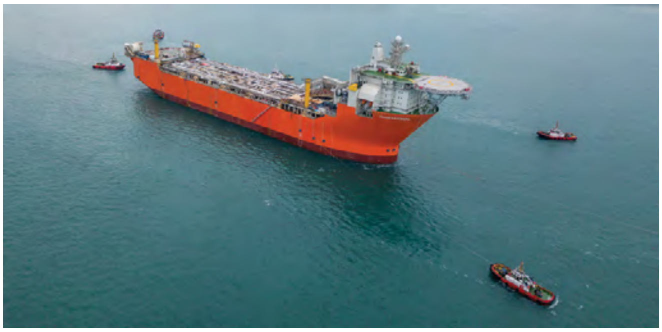


Fig. 4. Russian operators, in an effort to maintain current production and boost output further, are expected to combine for a 16% drilling increase during 2022. Image: Gazprom Neft.

Fig. 5. Ghana's dominant operator, Tullow Oil, is striving to have both of its FPSOs operate in excess of 95% uptime.

Fig. 6. Saudi Arabian drilling should be up 15% this year, including new work at the massive Jafurah unconventional field development. Image: Saudi Aramco.

Libya faces a long road back to its role as a major contributor to OPEC production. Infrastructure budget challenges, regional skirmishes, and even weather issues are combining to keep Libyan barrels off the market. Despite these troubles, drilling activity is increasing, with wells drilled expected to climb 5.9% during 2022.

Nigeria is exploring a post-supermajors future for its oil and gas industry. A renewed focus on environmental integrity and support of domestic industry will see local operators like Heirs Oil & Gas take over from legacy operators, such as Shell. Drilling activity in Nigeria is projected to increase 15.4%.

Angola is seeking to reverse the tide of dwindling outflows by increasing the inventory of new fields available for development. Chevron's Angola subsidiary recently signed a 20-year extension for Block 0, representing an important commitment by Chevron and its partners, Sonangol, TotalEnergies, and Eni Angola to continue E&P activity. As such, *World Oil* expects drilling in Angola to increase 16.2%.

Ghana. Tullow Oil and its partners are investing over $4 billion over this decade through their ambitious "Value Maximization Plan," which will deliver over 50 wells. In April 2021, Tullow began a multi-year, multi-well campaign, drilling four wells during the year, consisting of two Jubilee production wells, one Jubilee water injector well and one TEN gas injector well. The J56 production well went onstream in July 2021.

The Value Maximization Plan also focuses on a program of operational turnaround, which is targeting in excess of 95% uptime at both FPSOs, **Fig. 5.** Tullow is also making sure that both fields continue to supply natural gas, consistently and reliably.

MIDDLE EAST

Among the world's regions, the Middle East has been at a high rate of drilling activity, and that trend is set to continue. After taking extraordinary measures to support oil prices during the worst of the Covid pandemic by throttling output, key players are ready to open the taps, albeit in a measured fashion. With OPEC's global oil demand projections strong through 2023, there looks to be no shortage of buyers for every barrel and molecule produced. *World Oil* expects drilling across the region to increase 15.2% this year.

Saudi Arabia. In addition to maintaining oil output, Saudi Aramco has awarded $10 billion of contracts for the vast Jafurah field development. This is a major effort to develop unconventional gas and condensate reserves. Production is expected to reach up to 2.0 Bcfd of sales gas, 418 MMcfd of ethane and around 630,000 bpd of gas liquids and condensates by 2030. The project aims to meet rising demand for high-value petrochemicals feedstock, complement Aramco's focus on hydrogen, and support expansion of its integrated gas portfolio. We predict that Saudi Arabian drilling will jump 15.3% higher this year, **Fig. 6.**

Iraq is the Middle East's second-largest oil producer, but it continues to be bedeviled by output challenges. Most of its OPEC output targets have been missed, even when accounting for cuts due to slumping pandemic demand. The nation continues its search for a buyer for ExxonMobil's stake in the 20-Bbbl West Qurna 1 oil field, after which production could be anticipated to improve. Drilling in Iraq is set to increase 13% in 2022.

UAE-Abu Dhabi. The government-owned Abu Dhabi National Oil Co. (ADNOC) is continuing its quest to increase output of unconventional gas, while also exploring new alternative-fuel ventures. UAE Energy Minister Suhail Al-Mazrouei is keen to take the title of world's largest LNG exporter away from the U.S., Australia or Qatar (whichever one is leading at any moment), as global demand for the fuel reaches record highs.

On Feb. 3, 2022, ADNOC announced the discovery of natural gas resources offshore Abu Dhabi. Interim results from the

Fig. 7. Epitomized by work being conducted at the West Ganal PSC by Eni (operator) and partners Neptune Energy and Pertamina, Indonesia's offshore drilling will be up 10% this year, with nationwide wells, overall, up 14%. Image: Neptune Energy.

first exploration well in the Offshore Block 2 Exploration Concession, operated by Eni, indicate between 1.5 Tcf and 2.0 Tcf of raw gas in place. *World Oil* expects Abu Dhabi drilling to increase 20.5%, up significantly from 2021's modest increase.

Oman is the Middle East's largest oil producer outside of OPEC and is expected to maintain a rapid drilling pace in 2022. In addition to conventional oil and gas production, Oman is working with TotalEnergies to develop low-carbon LNG production and export facilities. Meanwhile, an agreement has been struck with BP to jointly develop a multi-gigawatt renewable energy and green hydrogen program by 2030. Oil and natural gas remain the primary focus, however, and drilling is expected to increase 5.8% this year.

FAR EAST

China's drilling programs typically set the pace for the Far East average overall, and this year is no exception. Building upon an already sprawling drilling program, China will help lead the region to a 12.4% increase for 2022.

China. A commitment to reduce fossil fuels to 20% of its total energy mix by 2060, plus an economy that's still recovering in fits and starts from the pandemic, would be enough to slow any country's drilling activity. Yet, China will continue to be the world's leading driller of oil and gas wells, with *World Oil* projecting a 12.3% increase in activity during 2022.

China's national oil companies, CNPC, CNOOC and Sinopec, are expected to spend over $120 billion on drilling and well services by 2025, to help meet rising domestic oil and gas demand.

Indonesia. A subsidiary of state firm Pertamina is preparing to support a massive work plan, to drill 400 to 500 new wells in the Rokan Working Area this year. Activity should be up about 14% nationwide, including a 10% boost offshore, **Fig. 7.**

Malaysia. State company Petronas awarded six of 13 offshore exploration blocks offered in the recently concluded bidding round. The six blocks were awarded to existing and new operators.

SOUTH PACIFIC

In the South Pacific, the region is mostly a two-country realm of activity (Australia and Papua New Guinea), and upstream work has become increasingly gas-focused. We expect the region's drilling to increase by a relatively modest 8.1%, to 280 wells.

Fig. 8. Symbolized by the Woodside Energy-operated Pluto LNG plant on the shore of Western Australia, the country continues to pursue a goal of becoming the world's largest LNG exporter. Image: Woodside Energy Ltd.

Fig. 9. Papua New Guinea continues to produce oil from its fields in the remote mountains, but output has come down considerably from the peak. Production averaged just over 38,000 bopd in 2021. Image: JX Nippon Oil & Gas Exploration Corporation.

Australia is maintaining its ambition to become the world's largest LNG exporter (**Fig. 8**), but cost overruns and domestic shortages present challenges. And yet, new drilling is at the center of Australian plans to improve tax revenue while meeting domestic needs. *World Oil* expects the country's drilling to increase 9.2% this year. The heightened activity is expected to be led by Santos and a number of smaller, independent explorers.

Papua New Guinea will see drilling increase slightly this year, as the pandemic recovery gathers pace and delayed projects are brought back online. In December 2021, Santos completed its acquisition of Oil Search Limited and all its holdings, including the oil fields (**Fig. 9.**) of Papua New Guinea and a share of the PNG LNG project operated by ExxonMobil. Meanwhile, the country's dominant drilling contractor, High Arctic Energy Services, returned one of its rigs back to service after a long inactive period. WO

Positives try to outweigh the negatives in Canada's upstream

As the global economy recovers from the pandemic, indicators have shifted to a positive outlook for the first time in many years. But politics, especially in Canada, have cast a pall over any potential turnaround for the Canadian industry.

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As the Covid-19 crisis appears to be shifting into the endemic phase, protests across Canada are focused on the temporary measures put into place by governments and their impacts. What's been lost is the federal government's almost singular focus on eliminating fossil fuels dependance and dismantling the industry that has been the single most-important driver of the country's economy for the vast majority of the past century.

THE BIG PICTURE

Ironically, the Canadian oil patch is widely regarded as innovative, forward-thinking, and green, compared to most jurisdictions around the globe. There is a huge opportunity for governments to tap into that resourcefulness. They can partner with industry and put Canada at the vanguard of a measured and informed transition, into an energy mix that includes new technologies, more reliable and less costly renewables, and the continued use of fossil fuels with significantly reduced environmental impacts.

A measured and thoughtful transition also would reduce the enormous financial burden associated with a forced and uneven transition—a burden that will be borne by taxpayers. To date, those looming impacts have not been communicated effectively to average Canadians, and the opportunities to collaborate are largely ignored.

The result is an industry plagued by uncertainty and doubt, guarded in its planning because it must hedge against political risk. Meanwhile, billions of dollars have been diverted elsewhere, often to jurisdictions that have little or no regard for the environment or basic human rights. Instead of leading the way as a beacon of change and hope, Canada's oil and gas industry remains in a year-to-year planning cycle, waiting for the next ideological edict from politicians more interested in virtue-signaling than tackling real-world problems in a meaningful and constructive way.

Fig. 1. Symbolizing the resurgence of Canadian drilling, three rigs work on a pad at Kakwa, Alberta, in November 2021. Image: Precision Drilling Corporation.

MARKET FACTORS

Meanwhile, without any meaningful support from Ottawa, Canadian oil sands producers have formed their own consortium to achieve net zero emissions by 2050. Entitled "Oilsands Pathways to Net Zero," the group consists of six companies: Imperial Oil Limited, Canadian Natural Resources Limited, Suncor Energy Inc., Meg Energy Corp., ConocoPhillips, and Cenovus Energy Inc. The group expects to spend C$70-75 billion over three phases, eliminating 68 megatonnes of oil sands emissions. The first phase is building a trunk line from Fort McMurray to Cold Lake, Alberta, to ship CO_2 to sequestration facilities. The group also says it is meeting regularly with the provincial and federal governments to keep them apprised, seeking investment tax credits and other financial supports.

Prices/activity. The good news is that commodity prices are up—even natural gas—and results are very strong for most producers. As a result, drilling has taken a jump upward (**Fig. 1**), land sales have a pulse again, and spending plans have increased for 2022. The classic issues with Canada's cyclical oil patch are back, of course: a lack of skilled labor, market access, and skittish markets. Additionally, supply chain issues, which are problematic across virtually every industry, have compounded things for oil and gas producers too.

There was modest recovery in 2021, but only in comparison to the disastrous 2020, where virtually every measure fell to unprecedented lows, due to Covid-related lockdowns that drastically reduced travel and global oil demand. If the Canadian industry can show continued growth this year, then a recovery back to pre-Covid activity may indeed be in place.

Market access remains a top-of-mind issue, as the Trans-Mountain pipeline expansion faces a seemingly endless parade of challenges, cost overruns, and other delays, including Covid restrictions. The beleaguered project, which is owned by the

Canadian federal government, is estimated to have a C$17 billion price tag, with its in-service date now delayed until 2023. Originally, the project had a C$7.4 billion estimated cost.

And although TC Energy's Keystone XL project is officially dead after U.S. President Joe Biden reversed its approval, the saga is not over. In addition to TC's legacy NAFTA claim launched last year—seeking more than C$15 billion in damages from the U.S.—the Alberta government also added its own claim in early February, seeking compensation for the $1.3 billion it invested in Keystone.

Capital spending. Amid the turmoil, Canadian producers' spending plans have increased substantially in 2022. According to the Canadian Association of Petroleum Producers (CAPP), capital spending will increase by C$6 billion this year, up more than 20%, versus $26.9 billion in 2021. Of this, C$21.2 billion is ticketed for conventional oil and natural gas, and C$11.6 billion for Alberta's oil sands. CAPP also notes that spending is still well below Canada's record of $81 billion in 2014.

Individual spending plans for 2022 include Suncor, at C$4.7 billion, increasing slightly over its estimated 2021 expenditures of C$3.8-4.5 billion; CNRL, at C$4.35 billion, up almost 25% over 2021 spending of C$3.48 billion; Cenovus, at C$2.6-3.0 billion, compared to C$2.3-2.7 billion last year, and Imperial plans to spend C$1.4 billion, up 27% over C$1.1 billion in 2021.

M&A levels. Merger and acquisition activity was C$18.1 billion in 2021, according to Calgary-based Sayer Energy Advisors, down 9% from C$19.9 billion the year previous, although that number was almost entirely due to the Cenovus/Husky merger in late 2020. Over 40% of the total M&A in 2021 was from three transactions: ARC Resources Ltd. Acquiring Seven Generations Energy Ltd. for C$5.1 billion in February, Tourmaline Oil Corp. purchasing Black Swan Energy Ltd. for C$1.1 billion in June, and in November, Canadian Natural Resources Limited taking over Storm Resources Ltd. for just over C$1.0 billion.

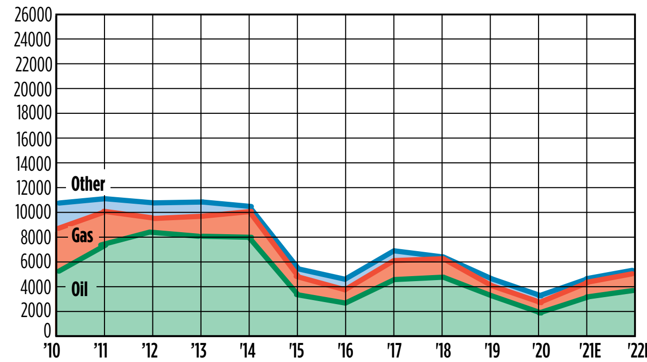
Producers are also benefitting from the continued the low level of the Canadian dollar, which continues to hang around the US 78-cent mark this year versus the U.S. dollar. A low Canadian dollar provides a buffer for the export-driven oil and gas industry, which ships substantial volumes of oil and gas south to U.S. customers.

DRILLING

As expected, drilling numbers increased dramatically over the dismal numbers posted in 2020 in Canada. Drilling levels surged more than 56% in 2021, to 4,648, compared to just 2,978 wells drilled the year before, according to Daily Oil Bulletin records. Just over 65% of the wells targeted oil, and 27% targeted gas.

In Alberta, drilling increased just under 85%, to 2,659 wells drilled, compared to 1,439 the year before. In Saskatchewan, drilling was up almost 27%, with 1,359 wells drilled, versus 1,073 in 2020. British Columbia operators drilled 464 wells last year, up more than 26% from 367 in the previous year. And in Manitoba, drilling increased almost 88%, to 156 wells in 2021, compared to 83 in 2020.

Fig. 2. Canadian drilling is recovering from the extremely low level of 2020, but it is still nowhere near the levels of the 2009-2014 period. Chart: CAPP and *World Oil* data.



For the year ahead, the Canadian Association of Energy Drilling Contractors is predicting that drilling will increase almost 27%, to 6,457 wells drilled, with a corresponding increase in employment levels and a modest bump in the rig fleet, to 489 from 481. Meanwhile, the Petroleum Services Association of Canada, typically more bearish, is calling for a total of 5,400, an increase of just over 16%. Both associations see global demand increasing, as the world continues to recover from Covid-19, although labor shortages remain a major issue for the drilling sector.

World Oil survey results are similar. The Canadian Association of Petroleum Producers is projecting drilling to increase about 16% to 5,400. Saskatchewan is very bullish on activity in 2022, predicting that over 2,000 wells will be drilled, an increase of 52%. British Columbia provided 2021 actuals, but not a forecast, and both Manitoba and the Alberta Energy Regulator failed to submit a survey.

LAND SALES

After land sales were reduced or outright canceled in 2020, the numbers had nowhere to go but up in 2021. According to *Daily Oil Bulletin records,* industry increased spending by more than 230% to C$126.65 million, compared to $38.16 million in 2020. But that increase is deceptive, given that the industry set a record high of $5 billion in 2008, during the last activity boom.

In Alberta, spending came in at $113.58 million, an increase of over 280% over the 2020 total of $29.7 million, which was the lowest total ever collected annually in Alberta. British Columbia brought in $3.78 million last year, after collecting a meagre $57,000 before sales were halted in 2020.

Saskatchewan, which maintained its full land sale schedule throughout, garnered $9.1 million, up 11.9% over $8.1 million in 2020. Manitoba took in $191,660 in 2021, continuing the downward trend it's seen over the past three years. In 2020, the province collected $293,303.

Although it's positive to see recovery in land sales—a bellwether of future activity—the recovery last year was extremely modest. The dollars invested by the Canadian industry in 2022 will be far more indicative of how robust any recovery will be for the oil patch. WO

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