Innovating the Oil & Gas Industry, Volume III

UNCOVER GLOBAL INSIGHTS

"Having a better understanding of the timing of potential new reserves additions is key to understanding how new reserves additions may match up—or not—with new global demand for oil and gas."

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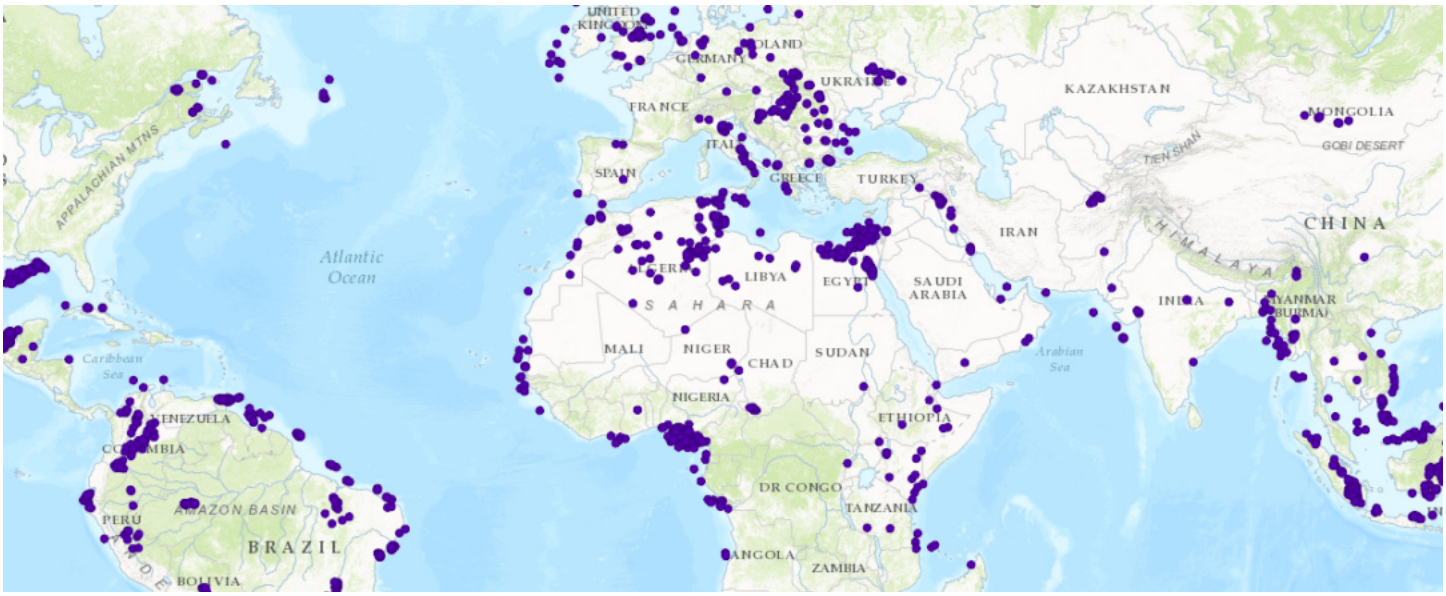
International Rig Counts—Looking Through to 2018



Everyone follows US rig counts—it's the most widely used 50,000' proxy for gauging the health of the upstream oil and gas industry.

However, domestic observers need to realize that the industry has a vibrant international component that most analysts don't pay attention to—most likely because most international exploration is still conventional in nature and project lead times and time to first oil is long.

Getting a sense of where international operators will be deploying their exploration and development capital is critical in assessing how to model, very roughly, potential additions to world reserves.

Knowing when they plan to do this allows us to leverage political perspectives into the mix as well.

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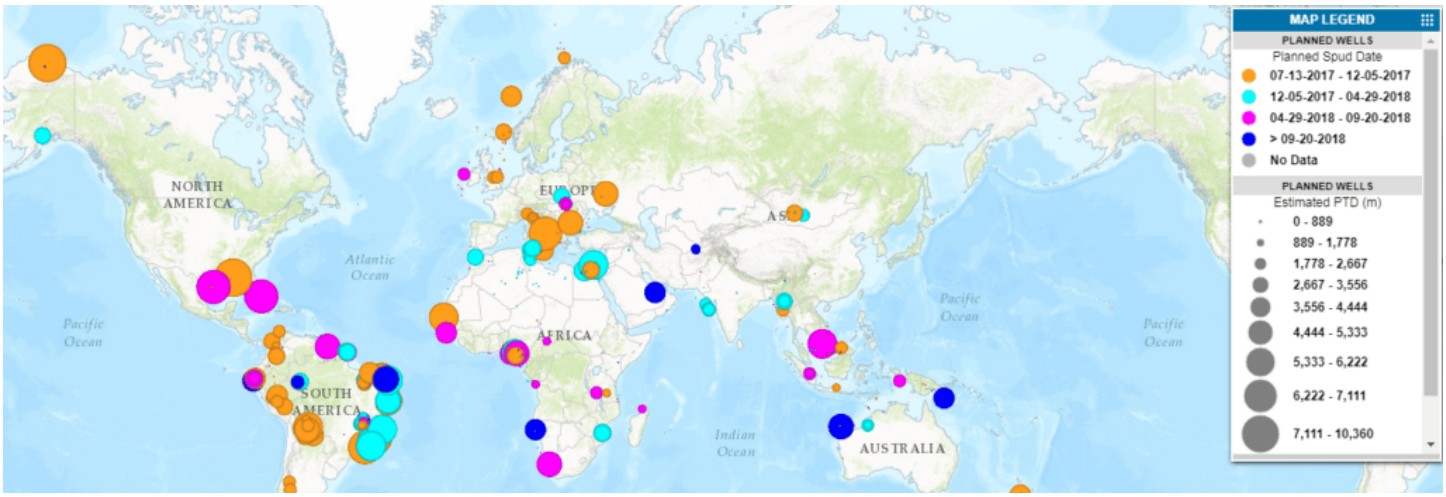
Are wells planned to be drilled in politically stable or militarily fraught areas?

Are they timed to potentially avoid either national political crosscurrents or trending economic forces?

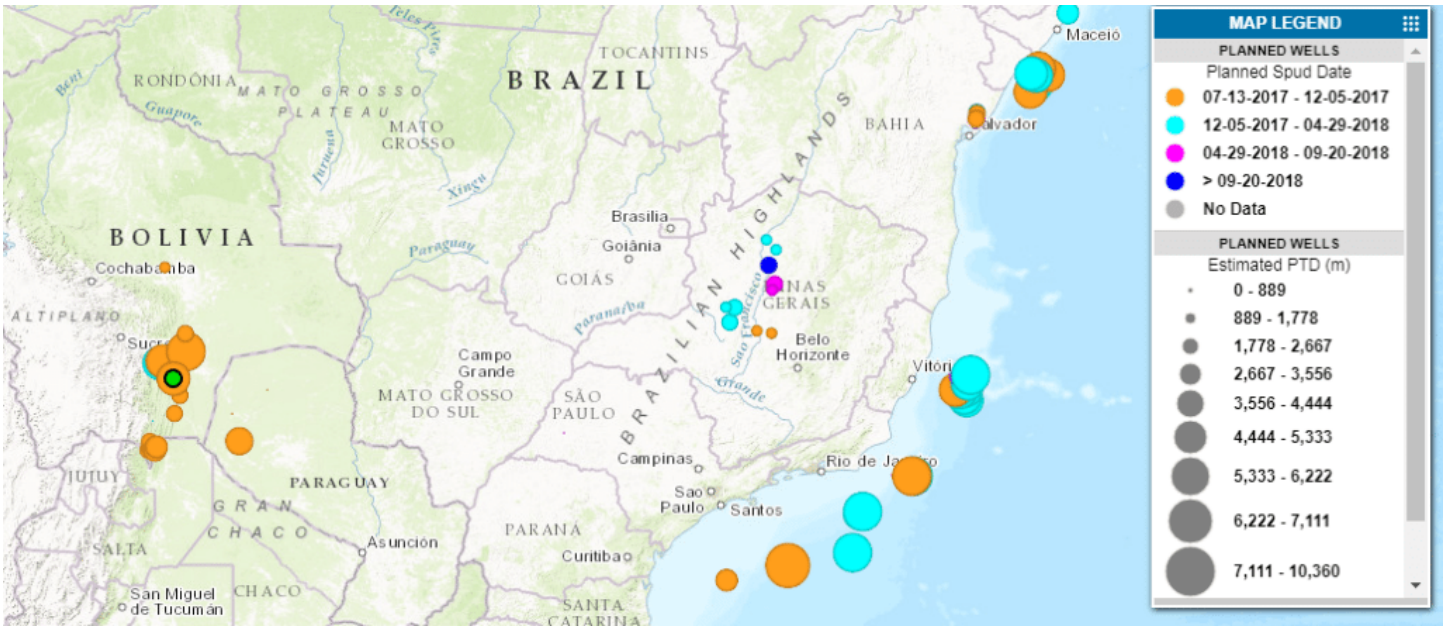
For example, the map below implies that exploration drilling on or close to Australia will not occur until the end of 2017 or later in 2018, whereas there is a lot of planned exploration activity in South America slated for the latter part of this year.



European exploration also looks to be concentrated towards Q4 2017, whereas West African planned wells are scheduled pretty evenly across the remainder of 2017 and into later 2018 (except for offshore Namibia)

Interestingly in this search—which was constrained from September 1, 2017 to December 31, 2018—nearly 85% of the wells are classified as exploration, NOT development wells.

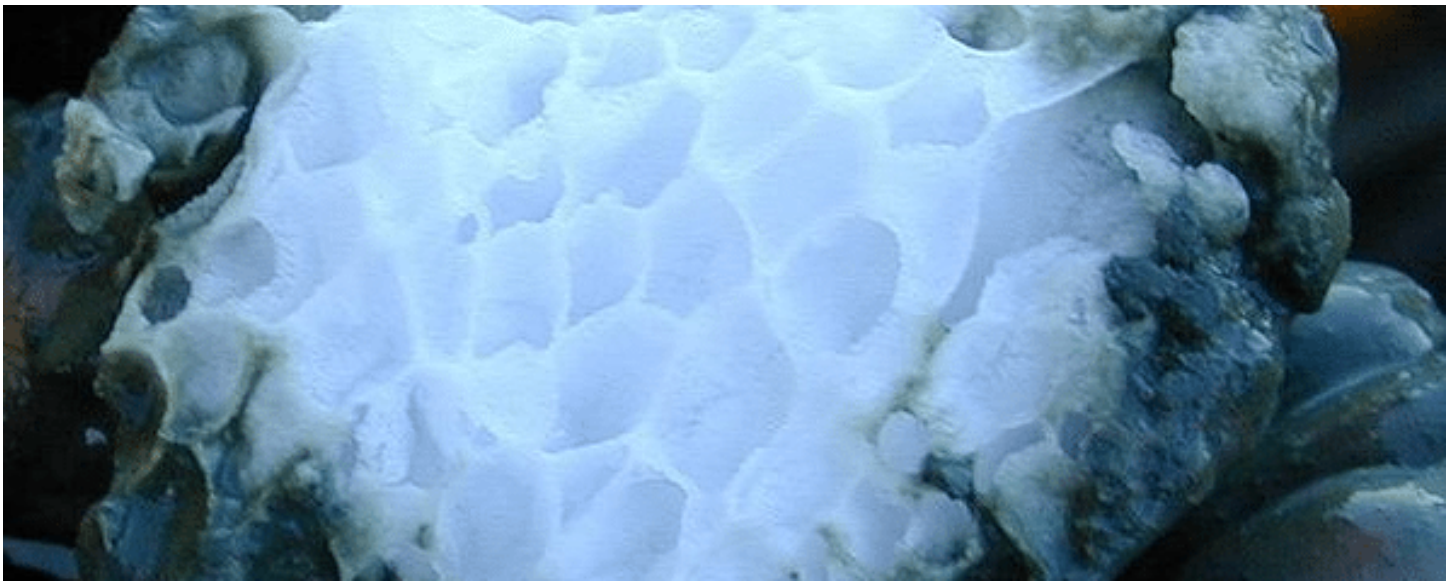
Intensifying exploration activity in Bolivia and offshore Brazil in Q3,4 and Q1,Q2 2018 would point to added interest in subsalt opportunities in Brazil and interest in the deeper section in Bolivia's Andes foothills, going to 6100 est PTD in Pulspetrol Bolivia Corp SA's Tajibo Sur X-2— nearly 3500m deeper than previous on-trend wells.



Having a better understanding of the timing of potential new reserves additions is key to understanding how new reserves additions may match up—or not—with new global demand for oil and gas.

2

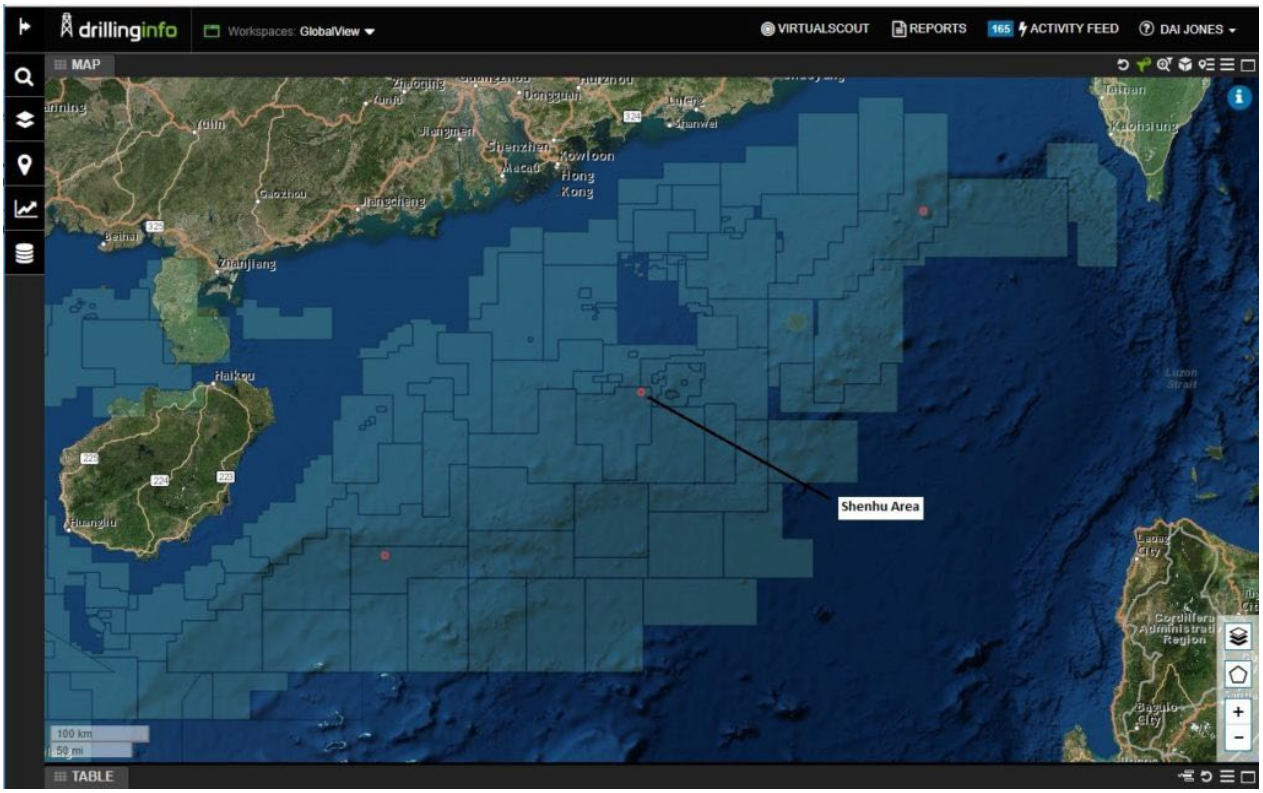
Methane Hydrates: Is 'Fire-Ice' the Next Energy Revolution?



RECORD BREAKING

Recent news of China's success in producing gas from sub-sea methane hydrates has re-ignited the emergence of these deposits as a possible alternative energy source, which could usher in a new energy revolution. On July 9 2017, China announced that it had achieved continuous gas production from hydrates during a 60-day trial, located ~300km southeast of Hong Kong, and at depths of 203m-277m beneath the seafloor (1,266m water depth), in the Shenhu area of the South China Sea. Using the CNPC-owned Bluewhale 1, a semi-submersible that was domestically designed and constructed, China set a new world record producing a total of 309,000 cubic metres (cm) of gas (~10.9 million cubic feet of gas (MMcfg)). The average production during the trial was 5,151cm per day (~181 thousand cubic feet of gas per day

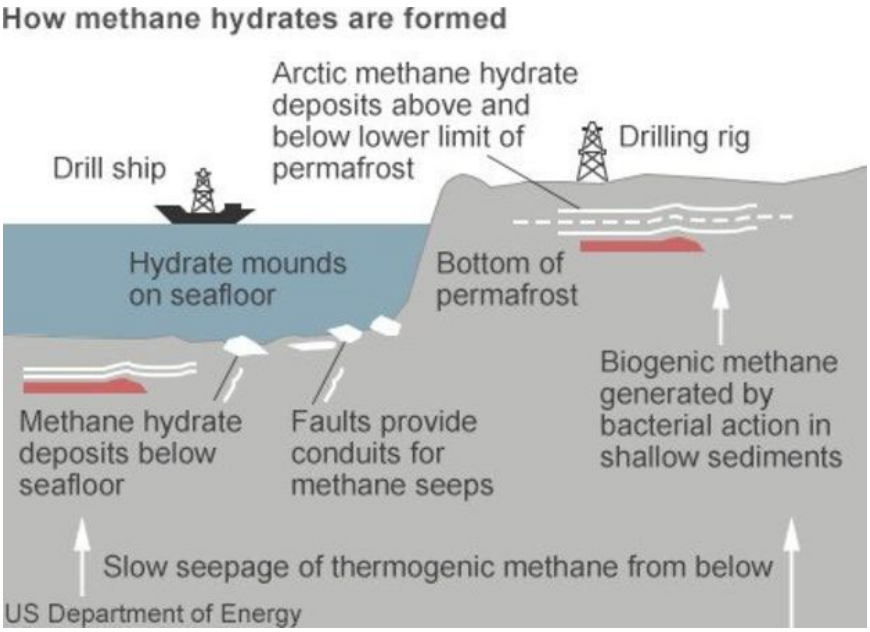
(Mcfg/d)) and the gas was reported to have had a methane content of up to 99.5%. The trial has been heralded as a breakthrough in the search for alternative, cleaner energy sources; however, China isn't the only country pursuing the colloquially named 'fire-ice', as countries including Japan, India, South Korea, and the United States are all actively investing into research and development of the unconventional resource.



WHAT IS 'FIRE-ICE'?

Methane hydrates or 'fire-ice' is a globally distributed fossil fuel. It is composed of methane trapped inside a lattice of water molecules, which forms a white, energy-dense substance that can be easily ignited, like solid ethanol. The hydrates form at relatively shallow sub-surface depths, in high pressure and low temperature environments, typical of outer continental margins and permafrost areas. Once the substance is heated and depressurised to normal conditions, 1cm of hydrates equates to ~164cm of regular natural gas. The gas consists of 80-99.9% methane and produces much less pollution than coal and oil when burned—estimates suggest that natural gas emits just 60% of the carbon emissions generated by coal,

and 80% of the emissions generated by oil.

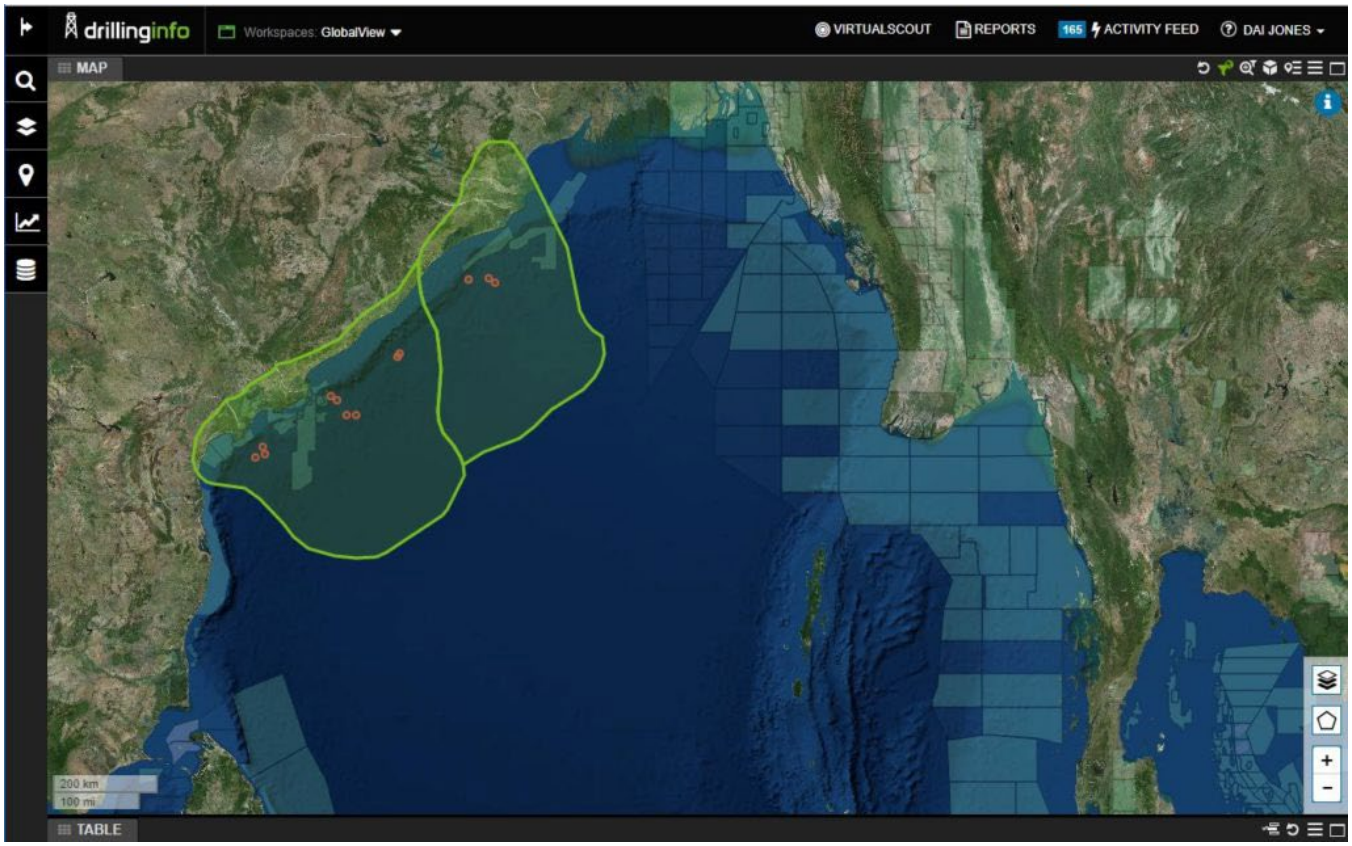


PREVIOUS EXPLORATION

Methane hydrates were first discovered by Russia in the 1960s, but research into them has only expanded in the last 10-15 years. China, Japan, and India are among the most recent pioneers. In total, China has completed four tests since 2007, although Japan was the first country to successfully produce gas from deep water hydrates back in 2013. On March 19 2013, Japan Oil, Gas, and Metals National Corporation (JOGMEC) announced that it had successfully produced a total of ~120,000cm of methane gas (~4.2 MMcfg) in the eastern Nankai Trough, after lowering the bottom-hole pressure in the production well from 13.5MPa to 4.5MPa. The trial continued for six days until sand infiltrated the well and production was terminated; the country began its second production trial in May 2017. During this second trial, two wells have been drilled using Chikyu, a deep-sea drilling vessel, to reach methane hydrates located ~300m beneath the seafloor, in water depths of ~1,000m. It has been reported that the first well produced ~35,000cm of gas (~1.2 MMcfg) over a 12-day period, until sand once again intruded and ceased production. The second well was completed on June 28 2017 and produced ~200,000cm (~7 MMcfg) in 24 days. India has also recently completed its second expedition. Between March 3 2015 and July 28 2015, the country drilled 42 holes in the Krishna-Godavari and Mahanadi Basins, in water depths ranging from 1,519m–2,815m, with sub-seafloor depths ranging from 239m–567m. The research confirmed the presence of large, highly saturated gas hydrate accumulations in sand-rich depositional systems, and has highlighted areas for further research.

COMMERCIAL VIABILITY

As unconventional gas is taking on a more prominent role in the total gas mix, questions are raised about the commercial viability of methane hydrates. Following recent tests, Japan is anticipating commercializing

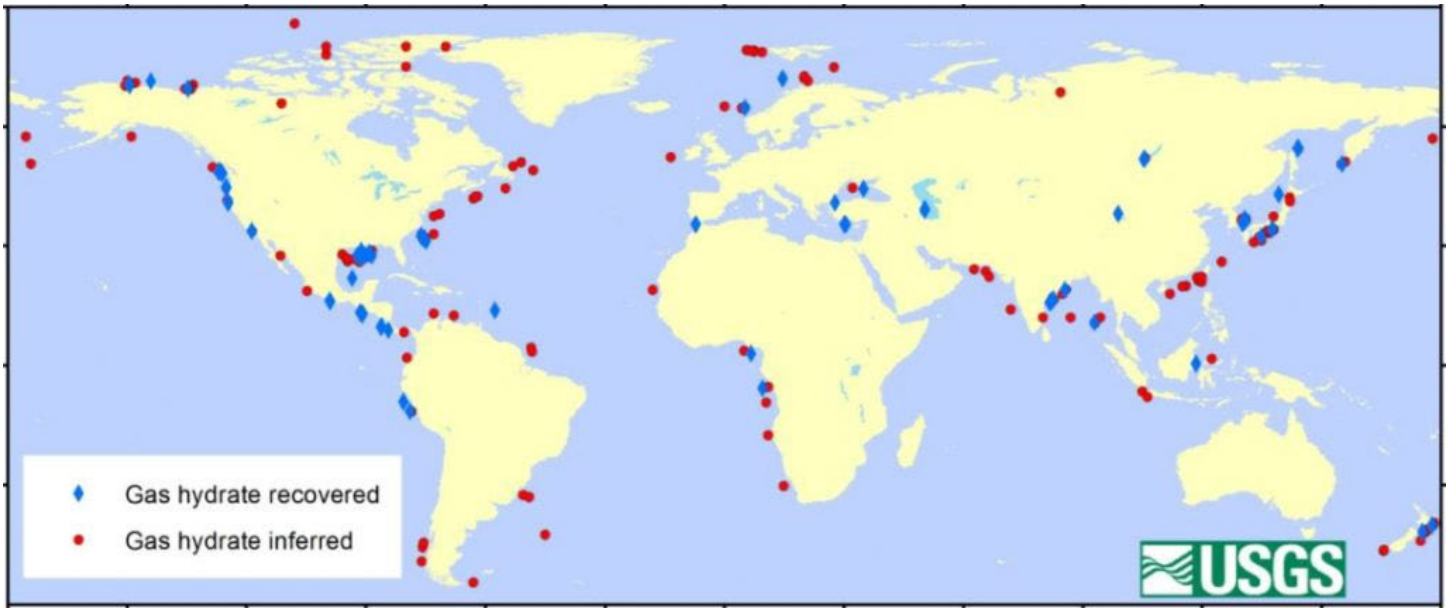


hydrate-extracting technology as early as 2023, and China is planning to begin commercial production of hydrates by 2030.

Commercial-scale production of the resource could be revolutionary for some countries. Japan has a large industrial sector but is heavily reliant on LNG imports, following the mothballing of its nuclear power plants, after the 2011 tsunami disaster. For the country, this new resource offers an opportunity to reduce its dependence on imported fuels (estimated to be as high as 90% of its energy needs) and access domestic reserves off the coastline. Furthermore, with the battle against climate change in full swing, 'fire-ice' may become a welcomed alternative for countries like China seeking to ease the pressure on reducing its carbon emissions and remedy its drastic air pollution problems in urban areas, particularly Beijing.

However, to date only small-scale pilot projects have been completed and a number of factors are currently contributing to making the resource uneconomical. Firstly, dissociating the methane from the hydrates is technologically challenging, and expensive as a result. It has been estimated that the present cost of

producing gas from the hydrates is ~US$ 200/cm. Current daily production rates from each well are also low. The highest daily output from China's latest trial was 35,000cm (~1.2 MMcfg). These comparatively low production rates coupled with high costs are unsustainable at current gas prices. Additionally, the U.S. Energy Information Administration has noted that estimates of worldwide reserves range from 280 trillion cubic metres (tcm) to 2,800 tcm. However, unlike conventional hydrocarbon resources, hydrates are typically found in low concentrations and are distributed over vast areas and therefore resource density may also be an additional contributing factor in determining their commerciality.



ADDITIONAL CONSIDERATIONS

Simultaneous to the commercial threshold, environmental and political factors may play an important role in determining whether this resource results in a new energy revolution. The environmental impact of commercial drilling is currently unknown; however, until recently methane hydrates have presented more problems than solutions to the energy industry. Previously, preventing their formation around deep water drilling equipment has been a key component of well design and planning; this is because 'fire-ice' disintegrates when removed from its stability zone, allowing methane to be released from the hydrate chemical structure. Unburned methane is a potent greenhouse gas that is estimated to have 20-30 times the heat trapping potential of carbon dioxide, and may contribute significantly to climate change if

unchecked and/or potentially damage fragile seafloor ecosystems. Improper drilling may also destabilize seabed structures, increasing the risk of geological disasters like earthquakes and tsunamis. Another consideration that may need to be addressed is the distribution of the resource. Methane hydrates are widely distributed over deep-water environments. Inevitably, this means that the resources may straddle economic boundaries, and much like conventional accumulations, this may aggravate existing political tensions and provoke sovereignty claims between neighboring countries.

FOOD FOR THOUGHT

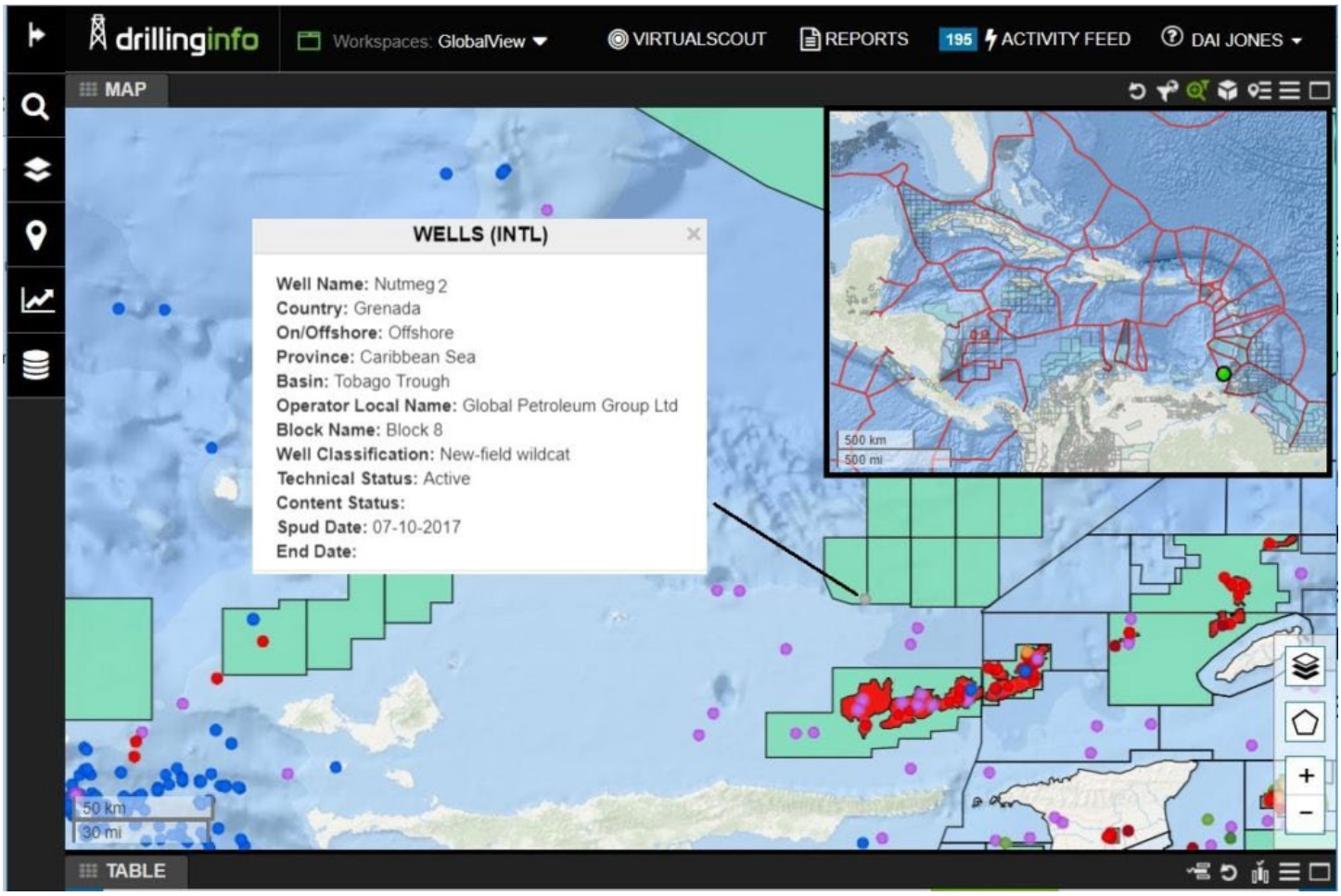
It seems that, if an economically feasible production method can be identified, methane hydrates offer great potential. The United Nations Environment Programme has estimated that the resource could potentially satisfy up to 53% of gas demand, which could result in them being considered as a strategic alternative to coal and oil in the future. Nevertheless, in the lower-price commodity environment, companies are tending to favor shorter-cycle projects with faster returns, such as shale gas. This emphasizes the need for political bodies to consider the longer-term security of supply by improving pricing mechanisms, and providing regulations on exploitation management of the resource. Other challenges involved in realizing this potential will be addressing the environmental factors and identifying areas of high-resource concentration; both of which can be improved through further exploration. Multiple countries have ongoing research initiatives to help determine the potential impacts of commercial production, and to advance industry understanding of the physical properties of hydrates.

3

Grenada Makes Splash with First Ever Offshore Wildcat

The Global Petroleum Group-operated Nutmeg new-field wildcat (NFW) currently drilling in Grenada's offshore was named after the fragrant tropical seed that helped to make this "Spice Isle" famous. While there's no hard rule behind the arcane practice of naming prospects and wildcats, observers can't help to wonder if GPG's word choice for the island's first ever offshore wildcat portends the sweet smell of success.

NUTMEG 2 WELL LOCATION



Grenadian Prime Minister Keith Mitchell, who also acts as Energy Minister, popped the cork over the planned well in June.

"(GPG's) achievements to date, represents the furthest any company conducting petroleum exploration in Grenada has ever reached—and the quest continues, with future prospects in sight," Mitchell said at the time.

But there's only been radio silence since then.

To use the vernacular of wildcatters, GPG's Nutmeg is a tight well. According to industry sources, the Nutmeg-2 NFW is drilling in an area of the offshore covered by SeaBird's 1,600 sq km 3D survey. That's

the survey shot by the crew of the "Geo Pacific" in 2013.

Sources also say that GPG tapped Transocean's "Development Driller III" S/S for the drilling campaign targeting objectives in the Eocene. The well is sited in water depths of around 180m. the NFW has a planned total depth of about 3,352m near Grenada's maritime border with troubled Venezuela.

Several prospects have been identified, and if Nutmeg hits pay, more exploration work is expected.

Prime Minister Mitchell's initial optimism about the well is understandable. The 11 licenses extending 7,450 sq km, were awarded in 2008 but lay dormant for a while after the election of a new government. It clearly makes sense for Grenada to open its doors for energy exploration.

With a Gross Domestic Product of just over US$ 1 billion, this balmy island with about 100,000 inhabitants needs to keep its tourist-driven service industry and spice farming sector primed for more expansion. Grenada is the globe's second largest supplier of the spice, according to the World Bank.

With its energy needs likely to grow on the back of its much applauded economic recovery, Grenada's forward-looking Parliament recently passed the Hydrocarbon Exploration Incentive Bill 2017 (Hydrocarbon Exploration Incentive Act 2017) that contained a package of incentives to spur exploration for oil and gas.

While the GPG-operated Nutmeg well is drilling ahead, more companies are looking at Grenada's untapped potential. Even though the government had to fend off criticism over a non-binding agreement late last year, MX Oil and the Caribbean island nation signed a Memorandum of Understanding that, if successful, could serve as the basis for a potential Production Sharing Agreement (PSA) covering part of Grenada's share of the Tobago Basin near the Venezuelan/Trinidadian Patao-Poinsettia natural gas trend.

4

Mexican Oil and Gas Gaining Momentum

Mexico held back-to-back licensing rounds on July 12 2017 as part of the President Enrique Peña Nieto administration's goal to lure private investment to the Latin American nation's upstream.

To use an American baseball analogy, Mexico knocked it out of the park each time and now Mexican oil and gas is gaining momentum.

The duo-round system on July 12 encompassed a total of 24 blocks. By the end of the day, 21 blocks had been awarded.

The July 12 bid round blocks were varied in that they spanned Mexico's vast geography, from the northern Burgos Basin to the southeastern Sureste play. Blocks were also located in the Chiapas Foldbelt, Tampico-Misantla, Veracruz, Salina del Istmo, and Macuspana basins.

In the second auction (Round 2.3) of the day alone, the blocks included 25 producing fields. The total combined area covered 2,595 sq km and is thought to hold prospective resources of 251 MMboe.

Given the highly competitive nature of Round 2.3, there were more than a few Mexican-style standoffs as bidders went head-to-head over a raft of highly-prized blocks.

Winners were only declared after officials sliced open the "tiebreaker" cash bonus envelopes. At one point there was a seven-way tie for Area 5 in the Tampico-Misantla Basin. Each bidding entity offered an additional royalty rate of 40% with an additional investment factor. A US$ 26.1 million tiebreak bonus landed Mexican startup Jaguar the contract. In all, Mexico raised US$ 88 million alone from the cash bonuses on July 12.

CNH Director Juan Carlos Zepeda has estimated that the wining companies—including Mexican tycoon

Carlos Slim's oil and gas company Carso, will plough some US$ 2 billion into the investment-starved onshore.

That money will help Mexico pump more Black Gold. Winning companies from rounds 2.2 and 2.3 are forecast to produce an additional 79,000 bo/d and 378 MMcfg/d by 2025. Initial output should begin as early as 2019.

Moreover, the rounds will aid Mexico to create 20,000-plus jobs in the next seven years, says Deputy Energy Minister Aldo Flores.

Round 2.2 and 2.3 are also part of a wave of ongoing licensing success for Mexico.

Since 2015, Mexico has offered a total of 94 blocks to the industry. Despite volatile oil prices, the CNH has awarded 70 blocks. That's equivalent to 74% of the total inventory.

"That's well above what was hoped for," says SENER chief Pedro Joaquin Coldwell.

Beyond having a transparent bid round framework, empty pipelines and storage facilities have helped shore up the industry's interest in Mexico.

Mexico's dramatic 1 million-plus bo/d decline in oil production over the past decade has left critical energy infrastructure in the shallow-water sector and onshore with spare capacity. Decades of under investment on the part of Pemex means that fields with 3P reserves still have ample room for further exploration.

Mexico, and the Mexican oil and gas industry—by all accounts, isn't about to let that momentum grind to a halt.

The Comision Nacional de Hidrocarburos (CNH) in July 2017 announced that the highly anticipated Deepwater Round 2.4 will take place on January 31 2018. Thirty areas will be on offer spanning the Cordillera Mexicana (Mexican Ridges), Salina Basin, and Perdido Fold Belt.

Round 2.4 encompasses a total area of 70,844 sq km. Of the 20 blocks, 21 have a surface area of 2,000 sq km; eight cover 3,000 sq km, and one covers 4,400 sq km. The Mexican Energy Secretary (SENER) said that if only 25%, or seven contracts, are successfully auctioned off, the government is still forecasting that the contest will lure in some US$ 31.5 billion in investments.

With seven licensing processes under its belt, including one previous Deepwater Round (1.4) in December 2016, which saw some of the world's largest NOCs and IOCs, such as China National Offshore

Oil Corporation (CNOOC) and Chevron, respectively, win acreage, Mexico is bearing the fruits of energy reform in other areas.

In July 2017, the Talos Energy-led group announced a discovery with the Zama-1 (Zama-1SON), located on Block 7 (Contracto CNH-R01-L01-A7/2015). The well found a contiguous gross oil bearing interval of over 335m, with 170m-200m of net oil pay in Upper Miocene sandstones with no water contact.

Initial gross original oil in place estimates for the Zama-1 well range from 1.4 Bboe to 2 Bboe.

Talos operates Block 7 with 35% WI. Sierra holds 40% WI and Premier holds 25% WI, after Premier exercised its option to increase to 25% from 10% WI.

That wasn't the only good news Mexico reaped from the Round 1 blocks. Eni reported in July that the Amoca 3 (Amoca 3DL) well (CNH-R01-L02-A1/2015) encountered multiple "significant oil levels" in the Cinco Presidentes (Early Pliocene) and Orca (Middle Pliocene) formations during drilling operations.

The well encountered 410m of net oil in the deeper sequence of Cinco Presidentes, and in various cluster levels of Pliocenic age, demonstrating "good reservoir characteristics." Eni boosted the resource estimate of the Amoca field to 1 Bboe in place and the Area 1 total estimated resource base to 1.3 Bboe, of which 90% is oil, with further upside."

The companies are now mulling development.

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