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Venezuelan oil production 'close to zero'

Venezuelan – one of the world's earliest and, at one time, largest oil producers, as well a founding member of OPEC – could soon be production close to zero soon be producing close to zero barrels of oil, according to new analysis by HIS Markit.

The country's crude oil production is currently around 100,000 – 200,000 b/d and falling. Production was around 650,000 b/d just a year ago and had been as high as 2mn b/d as recently as 2017. It is now conceivable that the country could soon be producing zero barrels, or very close to it, reports the consultancy.

'Never before has a former oil producing country seen output fall so low for so long. In Venezuela's case, if there is any surprise it is that the disintegration did not happen faster,' comments Jim Burkhard, Vice President and Head of Oil Markets, HIS Markit.

The country is now the third smallest producer among OPEC's 13 members, just ahead of Equatorial Guinea and war – torn Libya.

Venezuela's production fall – the product of decades of decline and decay – has been exacerbated more recently by the COVID – induced oil price collapse of 2020. US sanctions and limited domestic oil storage.

While the slide toward zero production is a historical milestone, Venezuela's demise as an oil producer will have little to no impact on global oil markets given the much larger shifts in world oil demand and supply wrought by COVID – 19 and its repercussions.

'In terms of market impact, if you had to choose a time for the fall of a major global oil producer – a founding member of OPEC, no less – this would be it. There is ample production capacity around the world to satisfy the recovery in world oil demand that has been underway since May,' remarks Burkhard.

Given the size of the country's reserves, a restoration of production somewhere in the future is always a possibility. But the state of Venezuela's infrastructure, ongoing US sanctions and lower global demand make it increasingly unlikely, suggests HIS Markit.

'The decay of Venezuela's oil industry has been due to poor management, not lack of below ground oil resources. It is conceivable that a rebuilding of infrastructure under appropriate investment and security conditions could return the country to the ranks of major oil producers,' notes Ha Nguyen, Director, Global Oil Supply, IHS Markit. However, he continues: 'Any recovery would take a considerable amount of time given the degree of dilapidation throughout the country's energy infrastructure. It looks like close – to – zero oil production is Venezuela's new normal for the foreseeable future.'

Cairn to sell Senegal interests to Lukoil

Cairn is planning to sell to Lukoil its entire 40% interest in the Rufisque Offshore, Sangomar Offshore and Sangomar Deep Offshore (RSSD) contract area, including the Sangomar development, offshore Senegal, for a cash consideration of up to $400mn.

Following completion, the company intends to return at least $250mn to shareholders.

Commenting on the announcement, Conor Ward Upstream Analyst at GlobalData, says: ‘News that Lukoil is looking to expand in Western Africa comes as no surprise as the region has seen a flurry of spending from the company over the last decade – with its acquisition of a stake in major projects such as the Pecan field in Ghana, the Bonga Southwest / Aparo field in Nigeria, the Marine XII licence offshore the Republic of Congo, and the Fortuna LNG project in Equatorial Guinea. Lukoil hopes to see major growth form these projects in the next decade as its foothold in Western Africa has potential to grow five – fold from approximately 14,000 b/d in 2020 to approximately 70,000 b/d by the mid-2020s. sangomar will add an estimated 20,000 boe/d to Lukoil’s portfolio at peak.’

He continues: ‘It is not just West Africa where Lukoil is making acquisitions, but also in the Middle East where the company purchased a 5% stake in the Ghasha concession, which is expected to add a further 12,000 boe/d to the company’s portfolio when it reaches plateau.’

‘Many of the projects that Lukoil has acquired shares in have faced multiple delays, such as Bonga Southwest / Aparo where the final investment decision (FID) was expected in 2020 but is now not expected until 2021 at the earliest. The participants of Pecan are still considering a new development concept and the same goes for the Fortuna development, while the Etinde field Cameroon hangs in doubt. The acquisition of the Sangomar field will really bolster the company’s West African growth plans as it achieved FID in 2020 and the operator Woodside has remained adamant that first production will be seen in 2023 as originally planned.’

Fugro has delivered what is claimed to be the first fully remote inspection of an oil and gas platform in UK waters, 250 km east of Scotland, using a remotely operated vehicle (ROV) and Fugro’s state – of – the art remote operations centre (ROC) in Aberdeen. Karl Daly, Fugro’s Director for IRM Services in Europe, says: ‘This innovative approach allowed for efficient scope delivery and demonstrates to clients the opportunities for maximising operational windows whilst reducing offshore HSSE exposure, which is always important but even more so during the current pandemic.’

Libya’s oil blockade entered its seventh month in August, with the war – torn country’s oil output hovering at just 100,000 b/d instead of the pre – crisis 1.2mn b/d. Without a peaceful solution on the horizon, Rystad Energy is further pushing back the country’s expected restart to 4Q2020, a change that will help reduce the expected global production surplus to just 58.6mn barrels, or to about one – third of its previous forecast.

New research by HIS Markit shows that the combined greenhouse gas intensity of Canadian oil sands projects fell 20% from 2009 levels. It is forecast to decline by at least 16 – 23% by 2030 (to a level 30% below 2009)

A total of 10 projects across Scotland have been awarded grants totaling £1.84mn in the fourth round of the Scottish government’s Decommissioning Challenge Fund (DCF). The projects include innovation, research and development in well plugging and abandonment, and subsea recovery; decommissioning port infrastructure upgrades; feasibility studies; and the purchase of specialist decommissioning equipment.

Total and its partners have taken the investment decision for the third phase of the Mero project in the Libra block in the pre – salt area of the Santos Basin. The Mero 3 floating production, storage and offloading vessel (FPSO) will have a liquid treatment capacity of 180,000 b/d and is expected to start up by 2024. It follows investment decisions for the Mero 1 (start – up expected in 2021) and Mero 2 (onstream in 2023) FPSOs, both of which also have a liquid processing capacity of 180,000 b/d. The Mero field is estimated to hold 3 – 1bn barrels of oil.

New European hydrogen network plan

A plan to build a dedicated hydrogen pipeline network of almost 23,000 km within nine European countries by 2040 has been released by 11 European gas infrastructure companies, report Keith Nuthall. Enagas, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas (Nordion Energi), Terega and the consultancy Guidehouse have called their proposed network a 'European hydrogen backbone'. It would serve Germany, France, Italy, Spain, the Netherlands, Belgium, the Czech Republic, Denmark, Sweden and Switzerland, with links to neighbouring European states (including the UK) and to North Africa.

The conversion of existing natural gas pipelines will be key. The consortium believes such 36 – and 48 – inch diameter pipelines can transport around 13 GW of hydrogen per pipeline (at lower heating value) across Europe.

The initiative comes as the European Commission launched on 8 July 2020 its EU Hydrogen Strategy including supporting the production of 40 GW of renewable hydrogen electrolysers across Europe by 2030.

Some €27 – 64bn is expected to be required to build a 'backbone' network, comprising 75% converted natural gas pipeline and 25% new pipelines. The wide range of the estimate is due to uncertainties in compressor costs, explains the consortium. This is because the energy density of hydrogen is three times lower than natural gas. So to produce the same energy output, three times more hydrogen must be transported. Given its low mass and large volume flow, 'greater efforts for compression are to be expected with hydrogen', which means some compressors will need to be replaced and others refitted, says the consortium. However, it estimates overall operational costs at €0.09 – 0.17/kg of hydrogen per 1,000 km2, 'allowing hydrogen to be transported cost – effectively over long distance across Europe'.

Cutting Asia – Pacific LNG plant emissions

Using renewable energy to power LNG plants in the Asia – Pacific region could reduce emissions by about 8%, according to Wood Mackenzie analysis. The Asia – Pacific producers over a third of the world's LNG, but also generates over 50mn tCO2e of emissions during liquefaction, reports the market analyst, while Australian LNG projects account for over half, or 29mn tCO2e, of liquefaction emissions from LNG projects in the region.

Many of the Asia – Pacific's LNG facilities are located in remote areas, far from the power grid. As a result, feedgas is used to generate electricity to run the plant and fuel the liquefaction process. Typically, 8-12% of feedgas is consumed at the plant to run these processes. Older, more inefficient plants, as well as nascent floating LNG (FLNG) vessels, operate with far higher losses.

Wood Mackenzie Senior Specialist Jamie Taylor says: 'Three main decarbonisation levers could help reduce emissions at LNG plants – namely operational efficiency, design changes, and the use of renewable energy, which could be sourced from the grid or generated onsite.'

Feedgas is used to fuel gas turbines to generate electricity to power the plant. Replacing these gas turbines with electricity could greatly reduce emissions, assuming the grid power is less carbon intensive. The other option is to install on – site renewable power, in particular solar.

Taylor says: 'If a solar plant or a hybrid solar battery storage plant is installed at the LNG facility, back – up generators could be switched off and renewable electricity could be used to meet the power load. A s costs continue to decline and technology improves, renewable plus battery storage could become an alternative in the future, especially for new LNG plants.'

'We are already seeing Australian LNG plant operators examining ways to reduce carbon emissions throughout the value chain. Initiatives are underway at the upstream assets supplying the North West Shelf and QCLNG, and Darwin LNG has installed a battery that reduces the need to run one of the gas turbines. Our analysis shows that installing renewable energy generation could reduce emissions at Asia – Pacific's LNG plants by 8% in 2020 alone.'

While LNG has clear benefits over other fossil fuels in power generation, the industry is increasingly scrutinizing the emissions intensity of its upstream supply and the production process. Several industry players have set carbon neutrality 2050 targets and there are indications LNG buyers are looking more closely at the emissions associated with cargoes they are procuring. Stricter project financing criteria, especially from European banks, is another cause for concern for companies developing capital intensive Greenfield projects.

But perhaps the biggest driver for decarbonisation is the potential for carbon tax or tighter regulations in both exporting and importing countries. This would significantly impact the already strained project economics post oil price crash. Taylor comments: 'A carbon tax is likely to be the biggest driver for LNG projects to switch to renewable energy at the plant or deploy carbon capture and storage to reduce emissions from upstream gas, or both.'

'Using less feedgas as a fuel would result in more gas being available to supply either the domestic market or be converted into LNG for exports. Rather than increasing annual LNG output, which would only be possible by debottlenecking the plant, this 'saved' gas would be used to extend the plateau LNG production level by a few years. Revenues associated with the resulting extended plateau could reach into several billion dollars longer – term.'

'In APLNG, for example, installing 60 MW of solar in 2020 at a cost of $60mn increases the remaining value of the project by $62mn. 'This is due to the additional revenues generated from selling the 'saved' feedgas. The relative benefits of installing solar are increased further when a carbon tax is considered.'

Stepping on the gas post – pandemic

After growing by more than 2% in 2019, global gas use is set to fall by around 4% in 2020, as the COVID – 19 pandemic reduces energy consumption across the global economies. However, the resulting low gas prices, as well as clean air and climate policies, will promote further switching to gas form other more polluting energy sources, such as oil and coal. This trend was already underway before the pandemic, thanks to cost – competitive gas in key sectors including power, industry and transport, and major regions including Europe, North America and Asia. These are the key findings of the Global Gas Report 2020, published by the International Gas Union (IGU), BloombergNEF (BNEF) and Snam.

The report shows that medium – term growth will come from increasing cost – competitiveness and increased global access to gas. A particular growth opportunity exists in LNG. LNG imports reached 482bn cm in 2019, up 13% from 2018, and while this figure is expected to fall by around 4.2% in 2020, it could rebound quickly to previous levels as soon as 2021, depending on the persistence and longevity of the pandemic, says the study.

Ample natural gas resources exist to support demand growth, but greater gas infrastructure development is needed to support growth in the medium term, suggests the report. India is planning to almost double the length of its gas transmission grid, while China will grow its gas network about 60% by 2025.

In the longer term, there are major opportunities to scale up the use of low – carbon gas technologies, but these depend on substantial policy action and infrastructure investment in the coming years. Clean hydrogen could abate up to 37% of energy – related greenhouse gas (GHG) emissions, according to BNEF estimates. However, this would require a range of meaningful steps, including emissions pricing linked to clear, Paris – aligned long – term climate targets; harmonized standards governing hydrogen use; coordinated strategies regarding regional and global infrastructure roll – out, and the deployment of hydrogen – ready equipment, such as pipelines, gas turbines and end – use appliances.

The development of an international hydrogen market could also accelerate adoption. The report finds that Germany, which is pursuing rapid development in hydrogen, could procure cost – competitive hydrogen (at about $1/kg) in 2050 from a variety of sources, including via electrolysis from its own domestic renewable power, or via pipeline imports from North Africa or Southern Europe.

The report also reviews the long – term outlook for natural gas under different existing scenarios, including those from the IEA, BNEF and IGU analysis. The IEA's Stated Policies Scenario, from its 2019 World Energy Outlook, envisions gas use growing 1.4%/y to 2040, while BNEF's economics – led New Energy Outlook 2019 foresaw 22% growth in power sector gas demand to 2050.

In contrast, the IEA's Sustainable Development Scenario form the end of the 2020s onward as the global energy demand flattens and the world embraces stronger climate action. And both IGU and BNEF analysis indicate that around one – third of energy – related emissions could be abated by adoption of clean gas technologies.

This divergence in outlooks highlights both the risks and the opportunities for the global gas sector in the energy transition – and the importance of actions taken by both industry and government to capture the new opportunities and mitigate the risks for the sector in the coming decades.

'Decade of delivery' drives BP net zero strategy

BP has set out its strategy for a 'decade of delivery' towards its net zero ambitions, which it says will 'reshape' its business as it 'pivots from being an international oil company (IOC) focused on producing resources to an integrated energy company (IEC) focused on delivering solutions for customers'.

Within 10 years, BP aims to have increased its annual low carbon investment 10 – fold to around $5bn/y, building out an integrated portfolio of low carbon technologies including renewable, bioenergy and early positions in hydrogen and carbon capture, use and storage (CCUS). It aims to have developed around 50 GW of net renewable generating capacity by 2030 – a 20 – fold increase from 2019 – and to have doubled its consumer interactions to 20 million a day.

Over the same period, the company's oil and gas production is expected to reduce by at least 1mn boe/d, or 40%, from 2019 levels. Its remaining hydrocarbon portfolio is expected to be more cost and carbon resilient.

BP is also aiming for emissions from its operations and those associated with the carbon in its upstream oil and gas production to be lower by 30 – 35% and 35 – 40% respectively by 2030.

The company has also set out a new financial framework to support a fundamental shift in how it allocates capital, towards low carbon and other energy transition activities. 'The combination of the strategy and financial framework is designed to provide a coherent and compelling investor proposition – introducing a balance between committed distributions, profitable growth and sustainable value – and create long – term value for stakeholders,' notes BP.

'Energy markets are fundamentally changing, shifting towards low carbon, driven by societal expectations, technologies and changes in consumer preferences. And in these transforming markets, BP can compete and create value, based on our skills, experience and relationships. We are confident that the decisions we have taken and the strategy we are setting out today are right for BP, for our shareholders, and for wider society,' said Helge Lund, Chairman, BP.

Innovative solutions found for offshore wind workforce during pandemic
As the energy industry adjusts to working with increasing physical separation during the ongoing COVID – 19 pandemic, G+ Global Offshore Wind Health and Safety Organisation, based at the EI, has recognized five organizations for initiatives to improve operational safety.

With social distancing severely reducing the number of offshore wind turbine technical permitted to undertake wind farm inspections, maintenance vessel innovation challenge was launched, in partnership with ORE Catapult, KTN and the Workboat Association.

Five companies were selected as finalists. Demonstrations are now underway with Flameskill, offering a particle filtration head top to protect users from solid and liquid particles and micro – organisms, and Entex, with its Disinfex Booth, generating a dry fog of non – toxic disinfectant that kills viruses, pathogens and bacteria. Canary Sentinel, Sea Sure and Life's Shield were also selected.

Commenting on the submissions, G+ General Manager Kate Harvey said: 'For offshore wind, the pandemic present additional challenges in what is already a complex working environment. We've been impressed at the breadth and ingenuity shown in response to our call for proposals.

As offshore wind capacity grows, the sector continues to work tirelessly to uphold the highest safety standards. These varying solutions will allow vital operations to be carried out in a more efficient and safe manner.'

How offshore wind can help deliver a green recovery from COVID – 19
Offshore wind is a largely untapped resource in Europe's energy mix. Exploiting it will enhance the way we power our homes, businesses, and economies. EU decarbonisation scenarios require offshore wind to grow from 22 GW of installed capacity today to 450 GW by 2050.

The EU says Europe needs around 20 times more offshore wind than it has today to meet the goal of decarbonising its economy. The IEA believes offshore wind could become the number one source of electricity generation in Europe in the early 2040s. The numbers are huge, but do – able and affordable. With the presentation of the EU Offshore Renewable Energy Strategy this autumn, 2020 will be a key year for offshore wind.

To get to 450 GW the EU first needs to align maritime spatial planning with climate change goals. This means putting Europe's climate goals at the centre of the conversation when deciding on-site availability. It means establishing cooperation mechanisms to ensure alignment between countries, proper regulatory guidance, and funding for research on the co-use of wind farm areas.

Offshore wind developers are not the only ones that want to make use of sea space. The success of the EU Offshore Renewable Energy Strategy depends on the happy coexistence with other maritime activities such as aquaculture, fishery, military and tourism.

This mean improving our knowledge of offshore wind's environmental impacts and mitigating them. The Strategy needs to harmonise the methodologies for carrying out environmental impact assessments across the Member States with a specific focus on data collection and sharing.

The EU must also support Member States to fine – tune detailed policy measures in their National Energy and Climate Plans. There should be clear incentives for countries to deliver higher volumes of renewable based on the EU's Recovery Plan for COVID – 19, and an updated 2030 greenhouse gas emission reduction target.

Finally, we need to invest in power grids. Only a long – term oriented and integrated offshore grid master plan can ensure that electricity produced offshore finds its way to industrial off – takers, private households and electrolysers.

First – mover advantage
We have a first – mover advantage Offshore wind was developed in Europe, European companies are driving the global expansion and Europe has ideal conditions to remain a world leader in the energy transition by harnessing the potential of offshore wind. The political actions taken in the second half of 2020 will be decisive on how we make best use of the offshore resources we have at hand for decades to come.

There is some good news. The rotating EU Council Presidency makes Germany an important player in brokering the EU Offshore Renewable Energy Strategy. Its Presidency Programme recognizes the key role that a rapid expansion of offshore wind has to play in achieving the EU's renewable energy targets and ensuring security of supply. Germany plans a framework for joint offshore wind projects between countries, so-called hybrid projects which go beyond one single grid connection from the wind farm to the shore.

The Germans also have ambitious plans for the development of a European hydrogen economy. They plan to use electricity from offshore wind farms to produce renewable hydrogen, an important element in the decarbonisation of hard – to – abate sectors such as heavy – duty transport, aviation, steel and chemicals.

Last, the German Presidency programme will seek consensus to raise the EU target for greenhouse gas emission reduction for 2030 from 40% to 55%. A step that would encourage the fast deployment of new offshore wind capacities.

The EU Offshore Renewable Energy Strategy will be crucial to set the scene for future investment decisions and expansion paths. Planning procedures for offshore wind projects can take up to ten years. On the way to carbon neutrality by 2050, we have 30 years left. Now the EU has a unique opportunity to get offshore wind regulation right. And COVID – 19 increase the pressure to act.

COVID recovery plan

The EU Recovery Plan singled out renewable as an essential vehicle to kickstart the European economies. Wind energy has proven its resilience throughout the crisis. With 5.1 GW, new installations remained stable in the first half of 2020. And the share of wind in the EU's electricity generation rose to 17%.

For countries such as Denmark, Ireland, the UK or Germany wind was the most important source of electricity in the first half of 2020. In the offshore wind sector, large projects reached final investment decision, among them the Seagreen Alpha and Bravo project in the UK with a total capacity of 1.1 GW.

Offshore wind is shovel – ready and scalable. Floating wind is in the starting blocks. Channeling recovery funds into offshore wind, grids, port infrastructure and the related supply chain will not only acceleration the energy transition but also create local jobs while ensuring Europe stays on track for carbon neutrality.

LPG and electricity interconnector projects underway

While the COVID pandemic has depressed many parts of the economy, the recent start – up of two UK energy infrastructure projects shows the energy industry continuing to develop.

First, construction of the Viking Link Interconnector project – a high – voltage direct current (HVDC) link between the UK and Denmark – has commenced, with Siemens Energy beginning construction of the first stage of works, a 2.4 km access road for the Bicker Fen, Lincolnshire, converter station.

Viking Link is a joint venture between National Grid Ventures and the Danish electricity system owner and operator, Energinet. The 1.5 GW interconnector will be the longest in the world when completed, stretching 765 km subsea and onshore to connect Bicker Fen in the UK to Revising in South Jutland. Denmark to enable clean energy to be shared, Siemens Energy was appointed to construct the UK and Denmark converter stations at each end.

Meanwhile, liquefied petroleum gas (LPG) supplier Flogas Britain has started work on what will become the nation's largest LPG storage terminal, with the capacity to store 34,500 tonnes. The project involves conversion of the former National Grid LNG facility at Avonmouth, Bristol, to significantly increase Flogas' LPG storage capacity. This will provide greater security of supply to commercial and residential customers nationwide, says the company.

The Avonmouth facility is being converted for LPG storage by TGE Gas Engineering, as part of a £40mn investment by Flogas Britain, Design work is underway, with physical works expected to start on site in summer 2021 and full takeover planned for summer 2022. Once completed, the site will be filled and operationally ready for the winter of 2022.

The new Avonmouth facility is in line with Flogas' strategy to build a lower carbon future for off – grid homes and businesses. The site will be 'bio – ready' from the outset, says the company, capable of storing bioLPG, a chemically – identical renewable alternative to LPG. As a ‘drop in’ fuel, bioLPG can be blended with or replace LPG, without the need for changes to infrastructure, boilers or equipment.