Norway Deals a Blow to an Oil Industry That's Quickly Losing Friends

The decision of the world's largest sovereign wealth fund to reduce holdings in oil stocks wasn't as far-reaching as the industry feared, but dealt a symbolic blow to fossil fuels that will reverberate for energy companies and their investors.

While the divestment by Norway's $1 trillion fund doesn't include Big Oil, instead rooting out $7.5 billion of companies that focus purely on exploration and extraction, the impact of the announcement rippled through the sector. Shares of all oil companies initially plunged on the news, suggesting the move sets the industry up for greater disruption.

It's a bitter taste of the new reality for oil producers, which increasingly have to fight for investor dollars rather than enjoying the perks of being indispensable to the global economy.

“The Norwegian sovereign wealth fund is seen as something of a poster-child amongst sovereign wealth funds,” said Alejandro DeMichelis, director of oil and gas research at Hannam & Partners LLP. “This decision could also trigger other large investors to review their stance toward investing in the oil and gas sector.”

Life is changing for oil companies. Ten years ago, they accounted for about 15 percent of the S&P 500 index. Today, they make up just 5 percent, having been mostly displaced by technology giants such as Facebook Inc. and Apple Inc.

Driving this shift is a smorgasbord of new energy sources that’s bringing unprecedented competition for capital. Consumer choices are set to drift farther from the hydrocarbons of the 20th century, with renewables potentially meeting about a quarter of demand by 2040, according to oil major BP Plc.

It’s no surprise, then, that investors are increasingly questioning the wisdom of betting on oil and gas. A divestment campaign started by activist group 350.org in 2012 has already persuaded funds holding $8 trillion to back away from fossil fuels, according to its website.

Scrutiny could intensify as AGM season approaches. Catherine Howarth, chief executive officer of ShareAction — a group that has targeted Royal Dutch Shell Plc in the past — said she expects a “ramp-up” of pressure at annual general meetings that start in the spring.

‘Vulnerable’ Industry

“Institutional investors are withdrawing their capital from oil and gas companies on the grounds that quicker-than-expected growth in clean energy and associated regulation is making oil and gas business models highly vulnerable,” Howarth said in an email.

It’s not only oil companies facing pressure. One of the world’s biggest sellers of coal, Glencore Plc, yielded to investor demands earlier this year by promising to limit production of the fuel and align the business with Paris climate targets. In oil and gas, Shell and BP have made pledges around transparency and climate after facing the wrath of shareholders.

The list of companies to be excluded from the Norwegian fund includes Anadarko Petroleum Corp., Cnooc Ltd. and Tullow Oil Plc. Shale producers like EOG Resources Inc., which extract fuel from the heartland of America’s oil and gas boom, are also included.

Higher Costs

In the longer term, a dearth of capital will push up the cost of borrowing to explore for oil and gas, with those costs likely passed on to consumers, according to Georgi Slavov, head of research at energy broker Marex Spectron. That makes renewables comparatively cheaper, further pushing fossil fuels out of the market.

While Shell, BP and other oil majors were spared in Norway’s decision on Friday, they may yet be earmarked for divestment in the future.

“The country may eventually revisit the issue and target such holdings,” said Rob Barnett, an analyst at Bloomberg Intelligence. In particular, the fund could consider shedding “integrated companies not allocating a portion of their capital spending toward clean energy.”

For those oil companies moving to diversify, there’s light at the end of the tunnel. In its statement, Norway said some of the biggest investments in renewables now come from Big Oil. The fund “should be able to participate in this growth,” the Finance Ministry said.

“While the fund was initially built on revenue from oil and gas, the Ministry of Finance understands that the future belongs to those who transition away from fossil fuels,” said Mark Campanale, founding director of energy researcher Carbon Tracker. “Now is the time for smart investors around the world to follow their lead and make decisions driven by the reality of the energy transition.”

CCUS is a stopgap to a big hydrogen world

As a proponent of hydrogen being key to the UK’s atmospheric decarbonisation drive, I am concerned that hydrogen receives so little press when compared with carbon capture and storage

(CCS).

CCS, to my mind, has some serious flaws; the major concern being that CCS has a large parasitic energy load.

To provide the energy required for CCS means that more hydrocarbons have to be combusted, which in turn means more carbon dioxide (CO2) is produced.

The parasitic load for the CCS compressors, dryers and CO2 absorption plant typically requires 15-30% more fuel.

Of course around 90% of the CO2 is captured by the CCS plant so what's the problem?

The additional 15-30% fuel has to be supplied by the oil and gas producers, the consequence being that the associated energy use in production will increase.

The upshot is the additional harmful emissions of CO2, nitrous oxide, sulphur dioxide and particulates from the producing plant. Also CCS does not address the huge swathe of emissions from transport.

CCS could be combined with hydrogen production. The main industrial process for hydrogen production is steam methane reforming (SMR).

Here, methane (natural gas) is combined with water (steam) to produce hydrogen and CO2. The two reaction products are separated with the CO2 vented to the atmosphere and hydrogen used as a feedstock to multiple processes.

A CCS plant is bolted on to deal with the CO2, thus a combined CCS and SMR plant would produce low carbon hydrogen; the hydrogen being used as carbon free fuel for power and transport.

This combined process is termed carbon capture utilisation and storage (CCUS). Hydrogen-based CCUS is an improvement over CCS

but, like CCS, it requires more hydrocarbons to be produced to feed and fuel the process.

An alternative is to produce hydrogen by seawater electrolysis using renewable energy – a process that produces no CO2 or other harmful emissions. A process that can also use surplus renewable energy and has an almost limitless, free feedstock. Electrolysis though is viewed as too expensive when compared to SMR but that is changing.

Shell and others are investigating electrolysis as a competitive route to large scale hydrogen production. Are we in a similar position with hydrogen by electrolysis as wind power was a decade or so back?

Wind was viewed as commercially unattractive but that position has changed as offshore wind technology has driven the cost of electricity production down.

“CCS is a false climate solution that bolsters big oil” claim Greenpeace. I am not quite there but I do understand Greenpeace’s position – CCS requires the extraction of more fossil fuels hence could be viewed as a favourable option for oil and gas companies.

Whilst the government and other commentators believe CCS/CCUS is essential to meet the UK’s climate goals, I remain to be convinced. CCS/CCUS feels like a blunt, end of pipe, short term solution.

There is some excellent hydrogen research and development being undertaken through government and industry initiatives, but are we putting sufficient effort and funding into its development? CCS/CCUS is a stopgap to a big hydrogen world. We should bypass CCS/CCUS and deliver on hydrogen.

Finally, hydrogen will not solely deliver on decarbonisation – energy efficiency, land use, renewables and battery power all have their part to play.

Carbon emissions leap as global growth strengthens fossil fuel demand

Carbon emissions from fossil fuel use hit a record last year after energy demand grew at its fastest pace in a decade, reflecting higher oil consumption in the U.S. and more coal burning in China and India.

Those findings from the International Energy Agency mark a setback for the effort to rein in the pollution blamed for global warming just three years after a landmark deal in Paris where all nations committed cut emissions.

The figures showed that natural gas is becoming a preferred fuel for factories and utilities while the pace of installing renewable forms of energy is lagging. The report also indicated the strength of the global economic expansion last

year, with gains in electricity consumption and more notably in the U.S.

“We have seen spectacular growth of the economy in the U.S.,” said Fatih Birol, executive director of the Paris-based institution advising nations on energy policy. “We have seen several new petrochemical projects coming on line.”

Energy demand grew 2.3 percent last year, the most in a decade, according to the IEA. It showed a record 33 gigatons of carbon emissions from energy, up 1.7 percent from the previous year. Global electricity demand rose 4 percent and was responsible for half the growth in overall energy demand.Global coal demand grew for the second consecutive year in 2018, driven by Asia’s appetite for the dirtiest fossil fuel. Even as coal’s share of the global energy mix declined, it remains the world’s largest source of electricity. Natural gas use rose 4.6 percent, its fastest growth since 2010.

The U.S. increased its use of oil products at a faster rate than any other country for the first time in 20 years, overtaking China. The U.S. boosted oil use by 540,000 barrels a day, a fifth more than China even though the Asian nation has four times the population and is moving toward a less oil-intensive model in order to improve its urban air quality.

The pace of energy efficiency improvements fell, and renewables growth is didn’t keep pace with surging electricity demand, falling below 50 percent of new power supply last year.

Global output of greenhouse gases from energy-related sources rose to a record as energy demand jumped at its fastest pace in a decade.

“Renewables growth is not keeping pace with the electrification of our society,” Birol said on a call with reporters. “We need to see more support for renewables.”

Global energy-related emissions hit an all-time high in 2018 of 33 billion tons of carbon dioxide, a growth rate of 1.7 percent, which represents the fastest increase since 2013. Coal-fired power plants, which are closing across western Europe, were the single largest contributor to the growth in emissions, accounting for 30 percent of the increase, the IEA said.

Emissions are still increasing in China and India. The U.S. saw an increase of emissions after they fell in 2017. Germany, Japan, Mexico, France and the U.K. all saw declining output.

The world needs to cut the use of coal-fired power to almost nothing by 2050 to get anywhere close to limiting global warming to 1.5 degrees Celsius, a panel of United Nations scientists said in a report last year.

Shell boosts its bet on U.S. LNG exports

Royal Dutch Shell PLC and Energy Transfer LP said they are pursuing plans to convert a liquefied-natural-gas import facility in Louisiana into an export terminal, a bet that the future of U.S. shale gas lies in selling it for higher prices in overseas markets.

The Anglo-Dutch energy giant and U.S. pipeline operator said they are putting contracts out for bid to engineers and construction companies to reconfigure Energy Transfer's existing import facility in Lake Charles, La. The proposed facility would have the capacity to ship 16.5 million tons of U.S. natural gas a year, the companies said Monday.

"You can model and study it but the best way is to go out to tender and get a price that someone is willing to commit to," Maarten Wetselaar, Shell's director of integrated gas and new energies, said in an interview Monday in New York. "We are done theorizing on it; we just want to find out."

The move comes amid a prolonged period of low natural-gas prices in the U.S., where futures for April delivery settled Monday at $2.755 per million British thermal units. That is up 5% from a year ago but still low enough to put financial pressure on the producers that have flooded the domestic

market with shale gas in recent years.

Shell and Energy Transfer own equal economic stakes in the Lake Charles project, which was built at a time when many believed the U.S. was running low on gas and would rely on imports. The partners will decide together whether they should proceed with converting the Louisiana terminal pending the outcome of bidding and their analysis of the global LNG market.

One key factor, Mr. Wetselaar said, would be finding the 5,000 workers the companies estimate they will need to build the export facility. Labor might be particularly tight at a time when Exxon Mobil Corp. and Qatar Petroleum have announced they will build a rival export terminal nearby in Texas.

Mr. Wetselaar said the Lake Charles plant should have advantages over competitors because much of the necessary infrastructure has already been built. “If you can be the cheapest Gulf Coast project, then you’ll always be in the money because it’s such a big source of supply,” he said.

U.S. LNG exports have surged since early 2016. There are now three export facilities operating from the U.S. mainland, with several more slated to come online over the next few years as big energy companies seek to mop up the cheap shale gas and ship it in liquefied form to customers overseas, where the price is better.

China has emerged as a key buyer of U.S. gas as the country combats air pollution by replacing coal-fired power plants with those that produce electricity from cleaner inputs, such as natural gas, wind and solar.

Lately, LNG prices in Asia have sunk below $5 per million British thermal units, their lowest level in nearly three years. Shell, which supplied roughly 25% of China’s LNG last year, is bullish on the market regardless of current price moves because of the Chinese government’s goal to boost the

amount of gas used to produce electricity there to 15% from about 7% by 2030, Mr. Wetselaar said.

“Even if the Chinese economy decelerates, the quest to clean up the air in the big cities is going to continue,” he said.

Houston investment bank Tudor, Pickering, Holt & Co. told clients on Monday that the recent weakness in global LNG prices may prompt U.S. exporters to schedule extended downtime for maintenance this summer or to delay starting up new facilities if international prices languish. LNG export facilities have been counted on to absorb domestic production that has been soaring to new highs, and delays could push local prices lower.

“With the U.S. accounting for more than 80% of global new export capacity expected online through 2020, U.S. gas prices will become progressively more influenced by the strength of the Chinese economy,” Barclays analysts said in a report last week.

Shell, which last year accounted for about a quarter of all LNG sold globally, has already committed, along with several large Asian investors, to build a $30 billion LNG export facility in British Columbia that will transport gas gathered in western Canada to markets abroad.

Shell’s leadership staked the company’s future on natural gas in 2016 with the $50 billion purchase of rival BG Group PLC, a major player in LNG markets.

In the U.S., natural gas surpassed coal in 2016 as the top fuel for generating electricity. The U.S. Energy Information Administration on Monday said gas widened its lead over coal in 2018, accounting for 35% of electricity generation, compared with coal’s 27%. Overall, domestic natural-gas consumption rose 10% last year to an all-time high, the EIA said.

Claim that LNG is no greener than coal gets new scrutiny

One of the biggest bites ever taken out of greenhouse gas (GHG) emissions in any developed country is one that environmentalists and renewable energy advocates never seem to mention.

Since 2005, energy-related GHG emissions in the U.S. have fallen by 14%.

While some of those lower emissions can be attributed to renewable energy investments, the emissions decrease was “mainly” due to natural gas displacing coal power, according to the U.S. Energy Information Administration (EIA).

When burned for power, natural gas produces 50% to 60% fewer carbon dioxide emissions than coal does.

Proponents of B.C.’s nascent liquefied natural gas (LNG)

sector, including the BC NDP government, have therefore promoted the environmental advantage of LNG, since the biggest market is Asia, where LNG would presumably replace coal power and backstop intermittent renewable energy.

But environmentalists opposed to fossil fuels claim that "fracked gas" is as bad as coal or even worse, in terms of its global warming potential, due to fugitive methane emissions.

David Suzuki recently made the claim, accusing Prime Minister Justin Trudeau of hypocrisy in committing to climate change targets while supporting the $40 billion LNG Canada project.

"He proudly announced approval of a $40 billion facility to liquefy fracked gas, calling it a transition fuel to help China reduce coal dependence, even though fracked gas has a carbon footprint at least as bad as coal (because of fugitive methane release)," Suzuki recently wrote.

So are natural gas and LNG really worse than coal?

"I don't know," said John Werring, senior science and policy adviser for the David Suzuki Foundation, who was co-author of a study that estimated fugitive methane emissions in the Montney play of B.C. to be 2.5 times higher than those reported by industry and government.

"There's not enough information to make that determination," Werring said.

Measuring and monitoring of methane from the oil and gas sector in B.C., and elsewhere, is still inadequate, according to a recent report for the C.D. Howe Institute.

And until there is better baseline data, the LNG industry will remain vulnerable to the claim that it's no better than coal. It will also be impossible to apply carbon taxes to upstream methane emissions, or properly report on whether it is meeting a 45% reduction target.

“The magnitude of these emissions is unresolved,” says the C.D. Howe Institute report, written by Sarah Jordaan at Johns Hopkins University and Kate Konschnik at the Nicholas Institute for Environmental Policy Solutions at Duke University. “Policy-makers are thus left without defensible evidence describing the trends in methane emissions from the oil and gas value chain over time.”

The claim that natural gas may be as bad as, if not worse than, coal, from a global warming perspective, appears to be based largely on a 2011 study by Cornell University ecologist Robert Howarth, who concluded that, due to methane emissions, the GHG footprint of natural gas from shale production could be 20% to 50% higher than that of coal.

That study was rebutted by Howarth’s own colleagues at Cornell, who said in a paper that Howarth had significantly overestimated fugitive methane emissions.

A scientific panel report on fracking in B.C. that was published last week points out the Howarth study assumed that natural gas is released in large volumes as blowback during well completions. In B.C., that blowback is contained, by regulation, either through “green completions” or flaring, the panel noted.

Methane, the GHG problem child

Methane is the problem child of GHGs. It does not persist in the atmosphere as long as CO2, but it is magnitudes worse in terms of its heat-trapping properties.

Whereas the CO2 produced from combustion is easy to calculate, getting a handle on methane emissions is more difficult.

For one thing, there are many natural and other manmade sources of methane – swamps, dairy farms, landfills – so it can be difficult to pinpoint where it’s coming from.

There are thousands of oil and gas wells in B.C., so it's difficult to test them all for methane leakage.

The most common GHG associated with natural gas and LNG is CO2, from combustion. But extraction also produces methane.

If natural gas extraction produces large amounts of methane, it could indeed put it on par with coal, according to the EIA.

But even if the methane produced in B.C. from natural gas extraction is 2.5 times higher than the government estimates – as one study has suggested – it is still well below the threshold that the EIA has determined would be needed to put it on the same level as coal.

That threshold is 3%. That is, if 3% of the natural gas produced escapes, either through venting or fugitive emissions, then it would indeed be as bad as coal in terms of its global warming potential, the EIA calculates.

B.C.'s methane emissions intensity is 0.3%, according to the B.C. government.

But a study by St. Francis Xavier University – in which Werring was a co-author – estimated upstream methane emissions in the province are 2.5 times higher than the government estimates – 111,800 tonnes annually in B.C.'s Montney formation alone, as opposed to industry estimates of 78,000 tonnes provincewide.

Other studies elsewhere have come to similar conclusions.

But even if the methane emissions overall in B.C. are indeed 2.5 times what the government estimates, that's still an emissions intensity of just 0.7%. That's far below the global average of 1.7%, according to the EIA.

"Gas on average generates far fewer greenhouse gas emissions than coal when generating heat or electricity," the EIA states.

But how could B.C.’s methane emissions be so low? Either the emissions are dramatically underestimated or the industry and regulators are doing a better job of limiting methane emissions.

One way the industry in the province has reduced methane is through “green completions” – a method of capturing “blowback” and preventing venting when a well is first fracked and put into production.

In 2017, 85% of the wells drilled were green completions.

Electrification of the Montney has also allowed some companies, like Royal Dutch Shell, to electrify their plants and install electric actuator valves instead of pneumatic valves that release natural gas every time they are activated.

Shell estimates the methane emissions intensity from its Groundbirch operations in northeastern B.C. is 0.1%.

That may explain why regulators in Washington have insisted that a proposed LNG plant in Tacoma source its natural gas from B.C.

A life-cycle analysis done by the Puget Sound Clean Air Agency last year concluded that natural gas from U.S. producers could have emissions that are as much as eight times higher than emissions from gas produced in B.C. It cited tighter regulations for drilling and natural gas processing in B.C. for the low emissions profile of B.C. gas.

“British Columbia has adopted comprehensive drilling and production regulations that are intended to reduce methane emissions,” the agency stated.

Taxing methane emissions “not possible”

When the Pembina Institute developed its shale scenario tool to model the total GHGs from a B.C. LNG industry, the methane

appeared to be insignificant compared to the CO2.

“What we learned from that is that the leakage for B.C. is around 0.2% according to government reporting, which is extremely low,” said Maximilian Kniewasser, who developed the shale tool.

“The U.S. [Environmental Protection Agency] did some really detailed analysis, and they found that over the same part of the supply chain methane emission rates are around 1.3%. So B.C. is like one-sixth of what it is in the U.S. So there seems to be a discrepancy.”

The problem for any scientist trying to estimate methane emissions is a dearth of baseline data. The measuring, monitoring and reporting is still insufficient, so all modelling is based on snapshot data that may not provide accurate estimates.

Until there is better baseline data, it will be difficult to measure the success of methane reduction regulations, and impossible to apply carbon taxes to upstream methane emissions.

“At the current level of detail that we have, it would not be possible to tax methane,” Kniewasser said. “That is my opinion. And that’s just because we don’t have a good enough sense of what those emissions are exactly.”

The absence of good baseline data also poses a challenge for the government in demonstrating that its new regulations requiring a 45% reduction of methane emissions are hitting their targets. In B.C., new drilling and processing regulations come into effect in 2020.

“When we’re talking about reducing methane emissions in the oil and gas industry by 45%, the question then becomes 45% of what?” Werring said. “What is your baseline? And we don’t have a handle on that baseline, unfortunately. But there is

technology and there are opportunities here to move forward with regulations that require companies to be more proactive in their reporting.”

But both Kniewasser and Jordaan say that the absence of good baseline data is no reason not to establish a better regulatory regime.

“You can mandate what kind of equipment you can implement or how often you have to check your facility,” Kniewasser said. “So even if you don’t have great data right now, it’s totally possible to regulate and mandate better practices.

“There’s uncertainty around what the problem is in B.C. with methane emissions, no doubt. What we do find is that there is a lot of opportunity to reduce methane pollution, or carbon pollution, across the LNG and natural gas supply chain.

“It’s a young field, but there is so much opportunity to reduce methane pollution. It is really the cheapest opportunity in the whole economy.”

Werring would like to see better monitoring of gas wells on an ongoing basis, especially older ones.

“The wells that are in production, they are probably pretty well monitored,” Werring said. “But then there all these other wells – they’re abandoned and suspended wells – that are not being appropriately monitored.”

Methane detection improving

By 2025, the B.C. government hopes, new regulations will result in a 45% reduction in methane leakage from the province’s natural gas sector.

The new regulations will force the natural gas industry to adopt new technologies and best practices that reduce methane emissions from natural gas wells, pipelines and processing plants.

But it may be hard to determine if it has hit its targets, because methane measuring and monitoring are still spotty.

Technology is evolving, however, that can give regulators a better idea of just how much methane is coming from the oil and gas sector.

GHGSat, for example, is a Canadian company that is using satellites to detect large methane sources from space. The company has one satellite in orbit and plans to launch a second one this summer.

“We are going to be able … to do direct measurements of oil and gas installations across the world, including British Columbia, and be able to offer a more efficient and lower-cost method of detecting and quantifying emissions from natural gas facilities,” said GHGSat president Stephane Germain. “We can help them identify where the big leaks are fast so they can fix them faster.”

While some Canadian companies have been using GHGSat, the BC Oil and Gas Commission has not yet used it.

While satellite imaging can identify the big emitters, it’s still something of a low-resolution approach.

Once the bigger emitters are identified, more refined detection technologies to pinpoint sources can be used to zero in on specific wells, pipelines and plants that may be emitting methane at high rates.

Geoscience BC has been piloting a project that uses “sniffer” drones developed by NASA that can take aerial surveys to detect methane emissions from natural gas infrastructure and other sources, including feedlots.

It is also using carbon isotope fingerprinting that can identify the signatures of molecules from a specific area. It is using the technologies to develop an “atlas” that will

allow Geoscience BC not only to detect methane, but also to identify which well it may have come from.

“It gives us what I call the postal code of that molecule of gas,” said Carlos Salas, chief science officer at Geoscience BC. “So if there was to be a leak, and you were flying this drone, it would tell the company not only which wellhead is leaking, but it also gives you the depth as to where they think it’s coming from.

“We haven’t found any mega-emitters or anything like that. They tend to be just small emissions.”

MPs demand scrapping Israeli gas deal ‘at any cost’

AMMAN – The Lower House on Tuesday declared its “utter

rejection” of the gas deal between Jordan’s National Electric Power Company (NEPCO) and the Israeli occupation authorities.

House Speaker Atef Tarawneh said that all segments of society and MPs reject the gas deal signed with the “Zionist entity”, requesting that the agreement be “cancelled at any cost”.

Deputy Prime Minister Rajai Muasher said that the government has decided to refer the gas deal with Israel to the Constitutional Court for interpretation of Article 33 of the Constitution.

Paragraph B of the said article reads: “Treaties and agreements which involve financial commitments to the Treasury or affect the public or private rights of Jordanians shall not be valid unless approved by the National Assembly. In no circumstances shall any secret terms contained in any treaty or agreement be contrary to their overt terms.”

Meanwhile, dozens of citizens staged a protest in front of the Parliament on Tuesday demanding the termination of the gas deal with Israel.

A total of 16 deputies signed a memorandum, requesting a vote of no confidence in Prime Minister Omar Razzaz’s government for signing the gas deal with the “Zionist entity”.

Muasher said that the government would refer the deal as a law to the Parliament if the Constitutional Court required it to do so.

“But if the court rules that the deal is between two companies and the Parliament has no say over it, the government will review the agreement again and take the necessary decision in consultation with the House,” Muasher added.

In response to Muasher, Tarawneh said that “the deal is completely rejected and we demand it gets cancelled at any cost and no matter what the Constitutional Court says”.

MPs called on the government to look for alternative energy resources from Arab states, arguing that the gas deal threatens Jordan’s energy security and serves the Israeli occupation’s economy.

Other deputies called for suing the government that signed the gas deal with Israel.

In September of 2016, NEPCO signed a 15-year agreement with Noble Energy, a Houston-based company that holds the largest share in the Israeli Leviathan Gas Field, to purchase $10 billion worth of natural gas.

The government then said it would import 250-300 million cubic feet of natural gas per day from Noble Energy, which is expected to save the Kingdom around JD700 million.

Under the deal, Jordan will receive 3 billion cubic metres of gas per year.

Let’s talk about geoengineering

By David Keith/ Cambridge

Negotiations on geoengineering technologies ended in deadlock at the United Nations Environment Assembly in Nairobi, Kenya, last week, when a Swiss-backed proposal to commission an expert UN panel on the subject was withdrawn amid disagreements over language. This is a shame, because the world needs open debate about novel ways to reduce climate risks.

Specifics aside, the impasse stemmed from a dispute within the environmental community about growing scientific interest in solar geoengineering – the possibility of deliberately reflecting a small amount of sunlight back into space to help combat climate change. Some environmental and civil-society groups, convinced that solar geoengineering will be harmful or misused, oppose further research, policy analysis, and debate about the issue. Others, including some large environmental groups, support cautious research.

By reflecting sunlight away from the Earth – perhaps by injecting aerosols into the stratosphere – solar geoengineering could partly offset the energy imbalance caused by accumulating greenhouse gases. Research using most major climate models suggests that solar geoengineering might reduce

important climate risks such as changes in water availability, extreme precipitation, sea level, and temperature. But any version of this technology carries risks of its own, including air pollution, damage to the ozone layer, and unanticipated climate changes.

Yet research on solar geoengineering is highly controversial. This has limited research funding to a few tiny programmes around the world, although a larger number of climate scientists are beginning to work on this topic using existing funds for climate research.

Why the controversy? Many fear, with good reason, that fossil-fuel interests will exploit solar geoengineering to oppose emissions cuts. But most researchers are not driven by such interests. The vast majority of those researching solar geoengineering or advocating for its inclusion in climate-policy debates also support much stronger action to reduce emissions. Still, it's very likely that Big Fossil – from multinational energy companies to coal-dependent regions – will eventually use discussion of geoengineering to fight emissions restrictions.

But that risk is not a sufficient reason to abandon or suppress research on solar geoengineering. Environmentalists have spent decades fighting Big Fossil's opposition to climate protection. And although progress to date has been insufficient, there have been some successes. The world now spends over $300 billion per year on low-carbon energy, and young people are bringing new political energy to the fight for a safer climate.

Open discussion of solar geoengineering would not weaken the commitment of environmental advocates, because they know emissions must be cut to zero to achieve a stable climate. At worst, such a debate could make some in the broad, disengaged middle of the climate battle less interested in near-term emissions cuts. But even this is not certain; there is empirical evidence that public awareness of geoengineering increases interest in cutting emissions.

It is sensible to focus on cutting emissions, and reasonable

to worry that discussing solar geoengineering could distract from that fight. But it’s wrong to indulge a monomania whereby emissions cuts become the sole objective of climate policy.

Vital as it is, eliminating emissions simply stops adding to the burden of carbon dioxide in the atmosphere. The CO2 from the fossil-fuel era, and the resulting climate changes, will persist. We need adaptation that increases resilience to climate threats. But adaptation by itself is no solution. Neither is solar geoengineering. And nor is removing CO2 from the atmosphere – another emerging set of technologies that were considered in the Swiss-backed proposal in Nairobi.

As the American writer H L Mencken put it, “there is always a well-known solution to every human problem – neat, plausible, and wrong.” Complex problems like climate change rarely have a single solution.

My hope is that emissions cuts, solar geoengineering, and carbon removal can work together to reduce the human and environmental effects of climate change beyond what is possible with emissions cuts alone.

Are these hopes justified? The geoengineering research community is small and dominated by a narrow group of members, most of whom are (like me) white, male, and based in Europe or America. Groupthink is a distinct possibility. We may simply be wrong. It would be reckless to deploy solar geoengineering based only on hope and early research.

Instead, an international, open-access research program could, within a decade, dramatically improve understanding of the risks and efficacy of solar geoengineering. Such a programme would cost a small share of the sum currently spent on climate science, and far less than 0.1% of outlays to cut emissions. A wise program would reduce groupthink by increasing the diversity of researchers, and by establishing a deliberate tension between research teams developing specific scenarios for deployment and others tasked with critically examining how these scenarios could go wrong.

Governance is the toughest challenge for geoengineering. A global research program should therefore be coupled with

greatly expanded international discussion about these technologies and their governance. Such a debate was unfortunately cut short in Nairobi last week.

Although my generation will not use solar geoengineering, it seems plausible that before the middle of this century, a dramatic climate catastrophe will prompt some governments to consider doing so. By foregoing debate and research on geoengineering now, political leaders may be hoping to eliminate the risks of its future misuse. But their stance may actually increase this danger.

Humans rarely make good decisions by choosing ignorance over knowledge, or by preferring closed-door politics to open debate. Rather than keeping future generations in the dark on solar geoengineering, we should shed as much light on it as we can. – Project Syndicate

* David Keith, a professor of applied physics at Harvard's School of Engineering and Applied Sciences (SEAS) and a professor of public policy at Harvard's Kennedy School of Government, is the founder of Carbon Engineering.

Fed's big surprise could spell disaster for dollar bulls

Bloomberg New York

***Dollar plunges by the most since January on Fed's surprise; further losses may hinge on economies outside US perking up**
The Bloomberg dollar index tumbled 0.5% on Wednesday, making it the worst day since January, after Fed policy makers unexpectedly signalled they'd hold their rates benchmark steady all year because of troubling signs from the economy. Among other problems, that could undermine the currency's appeal by cutting into any yield advantage on dollar-denominated assets.

Some investors and economists were caught off guard by the extent of dovishness in the statement. The Fed's shift comes a week after hedge funds and speculators boosted bets that the greenback would outperform peers to the highest level since January.

Before Wednesday, "we were mildly bullish with the intention

of flipping as soon as the Fed signalled that it was done tightening through QE and rate hikes," said Greg Anderson, global head of foreign-exchange strategy at BMO. "The Fed dropped those hints a whole lot faster than we thought."

As 2019 began, dollar bears proclaimed that the Fed would stop or slow interest-rate hikes, US growth rates wouldn't be able to consistently outperform the rest of the world, and the advantage an investor gets from holding greenbacks would diminish. But the currency generally remained buoyant.

The Bloomberg dollar index rose about 7% through Tuesday's close from a three-year low in February 2018. Then came Wednesday and the revised dot plot — the chart Fed policy makers use to convey their rate forecasts.

"The dots are dinging the dollar," said Mark McCormick, a foreign-exchange strategist at TD Securities. It strengthens the "bearish" case for the greenback, he added.

The Fed's new stance "partially" vindicates the bears, but for the dollar to weaken more, economies outside the US will need to perk up, according to Bipan Rai of Canadian Imperial Bank of Commerce.

"The key ingredient to ensure that the USD sells off consistently is a pick-up in the fundamental story for the euro zone," said Rai, the head of North American foreign-exchange strategy at CIBC. "We're seeing some nascent signs there, but we need more evidence — especially in Germany."

BNY Mellon also argues a dovish Fed may not doom the dollar, as central banks all over the world move toward the same direction, FX strategist John Veliswrote in a note.

"One would be tempted to think that this still-more-dovish turn by the Fed will take DXY down, but then again, that prediction would have been sensible in January after the Fed's pause was announced," he said. "It didn't happen then, and it

might not happen now.”

Oil majors rush to dominate US shale as independents scale back

In New Mexico’s Chihuahuan Desert, Exxon Mobil is building a massive shale oil project that its executives boast will allow it to ride out the industry’s notorious boom-and-bust cycles.

Workers at its Remuda lease near Carlsbad – part of a staff of 5,000 spread across New Mexico and Texas – are drilling wells, operating fleets of hydraulic pumps and digging trenches for

pipelines.

The sprawling site reflects the massive commitment to the Permian Basin by oil majors, who have spent an estimated $10 billion (Dh36.72bn) buying acreage in the top US shale field since the beginning of 2017, according to research firm Drillinginfo.

The rising investment also reflects a recognition that Exxon, Chevron, Royal Dutch Shell and BP largely missed out on the first phase of the Permian shale bonanza while more nimble independent producers, who pioneered shale drilling technology, leased Permian acreage on the cheap.

Now that the field has made the US the world's top oil producer, Exxon and other majors are moving aggressively to dominate the Permian and use the oil to feed their sprawling pipeline, trading, logistics, refining and chemicals businesses. The majors have 75 drilling rigs here this month, up from 31 in 2017, according to Drillinginfo. Exxon operates 48 of those rigs and plans to add seven more this year.

The majors' expansion comes as smaller independent producers, who profit only from selling the oil, are slowing exploration and cutting staff and budgets amid investor pressure to control spending and boost returns.

Exxon chief executive Darren Woods said on March 6 that Exxon would change "the way that game is played" in shale. Its size and businesses could allow Exxon to earn double-digit percentage returns in the Permian even if oil prices – now above $58 per barrel – crashed to below $35, added senior vice president Neil Chapman.

Exxon's 1.6 million acres in the Permian means it can approach the field as a "megaproject", said Staale Gjervik, the head of shale subsidiary XTO Resources, whose headquarters was recently relocated to share space with its logistics and refining businesses. The firm also recently outlined plans to

nearly double the capacity of a Gulf Coast refinery to process shale oil.

“It sets us up to take a longer-term view,” Mr Gjervik said.

The majors’ Permian investments position the field to compete with Saudi Arabia as the world’s top oil-producing region and solidifies the United States as a powerhouse in global oil markets, said Daniel Yergin, an oil historian and vice chairman of consultancy IHS Markit.

“A decade ago, capital investment was leaving the US,” he said. “Now it’s coming home in a very big way.”

The Permian is expected to generate 5.4 million barrels per day (bpd) by 2023 – more than any single member of the Organization of the Petroleum Exporting Countries (OPEC) other than Saudi Arabia, according to IHS Markit. Production this month, at about 4 million bpd, will about double that of two years ago.

Exxon, Chevron, Shell and BP now hold about 4.5 million acres in the Permian Basin, according to Drillinginfo. Chevron and Exxon are poised to become the biggest producers in the field, leapfrogging independent producers such as Pioneer Natural Resources.

Pioneer recently dropped a pledge to hit 1 million bpd by 2026 amid pressure from investors to boost returns. It shifted its emphasis to generating cash flow and replaced its chief executive after posting fourth quarter profit that missed Wall Street earnings targets by 36 cents a share.

Shell, meanwhile, is considering a multi-billion dollar deal to purchase independent producer Endeavor Energy Resources, according to people familiar with the talks. Shell declined to comment and Endeavor did not respond to a request.

Chevron said it would produce 900,000 bpd by 2023, while Exxon

forecast pumping 1 million barrels per day by about 2024. That would give the two companies one-third of Permian production within five years.

At first, the rise of the Permian was driven largely by nimble explorers that pioneered new technology for hydraulic fracturing, or fracking, and horizontal drilling to unlock oil from shale rock, slashing production costs.

The advances by smaller companies initially left the majors behind. Now, those technologies are easily copied and widely available from service firms.

Surging Permian production has overwhelmed pipelines and forced producers to sell crude at a deep discount, sapping cash and profits of independents who, unlike the majors, don’t own their own pipeline networks.

Even as the majors have ramped up operations, the total number of drilling rigs at work in the Permian has dropped to 464, from 493 in November, as independent producers have slowed production, according to oilfield services provider Baker Hughes .

Shell, by contrast, plans to keep expanding even if prices fall further, said Amir Gerges, Shell’s Permian general manager.

LNG slump seen close to end as price collapse stimulates

demand

Bloomberg London/Singapore

Liquefied natural gas prices may be about to hit the bottom after losing more than a third of their value this year.
Sellers of the world’s fastest-growing fossil fuel may first have to face a cut of another 10% over the next two months before prices rebound from the lowest since July 2017, according to traders surveyed by Bloomberg News. It might be good news for the climate, as price-sensitive users in India and Bangladesh switch to cleaner natural gas from oil and coal.
Asia, the biggest consuming region for LNG, uses most of it for heating and power but a mild winter, an abundance of new supplies and a better preparedness of Chinese buyers meant prices went against the trend over the past few months by falling rather than rising. Traders are now watching for signs that summer cooling demand and buying by price-sensitive nations will spur a rally.
“LNG prices could have further downside heading into the second quarter, but should find support from demand in India, South Korea, China and Thailand towards the third quarter,”

said Nick Boyes, a senior gas and LNG analyst at Swiss utility and trader Axpo Group.

Japan Korea Marker futures, a benchmark for spot LNG, will probably bottom at $5 per million British thermal units, according to the median of seven traders, brokers and analysts surveyed by Bloomberg. Most respondents said that level is most likely in April or May, though some said that the price may continue to fall and hit $4.50 by spring 2020.

LNG prices are still dropping because more spot cargoes are entering the market and buyers in Japan, South Korea and China – the biggest users – are holding off from purchases.

India, which is seen emulating China in its unprecedented use of LNG to fight air pollution, may burn more gas rather than dirtier coal if LNG prices fall to $5 per million Btu, according to Energy Aspects Ltd. At $6, there will be little increase in India's power sector demand given prevailing coal prices, the industry consultants said in a note.

There are already signs that the price slump is boosting demand. India's Torrent Power Ltd bought an LNG cargo for May 26 at the high-$5 to low-$6 per million Btu level including transport and delivery and Reliance Industries Ltd is looking for 12 cargoes through March 2020.

"India is price-sensitive and its coming up with tenders now is a good sign that we may be approaching the bottom," Eric Bensaude, managing director at Cheniere Energy Inc's marketing unit in London, said in an interview. "I'd want to believe that."

The price of cargoes for late June were above those for early May in a recent spot supply tender in neighbouring Pakistan, a further indication that the end of the slump is approaching.