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 CO_2, 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.

Germany : Siemens to explore gas turbine deal with Asian partner

Mar 22, 2019 (Euclid Infotech Ltd via COMTEX) — Siemens AG is exploring a combination of its large gas turbine business with an Asian partner, according to people familiar with the matter.

The German company has held talks with firms including Mitsubishi Heavy Industries Ltd, said the people, who asked not to be identified because the talks are private. Options range from a full or partial sale of the division to a joint venture, the people said. No final decisions have been made and Siemens may still decide to keep the unit, they said.

Siemens has been considering options for the large gas turbine business, which forms the biggest part of its power-and-gas division, since at least last June, when people familiar with the matter said the German engineering company was considering a potential sale. The business was worth about 3.2 billion euros (S$4.9 billion), Berenberg analyst Simon Toennessen estimated at the time.

“The situation on the global market for fossil power-plant technology remains unchanged,” the company said in a statement, declining to comment on talks about the turbine business. “Siemens began tackling these challenges back in early 2015.”

A spokesman for Mitsubishi Heavy declined to comment. Siemens shares advanced as much as 2.6% following the Bloomberg report, the most in more than a month. The stock was up 0.9% to €98.20 at 1:13pm in Frankfurt yesterday.

The global market for gas turbines has collapsed as renewable energy has become cheaper. Siemens announced in 2017 it would cut 6,900 jobs in its power and gas division to respond to that shift. General Electric Co was the top producer of gas turbines last year, with about 33% of global orders by capacity, according to Barclays Plc. Mitsubishi Hitachi Power Systems followed with 30%, while Siemens was third with 26%.

The German company was set to generate about €5.2bn in revenue from turbine sales and service in 2018, Berenberg estimated last year. Siemens’s power-and-gas division will be renamed gas and power on April 1, refl ecting the company’s new structure. Siemens announced last year that it was shrinking the number of operating divisions from three to fi ve and that it would focus on factory software and energy distribution, attempting to get the jump on newer technologies that had been disrupting its core business.

Oil trader Vitol says demand will grow for 15 more years

Oil tanker is seen at sunset anchored off the Fos-Lavera oil hub near Marseille, France (file). Vitol Group, the world's biggest independent oil trader, expects global demand for the fuel to continue rising well into the 2030s despite a predicted surge in electric-vehicle sales. "Oil demand will continue to grow for the next 15 years," chief executive off icer Russell Hardy said on Tuesday. The shift to renewable energy can't be achieved "across all sectors in the near to mid-term without halting economic development in large parts of the world." It's a more bullish prediction than in 2017, when he said global demand for road fuels could peak as early as 2027. Vitol trades millions of barrels of crude and oil products every day, but – like the fuel producers themselves – is grappling with a move toward cleaner forms of energy. Although the closely held, Rotterdam-based company takes an optimistic view on global demand, it's among trading houses quietly preparing for an eventual shift away from crude. "We are supportive of the need to move to more renewable sources of energy," Hardy said in a statement outlining Vitol's annual traded volumes and performance. The company has in recent years announced investments in wind farms, energy storage and distributed power generation.

GECF chief: Qatar proved its ability in overcoming challenges

QNA /Doha

Qatar has established itself as one of the largest producers and exporters of natural gas in the world after it proved its ability in overcoming challenges, Secretary-General of the Gas Exporting Countries Forum (GECF) Dr Yury Sentyurin has said.
In an interview with Qatar News Agency (QNA), Dr Yury Sentyurin said that Qatar, despite recent challenges, has continued to be resilient and was able to secure LNG supplies to its partners and clients worldwide through providing LNG to remote consumption areas and markets, which don’t have access

to sustainable and clean sources of energy.
He expects Qatar to continue to play a key role in natural gas markets globally and maintain its position as one of the largest natural gas producers and exporters in the world.
Furthermore, he pointed out that Qatar has great potential to develop its natural gas resources and increase its LNG exports.
Dr Sentyurin added that Qatar’s recent decision to increase its LNG production level from 77Mt to 110Mt will improve the country’s position as one of the main exporters of LNG to the global markets and reinforce its position as the world’s largest reliable LNG supplier.
He pointed out that Doha’s announcement can contribute to increasing demand for LNG, mostly from Asia and especially China.
Qatar’s export level will, also, reinforce the position of the GECF as a whole in the global LNG trade.
Dr Sentyurin praised Qatar’s loyalty to its clients in the hardest moments, pointing out that its support of Japan during the shortage of LNG procurement of the country after Fukushima disaster showed how loyal Qatar is to its clients.
He stated that Qatar recovered its status as the largest annual LNG exporter.
It loaded around 6.9Mt of LNG with the support of many factors, including the large quantities produced in the North Field, storage capacity, low production costs, and other factors.
He stated that the Forum continues to support and promote co-operation among its member states through dialogue between gas producers and consumers and through promoting the use of natural gas as an affordable, abundant and, sustainable energy source.
Dr Sentyurin pointed out that the global energy market is becoming more and more dynamic, with the interplay of economics and geopolitics getting more complex.
This increased degree of complexity and dynamics brings a higher degree of unpredictability, which in turn raises the

volatility of various commodities, including the oil price.

He added that the role of large-scale and institutional players is very important, pointing out that players like the GECF often aim at market balance and stability, as oil and gas projects are usually very capital intensive and have a long project life cycle; such long-term projects require predictability and low volatility to be executed and thrive.

This is why today's situation is a great opportunity for the GECF to play a more hands-on role in the gas and LNG markets.

He pointed out that GECF is an intergovernmental organisation of gas exporting countries, which provides the framework for exchanging experience and information among its Member Countries, builds a mechanism for dialogue between gas producers and consumers for the stability of security of supply and demand in gas markets, promotes natural gas as a fuel of choice to achieve the United Nations Sustainable Development Goals (UN SDGs) and goals of the Paris Agreement, while respecting the sovereign rights of its member-countries over the exploitation of their natural gas resources.

Dr Sentyurin stressed that at the GECF has no intention to collectively reduce gas/LNG production to balance the market during any potential oversupply based on its commitment to the sovereign rights of its member countries. Regarding the developments in the oil market, Dr Yury Sentyurin stated, "We've seen in the past that gas market has always been able to balance itself and we believe this will be the case in the future". He also placed emphasis on the GECFs active role in gas markets, as it possesses around 70% of the global proven gas reserves, leading the exports of natural gas by pipeline and in LNG forms worldwide, thus contributing to the security of supply and stability of the market.

Its marketed gas production accounted for 45% of the global gas production respectively as of 2018.

Dr Sentyurin confirmed that the GECF member countries continue to be a very important source of natural gas supply needed, to not only satisfy their contractual obligations, but also to meet their domestic gas requirements, as well as entering new markets and new sectors, noting that the total production growth of the GECF is mostly comprised of production increase from Russia, Iran, Egypt and Nigeria.

He also pointed out that increased demand for natural gas, along with the development of new fields and the commissioning of new projects, such as new phases of South Pars gas field in Iran and Zohr field in Egypt, are among the main factors contributing to the production boost in GECF member countries.

Regarding a question about new applications by states who want to join the Forum, Dr Sentyurin said, “We are open to welcome any country exporting natural gas that is willing to join our Forum. In line with this, we are proud to announce that the Republic of Angola, one of the major producers of natural gas, joined the GECF and that is our 6th African country”.

He was optimistic about the growth of the GECF, which will reinforce the position of the Forum internationally.

Regarding how the Forum dealt with the decline of demand, in some regions, in favour of less environmentally friendly energy sources such as coal, he stated that global energy demand conversely increased.

From 2000-2017, demand grew annually by 2% and reached 14,144 Mtoe.

Furthermore, he said natural gas consumption grew by 3-4% over the past two years, and that this upward trend would continue in the near future, which would be driven mainly by higher consumption in Asia, especially in China, India, Pakistan and Bangladesh and in the United States, as well as in Europe and the Middle East, particularly Iran and Egypt.

Regarding coal, which is most carbon-intensive and polluting fuel, he said that the Asia-Pacific region represents the largest market in 2017 almost 2,800 Mtoe or 74% of global coal demand was absorbed by Asian economies; within the aforementioned period, coal consumption in this region surged by 5.8% per year.

He stated that coal will remain an important option for Asian countries in meeting future energy needs.

However, extended efforts to support natural gas, renewables, and energy efficiency are expected to mitigate coal demand growth in the Asia Pacific region.

He pointed out that global policy orientations to limit the environmental impact resulting from coal-related emissions.

He said, “Under these assumptions, we project that global coal consumption through to 2040 will remain flat, while natural gas will rise by 1.7% per annum.

This will enable gas to overtake coal as the second largest source of energy”.

The GECF secretary-general said that energy policies, including those deriving from the Paris agreement, are a key determinant of the future trend of the energy mix, which the Forum believe will naturally call upon natural gas.

However, he pointed out that the markets witnessed some surprises previously.

A few years ago, EU gas demand has dropped significantly, when the power generation sector lost more than 50 Bcm on natural gas in favour of more polluting energy sources like coal and lignite.

He also pointed out that China, despite the ambitious coal to gas switching policies engaged recently to tackle the air pollution issues in the cities, has eased these policies to encourage the usage of coal, especially for heating in winter period.

This adds uncertainty about the near-future energy mix of the country.

He added that China, accounting for about 51% of the global coal consumption, has been increasing its natural gas consumption to curb air pollution through its blue sky energy policy, which could be sustained in the long-term with the engagement towards health issues and environmental concerns.

The Forum thinks that this trend could be potentially replicated by other economies in Asia, the largest consumers of coal worldwide, favouring natural gas that is affordable, abundant and accessible.

Regarding the future of the gas industry, Dr Sentyurin said that the natural gas industry faces a number of concerns both on demand side and supply side related to energy policies, technology shifts, price volatility and intra-fuel competition, adding that gas demand is significantly affected by unclear and unstable policies that often do not recognise the crucial role of gas in the transition to a clean and sustainable energy future.

Some countries in Asia and Europe still supporting coal despite its high carbon intensity.

Furthermore, there are unclear policies on the future role of nuclear energy in some countries.

He clarified that these challenges contribute to biased intra-fuel competition of coal, renewables and other fuels with gas, which could impact the growth in gas demand.

Exxon’s talks to tap Algeria shale gas falter due to unrest – sources

* Exxon, Sonatrach met in Houston to discuss Ahnet field

* Exxon opted to suspend process due to violence in Algeria

* Discussions part of tightening ties between companies

By Lamine Chikhi, Dmitry Zhdannikov and Ron Bousso

ALGIERS/LONDON, March 20 (Reuters) – Talks between Exxon Mobil and Algeria to develop a natural gas field in the North African country have stalled because of domestic unrest, industry sources said.

Irving, Texas-based Exxon entered talks with Algeria’s national oil company Sonatrach several months ago to develop a field in the southwestern Ahnet basin, the sources close to the discussions said.

The talks were part of a deepening of ties between the two companies that followed Sonatrach’s acquisition last May of Exxon’s Augusta refinery in Sicily, Italy.

Last week, officials from the two sides held talks in Houston, Texas to hammer out details but Exxon opted to suspend the discussions, temporarily at least, due to the recent protests in Algeria over President Abdelaziz Bouteflika’s 20-year rule, the sources said.

Exxon and Sonatrach declined to comment.

The refinery acquisition and increased cooperation between the two companies were seen as key for Sonatrach’s efforts to modernise its business and reduce reliance on fuel imports under Chief Executive Abdelmoumen Ould Kaddour.

The collapse of the talks follows years of attempts by Sonatrach to attract foreign companies to develop its vast oil and natural gas resources.

Sonatrach hopes to tap foreign experience in fracking, a drilling technique that led to the rapid expansion of U.S. oil and gas production, to develop its own shale reserves, estimated at 22 trillion cubic metres, the world’s third largest.

The North African country is a leading gas supplier to Europe, but exports have suffered from delays to several projects and a steep rise in the use of subsidised gas at home as the population has grown. (Additional reporting by Florence Tan and Jennifer Hiller in Houston; Writing by Ron Bousso; Editing by Dale Hudson)