GAS IN TRANSITION

VOL 1 ISSUE 2 / MAY 17, 2021

MAGAZINE

The methane *problem*

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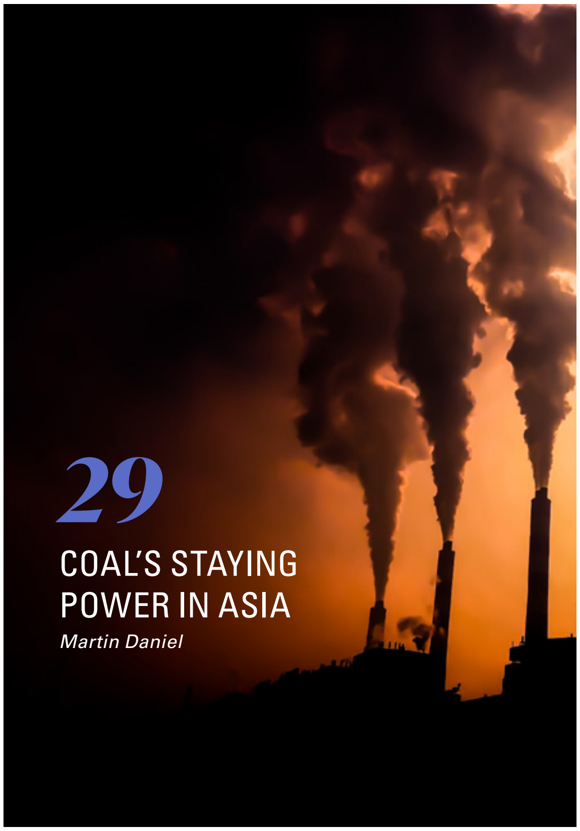
Contents

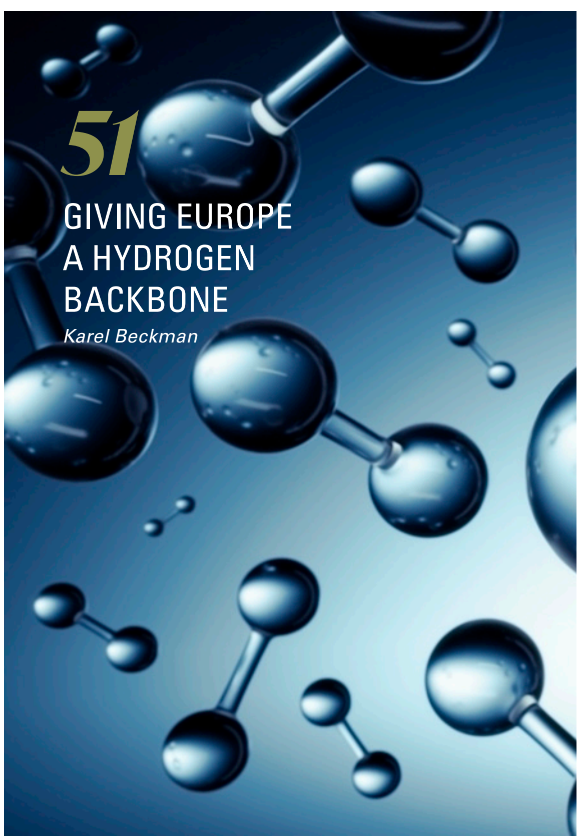
GAS IN TRANSITION

FOCUS ON: **NATURAL GAS VEHICLES**

LNG CONDENSED



LOW-CARBON FUTURES



GAS IN TRANSITION

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FROM THE EDITOR | **Joseph Murphy**

The methane problem

THE UNEP REPORT IS LIKELY TO PUSH THE CLIMATE CHANGE CONVERSATION, WHICH HAS SO FAR CENTRED ON CO_2, FURTHER IN THE DIRECTION OF METHANE

The global climate change discussion has chiefly revolved around CO_2 emissions and efforts to reduce them. But there is a growing view that methane mitigation too has a vital role to play.

This shift in focus was highlighted by a landmark report published by the UN on May 6 which concluded that cutting methane emissions was critical to avoiding global temperature growth. Reducing how much methane escapes into the atmosphere could also have a much more rapid impact than efforts to curb CO_2 emission, the UN Environment Programme (UNEP) argues in its *Global Methane Assessment*.

"Cutting methane is the strongest lever we have to slow climate change over the next 25 years and complements necessary efforts to reduce CO_2," Inger Andersen, UNEP's executive director, explains. "The benefit to society, economies and the environment are numerous and far outweigh the cost."

CO_2 has been the main driver of climate change, although methane comes in second place owing to its much greater potency, UNEP argues, even though it is released in much smaller volumes. UNEP finds that methane has been responsible for around 30% of global warming since the pre-industrial era. And its atmospheric concentration is currently increasing faster than at any time since record-keeping began in the 1980s. Failure to act could see methane emissions continue rising through at least 2040, the organisation warns.

Avoiding further temperature growth is one clear reason to act, according to the report. But there are other gains to be made by addressing methane. For one, it is a key ingredient in smog, with UNEP estimating that its mitigation could prevent some 260,000 premature deaths and 775,000 asthma-related hospital visits annually, as well as 25mn mt of crop losses.

The good news is that methane decomposes in the atmosphere much faster than CO_2. Whereas CO_2 can take hundreds of years to break down, methane has an atmospheric lifetime of roughly a decade, according to UNEP. This means that efforts to rein in methane emissions will take far less time to yield results, it says.

Through a concerted effort, UNEP argues, methane emissions from human activity could be cut by 45% as early as 2030. This reduction of around 180mn mt/year could avoid almost 0.3 oC of temperature growth as early as the 2040s, it says.

The onus falls largely on the oil and gas industry to tackle the methane problem, according to UNEP. The sector is not the biggest contributor of human-caused methane emissions – an honour that falls on agriculture – but it is the area where the greatest reductions can be achieved.

The oil and gas sector accounts for only 23% of total human-caused methane emissions, whereas agriculture, chiefly livestock, causes around 40%. Waste contributes a further 20% and coal mining 12%. However, UNEP's assessment identifies available solutions that could reduce methane emissions from human activity by 30%, and these are mainly found in the hydrocarbon sector.

"The fossil fuel sector has the greatest potential for targeted mitigation by 2030," the report states. "Readily available targeted measures could reduce emissions from the oil and gas sector by 29-57mn mt/yr and from the coal sector by 12-25mn mt/yr."

What is more, most of the 30% reduction in human-caused emissions could be achieved at a low cost, and just over 50% at negative cost, meaning that the measures would pay for themselves quickly. In the oil and gas sector, up to 80% could be implemented at a low or negative cost. This negative cost is largely derived from using the methane that would have escaped into the atmosphere as energy. It lists specific measures such as improved upstream and downstream leak detection and repair, better control of unintended fugitive emissions from production and more advanced monitoring.

It also suggests that a rising global tax on methane emissions starting at around $800/mt, which could reduce emissions by as much as 75% by 2050.

Measures targeted at methane reduction alone are not enough, however, the report states. To achieve the full 45% cut envisaged by 2030 across the hydrocarbon, agricultural and waste sectors, additional measures must be implemented that do not target methane specifically, such as shifting to renewable energy, improved residential and commercial energy efficiency and a reduction in food loss and waste.

The report also flags key challenges to overcome, namely incomplete knowledge and monitoring of emissions in some sectors, limiting potential for technical innovations in mitigation and strategic decisions on efficiently reducing emissions. There also needs to be greater regional and global coordination and governance of emissions, beyond local and national laws and voluntary programmes already in place, it argues.

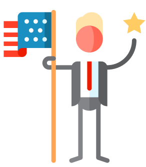
While most government climate targets concern CO_2 emissions, legislators are starting to set their sights on methane. The European Commission is currently drafting legislation to strengthen methane reporting and monitoring requirements for oil and gas companies, after publishing an EU methane strategy last year. In the US, the Biden administration is now reinstating methane emission regulation that had been dismantled by its predecessor.

The UNEP report is likely to push the climate change conversation further in the direction of methane. And its publication comes ahead of the UN Climate Change Conference (COP26), where world leaders will try to outdo themselves in making old climate pledges new, including on methane. However, measuring methane emissions is a contentious issue. There is much disagreement about how much methane each sector contributes, and over which measurement methods should be used. Creating the right legislation to help rather than hinder various industries from addressing their environmental impact will be no small task. •

US reverses course on *methane emissions* from oil and gas

THE US IS IN THE PROCESS OF RESTORING OBAMA-ERA RESTRICTIONS ON METHANE EMISSIONS THAT WERE ROLLED BACK BY FORMER PRESIDENT DONALD TRUMP

Anna Kachkova



The Trump administration dismantled over **100** regulations related to climate change, seeing them as a hindrance to the growth of oil and gas and other industries.

THE US IS CHANGING COURSE on regulating methane emissions generated by the oil and gas industry. This is part of a broader pivot on environmental issues under US president Joe Biden, who took office in January.

The country is currently in the process of reinstating oil and gas industry regulations that were brought in during former US president Barack Obama's term in office but rolled back by his successor, Donald Trump. Indeed, the Trump administration dismantled over 100 regulations related to climate change, seeing them as a hindrance to the growth of oil and gas and other industries. Now, the new administration is bringing previous rules back. And given Biden's recent adoption of a new target to reduce US greenhouse gas (GHG) emissions by 50-52% by 2030, further and stricter regulations are likely to follow.

In late April the Senate – the upper house of US Congress – passed a bill to reinstate the 2012 and 2016 Oil and Natural Gas New Source Performance Standards set by the Obama administration, which govern oil and gas production and processing. Democratic Senate majority leader Chuck Schumer described the 52-42 vote as the "first of many important steps" the Senate would take in pursuit of Biden's climate goals.

The measure still needs to be passed by the House of Representatives before being signed into law by Biden, but this is expected to happen, marking another step forward for the administration's climate change agenda. It also appears to be a sign of things to come for the country's oil and gas industry.

"The industry should definitely be ready for more stringent methane regulations," Wood Mackenzie's Americas vice chair, Ed Crooks, tells *NGW*. "On his first day in office, president Joe Biden promised to bring forward 'new regulations to establish comprehensive standards of performance and emission guidelines for methane and volatile organic compound emissions from existing operations in the oil and gas sector, including the exploration and production, transmission, processing, and storage segments', by September 2021."

The rules in the process of being reinstated now target methane leakage from oil and gas infrastructure, such as wells and pipelines, in particular. Anna Mikulska, a non-resident fellow in energy studies for the Center for Energy Studies at Rice University's Baker Institute for Public Policy, tells *NGW* that such methane leaks are the "low-hanging fruit" within the bigger picture of GHG emissions reduction efforts. This is in comparison with carbon dioxide (CO_2) emissions, for example, tackling which will require considerably more investment and technological solutions such as carbon capture and storage (CCS).

Nonetheless, addressing fugitive methane emissions will be a step forward – and one that will be welcomed by investors that are increasingly concerned about oil and gas companies' environmental credentials.

"The largest US gas producers are under pressure from investors and increasingly from customers to curb their methane leakage, and many have made commitments to reduce their emissions," says Crooks. "New regulations may mean little or no additional burden of compliance on top of costs they would have incurred anyway, and will help level the playing field in competition against smaller operators that are less likely to have made those commitments."

INDUSTRY ATTITUDES

Given the growing number of oil and gas companies setting new emissions goals, the return of Obama-era regulations is expected to be supported by at least some industry players. This is nothing new, though, and was already evident during Obama's time in office.

"Large producers including ExxonMobil and Royal Dutch Shell supported the Obama-era rules, and thought the move towards deregulation under the Trump administration was a step in the wrong direction," said Crooks. "However, groups such as the Independent Petroleum Association of America, representing smaller producers, had opposed the Obama administration's rules, particularly the 2016 changes which added new source performance standards for methane."

> ***"The industry should definitely be ready for more stringent methane regulations."***
>
> **Wood Mackenzie**

This was echoed by Mikulska, who says that larger players have the funding and economies of scale to address methane leakage with relative ease, while smaller players struggled with this and were therefore more likely to oppose additional regulatory burdens. And with the shale industry initially dominated by smaller independent producers, it is not surprising that such players lobbied against Obama's regulations.

Now, though, the composition of the shale industry has changed compared with its early days.

"What you've seen in recent years, particularly 2020 and 2021, also within the US shale patch – you've seen a huge amount of consolidation," Mikulska says. "So those companies that had already been hurting, that could not afford any type of methane leakage monitoring or prevention, they are probably gone at this time. They've probably been absorbed by larger companies."

Mikulska added that mergers and acquisitions can help to free up capital as companies achieve cost savings and synergies while minimising inefficiencies.

"Fewer people are now working and the companies are more efficient. It frees up capital for efforts like decarbonisation," she says.

In line with these trends, various large producers have already voiced their support for a return to methane regulation for the industry. Crooks cited the example of EQT, the largest gas producer in the US, which issued a statement backing a return to the Obama-era rules last month. The company said it was committed to working with governments and regulators, among others, "to establish sound environmental policies that promote increased access to clean and affordable energy sources".

This illustrates a desire among the industry to participate in the development of regulations rather than being excluded from the process because a given company opposes the measures being brought in.

"That's probably what we're seeing, for the industry, that it's better to be in the room than outside it," Mikulska says.

As well as EQT, Occidental Petroleum has been prominent in its recent support of a return to methane regulation.

"We need to have regulations in place to ensure that we have adequate controls throughout the industry," Occidental's president and CEO, Vicki Hollub, told the Senate Committee on Energy and Natural Resources during a hearing in late April. She told the committee that Occidental supported the direct regulation of methane.

As well as individual companies, industry organisations are also starting to embrace methane regulation.

"Significantly, the American Petroleum Institute [API], the most influential industry group, has said it 'supports cost-effective policies and direct regulation that achieve methane emission reductions from new and existing sources across the supply chain'," said Crooks.

It is worth noting that France's Total withdrew from the API at the start of 2021, having found that the group's climate positions were only "partially aligned" with its own. Then, in early May, BP announced that it had decided to remain a member of the API after the group had made certain policy shifts, including choosing to support the federal regulation of methane emissions.

Despite this, industry support for the return of methane emissions regulations will not be universal, with Crooks saying he expected the industry to be divided again, "as it was over the Trump administration's deregulation strategy, with support for new regulations from larger producers but opposition from some smaller companies and their representatives". Nonetheless, industry consolidation is ongoing, investor pressure on producers over environmental targets is rising and a growing number of companies supports the new rules. Given all of this, even with some resistance from pockets of the industry, there is ever-growing momentum behind the new regulations. •

European gas storage in a *global market*

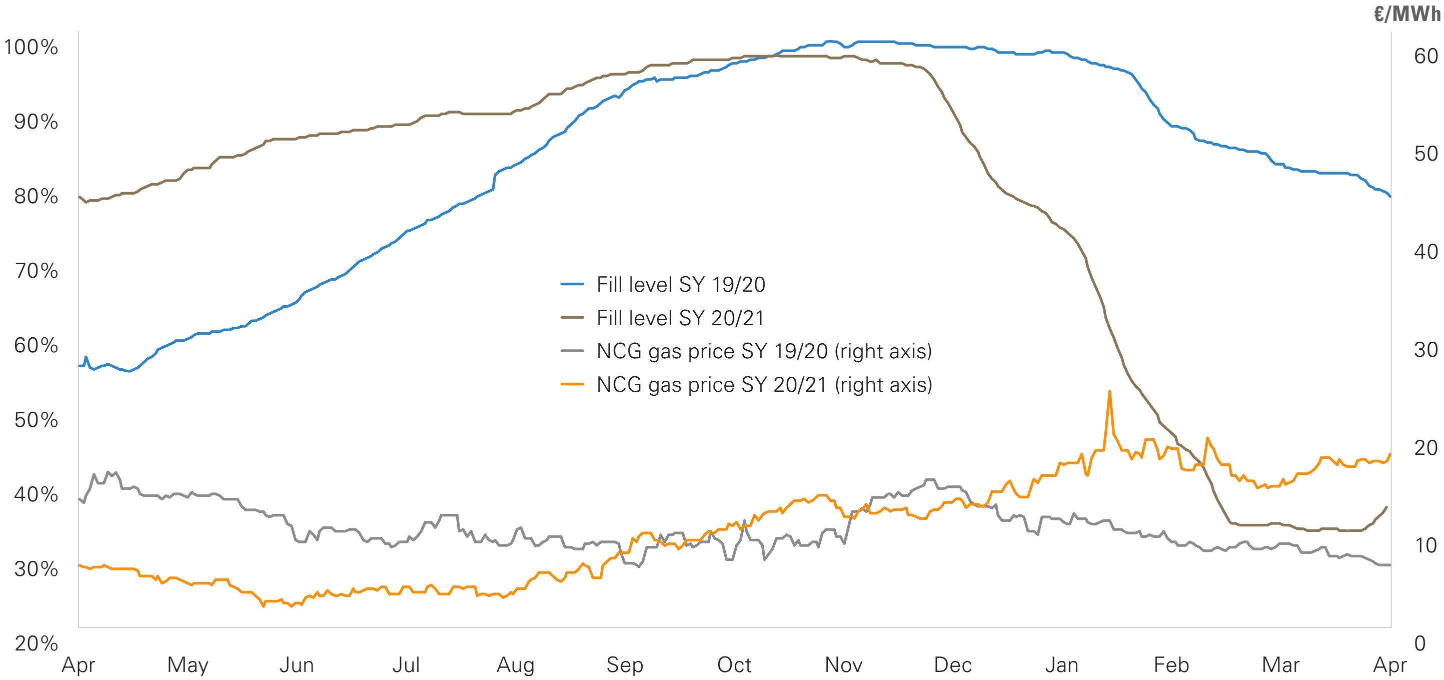
APRIL WAS A SHOULDER MONTH LIKE ALMOST NO OTHER: A COLLISION OF MANY FACTORS, OUTSIDE EUROPE'S CONTROL, COULD LEAVE THE CONTINENT UNDER-STOCKED BY THE NEXT HEATING SEASON.

William Powell

WITHDRAWALS FROM Europe's gas storage facilities were continuing well into May, more than a month after the injection period would have started in a typical year. This has raised questions about the continent's state of readiness for next winter and the prospect of higher prices for delivery after October.

Storage facilities exist because the alternative – major pipelines capable of carrying the customers' peak day demand – would be uneconomic. Gas flows at a steady rate over the year and in the days of European gas monopolies, it was injected into storage facilities at times of low demand.

FIGURE 1 Utilisation level in Uniper's gas storage portfolio *Source: Uniper*



In a competitive world, by contrast, the "invisible hand" of the market is meant to take care of storage by responding to summer-winter price signals. But this year there is no price signal: summer prices are almost the same as winter prices. There is no incentive now to inject.

There were three major reasons for the slow start on both the supply and demand side. First, it had been a very cold April, meaning gas was needed for heating for longer. Second, other sources of power generation such as wind, hydro and French nuclear power, were all low, making gas more necessary in the power sector too. And third, carbon prices were also high, reaching and even exceeding €50/metric ton in early May. The continuing bull run provided a reason to burn gas instead of coal where possible.

There were another three reasons on the supply side: lower than expected deliveries from Russia; maintenance offshore Norway, which will see less gas produced as essential maintenance work was held from last year by COVID-19; and US LNG, which might have been expected to come to Europe, went instead to capture the higher netbacks from Asia as it was cold there too.

More predictable is the fact that the Dutch Groningen gas field is no longer allowed to provide the swing service that it used to. This means that another source of peak gas supply is less.

It is true that Gazprom could have booked more short-term capacity through Ukraine as it did last year, at a cost; but it has chosen not to exceed the pre-arranged volume so far this year. Had Gazprom been allowed to complete Nord Stream 2 on time, it would by now be carrying more gas than the annual capacity deal with Ukraine allows: 55bn m³/yr compared with the 45bn m³ booked for this year.

All these factors explain the relatively small quantity of gas in store: 340 TWh as of May 8, which is where it had been a month earlier.

Uniper Storage – the fourth largest operator in Europe and Germany's largest, with facilities also in the UK and Austria totalling 7.5bn m³ – told *NGW* early May that the low inventory level (*Figure 1*) was all the more remarkable since facilities in Germany had been 94% full at the start of the winter but were now down to 30% full, at best.

Uniper Storage head Doug Waters said that storage had again "proved its worth" this winter; it met 61% of German gas demand in January, he said. Overall, storage had supplied 717 TWh last winter and it was still meeting demand in May, he said. During the particularly cold snap mid-month, it was also enabling gas to meet peak electricity demand in the UK for example, as there was almost no wind generation.

"There is no alternative to storage for physical gas supply," he said. The surest alternative to storage is LNG and the market had mistakenly assumed that more LNG would arrive than was the case: in the event, he said LNG deliveries to Europe were down about 45% year on year.

With the closure of Centrica's Rough facility in 2017 for financial reasons, the UK now only has **2%** of its supply covered by storage.

And yet now Europe faces the so-called "storage paradox," he said. Typically, market appetite for storage injections is reflected by the summer-winter price difference but at the moment, that has almost vanished.

There is no commercial benefit in buying gas now as the winter price is only €1/MWh higher. That difference has to cover the shippers' pipeline exit/entry capacity costs as well as the storage operators' margin. In order to attract injections, the difference between summer and winter has to widen, meaning winter 2021-2022 prices could rise at the major gas hubs.

"Low storage levels at the end of the heating season result in higher injection demand from storage sites; this further tightens the market through the summer; which in turn drives up summer gas prices more quickly than the winter contracts and hence reduces summer-winter spreads," the company explained. Waters said someone was going to be on the wrong side of this: storage would struggle to get above 80-90% full, he said, unless winter prices rise – or summer prices fall.

Commenting on the situation, consultancy Timera Energy said in a May 10 research note that: "curve backwardation in commodity markets (when forward prices are discounted against prompt delivery) is often bullish. It may be the back of the Dutch TTF forward curve that will be dragged up by higher near-term prices as 2021 progresses."

Some of Uniper's storage facilities straddle national borders: Etzel is on the Germany-Netherlands border and the Austrian facility 7Fields, which is technically operated by RAG but whose capacity Uniper markets, also allows traders to access the German market. It sells capacity on either a fixed (for one-year contracts) or indexed basis, where the price varies with the summer-winter price difference. On those contracts the volume is locked in but the price is not known until the average spread has been calculated each year. In common with other operators, it sells capacity both as bundled units, where space comes with injection and withdrawal; and as separate units, allowing owners to trade between themselves on the secondary markets.

UK: PROBLEMS AHEAD

Storage capacity, as a proportion of annual demand, ranges widely across Europe. Most countries have built storage capacity using depleted gas fields (long-range storage) or developed them from salt caverns (short-range storage) or aquifers. But the UK, which had been a gas exporter until almost 20 years ago, relied on swing production from the Morecambe Bay fields and the depleted and now unavailable Rough gas field to meet peak demand.

With the closure of Centrica's Rough facility in 2017 for financial reasons, the UK now only has 2% of its supply covered by storage, compared with about a quarter elsewhere in Europe. Demand for peak gas is often synchronised in northwest Europe as the weather tends to be the same across the region. So the UK is having to bid against others for the molecules.

This makes the UK vulnerable, according to Clive Moffatt founder of the UK Energy Security Group. He told *NGW*: "Natural gas is critical in what will be a slow transition to net-zero and whether it be to secure supplies of power or heat or a possible source of hydrogen, more UK gas storage is essential.

"We are vulnerable on physical supply and price security now and we will continue to be so because, despite the popular tide of liberal opinion, we are going to be dependent on gas domestic boilers. Hydrogen – be it blue or green – is, as the majors know, an economic non-starter; and heat pumps are simply too expensive and less effective in winter. And power generation – both for baseload to compensate for the lack of coal and nuclear and for peakload to combat system imbalance caused by more wind – will be necessary for many more years. And with our almost total reliance on imports after 2025 we need more storage. We cannot depend on pipes and LNG to be there when needed."

The UK government and the energy regulator Ofgem, ever since the closure of Rough, have said that the market, not taxpayers, should decide whether to take the risk of an investment in new storage facilities. And those that have the potential for conversion, such as the all-but-depleted Saltfleetby gas field in Lancashire, might be used for storing other gases altogether.

It is a complicated argument: for some governments, strategic stocks are a straightforward matter of controlling prices and responsibly ensuring supply; but nobody will invest in new capacity if there is the chance of government intervention that will make the asset worthless. Turn on the taps, and the investment loses its value. And in a theoretically single market, the actions of one operator will affect more than one country.

REFILLING: AN IMPERATIVE

Replenishing storage is an "imperative for this year," Giacomo Masato and Evangeline Cookson, analysts at brokerage Marex, told *NGW* in an interview late April. They drew comparisons with the last time the European injection season had got off to such a low start, which was 2018, and said injection demand had been the most important factor behind the high gas price.

This was an unusually cold April and this has meant that the customary rebound, with injections starting at the end of March, did not happen: in fact, facilities went from 30% full to 29% full in late April, before gaining a little afterwards.

The comparison with 2018 suggests worse is to come, because although European storage ended with less gas in store that winter, facilities were already filling up again during April. They said: "We had gone from 18% full at the end of March to 23% full by late April.

"It was the 2018 'Beast from the East' that led to a rapid withdrawal from European facilities at the end of the winter. The step-change came later on, from a large wave of LNG from the US and this lowered prices during the following winter."

Marex

"It was the 2018 'Beast from the East' that led to a rapid withdrawal from European facilities at the end of the winter. The step-change came later on, from a large wave of LNG from the US and this lowered prices during the following winter."

They continued: "This year, stocks had been 12% higher at the end of March relative to March 2018 but now [late April] we are only 6% higher than three years ago. Prices were pulled higher during that restocking phase and rose to $27-28/MWh.

"This is potentially worrying as 2018 ended with EU stocks at 85% full as the withdrawal season was about to start. That is a tight supply for the beginning of the forthcoming winter and the market is aware that a repeat of 2018 is possible." The October 2020 season began with storage about 93% full.

"April can deliver significant withdrawal, but injections cannot wait any longer than the start of May, so then injections have to happen, whatever the price. That is why now the price curve is flat from now until December in Europe: summer trading has eroded the summer-winter spread. If storage reaches only 85%-90% full by October, that will send a bullish signal. But if it goes above 90% full, the market will happily wait to see what demand does," they said.

There are some grounds – based on the current Asia-Europe spread from June onward – for believing that the LNG send-out over Europe may well decline during the second half of the restocking phase. And if Russia had booked incremental capacity through Ukraine – and it had been expected to do so, they said, judging from the brief drop in EU gas prices in late April – then that could lower Dutch TTF prices, making storage more attractive. But at the same time it would push more LNG into Asia, and away from Europe. The lower Europe's prices become, the less attractive a destination it is for LNG relative to Asia.

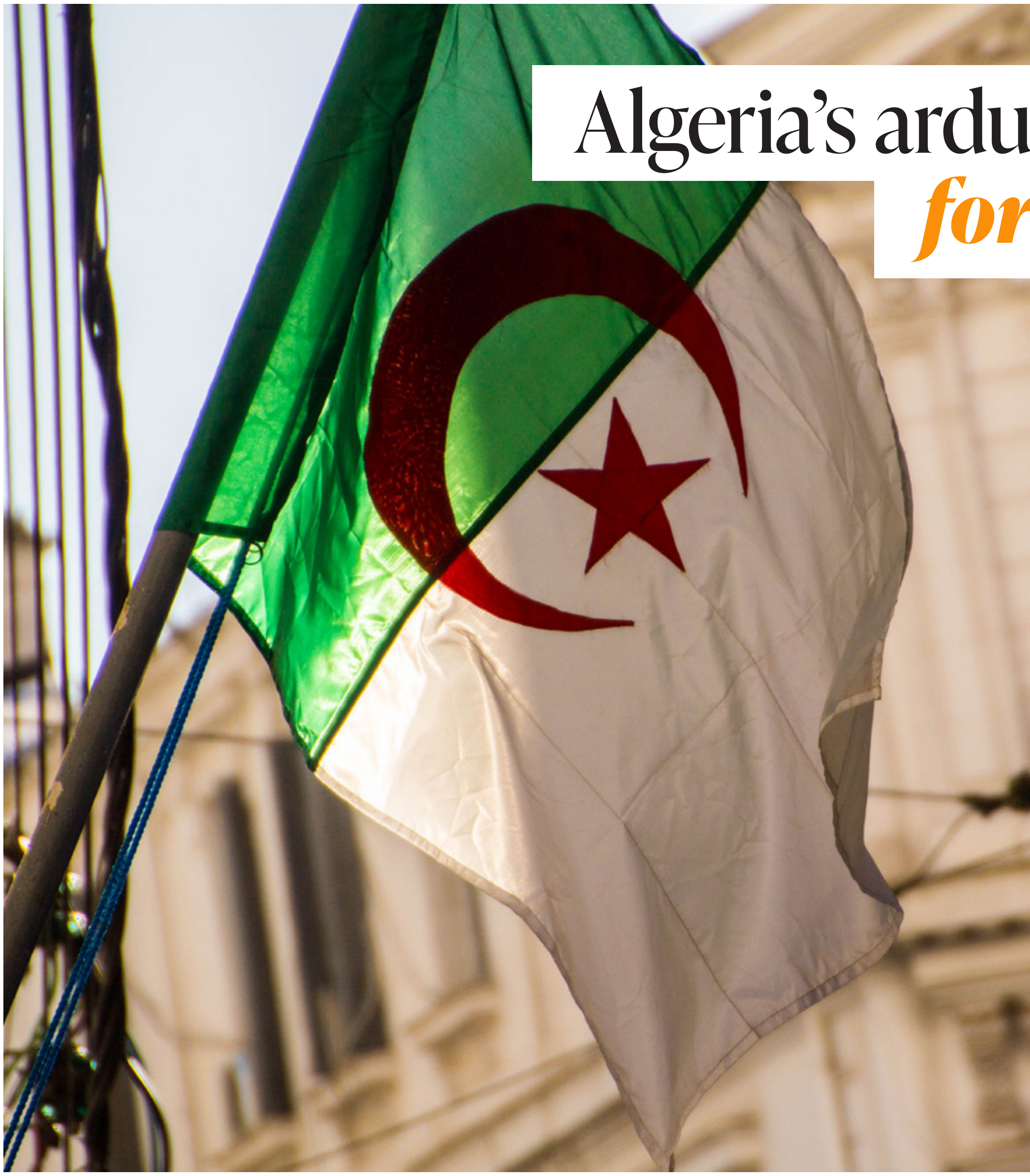
The Asian-EU premium for prompt delivery of spot – as opposed to long-term contracted – cargoes was about $1/mn Btu in late April. "We have noticed that when the difference between the two is well below $0.50/mn Btu then the LNG will primarily target Europe. But at $1/mn Btu or more, Asia becomes much more competitive and can erode parts of the global supply share away from Europe." However, a week later the premium was down to $0.4/mn Btu, suggesting that a turnaround in Europe's fortunes is coming.

As to the longer term, there are reasons the global market could redistribute LNG more evenly.

"US facilities are now at their highest levels of output but there have been delays across the value chain owing to the COVID-19 pandemic, slowing down buildout. If Asian import expansion continues to grow faster than expansion from key exporters (such as US and Qatar, among others) we will see the competition for gas between Asia and Europe maintained and naturally, prices will rise," they said.

But there is more optionality in Asia where power generation is concerned: gas is not the only fuel and there is no carbon market. Japan is bringing back more nuclear plants into service and coal is still widely burned. "All forms of diversification will be taken into account there, while in Europe the soaring price of carbon works against coal and in favour of gas," they said.

China has been upping the use of facilities that can use LNG and its expansion has been very rapid as it moves away from coal. Even building LNG import facilities gives it mini-LNG storage, the analysts say, which in turn fractionally eases the pressure on demand. •



Algeria's arduous search *for investors*

THE NORTH AFRICAN STATE IS PREPARING TO IMPLEMENT A NEW HYDROCARBON LAW, BUT FREQUENT RESHUFFLES AT STATE ENERGY INSTITUTIONS AND CLASHES WITH PARTNERS RISK UNDERMINING ITS INVESTMENT APPEAL

Joseph Murphy

ALGERIA IS LOOKING to open its oil and gas sector to greater foreign investment, in the hope of reversing production decline. But while there have been welcome signs of progress, including the introduction of more attractive hydrocarbon legislation in late 2019, there have also been more troubling developments. Decision-making at state energy institutions has been disrupted by frequent reshuffles of officials, and most recently, a $1bn dispute has broken out between national oil company (NOC) Sonatrach and an international partner.

REFORM

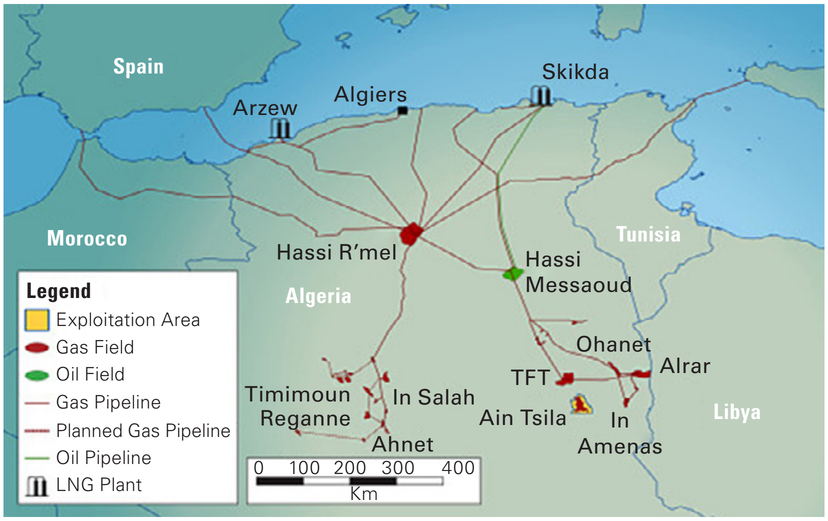
Years of underinvestment and project delays have seen Algerian oil output decline from a peak of 1.4mn barrels/day in 2008 to around 1mn b/d in early 2020. Marketable gas supply has also been on a downward trajectory for several years, totalling 87.7bn m^3 in 2020. This has squeezed the domestic gas balance and limited volumes available for export.

These trends are a considerable concern for the government, which relies on oil and gas for 60% of Algeria's state budget and 94% of the country's total exports.

The case for legislative reform to encourage investment has been set out by Sonatrach itself on many occasions. The company, which wants to expand its output and reserves significantly as part of its 2030 strategy, said in October 2019 that the overhaul of the hydrocarbon law was "essential to restore the attractiveness of the sector in the context of low oil prices and increased competition among producing countries to attract new investors."

Two months later the government's new hydrocarbon law was officially introduced. The new legislation marks a return to the attractive provisions

FIGURE 1 Ain Tsila field and other Algerian oil and gas assets *Source: Sunny Hill Energy*



in Algeria's 1986 hydrocarbon laws, which led to a number of major discoveries before regulations were changed in the mid-2000s, sapping investment.

"The new hydrocarbons law has shifted the needle positively for existent and would-be investors," Anthony Skinner, director for Middle East and North Africa at Verisk Maplecroft, tells *NGW*. However, international oil companies (IOCs) are still waiting for the implementation texts to be passed through parliament following the June 2021 general elections.

Furthermore, the law "cannot be treated in isolation," he notes. "It has been overshadowed by COVID-19, sub-optimal oil and gas prices, churn in Algeria's state energy institutions and concerns about the ability of the regime to manage mass-disenchantment."

Signalling renewed interest in Algeria, Sonatrach has signed a number of memoranda of understanding with foreign upstream partners since the new law's announcement. The signatories include US firms Chevron, ExxonMobil and Occidental Petroleum, Spain's Cepsa, Italy's Eni, Austria's OMV, Russia's Lukoil and Zarubezhneft, France's Total and Turkey's TPAO. These deals, though non-binding, are "the direct result of the amended hydrocarbons law being passed," Skinner believes.

Still, the law is no "silver bullet," the expert notes.

"On the positive side, investors welcome the greater selection of business contracts under the amended legislation," he says. "Whereas the old law required permits to be offered under concession terms, the amended law gives contractors the option to select between participation contract (concession), production-sharing or risk service contract terms."

Did you know?

Algerian gas supply is declining, but the country still boasts 4.3 trillion m^3 in proven reserves, according to BP.

IOCs can now carry out prospecting work in allocated areas and in the event of a discovery, they can formulate a research plan and secure a contract.

"Critics of the law says it does not go far enough to precipitate a big flow of new upstream investment to Algeria," Skinner explains. "Under the legislation Sonatrach retains its right to a 51% stake in participation contracts in JVs."

REGULAR RESHUFFLES

Investors also have to contend with a "regular churn among executives" at state energy institutions, most notably at Sonatrach and the energy ministry.

"The lack of continuity at the helm of Sonatrach has given rise to a regular reshuffle of vice-presidents and disrupted decision-making as these individuals come to grips with their new portfolios," Skinner explains. "Since the beginning of 2019, the NOC has had four chief executives, three of which have been replaced as a result of factionalism, ineffectiveness in their roles or a combination of both. This challenge has been exacerbated by long-standing realities: heavy bureaucracy and unpredictable decision-making."

Algeria's current energy minister Mohamed Arkab has been in the role since February, when he was appointed as part of a broader cabinet reshuffle. Arkad had served as energy minister between April 2018 and June 2020, when he was replaced by Abdelmadjid Attar in another reshuffle ordered by president Abdelmadjid Tebboune.

There could be a further overhaul of personnel following the upcoming general elections. "Another reshuffle has the potential to once again delay the passage of the hydrocarbons law implementation texts," Skinner warns.

Investors have also had difficulty buying and selling assets in Algeria. Italy's Edison had to exclude its Algerian business from the sale of its upstream portfolio to Mediterranean-focused Energean, after authorities in Algiers blocked the deal. A few years earlier, US firm Occidental Petroleum was unable to transfer assets it was acquiring from Anadarko in Algeria to France's Total for the same reason.

INVESTOR DISPUTE

At a time when Sonatrach is trying to promote Algeria's upstream appeal, a now-former upstream partner, London-based developer Sunny Hill Energy, has presented quite a different picture of the country's investment climate.

Sunny Hill accused the NOC in mid-April of seizing its share of the Ain Tsila gas and condensate field in eastern Algeria, warning it will seek "well in excess" of $1bn in damages.

The company has a 38.25% interest in the Ain Tsila field through its Petroceltic subsidiary. But Sonatrach has terminated the contractual interest without offering compensation, Sunny Hill said on April 15.

"Sonatrach has acted in an aggressive and irrational manner. Their expropriation of our interest without compensation is the type of action expected in Hugo Chavez's Venezuela and not from a country like Algeria that proclaims to respect the rule of law," Sunny Hill chairman Angelo Moskov said. "This unwarranted action will be highly damaging to the attempts by Algeria to attract foreign investment into the country."

"It is too early to pass judgement on whether Sonatrach's decision to cancel its JV with Sunny Hill Energy will sour already-qualified investor appetite."

Anthony Skinner
DIRECTOR, MIDDLE EAST AND NORTH AFRICA, VERISK MAPLECROFT

In its own statement, Sonatrach confirmed on the same day that it had ended Sunny Hill's upstream contract, citing the company's failure to meet contractual obligations.

Sunny Hill entered Algeria after acquiring Petroceltic in 2015. A development plan for Ain Tsila approved in 2012 envisaged the launch of a gas processing plant in 2017, expected to produce 10mn m^3 of gas, 17,000 barrels of LPG and 11,500 barrels of condensate/day. Petrofac won a contract in 2019 to build the plant by the end of 2022.

"Sonatrach will continue the development efforts of this project with the objective of bringing this deposit into production in November 2022," the Algerian company said.

The NOC did not respond to a request by *NGW* to comment. But its head Toufik Hakker told Bloomberg in April that project delays were the reason for the contract's termination. "We cannot tolerate delays in projects," he told the news agency. "It is a strategic project for Algeria and Sonatrach."

Speaking to *NGW*, Sunny Hill confirmed that its Petroceltic subsidiary had closed all operations and was exiting Algeria. The company said it could not disclose a breakdown of its claim at this time, but would do so when it filed the dispute with the International Chamber of Commerce.

Sunny Hill has invested "hundreds of millions of dollars" in the Ain Tsila site over the year, it said. The company has drilled and tested appraisal wells, including horizontal ones to improve production rates and recovery. Petrofac's contract to build the plant was worth $1bn, awarded by Sunny Hill's joint venture with Sonatrach. The plant is now 50% complete, the company said.

"Sunny Hill disagrees with the Sonatrach statement and refutes it entirely," the company said. "Our company has never not complied with the PSC; however, any elaboration of this disagreement would not be proper at this time."

The COVID-19 pandemic "naturally created delays," the company noted, "but because of Sunny Hill's commitment to an adaptable organisation, we overcame travel and country access difficulties by investing in remote working capabilities and onsite excellence programmes that minimised the schedule delays by Petrofac."

Whether or not the case will tarnish Algeria's image in investors' eyes remains to be seen.

"It is too early to pass judgement on whether Sonatrach's decision to cancel its JV with Sunny Hill Energy will sour already-qualified investor appetite. There is at this point no evidence to suggest it will have a negative knock-on impact," Skinner says. "Sonatrach is adamant that its decision was 100% legal and appears to have come to the decision over delays which it blames on Sunny Hill Energy."

He added that the case was not dissimilar to the cancellation of French firm Medex Petroleum's contracts for the Bourarhat North and Erg Issouane fields in 2016. Sonatrach won the subsequent arbitration process.

As part of the new and expanded editorial coverage of *Gas in Transition*, a new section, **Focus On:**, will highlight top-tier developments in natural gas and its place in the energy transition. This month, we focus on **natural gas vehicles**.

Russian NGVs *gather pace*

THE MAIN HURDLE TO OVERCOME IS INFRASTRUCTURE CONSTRAINTS, BUT GAZPROM IS SPEARHEADING EFFORTS TO EXPAND THE NETWORK

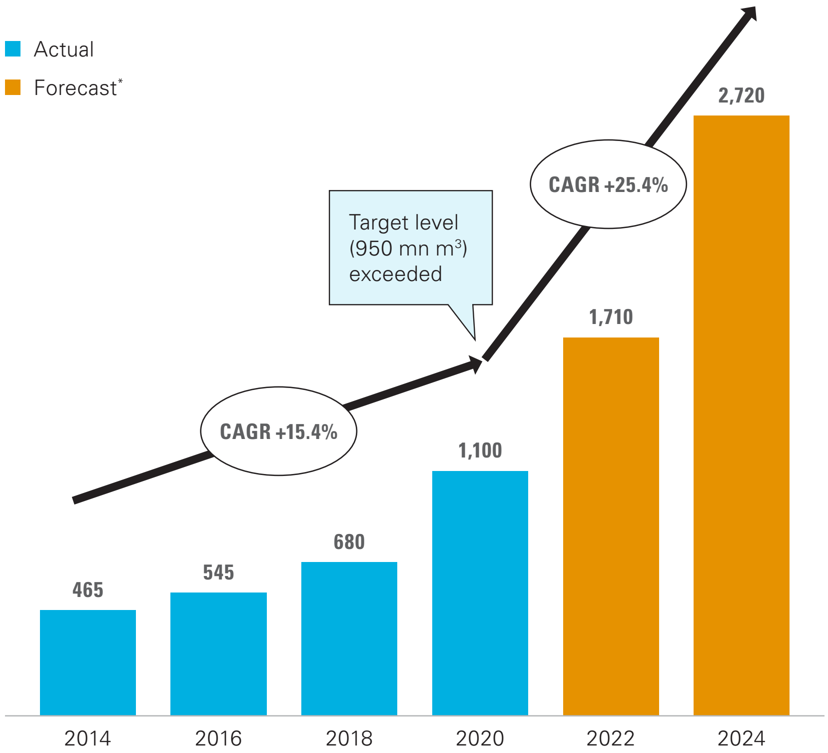
Joseph Murphy

THE RUSSIAN MARKET for natural gas as a vehicle fuel, while still considered a niche, is gaining momentum. Its growth is assisted by support from the government, which has both environmental and economic reasons for expanding the use of natural gas vehicles (NGV). The country's largest gas supplier Gazprom also has a vested interest in seeing the market grow.

Obstacles remain, namely a lack of compressed natural gas (CNG) and LNG filling stations, but the government and Gazprom are working to expand the network to make NGVs a more feasible option for transport.

FIGURE 1 Consumption of natural gas as a vehicle fuel in Russia, mn m^3

Source: Russian State Program for Energy Development , VYGON Consulting



*In accordance with the target indicators of the State Subprogram for NGV market development

Russia currently has around **530 CNG stations** in operation, located mostly in the country's European region and owned mostly by Gazprom.

Consumption of CNG and LNG in Russia's NGV fuel market has been rising steadily in recent years and the Covid-19 pandemic has not checked this growth. Demand grew by 10% to 1.1bn m^3 in 2020, Ivan Timonin, an analyst at Moscow-based Vygon Consulting, tells *NGW*, while consumption of gasoline and diesel declined by 5.6% and 6.7% respectively in the same year, owing to restrictions on movement put in place to stem the virus' spread.

"This trend will definitely continue in the coming years due to the economic efficiency of NGVs, the development of the filling station network and active government support," Timonin says. The targets set in Russia's energy strategy – consumption reaching 2.7bn m^3 by 2024 and 10-13bn m^3 by 2035 – are "quite achievable," he says.

INCENTIVES

Motorists have a clear incentive to switch to CNG given the low cost of the fuel. The average price of CNG in Moscow is currently around 20 rubles ($0.27)/$m^3$, while a litre of diesel, which has almost the same energy content, costs 49.5 rubles, and a litre of 92 RON gasoline sells for about 45.5 rubles, according to Vygon. Gazprom estimates that converting vehicles to natural gas can reduce fuel costs by up to 60%.

The government has also offered a range of subsidies to vehicle owners, infrastructure developers and automakers alike to support the sector's development. The state's interest in expanding NGV use is both economic and environmental, Timonin explains.

"Transportation costs are present in most supply chains and consequently, their reduction will increase the competitiveness of Russian manufacturers across almost all sectors of economic activity," the analyst tells *NGW*. "At the same time the exhaust gases of a methane-fuelled engine contain two-three times less carbon monoxide and two times less nitrogen oxide, which contributes to the achievement of national and global environmental goals."

In the case of passenger cars, for example, the government provides a subsidy that shaves 40% off the cost of converting them to run on CNG. Meanwhile Gazprom, by far the largest operator of CNG filling stations in Russia and eager to create extra demand for its gas, covers a further 30% of cost. This means that a motorist can make back what they spend on converting a gasoline-fuelled Lada Vesta, a popular Russian-made car, in just over 11 months, assuming 15,000 km of annual mileage, Vygon estimates.

The government's support is comprehensive, Timonin says. They also extend to the manufacturers of NGVs as well as the operators of LNG and CNG filling stations. The analysts estimates that subsidies offset 25-40% of the capital cost of constructing new filling stations.

"This amount is significant enough to make such projects economically attractive," he says.

INFRASTRUCTURE CONSTRAINTS

The main hurdle to overcome is infrastructure constraints, according to Vygon. There are currently only 530 CNG stations in Russia, owned mostly by Gazprom and largely situated in European Russia, as well as a handful of LNG facilities in the country. They are outnumbered by conventional filling stations by a ratio of 50 to 1.

"This is what stops the majority of potential consumers from switching to methane, which, in turn, limits the possible growth rate of the NGV market as a whole."

Gazprom is spearheading efforts to expand the network, however. Gazprom and its Gazprom Gazomotornoye Toplivo subsidiary already operate just under 330 CNG filling stations between them, according to the company's website. Gazomotornoye

The government has also offered a range of subsidies to vehicle owners, infrastructure developers and automakers alike to support the sector's development.

Gazprom CNG station in Moscow – the largest of its kind in Russia and Europe.

Source: Gazprom

Toplivo has 294, having added 130 over the past five years. But it wants to accelerate the pace of development, with plans to add 200 more in the next two years, the Moscow-based *Vedomosti* newspaper reported on April 22 citing sources. According to the newspaper, it is offering franchise deals to realise this ambition. Gazomotornoye Toplivo is finalising contracts with private investors for three facilities that will operate under its brand in the regions of Tatarstan and Krasnodar, Vedomosti said.

While Gazprom has dominated the market for CNG as a vehicle fuel, the franchise plan suggests it is aware that it cannot grow the sector on its own. Meanwhile, its rivals also want a slice of the market. Rosneft sells CNG at 14 of its filling stations mostly in central Russia and its CEO Igor Sechin said in August last year that the company wanted to add four more in the Moscow region, without disclosing a timeframe for their completion.

The government's strategy envisages an expansion in the CNG filling network to over 1,720 stations by the end of 2024.

HYDROGEN

NGVs are taking off in markets across the world, mostly in developing nations, which view them as both a means of addressing emissions in the difficult-to-decarbonise transport sector and a way of spurring economic growth. However, other nations are pursuing alternatives such as hydrogen fuel cell and electric cars.

Russia has its own ambitions in hydrogen production, but they are largely export-oriented. Some Russian automakers are investigating hydrogen fuel cell vehicles such as heavy vehicle manufacturer Kamaz, which said in April it was developing a hydrogen-fuelled bus prototype. But introducing models to the market is still some way away, and infrastructure would have to be built to support their use.

Prospects for hydrogen use in transport are "highly uncertain," Timonin notes.

"Hydrogen energy, including the transport segment, is noted in the Russian energy strategy to 2025 as one of the areas of interest, however specific targets have been set only in terms of hydrogen exports," he says. •

German LNG trucks showcase *natural gas strengths*

GAS IN THE TRANSPORT SECTOR WILL REMAIN A NICHE MARKET, BUT WITH HIGH PUBLIC VISIBILITY, LNG TRUCKS SERVE AS "AMBASSADORS FOR NATURAL GAS," TIMM KEHLER, CHAIRMAN OF GERMAN GAS INDUSTRY ASSOCIATION ZUKUNFT GAS, TELLS *NGW*

Karel Beckman

THE LNG MARKET in German road transport is booming. Last year, sales of LNG in heavy transport tripled in Germany, rising from 14,550 metric tons to almost 48,000 mt, saving 36,500 mt of CO_2 emissions, German gas industry association Zukunft Gas reported in March.

At the end of the year, there were 46 LNG filling stations in Germany. By March 2021, the number had already risen to 60 – and two dozen more have been announced.

That is not all. Under a government support program to promote "energy efficient and/or

"Natural gas – in particular in the form of LNG – has practically no rivals when it comes to alternative fuels in heavy transport."

Timm Kehler
CHAIRMAN, ZUKUNFT GAS

CO_2-poor commercial vehicles", 87% of over 5,000 applications were for LNG trucks and another 12% for CNG vehicles. Applications for electric trucks amounted to no more than 1%.

TRACTORS

The main driver of the German LNG transport market, explains Timm Kehler, chairman of Zukunft Gas, is government support. There are several ways in which the government supports switching from diesel to LNG: tax and road toll exemptions and direct funding in the form of a €12,000-18,000 ($14,600-21,900) subsidy for the purchase of an LNG truck.

The number of heavy-duty gas trucks, weighing over 12 mt, rose 31% last year. As of January 1 2021, there were 498 LNG vehicles (including LNG only and LNG-diesel models) in stock. A year earlier there were only 142.

Even tractors are increasingly using gas: 1,400 new gas-fuelled tractors were registered in 2020, a record.

As of January 1, 2021, the number of natural gas vehicles was 100,807, which is 2.2% higher than in the previous year. The number of gas vehicles increased for the third year in a row.

Although the current incentives will end by the end of 2023, and will probably be made more limited, Kehler does not think this will change the market trend: "Government support kickstarted the market, but it will not be left there. Natural gas – in particular in the form of LNG – has practically no rivals when it comes to alternative fuels in heavy transport. Electric trucks are not feasible and hydrogen trucks are far from market ready."

There are some experiments being conducted in Germany with trucks running on overhead lines, but Kehler does not believe this is likely to become a success. "The problem with overhead lines is that they make road transport inflexible."

MEDIA COVERAGE

Ironically, the truck manufacturers showing the strongest support for LNG trucking in Germany are Scania, Volvo and IVECO – all non-German companies. "The big German manufacturers tend to support diesel," says Kehler.

The amount of gas sold in the transport market is rather limited – some 2-3 TWh of 900 TWh (roughly 90bn m^3) of gas sold in Germany – and most of this is CNG. Nevertheless, Kehler believes the success of the LNG trucking market is important. "It gets a lot of media coverage. The LNG trucks are serving as ambassadors for natural gas."

This is useful, because there is ongoing debate in Germany about the role of natural gas in the energy system. The country is known for its ambitious climate policies. For Kehler, gas fits squarely into this climate space. "If we don't switch to gas, we will get stuck in the status quo. Which means with diesel, coal, nuclear power, oil heating. Last year we had record sales of gas boilers as consumers switched from oil to gas. We also have a coal phaseout policy which will mean we need to rely more on gas. We as an industry need to be vocal about this."

GREEN GAS

To maintain the position of gas in the German energy market, the development of biomethane and bio-LNG is of crucial importance, says Kehler. Freight traffic is good for 24% of traffic emissions in Germany.

"We see a strong move towards green gas in transport. Some 60% to 70% of CNG currently sold is bio-CNG."

Germany has 812 CNG filling stations, of which 435 offer CNG with biogas content and of which 417 are 100% bio-CNG stations. More than 50% of all petrol stations in Germany sell biogas.

Zukunft Gas is also promoting the use of bio-LNG in addition to LNG. "I expect to see similar growth in bio-LNG as in bio-CNG," says Kehler. Shell, which has just started operating four new LNG service stations in Germany along important traffic routes and has 12 LNG stations in all, is building a biomethane production facility near Cologne that will become operational in 2023.

Shell is building a complete delivery chain infrastructure for bio-LNG with a capacity of 1mn mt/yr. "This is an important part of our mission to become a net zero company and make a contribution to the Energiewende," the company has stated. Until production starts in Germany, Shell will source its bio-LNG from the Dutch company Rolande.

Overall Kehler is optimistic about the public perception of gas. Nord Stream 2 has led to "intensified public debate" over the role of gas, he says. Policymakers in Berlin, he notes, "have become even more aware that we need gas."

He notes that at a German-Russian conference taking place in late April, the German minister of economic affairs stressed that "Germany needs more gas, and needs Nord Stream 2."

To ensure that gas can play a significant role in the transport sector, regulators, both at national and EU level, should acknowledge its benefits, Kehler says. For example, "it is important that the upcoming revision of CO_2 standards for cars in the EU will be based on well-to-wheel calculations rather than just tailpipe emissions, as is currently the case. But I am optimistic about this."

Kehler is also satisfied that in the new EU Taxonomy for Sustainable Activities, biomethane is recognised as climate-friendly. "That will help direct investment towards biomethane activities." •

There were
60
LNG filling stations in operation in Germany at the end of March.

Environmental gains

According to Zukunft Gas, LNG offers a high emission avoidance potential. In terms of NOX emissions in particular, savings of up to 85% can be achieved even compared to modern Euro VI diesel trucks. Fine particulate matter emissions almost completely avoided. Noise emissions are around 50% lower. And there are CO_2 savings of up to 15%.

However, Brussels-based think tank Transport & Environment (T&E) disagrees with these assessments. In a report published in 2019, *Do Gas Trucks Reduce Emissions*, T&E concluded on the basis of on-road tests carried out by Dutch research institute TNO that LNG trucks emit more NOx and more particulate emissions than diesel trucks. It also argued that well-to-wheel greenhouse gas emissions (methane included) from LNG trucks are only marginally lower than from diesel trucks, and in fact even higher when compared to the most advanced diesel engines.

According to Fedor Unterlohner, freight & investment officer at T&E, the debate on the alleged environmental and climate benefits of gas in transport continues to this day. "We stand by our findings, which are based on research from TNO funded by the Dutch government."

Unterlohner says the German gas industry is promoting natural gas in transport with the promise that it will pave the way towards large-scale use of biomethane and bio-LNG, which has much more credible climate benefits. However, "we find this narrative misleading, because the amount of bio-based gas available is very limited and it's very expensive. We favour electric trucks and fuel-cell (hydrogen) trucks as alternatives."

Indian NGVs *enjoy tailwinds*

THE RISING COST OF CONVENTIONAL FUELS HAS BEEN ADVANTAGEOUS FOR THE NGV SECTOR

Shardul Sharma

INDIAN GASOLINE AND DIESEL prices have been trending higher in recent months due to rising global oil prices. High taxes have also been a factor pushing the prices up. The increase in prices is due to a higher excise duty, which rose by around 65% to roughly $0.45/litre in 2020, and value-added tax. Tax now accounts for over 60% of gasoline's retail selling price, compared with 47% in 2019, according to a study by Crisil Research published earlier this year.

These high prices are a boon for natural gas vehicles (NGVs), however, the difference between retail gasoline and compressed natural gas (CNG) prices is expected to remain wide because of higher taxes on the former, Crisil stated.

The competitiveness of CNG is evident in consumption volumes, which have seen a compound annual growth rate of about 11% over the past three years, according to the report. About 180,000 CNG-fuelled cars and passenger vehicles were sold in the fiscal year ending March 31, 2020, compared with 140,000 in the 2014-2015 fiscal year.

According to Crisil, CNG-fuelled vehicles account for about 5% of the passenger vehicles sold in the country each year. With the recent implementation of Bharat Stage 6 (BS6) emissions standards, the price of diesel vehicles has risen sharply, pushing most commercial players, such as radio-taxi companies, towards CNG.

SALES SURGE

India's biggest automaker, Maruti Suzuki India, sold over 157,000 factory-fitted CNG vehicles in the 2020-2021 fiscal year, up from 106,444 in 2019-2020. This is the highest-ever CNG car sales by the company. Maruti Suzuki offers a wide range of factory-fitted CNG cars including models such as Alto, Celerio, Wagon-R, S-PRESSO, Eeco, Ertiga, Tour S and Super Carry.

Shashank Srivastava, executive director at Maruti Suzuki India, said in April that CNG was becoming one of the most preferred alternative fuels due to its low economic cost versus gasoline and diesel and improving CNG filling infrastructure.

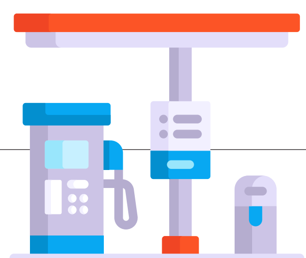
"With the government's clear focus on expansion of CNG outlets in the country, we are confident of greater acceptance of factory-fitted CNG vehicles," he said.

This focus is part of a broader effort by India's government to expand the share of natural gas in the country's primary energy mix from 6.2% at present to 15% by 2030. Despite a complete lockdown in the initial months of the 2020-2021 fiscal, more than 700 CNG stations were added during the entire year, a growth of more than 50%, Maruti Suzuki said.

"This rate of network expansion will aid the demand for CNG vehicles. At present, there are more than 2,800 CNG stations across the country, and this is likely to cross 10,000 over the next 7-8 years," the company said.

"At present, there are more than 2,800 CNG stations across the country, and this is likely to cross 10,000 over the next 7-8 years."

Maruti Suzuki



CNG-fuelled vehicles account for about

5%

of the passenger vehicles sold in the country each year

BRINGING HYDROGEN INTO THE MIX

Indian government has recently focused more on promoting the use of hydrogen-blended CNG. Indian petroleum and natural gas minister Dharmendra Pradhan inaugurated a hydrogen-CNG (HCNG) plant operated by state-run Indian Oil in Delhi in October last year, and launched a trial run of HCNG-fuelled buses. Indian Oil will run 50 HCNG buses during the pilot phase.

An existing internal combustion engine can be run on HCNG without significant modification and with a minimal upgrade to existing CNG infrastructure, according to Indian Oil. The blended fuel offers a 70% reduction of carbon monoxide and a 25% reduction in hydrocarbon emissions compared with standard CNG.

The Indian government permitted the use of HCNG as an automobile fuel in September 2020. The ministry of road transport and highways has allowed a CNG mix of up to 18% hydrogen to be used in engines. The Bureau of Indian Standards has also set specifications for HCNG for automotive purposes.

Pradhan said at a recent webinar that the government was now looking to kick start similar pilot projects in other cities as well. He said that hydrogen had huge potential as an emerging clean fuel and that by establishing synergies with natural gas, it could be easily adopted in the energy mix without incurring additional infrastructure costs. He said that HCNG could be used in the automotive sector as well as for domestic cooking applications.

GROWING GAS SUPPLY

India's domestic gas output has been on a downward trend for more than half a decade now, which has led to heavy dependence on costly imported LNG. There has been some good news on this front, however. Reliance Industries and its partner BP started production from the Satellite Cluster gas field in block KG D6 off the east coast of India in late-April. The Satellite Cluster is the second of the three developments due to come onstream, following the start-up of R Cluster in December last year.

RIL and BP are developing three deepwater gas projects at KG D6 – R Cluster, Satellites Cluster and MJ – which together are expected to meet about 15% of India's gas demand by 2023. These projects will utilise the existing hub infrastructure at the KG D6 block. Reliance is the operator with a 66.67% participating interest and BP holds a 33.33% participating interest. The third KG D6 development, MJ, is expected to start production towards the latter half of 2022.

Not only Reliance but state-owned ONGC is also expected to start producing gas from its fields in the KG basin soon. According to Mumbai-based brokerage HDFC Securities, the launch of projects by both Reliance and ONGC will lead to a 52% surge in India's gas output to 122mn m^3/day by 2024.

Natural gas production in the 2019-2020 fiscal year was 85mn m^3/d, and it is estimated to have fallen to 80mn m^3/day in the following year, HDFC Securities said in a report published on April 22. Output is projected to rise in the 2021-2022 fiscal to 93mn m^3/d, however, and up to 107mn m^3/d in 2022-2023 and 122mn m^3/d in 2023-2024, the brokerage said.

Higher availability of cheap domestic gas augers well for the city gas companies who market CNG. "This increasing gas supply from domestic sources should drive earnings growth and valuations for the Indian gas utilities, especially the gas transmission companies," HDFC said. •

Technology: *Dual-fuel LNG truck engines*

LNG TRUCK ENGINES ARE INTRINSICALLY CLEANER THAN DIESEL, OFFERING SUBSTANTIAL CO_2 AND NOx EMISSIONS REDUCTIONS AND A NEAR ELIMINATION OF PARTICULATE MATTER. A FOCUS ON METHANE SLIP WILL IMPROVE THEIR ENVIRONMENTAL FOOTPRINT FURTHER, AND WITH THE EMERGENCE OF BIO-LNG, THEY OFFER A QUICK, FUTURE-PROOFED PATHWAY TO LOW CARBON, LONG-DISTANCE HEAVY GOODS TRANSPORT

Ross McCracken

LNG for trucks delivers up to
1,600 km
range potential.

LONG-DISTANCE ROAD HAULAGE faces significant challenges when it comes to batteries. The key problem is the size and weight of the batteries required to deliver sufficient range. The large size leaves insufficient space and capacity for cargo haulage to be profitable, while recharging infrastructure remains limited.

In contrast, the low cryogenic temperature at which LNG is stored means it has sufficient energy density to deliver long driving ranges – up to 1,600 km.

Compressed natural gas (CNG) appears the best option for passenger autos running on gas, and is generally favoured for city distribution trucks, refuse collection and for urban and suburban buses (where electrification is also an option), but when it comes to regional and international transport, LNG is a mass-scale, alternative fuel deployable today.

Europe saw a 60% jump in the number of LNG refuelling stations in 2020 from 250 to 400. This reflects the growing number of natural gas-fuelled vehicles, particularly CNG and LNG-fuelled trucks; 6,802 new gas-powered truck registrations were made last year, according to industry association NGVA Europe.

LNG ENGINES – INTRINSICALLY CLEANER

LNG engines are internal combustion engines (ICEs) based on existing designs for diesel and gasoline engines.

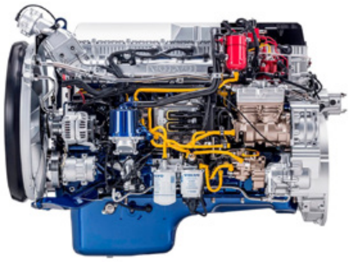
Diesel ICEs produce particulate matter (PM), a major contributor to local air pollution. This is the result of diffusion combustion, where the oxidizer and the fuel are separated before being burnt, which tends to lead to incomplete combustion and the production of soot.

Diesel ICEs also produce NOx because they are lean burn – i.e. the diesel is burnt with an excess amount of air and, as nitrogen is the main component of air, NOx production tends to be higher than for a rich burn engine.

Both NOx and PM are treated post-combustion in the exhaust system, but because this after-treatment is imperfect, there is usually a trade-off between the level of NOx and PM emitted into the environment.

LNG, even if injected as a liquid, vaporises quickly and mixes with air to provide much more complete combustion. PM emissions are negligible. This has an important knock-on effect because, as there is no trade-off between PM and NOx, the combustion and after-treatment processes can be optimised to reduce NOx emissions.

Carbon emissions are also lower for the simple reason that LNG contains less carbon than diesel. CH_4 (methane/natural gas) has a carbon to hydrogen ratio of 1:4, whereas diesel has a carbon to hydrogen ratio of about 1:1.75, although this varies depending on the season and in different markets and between suppliers.



Methane slip is an area which has improved significantly since the first LNG engines came on to the market and some older GHG emissions studies for road transport do not reflect the performance of modern engine designs.

Being relatively new to the market, dual-fuel LNG truck engines can benefit significantly from the application of advances in diesel engine technology.

PILOT FUEL

LNG is difficult to use alone in a compression ignition engine because it has a low cetane value. The cetane value represents ignition delay, or the time between the start of injection and the increase in pressure in the engine cylinder.

This is why a small amount of pilot fuel – diesel – is used to create first phase combustion in a compression ignition LNG engine, which provides a rapid build-up of pressure, sufficient to allow second phase ignition of the LNG/air mix.

While LNG has a low cetane value, it has a high octane value, which reduces pre-ignition or 'knocking'. Pre-ignition usually results in incomplete combustion and therefore PM emissions. As a result, the only PM emissions from dual fuel compression ignition LNG engines result from the small amount of pilot fuel used.

Diesel compression ignition engines have gone through multiple stages of innovation and development to improve efficiency and reduce emissions, the two most important developments being turbocharging and the shift from single injection points to multiple injection points. Although LNG use presents new challenges, both innovations can be applied to LNG compression ignition dual fuel engines, promising increased efficiency and lower emissions in the future.

REDUCING METHANE SLIP

According to LNG truck manufacturers, such as Sweden's Scania, CO_2 emissions reductions from LNG engines can reach up to 20%, compared with diesel engines, operating in optimal conditions. But studies, for example the Sustainable Gas Institute's *Can Natural Gas reduce emissions from transport?* show that real-life GHG reductions are lower, depending on the specific engine type, mode of operation and level of methane slip.

Methane slip is an area which has improved significantly since the first LNG engines came on to the market and some older GHG emissions studies for road transport do not reflect the performance of modern engine designs. Methane slip, like diesel's PM emissions, is the product of incomplete combustion, leading to some methane escaping through the exhaust system.

Methane is a considerably more potent GHG than CO_2, particularly if its effect is measured over a 20-year as oppose to 100-year period.

Marine engine manufacturer and developer Wärtsilä notes that it has cut methane slip from its dual fuel engines by 85% since 1993. It says there are a range of ways in which methane slip can be further reduced, mainly by focusing on engine designs which result in faster and more complete combustion. Wärtsilä believes its next combustion concept will reduce methane slip by more than 50% to around 1 gram per kWh. The first LNG engines had methane slip of about 16 g/kWh.

BIO-PATHWAY

However, LNG engines' GHG reductions see a step change when combined with biomethane liquefied to form bio-LNG, also known as liquid biomethane. This can be used in the same engines and with the same infrastructure without new modifications.

Using 100% bio-LNG can result in CO_2 emission reductions of up to 90%, compared with diesel, according to Scania, but a more likely prospect is for the share of bio-LNG in road transport fuel to rise gradually, to allow sufficient time for an expansion in biomethane production. For dual fuel engines, there are also options for replacing the pilot diesel fuel, for example with hydrogenated vegetable oil or biodiesel (Fatty Acid Methyl Ester).

NGVA Europe says that more than 25% of gas refuelling stations in Europe are already providing biomethane and that its use amounts to 17% of all gas used as transport fuel in the region. As the number of CNG and LNG vehicles rises, it may prove difficult to sustain or increase this percentage even if the absolute volume of biomethane rises. Nonetheless, NGVA Europe forecasts that by the end of the decade, there will be about 10,000 CNG and 2,000 LNG stations in Europe, and that the proportion of biomethane will have risen to an average 40%. •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LNG *Condensed*

Ross McCracken

The gas-for-coal conundrum

THERE IS AN EXPECTATION THAT THE US WILL JUMP STRAIGHT FROM COAL TO RENEWABLES OVER THE NEXT DECADE, BUT THIS IGNORES THE CRITICAL ROLE CHEAP NATURAL GAS HAS PLAYED IN MANAGING US COAL DECLINE

There is little question that countries long dependent on coal for a large proportion of their electricity generation face a greater challenge than others in meeting climate change targets. This is true for both developed and developing nations and usually reflects the use of domestic rather than imported coal as a historically cheap and readily available energy source.

Domestic coal industries often support whole communities, who face a huge readjustment as their local economies lose the mainstay of their existence. As such, it should be no surprise that there is resistance to change. Governments need to find funds to offer coal mining communities a positive role in the energy transition, one which promises re-training and new high quality employment.

MANAGING COAL'S DECLINE

In the US, coal production and consumption has dropped dramatically in recent years. From just over 1bn short tons (st) in 2014, US coal production fell to 706mn st in 2019. Consumption dropped from 918mn st to just 586mn st, led largely by reductions in the electricity sector, where coal use fell from 851mn st to 539mn st.

However, this was the result of economic factors just as much as policy designed to reduce greenhouse gas emissions (GHG) – the low price of US natural gas, a result of the shale boom, and a combination of federal support for renewable energy via tax credits, state level incentives and the downward cost trajectory of wind and solar power.

Gas, onshore wind and solar emerged as economic competitors at a time when the US coal fleet was old, leading to a wave of coal plant retirements, despite the interregnum in climate policy leadership represented by the Trump administration. The retirements reached a peak in 2019 of about 14 GW, followed by a further 9 GW last year and a forecast 8 GW over 2021 and 2022 combined.

COAL TO RENEWABLES JUMP

According to environmental organisation the Institute for Energy Economics and Financial Analysis (IEEFA), the number of US planned coal retirements in the period to 2030 has doubled in the past year from 37.4 GW to at least 75.5 GW.

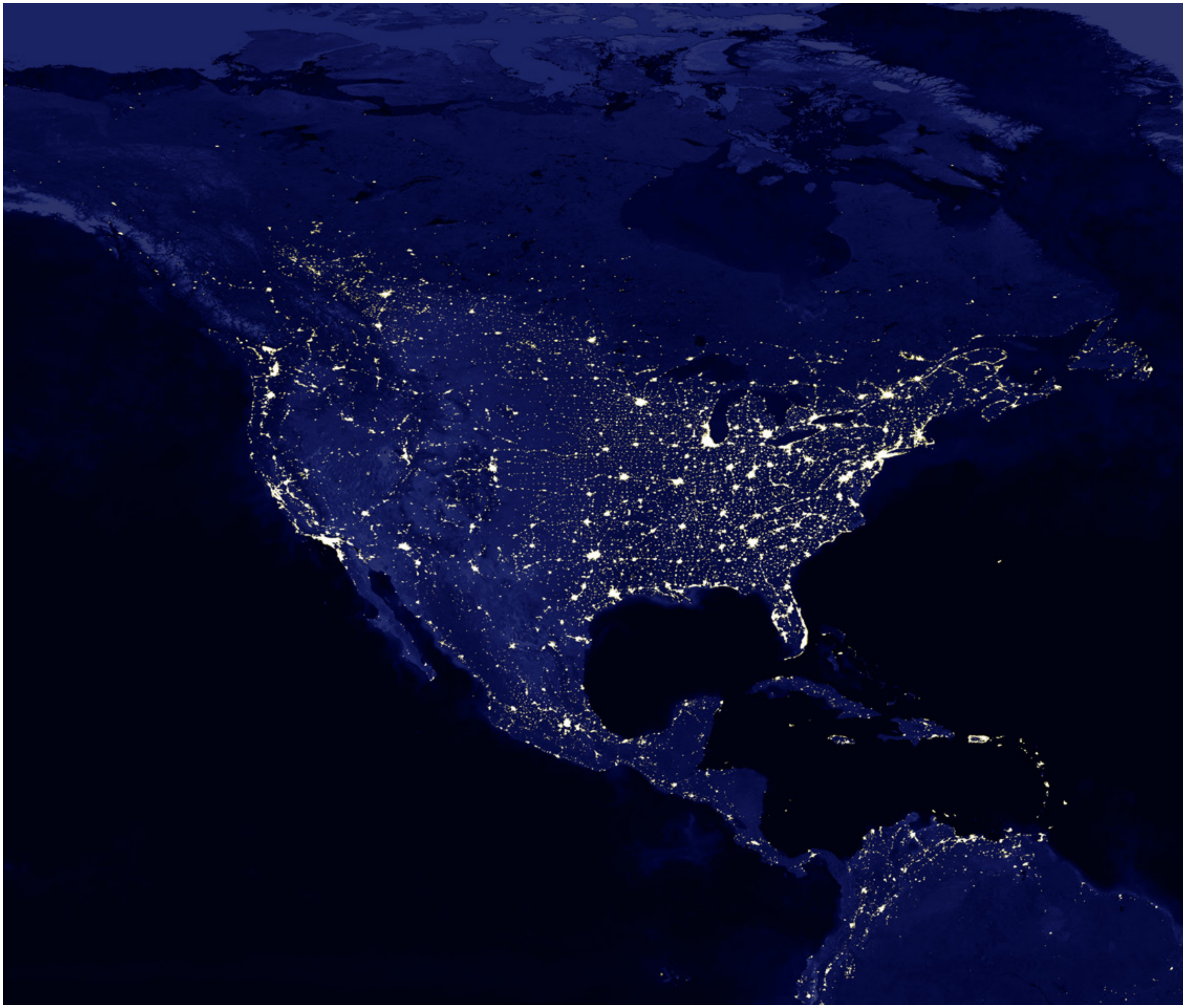
IEEFA attributes this to the wave of new renewable capacity that came online in 2020, and further large construction commitments over the next decade. It records 14 GW of utility-scale solar, 16.9 GW of wind and 1 GW of battery storage being connected to US grids in 2020. And this is before the country has embarked on meeting the Biden administration's target for 30 GW of offshore wind by 2030.

By 2030, IEEFA calculates that 175 GW of US coal-fired generation will have closed, representing 55% of the capacity that existed at its peak in 2011.

This year EIA data shows new wind and solar capacity additions making up an incredible 70% of all new capacity with another 11% coming from batteries. Natural gas' share of new capacity is just 16%. IEEFA sees this as a direct jump from coal to renewables.

However, this understates the amount of new US gas-fired plants built in recent years, which has allowed gas-to-coal switching and reduced GHGs as a result. Cheap gas availability and gas-fired generation, which hit a record 1,701 TWh in 2019, 70% higher than in 2011, has been critical in managing coal-fired generation's decline.

The data speaks for itself: between 2011 and 2019, US gas-fired electricity generation increased by 611 TWh, while coal-fired generation fell by 833 TWh. Renewable energy generation rose by 288 TWh.



COAL IN ASIA

The problem is much bigger in China and India, both of which use more coal than the US, China vastly so as it accounts for about two-thirds of global coal consumption. All of the world's largest three coal users have large domestic coal industries in common, but key differences between the US on the one hand and India and China in the other is the young age of the latter countries' coal fleets, a lack of domestic gas and higher rates of electricity demand growth.

Neither India nor China so far use huge amounts of gas in power generation. Instead, gas is used primarily for city gas consumption and industrial use. As the marginal unit of gas is imported LNG, gas for power generation is a relatively expensive option in both countries. And, as they both have young coal fleets, resistance to closures will be strong as companies seek to protect operational assets.

Just as in the US, higher gas use for a period is necessary to support coal's decline while renewable energy capacity grows sufficiently large to meet the targets of the Paris Agreement on Climate Change. In all three of the big coal consuming countries, carbon pricing and clear coal phase out policies, as in the EU, would help tilt the playing field in LNG's favour by providing more of an economic incentive to use the cleaner burning fuel. The alternative is that the majority of India and China's coal plants could remain operational for decades. •

Coal's staying power *in Asia*

THERE IS A WIDESPREAD EXPECTATION THAT GLOBAL COAL USE IS SET FOR INEXORABLE DECLINE. BUT THE TIMING AND EXTENT OF COAL'S REPLACEMENT WILL VARY GREATLY BY REGION, AS WILL THE DEGREE TO WHICH GAS WILL BENEFIT

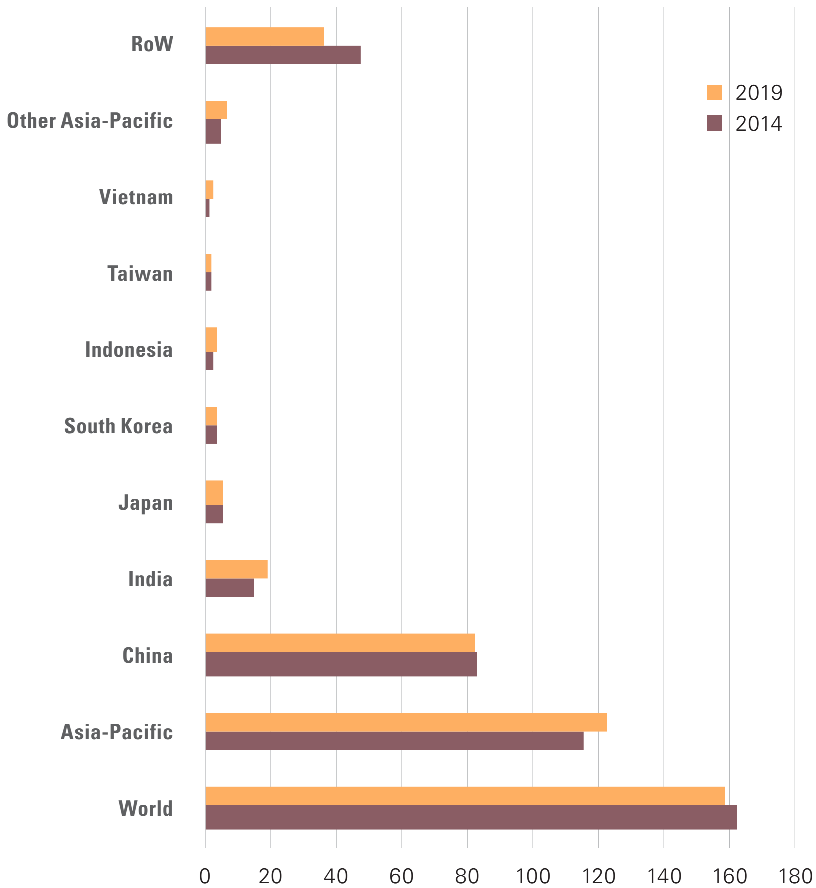
Martin Daniel

TRENDS IN THE second half of the 2010s did appear to support the expectation that global coal demand was set for an inexorable decline. Demand peaked in 2014 and declined thereafter, according to the *BP Statistical Review of World Energy 2020*.

The decline accelerated sharply in 2020 as a result of the COVID-19 pandemic. According to the International Energy Agency's (IEA) Global Energy Review 2021, coal demand fell last year by 220 million metric tons of coal equivalent, or almost 4% year on year.

The IEA noted that the electricity sector accounted for more than 40% of "the biggest drop since World War II" in the use of the fuel. Coal-fired electrical output fell by 440 TWh, or 4.4% year on year in 2020. The IEA observed that coal had been "squeezed in the power mix by lower electricity demand, increasing output from renewables, and low gas prices."

FIGURE 1 | Global coal consumption (EJ) | *Source: BP Statistical Review of World Energy 2020*



Much of the decline occurred in the US and EU, with the IEA noting that power station coal use fell by 20% in the former and 21% in the latter. The decline in Asia was less pronounced.

ASIA'S DIFFERENT PATH

This regional difference had already become apparent in the second half of the 2010s. While coal use fell globally between 2014 and 2019, the *BP Statistical Review* noted that it grew by more than 6% in Asia-Pacific (*Figure 1*). And it grew faster still in some countries within the region. For instance, in Vietnam, coal demand almost tripled between 2014 and 2019.

Much of the growth occurred in the Asian electricity sector, which is growing at a faster rate than the global average and is more dependent on coal. Asia's share of world power generation (*Figure 2*) rose from 37% in 2009 to 47% in 2019, while in the latter year coal accounted for 58.1% of total generation in Asia-Pacific compared to only 36.4% in the world as a whole.

These regional differences are expected to become even more pronounced this year. The IEA projects that global economy activity, energy consumption and electricity demand will grow in 2021 by 6.0%, 4.6% and 4.5%, respectively. It added that global coal demand will grow by 4.5%, with more than 80% of the growth occurring in Asia and more than 75% in the coal-fired generation sector, where global output is projected to rise year on year by 480 TWh.

The IEA projected that China alone will account for more than half the growth in world coal demand in 2021. This is despite the country's massive investment in renewables. China is forecast to generate over 900 TWh from solar and wind capacity in 2021, meaning coal will account for only 45% of the projected 8% increase in electricity output.

The IEA also projected that coal demand will grow outside Asia in 2021 as a result of rebounding economic activity. But it forecast that the fuel will claw back only a quarter of the sales it lost in advanced economies in 2020, with coal's recovery "curtailed by renewables deployment, lower gas prices and phase-out policies."

PRECONDITIONS FOR COAL'S REPLACEMENT

It does seem likely that coal will experience severe decline in most advanced economies, being replaced predominantly by renewables and gas. Relatively low GDP growth and a shift to less energy-intensive economic activity will both suppress energy demand growth and result in more energy being supplied as electricity.

The replacement of coal by gas will also be facilitated by the fact that many of these economies have large amounts of gas-fired capacity, well-developed gas infrastructure, various gas supply options, and market-based gas pricing policies. In addition, many of them plan to implement smart grids and emissions reduction policies. This applies equally to advanced economies in Asia, such as Japan and South Korea.

However, the position in most of Asia is very different. Strong growth in energy and electricity demand is expected, based on robust growth in often energy-intensive sectors of the economy. Gas-fired generating capacity is often limited. So too is the development of gas delivery infrastructure and regulatory structures, and the availability of diversified and competitive gas supplies. At the same time, in many developing Asian countries the potential for deploying renewables or nuclear power is limited by geographic, technical or financial factors.

However much their governments and populations may want to reduce emissions and other environmental problems, the replacement of coal could thus prove problematic.

FIGURE 2 Global electricity generation (TWH)

Source: BP Statistical Review of World Energy 2020

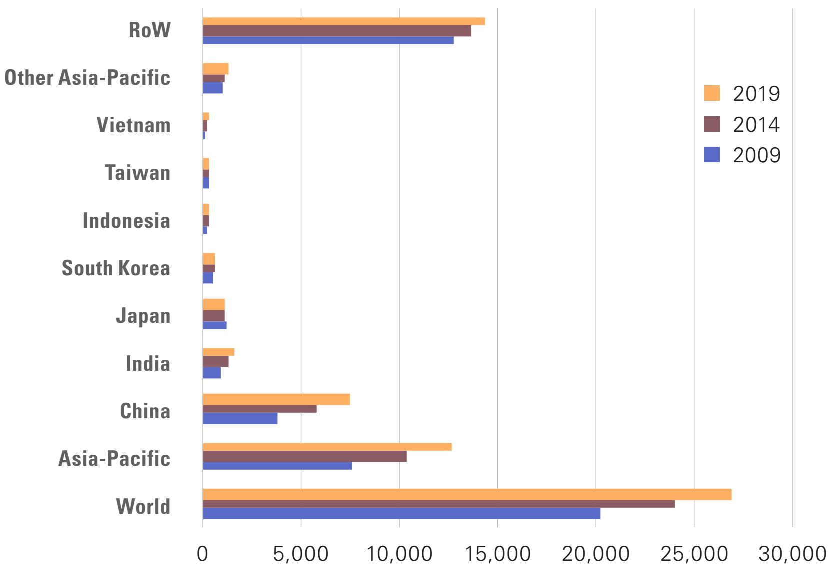
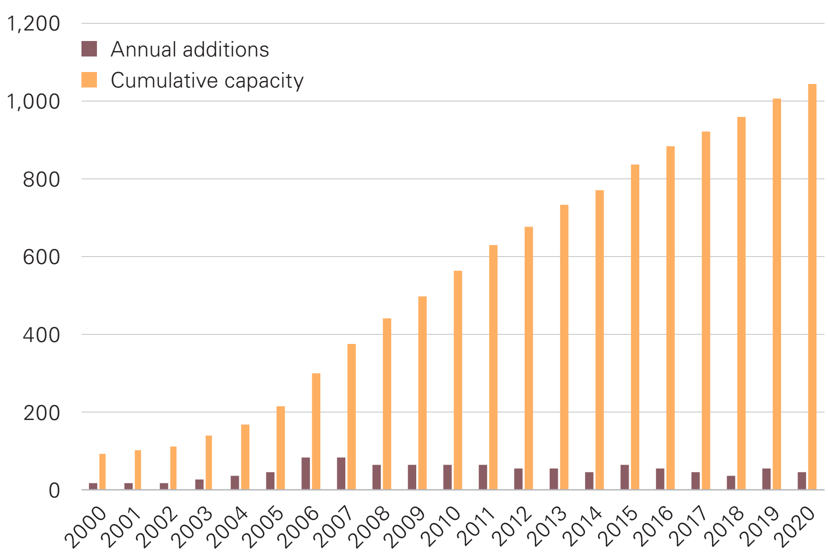


FIGURE 3 Newly operating coal plants in China by year (GW)

Source: Global Energy Monitor



In some cases, this reflects the fact that coal has been the dominant source of power generation for decades, with few signs that change is in the offing. China is the most obvious example, with a strong lobby arguing that continued large-scale coal use is necessary to maintain a reasonable level of energy self-sufficiency. Consumption reached more than 4bn mt in 2020, according to China's National Bureau of Statistics, while the country's National Coal Association has said demand could reach 4.2bn mt in 2025.

AN OLD FUEL IN NEW PLANTS

A large percentage of Chinese coal is used for power generation, with most being burnt in relatively new plants that could have up to five decades of remaining life. According to Global Energy Monitor's (GEM) global coal plant tracker, China had 1,043 GW of operating capacity in 2020, of which 505 GW was installed between 2010 and 2019.

Nor has the installation of new coal-fired plant ended, despite this being regarded as one of the main measures needed if Beijing is to achieve its policy of reversing emissions growth before 2030 and achieving carbon neutrality by 2060. Over 38 GW of coal-fired plant was commissioned in 2020, according to GEM (*Figure 3*), while another 73 GW was reported to have entered the project development process.

The rapid replacement of coal will be problematic not only for longstanding coal generators such as China and India, but also for countries where its use is more recent. This is especially the case in those countries in Southeast and South Asia where the shift to coal was driven in part by the desire to reduce gas use in power generation.

The shift was pursued for various reasons. For instance, in Malaysia and Thailand, investment in coal-fired plants was intended to mitigate concerns over security of supply and excessive dependence on gas-fired generation. In Vietnam, it was largely down to the lack of sufficient additional indigenous gas to meet the rapid projected growth in electricity demand. This was also a factor in Indonesia, where the use of low-cost indigenous coal for power generation was in part intended to allow the sale of gas production to higher-value markets, including gas exports.

KEY OPPORTUNITIES FOR GAS

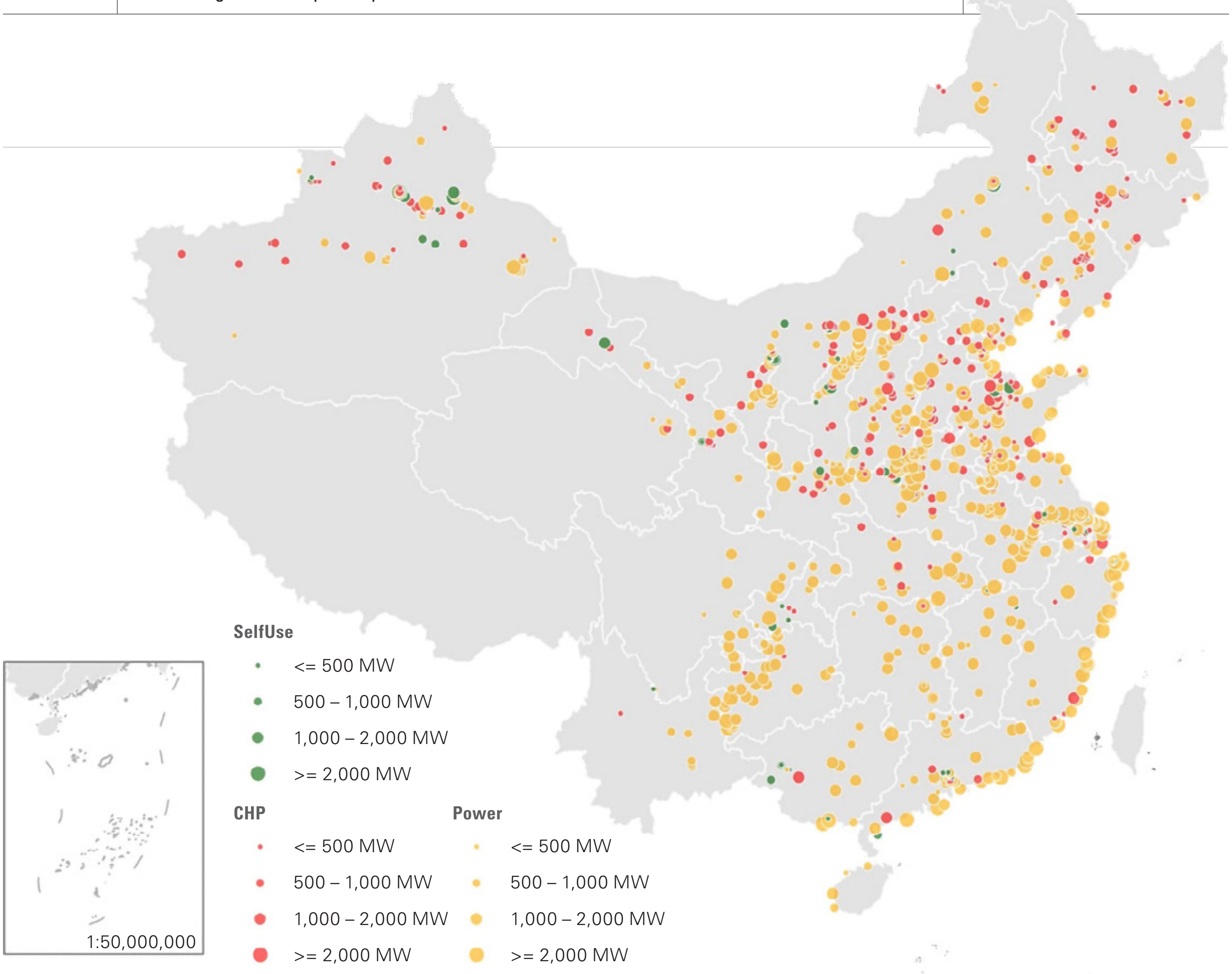
These factors mean a rapid shift from coal to gas in much of the Asian power generation sector is unlikely. But that is far from saying that Asian gas demand growth will be muted.

The IEA has projected that global gas demand will increase by 3.2% in 2021, driven by increasing consumption in Asia, the Middle East and Russia. However, it added that "nearly three-quarters of the global demand growth in 2021 is from the industry and buildings sectors, while electricity generation from natural gas remains below 2019 levels."

This is the case in China, where the burgeoning city gas market offers not only considerable opportunities, but better returns than the power sector. Much of the growth in Chinese gas use in the second

FIGURE 4 Existing coal fired power plants in China

Source: Carbon Brief, Cui et al (2021)



Did you know?

Chinese coal consumption topped 4bn mt in 2020, and the IEA predicts that the country will account for half of global coal demand growth this year.

half of the 2010s came from the conversion of coal-fired heating systems in northern cities, with more conversion projects planned in the commercial and industrial as well as residential sectors. By contrast, the relative cost and availability of coal and gas means gas-fired generation is not currently competitive in much of China, with a large part of the country's 97 GW of gas-fired capacity only operating at peak times, if then.

That is not to say that China and other countries in a similar position offer no scope for competitive gas-fired generation. For instance, gas-fired generating plants at coastal sites can play a key role in kick-starting the rollout of city gas networks and acting as the anchor customers for LNG import terminals. Moreover, gas-fired generation could surge if carbon pricing or other measures to reverse its competitive disadvantage are introduced.

But even then, the replacement of more than a small part of Asia's coal-fired generating fleet in the near to medium term is unrealistic, not least in terms of gas availability

It is certain Asia will see substantial growth in gas-fired and renewable output, with constraints to their inroads being reduced where accompanied by investment in smart grids and electricity storage capacity. But the sheer scale of coal's contribution to Asia's electricity requirements – 72% of operational coal-fired capacity is in Asia as is 93.5% of the coal-fired capacity under construction – means coal will be central to the region's power generation for decades to come. •

World Bank leaves LNG *out in the cold*

THE WORLD BANK'S DECISION TO PICK WINNERS – AMMONIA AND HYDROGEN – RISKS LEAVING OTHER SOLUTIONS FOR DECARBONISING MARINE TRANSPORT OUT IN THE COLD

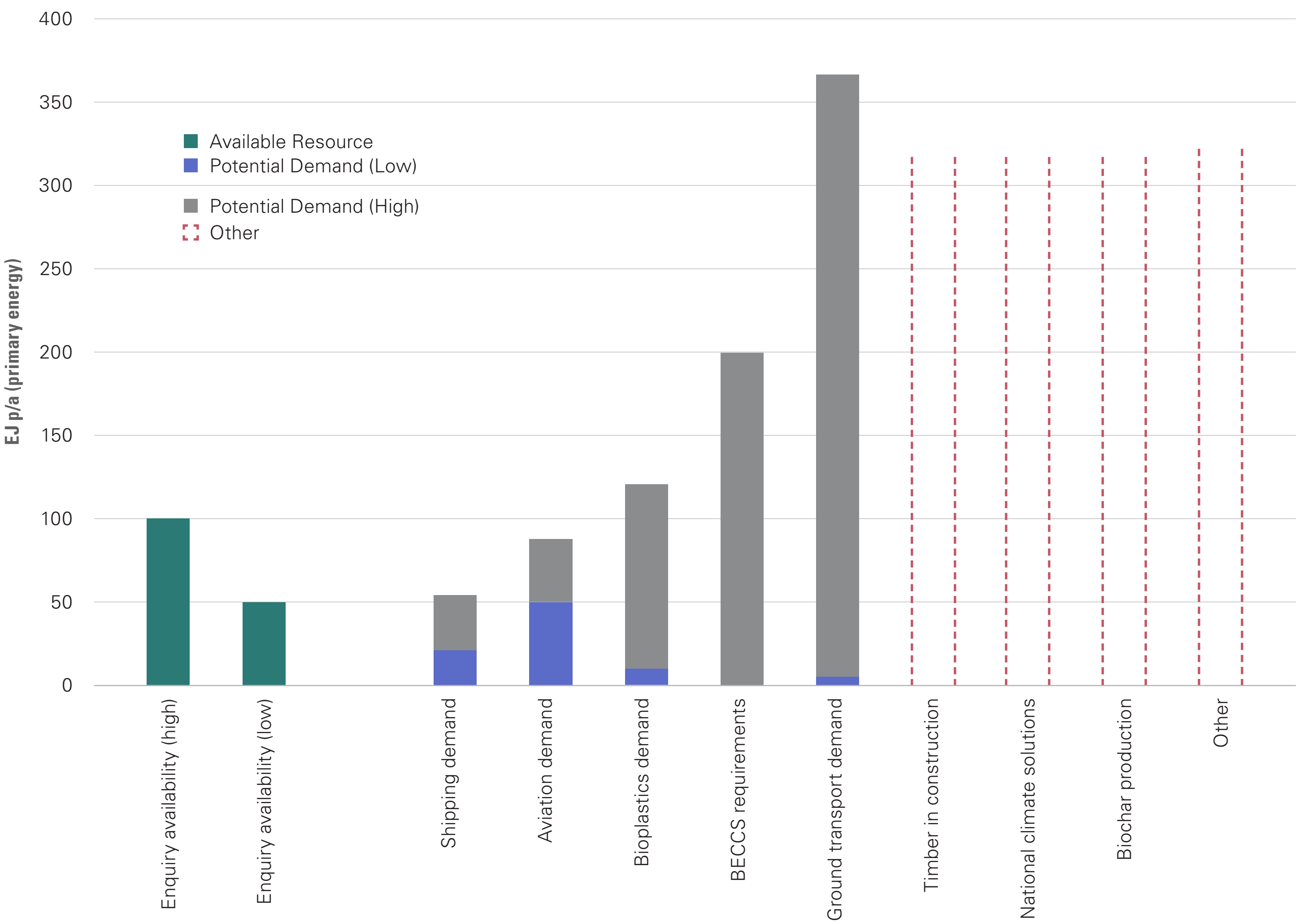
Ross McCracken

APRIL SAW A potentially devastating intervention by the World Bank into the debate surrounding the role of LNG in the decarbonisation of shipping. It came at the almost the same time as the publication of the *2nd Life Cycle GHG Emission Study on the Use of LNG as Marine Fuel*, a study conducted by consultants Sphera (formerly Thinkstep) and conducted on behalf of industry bodies SEA-LNG and SGMF (the Society for Gas as a Marine Fuel).

In its report, The Role of LNG in the Transition Toward Low and Zero-Carbon Shipping, the World Bank argues that LNG should play only a limited role in shipping decarbonisation, and will not be either a significant 'temporary' fuel nor a 'transitionary' fuel.

FIGURE 1 Projected availability of sustainable bio-fuel by 2050

Source: World Bank, The Role of LNG in the Transition Toward Low- and Zero-Carbon Shipping



This runs directly counter to LNG industry hopes that the fuel can play a key role in early partial decarbonisation of shipping, thereby creating a new source of LNG demand, and a role in full decarbonisation through the combined use of carbon offsetting and bio or synthetic methane.

The bank went further to recommend that governments move to end support for the deployment of LNG as a bunker fuel, warning that the uptake of LNG use in the marine sector carries financial and environmental risks.

To date, the EU and some governments have supported the construction of LNG import terminals, LNG bunkering facilities and the conversion of ship engines and systems to use LNG.

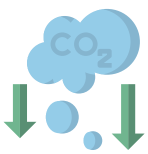
This support has been crucial in simultaneously creating both supply and demand for the fuel in the shipping sector.

MARKET DEVELOPMENT

The bank says the maritime market for LNG could develop in three different ways. First, LNG could emerge as a transitional fuel, remaining in use in some form in 2050. By this point, LNG would be carbon neutral as a result of carbon offsetting and the use of bio or synthetic LNG.

Second, LNG use could be temporary and superseded by zero carbon bunker fuels, such as green ammonia and hydrogen, probably from around 2030. Third, there could be no significant adoption of LNG.

The bank rules out a transitionary role for the fuel on the grounds that the reuse of LNG infrastructure in a zero carbon future would only be practical for biomethane and synthetic methane. It says that LNG technology and LNG supply infrastructure are not technically compatible with the two most promising zero carbon fuels, ammonia and hydrogen.



The Sphera report estimates that LNG use in shipping reduces GHG emissions by up to

23%

versus very low sulphur fuel oil, but how great a cut is achieved depends on the engine type and mode of operation.

It argues that there will not be sufficient volumes of bio and synthetic methane, owing to a lack of feedstock, claims from competing sectors such as aviation, and because their production costs are likely to remain high compared with other zero carbon fuels.

NO TEMPORARY ROLE

Nor does LNG make the cut as a temporary fuel, which the bank says would require an expensive double transition, first from oil to LNG and then from LNG to zero carbon fuels. This would require 30% more investment expenditure than that required to achieve full decarbonisation, the bank calculates.

Moreover, there is no certainty that LNG's use as a temporary fuel would result in GHG emissions reductions. Although it depends on the methane leakage assumptions used, shipping market penetration of 40% by 2030 would deliver GHG emissions reductions somewhere between plus 8% and minus 9%, the bank says.

In other words, the GHG benefits "would not be transformative," and in fact could be negative as a result of greater LNG use in shipping.

With demand for LNG peaking in the early 2030s in this scenario, then rapidly diminishing, its rise and fall would occur in a shorter timeframe than the life of the LNG assets invested in. This, the bank says, would be likely to create pressure for a more gradual phase out of the fuel, otherwise known as technical lock-in, which would have adverse environmental impacts.

On this basis – significant extra cost for uncertain climate benefits – it would be better for the shipping industry to wait until a single transition from oil fuels to zero carbon fuels is possible.

INDUSTRY PUSHBACK

The report has understandably provoked a strong reaction from the LNG industry. Key differences are the degree to which LNG reduces GHG emissions and whether bio and synthetic methane provide a realistic decarbonisation pathway. SEA-LNG argues that to delay LNG adoption on the basis of as yet uncertain alternatives will simply make the situation worse.

The Sphera report says that LNG use in shipping results in a reduction of up to 23% in GHG emissions, in comparison with very low sulphur fuel oil, on a full well-to-wake lifecycle basis, and that there are many reasons to believe these gains can increase as a result of technological improvements and reductions in methane emissions along the LNG supply chain.

In particular, SEA-LNG says its report, unlike the studies on which the World Bank report is based, uses the most up-to-date data on the latest engines in use, which significantly reduce methane slip from the incomplete combustion of fuel in the engine.

The organisation argues that the bank over-estimates the problem of methane slip, which means it under-estimates the GHG emissions reduction potential of LNG, leading to erroneous policy recommendations.

BIO AND SYNTHETIC METHANE

Just as there is no consensus over the level of GHG reductions from LNG, there is none on the potential growth and cost of bio and synthetic methane (*Figure 1*).

Based on its study, Outlook for biogas and biomethane: Prospects for organic growth, published in March 2020, the International Energy Agency (IEA) sees a very positive role for biogas and biomethane. They embody the idea of the circular economy, the agency says, as the fuels are produced from the increasing amounts of organic waste created by society.

Its report says the feedstocks available for sustainable production, excluding any that compete with food for agricultural land, are huge and that only a fraction is currently used. The study estimates sustainable biomethane potential at 730mn metric tons of oil equivalent (toe), more than 20 times the roughly 35mn mtoe produced today.

The IEA advocates supportive policies to unlock the potential of biogas and biomethane, which it considers essential to its Sustainable Development Scenario, in which the goals of the Paris Treaty on Climate Change are met.

In addition, a 2020 study, Availability and costs of liquified bio-and synthetic methane, the maritime shipping perspective, conducted by consultants CE Delft and commissioned by SEA-LNG, calculated a global maximum sustainable supply of liquid biomethane which far exceeded the forecast demands of the shipping sector in both 2030 and 2050 (as a maximum conceivable figure would), but also suggested enough liquid biomethane could be produced in its lowest output scenario.

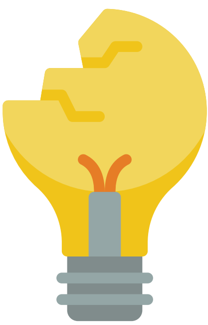
EVALUATING THE RIPOSTE

Like the Word Bank report, SEA-LNG's pushback and its latest study are unlikely to be received uncritically.

First, SEA-LNG commissioned both the Sphera report on LNG's GHG emissions from shipping and the 2020 CE Delft study, so the organisation will inevitably be accused of producing reports which say what it wants to hear. The World Bank can claim more objectivity, but SEA-LNG more industry knowledge.

Second, the World Bank report takes into consideration studies that look at both 20-year and 100-year global warming potentials (GWPs) for the impact of GHGs.

A shorter time span for the GWP accentuates the impact of methane vis-à-vis CO_2. The multiplier effect for methane versus CO_2 over 100 years is 36, but over a 20-year GWP horizon it is 87. Many environmental organisations, such as the International Council on Clean Transportation, argue that a 20-year GWP is the more relevant metric by which to judge LNG.



> *"By focusing on theoretical, unproven solutions, the World Bank stifles innovation in technologies that can also provide answers in the decades ahead."*
>
> **SEA-LNG**

Third, the headline figure that LNG use in shipping results in up to a 23% reduction in GHG emissions will face scrutiny. The phrase 'up to' is significant. The study says that the GHG savings for two-stroke, slow-speed engines is from 14% to 23% and for four-stroke medium-speed engines between 6% and 14%.

As the study explains, when it comes to the GHGs emitted by ships, as opposed to the full supply chain, performance depends heavily on engine type and operation.

The study is based on steady-state test-bed data using standard test cycles with data provided by the engine manufacturers for deep sea shipping. This reflects the operation of many large ocean going vessels, but as the report again notes, GHG emissions based on operational fuel consumption and measured emissions data will differ due to load cycles and duration.

The steady-state approach may have some validity, particularly as methane emissions in real operations are not measured, but it almost certainly presents a prettier picture than reality. CO_2 emissions are not measured either, but derived from fuel consumption.

PICKING WINNERS

However, the bottom line is that if the Sphera report is taken at face value, this is still not sufficiently transformative, given the International Maritime Organisation's stated goal of reducing GHG emissions from shipping by 50% by 2050 and the pursuit of carbon neutrality thereafter.

LNG's use in decarbonisation then starts to rest very heavily on the likely availability and cost of bio and synthetic methane. About this, the World Bank may be right to be sceptical in terms of future availability and cost, but as shown above, this is not a universal viewpoint. Moreover, by limiting a potentially significant market for bio and synthetic LNG, the bank risks curtailing development of a fuel source which the IEA sees as critical for its sustainable development pathway.

SEA-LNG's most potent criticism is that the bank is being heavily prescriptive in a technologically very uncertain environment. In particular, the bank's report does not seem to consider that LNG initially plus bio and synthetic LNG in future does not have to meet all of shipping's zero carbon fuel requirements to make a potentially substantial contribution to maritime decarbonisation.

And, as such, if viewed as one element among many, investment in LNG infrastructure need not become stranded.

If targeted at the ship operations for which it performs best in terms of emissions reductions, most studies agree that on a 100-year GWP, which is the standard approach, LNG does result in non-negligible emissions reductions. Moreover, LNG's superior performance in terms of air pollutants, and the consequent health benefits, cannot be ignored.

For ship owners, faced with extremely difficult investment decisions, the reality is that they can order an LNG-fuelled ship today and bunker at an ever-rising number of ports around the world, whereas they cannot order one running on ammonia or hydrogen.

SEA-LNG is right that in attempting to pick winners, the World Bank is being overly prescriptive. Moreover, in doing so, the bank's position threatens the 'all of the above' approach, which is appropriate at this stage of technological development and supported by the IEA. •

Photo: GIIGNL

INTERVIEW Vincent Demoury, *GIIGNL*

THE ANNUAL REVIEW OF LNG MARKETS, BY THE IMPORTERS GROUP GIIGNL, CONFIRMS THE DIRECTION OF TRAVEL FOR LNG: MORE PRODUCTION GOING TO MORE CUSTOMERS AND ON A SHORTER-TERM BASIS

William Powell

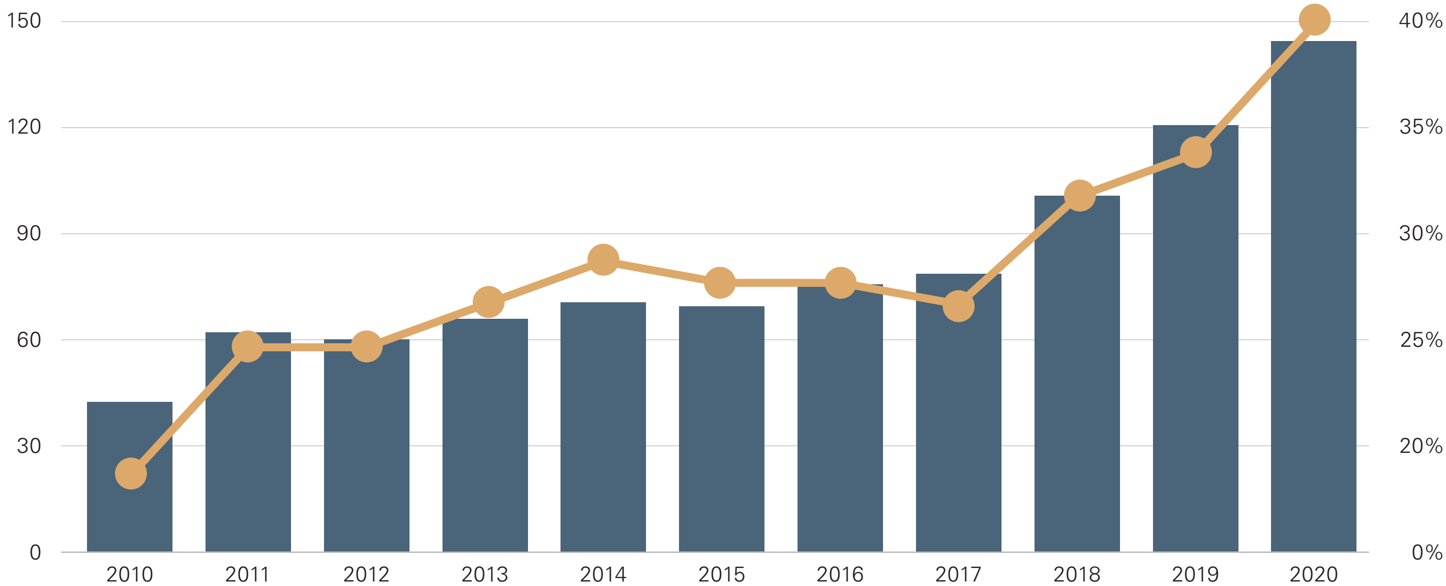
SCARRED AS IT WAS by the COVID-19 pandemic, last year saw a much lower growth in LNG trade. The amount of LNG imported grew fractionally in 2020 from 354.7mn metric tons (mt) to 356.1mn mt, despite the shut-ins of production and the falling demand for energy, according to a new report by the France-based International Group of LNG Importers (GIIGNL).

On balance it was not at all a bad year for LNG, the organisation's deputy general delegate Vincent Demoury tells *NGW*. After several years of compound annual growth rate nearing double digits, this 0.4% growth in volume from 2019 is comparatively small. "On the other hand, LNG was resilient, if you compare it with demand for other fuels over the same year, which fell," he said.

New regasification capacity continued to come online, with eight terminals commissioned in 2020 in Bahrain, Brazil – which has two – Croatia, India, Indonesia, Myanmar and Puerto Rico.

"2020 was the first year that new regasification online exceeded new liquefaction since 2015. We do not see regasification as the bottleneck, all the more so as floating storage and liquefaction units (FSRUs) can be deployed relatively quickly. Regasification brings optionality: it can be used for storage as well as regasification and, with volatile prices, we also see more storage capacity being built downstream," he said. Liquefaction capacity is roughly half regasification capacity: 454mn mt/yr compared with 947mn mt/yr.

FIGURE 1 | Share of spot & short term vs. total LNG trade (mtpa/%) | *Source: giignl.org/system/files/giignl_2021_annual_report_may4.pdf*



LNG imports were up slightly last year at **354.7mn mt**, despite shut-ins and falling demand.

"We see a gradual decline in new liquefaction capacity until the next wave of Canada, Mexico and Qatar from 2025 onwards. Demand in Japan is likely to stabilise or decrease, but should rise in China, India and southeast Asia where it can complement domestic production and replace coal and fuels in industry and power generation. In Latin America and Africa, LNG will complement renewable energy. LNG trade could grow at an average of 3-4%/year for the next 20 years, almost doubling in volume from today.

"South Korea and Japan already have far more regasification capacity than their annual demand requires. China is building more regasification and it gives them the opportunity to arbitrage between pipeline and LNG imports and to cope with demand seasonality," he says.

Prices were also volatile: from the very low demand in the summer and attempts by buyers to invoke force majeure, the market picked up in the autumn. This surprised many participants who had thought the market was oversupplied. But opportunistic buyers snapped up cheap cargoes. And in some cases pipeline gas was turned down to make room for LNG.

For some buyers, LNG is an alternative to pipeline gas: it drives a wedge between a monopolist supplier and its market, improving the buyer's negotiating position. This is the case in Lithuania and Croatia for example. For others, it is a choice between LNG or other fossil fuels such as diesel or coal.

These latter countries are more vulnerable to upstream risk: "LNG is still a physical commodity. One of the reasons for the high prices in late 2020 was congestion in the Panama Canal, coinciding with the cold weather and with a tight shipping market," Demoury says.

One of the most conspicuous changes was the shift from long-term to short and spot trade. 23.5mn mt more LNG were delivered within three months from the transaction date in 2020 than in 2019, reaching 35% of total imports during the year or 125mn mt, compared with 27% of total imports in 2019. Overall trade in LNG however grew just 1.4mn mt.

Most of that growth in spot trade may be explained by countries with a high sensitivity to price, such as India; or countries with the ability to arbitrage between pipeline gas and spot LNG, such as China or Turkey, he said. China saw annual growth of 12%, still impressive when compared with 14% the year before.

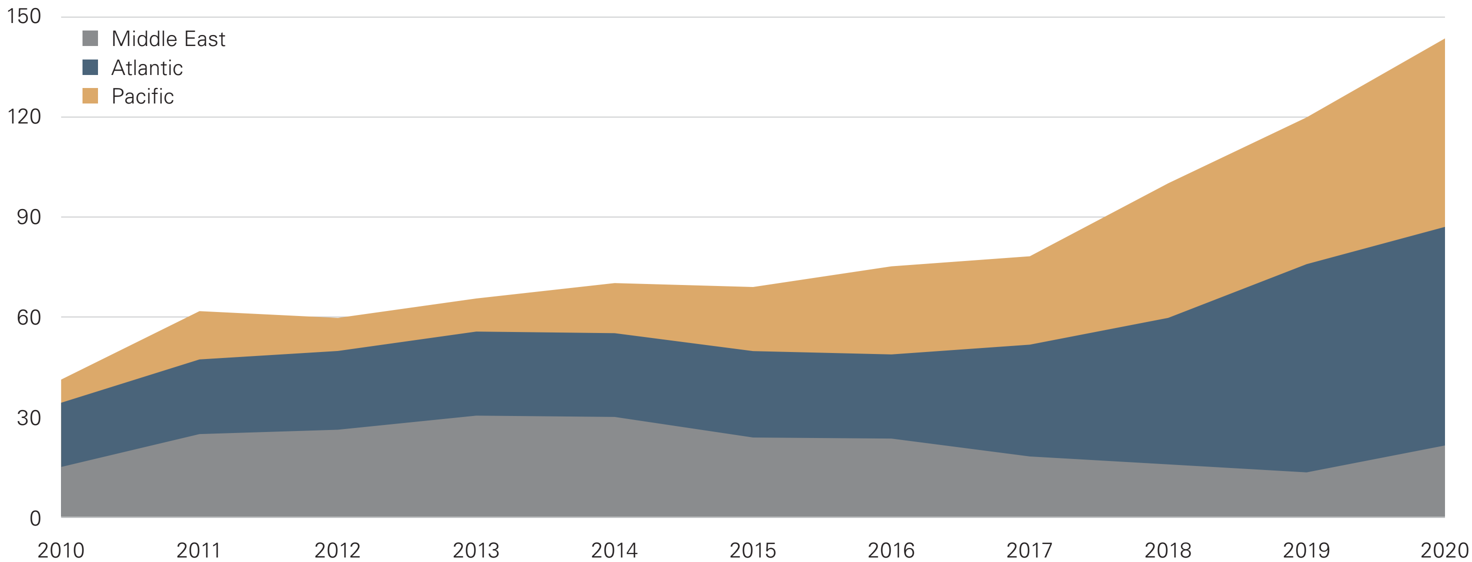
"Japan also took more spot cargoes as it nominated less from its long-term contracts and took advantage of the market to manage demand uncertainty. Portfolio players also moved cargoes around within their sales, buying cheap spot cargoes to honour long-term contracts," Demoury says.

LNG portfolio players with a bigger downstream position may also have the option to deliver not gas to a terminal, but MWh at the customer's power grid. That could free a cargo up for a more profitable sale elsewhere.

But there are limits to the extent that short-term cargoes can grow their share of the overall market: security of supply downstream and necessary return

FIGURE 2 Spot and short term flows by exporting region (mtpa)

Source: giignl.org/system/files/giignl_2021_annual_report_may4.pdf



on investments upstream remain important and that implies a continuing need for term contracts. "We don't see short term supply growth continuing at the same rapid pace for the next few years, now that the build-up of the first wave of US capacity is complete," he says.

> *"We don't see short term supply growth continuing at the same rapid pace for the next few years, now that the build-up of the first wave of US capacity is complete."*
>
> **Vincent Demoury**
>
> DEPUTY GENERAL DELEGATE,
> INTERNATIONAL GROUP OF LNG IMPORTERS

Another feature of last year was that the market was balanced mainly by producers shutting in production, he said. As well as the US, Egypt responded to price signals by curtailing its exports. And Algeria, normally a major LNG exporter, used gas to meet domestic demand instead.

But there were other, more familiar factors at play too that limited the supply: "Trinidad & Tobago and Malaysia each sold 2.4mn mt less because of a feed gas shortage. Two other plants, Hammerfest LNG and Prelude, were stopped by a fire and by electrical problems respectively. Another Australian project, Gorgon, also had technical problems with heat exchangers," he says.

SHIPPING

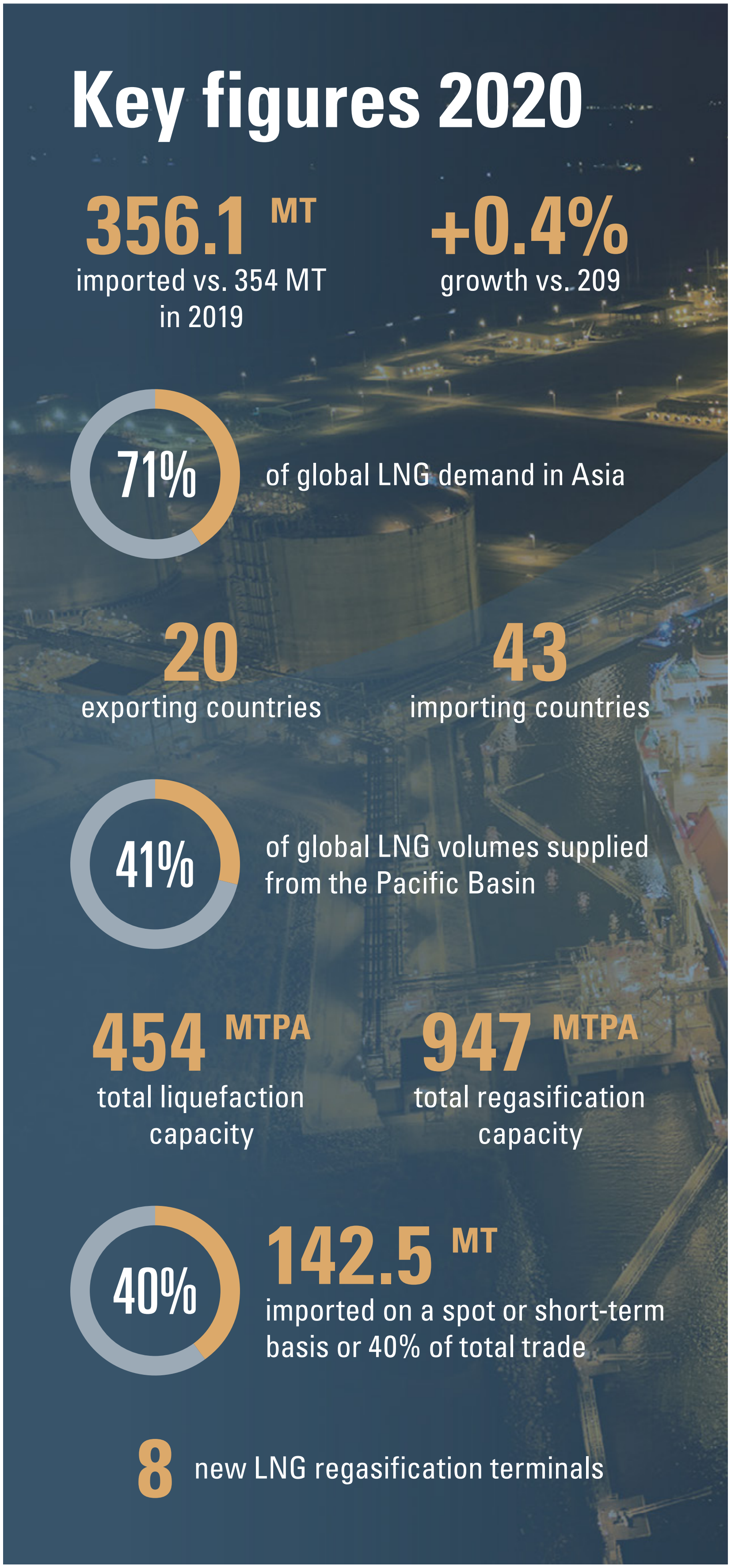
A major element of the delivered cost of LNG is the freight and Demoury believes "there are still inefficiencies to be squeezed out of shipping. Last year the rising share of LNG freight in the total LNG cargo cost, in addition to increased charter rates volatility, drove more companies to look at hedging the cost of freight. Some financial instruments have been developed for hedging purposes. The NYMEX LNG Freight Futures or the Spark joint venture owned by Kpler and Powernext are examples.

"Last year Singapore was the major re-exporting country, followed by France. Traders increasingly recognise the value of LNG storage – including in some cases vessels used as floating storage – for trading opportunities,"

EMISSIONS

GIIGNL is working both on its own and with other organisations to combat emissions, which are still perceived in some quarters as a problem facing LNG.

"There is no uniform methodology that is specific to LNG for the time being. More transparent and verifiable data should be disclosed," Demoury explains. "GIIGNL has begun work on a common approach to



monitoring, reporting and verifying emissions which it will publish in October. It has appointed a team of 30 experts from 19 companies within its membership to work on it.

"The aim is to quantify the carbon footprint associated with each cargo and reduce it as much as possible. The footprint varies from site to site: facilities in Qatar, Russia and the US will all have different footprints. And the methodology to quantify the emission intensity of associated gas will be different from the methodology used for dry gas, for example. Emissions which cannot be avoided or reduced could be offset through the purchase of carbon credits.

"Transparency will become more important as LNG customers and the financial sector focus more on environment, society and governance. Policy-makers will also demand more information on the carbon intensity of LNG, such as the Methane Strategy in the EU," he says.

Unsurprisingly, Demoury does not understand the World Bank's negative position on LNG [see previous feature]. It has advised governments not to support LNG as a bunkering fuel as it believes it would only play a minor role compared with hydrogen or ammonia.

This is "clearly wrong," he says. "Hydrogen and ammonia are still over a decade away as a bunkering fuel in meaningful volumes. LNG is a fuel that is already technically and commercially ready to help with the transition. It is reducing emissions now as it can also be a starting point towards net zero emissions, through offsets, fuel cells, bio and synthetic LNG or blending with hydrogen.

"It is cheaper than heavy fuel oil on an energy content basis and the payback time for conversions is short. LNG as a marine fuel will be needed for the next International Maritime Organisation's objective to reduce shipping emissions by 40% by 2030 compared with 2008."

But the World Bank's pleas appear to have fallen on deaf ears – in some quarters, at least. As a FueLNG vessel refuelled an Aframax crude tanker in Singapore with LNG early in May, Keppel, Anglo-Dutch major Shell's partner in the bunkering joint venture, praised the good that LNG can do today.

"LNG is an immediately available fuel solution that can reduce the environmental impact of maritime transport. The use of LNG as a marine fuel reduces greenhouse gas emissions by up to 23% on a well-to-wake basis, compared with current oil-based marine fuels," the company said.

The event was attended by the Singapore Maritime & Ports Authority CEO Quah Ley Hoon, who said the event was "another milestone in Singapore's journey as an LNG bunkering hub." •

Low-Carbon *Futures*

Karel Beckman

Shell is coming out of its shell

SHELL WILL NOT TRANSFORM FROM OIL AND GAS PRODUCER TO RENEWABLE ENERGY GENERATOR. INSTEAD IT WILL RELY ON ITS SUPPLY AND TRADING ABILITIES TO PROSPER IN THE NET-ZERO ECONOMY

Shell's *Energy Transition Strategy*, which the company published in April and will put up to its shareholders for an advisory vote at the Annual Meeting on 18 May, provides fascinating insight into how one of the major oil and gas companies in the world is planning to meet the climate change challenge.

Shell has clearly chosen to remain an integrated energy company – and indeed one of the major energy suppliers in the world. There is no reference in the strategy to divesting businesses or specialising in particular activities. On the contrary, Shell is aiming to broaden its activities to encompass alternative fuels and low-carbon products.

It may be surprising to some, but as David Hone, Shell's chief climate change advisor and one of the 13 members of the Shell Scenarios Team, explains in an exclusive interview with *NGW*, Shell regards itself above all an energy supply and trading company. The "trading" part is often underestimated. Shell produces around 1% of the oil and gas in the world, but supplies a stunning 4.6% of the world's primary energy. In other words, the company supplies much more energy than it produces.

And, as the *Energy Transition Strategy* makes clear, it intends to continue to do so in the future. This means it will try to secure leading positions in new products and activities, such as bioenergy, electric cars, renewable energy, carbon capture and sequestration (CCS), and carbon offsets. In all these sectors Shell will build or buy assets, since, as Hone notes, to trade successfully a company does need an asset base. But Shell will not necessarily try to dominate the "upstream" part of these activities.

None of this means that success is guaranteed for Shell. One big challenge is that, as the *Energy Transition Strategy* points out, in the emerging zero-emission economy it will be necessary to cooperate with many different players in the various sectors. Thus, for example it does not make sense for an energy producer to produce hydrogen, or for a shipbuilder to build a ship that runs on hydrogen, or a car company to manufacture hydrogen cars, if there is no hydrogen market and no hydrogen infrastructure. The same holds true in other sectors, such as CCS and electric transport.

This has important implications for the way the company has to operate. As the *Energy Transition Strategy* notes, rather than focusing on separate product value chains, Shell's activities will be much more sector-based and require much more cooperation with different actors. External relations will become crucial. That has not always been the company's strongest suit.

Looking at concrete sectors, natural gas is clearly still viewed by Shell as a key bridge (a rather long one) to the net-zero future. The company does see a "peak" lying ahead for natural gas, but later than for oil. Shell also intends to continue to make the most of its chemicals business.

The company still sees a long, if slowly declining, future of fossil fuels ahead, with emission reductions being achieved through "natural sinks" (offsets) and CCS. It is interesting to note that by 2030 Shell expects to achieve a five times larger reduction from natural sinks than from CCS. As the transition strategy notes, Shell participates in a number of large CCS projects, but it is not necessarily taking the lead in any of those.

Shell's plans in renewable energy generation are not very clear yet either. The strategy provides an overview of Shell's "new energy" activities, but they do not add up to a very coherent picture as yet, although it is likely that biofuels, electric charging and offshore wind will be attractive sectors for Shell. Nevertheless, the company will face tough competition with utilities and renewable energy producers which are

in many ways ahead of Shell in renewable energy. In line with David Hone's suggestions, Shell may well focus more on trading and selling renewable power than producing it.

Shell has a target to supply 560 TWh of electricity by 2030, which amounts to around 2% of today's global electricity production. With electricity demand expected to grow strongly, that share will be more likely around 1% by 2030. (For comparison, a country like the US consumes around 4400 TWh, while Germany uses some 650 TWh.) Shell's target in the increasingly important electricity sector seems therefore not hugely ambitious as yet.

How profitable will the new Shell company be? That may be the billion-dollar-question. The company may feel that its profitability will move in step with the global energy transition. After all, the transition will have to be paid for somehow, so Shell may feel, not unreasonably, that it can rely on the revenues – whether through government incentives or not – that the new activities must be able to generate.

However that may be, Shell clearly has no intention to withdraw into its shell and make the most of what it has. It is coming right out of there and meeting the energy transition challenge head on. That does show courage. •

Shell's transition *in focus*

Source: Shell

SHELL'S RECENTLY PUBLISHED STRATEGY OUTLINES WHAT NEW FORM THE ANGLO-DUTCH MAJOR PLANS TO TAKE IN ORDER TO PROSPER DURING THE ENERGY TRANSITION

Karel Beckman

SHELL PRESENTED a new *Energy Transition Strategy* in mid-April which it will put before shareholders for an advisory vote at the company's annual general meeting on May 18.

"This is the first time that an energy company has asked shareholders to vote on its energy transition strategy," the company said in a press release.

The report sets out the company's "short- and medium-term climate targets, customer-focused decarbonisation strategy, capital allocation and approach to climate-related policy and advocacy."

Shell notes that the decision to publish this strategy "follows continuing engagement with shareholders, including with Climate Action 100+ which represents investors with assets of around $54 trillion." The company will publish an update every three years until 2050. Every year, starting in 2022, it will also seek an advisory vote from its shareholders.

SECTORAL INTEGRATION

As one of the world's largest – if not the largest – supplier of energy, Shell sends quite an important message to the world with its *Energy Transition Strategy*. The company produces around 1.4% of total primary energy, notes the report, but it sells no less than "around 4.6% of final energy consumed in the world."

"Our share of energy production may decline over the coming decades, but we intend to grow our share of low-carbon energy sales," it adds.

Shell intends to "reduce the carbon intensity of our energy products by working with our customers, sector by sector, to help them navigate the energy transition. We will start by adding more low-carbon products, such as biofuels and electricity, to the mix of energy products we sell. Eventually, low-carbon products will replace the higher carbon products that we sell today."

One of the key elements of the new strategy is a focus on sectoral integration. Shell "is moving from an approach focused on types of products to one where our customer and account management is focused on sectors." The company is "introducing sector-based businesses accountable for driving the decarbonisation of the sectors they cover such as aviation, commercial road transport, passenger transport, shipping, technology and industry."

The report cites the road freight sector as an example, in which Shell is "working with transport companies, truck manufacturers and policymakers to identify pathways to decarbonisation. In the near term, we will continue to increase production of low-carbon biofuels. And we will offer biogas and LNG for trucks to customers in Europe, China and the US. In the longer term, we intend to increase our sales of hydrogen for transport. We are also part of the H2Accelerate consortium, which looks at ways to create infrastructure for generating and supplying clean hydrogen to hydrogen trucks as they become available across Europe."

IN STEP WITH SOCIETY

For Shell it is clear that the company needs to move in step with the transition taking place in the larger society. "If we moved too far ahead of society, it is likely that we would be making products that our customers are unable or unwilling to buy," says the strategy report. "(…) Shell cannot get to net zero without society also being net zero."

For example, says Shell, "if we invested in producing sustainable aviation fuel, and made it available on commercial terms at all the airports Shell serves today, the investment would not significantly lower our or society's carbon emissions. Most aircraft are not yet certified to fly on 100% sustainable aviation fuel and the cost of the fuel is considerably more

FIGURE 1 Carbon Targets - Scopes 1, 2 & 3 *Source: Shell*

Reducing net carbon intensity gCO_2e/MJ
2016 baseline

2-3% by 2021	3-4% by 2022	6-8% by 2023	20% by 2030	45% by 2035	100% by 2050

Carbon intensity		Absolute carbon
2016 baseline 79 gCO_2e/MJ		1.7 gtpa 2018
0 gCO_2e/MJ	2050	0 gtpa

***Reducing absolute carbon emissions: from 1.7 gtpa to net zero by 2050**. We believe total carbon emissions from energy sold peaked in 2018 at around 1.7 gigatonnes CO2e per annum (gtpa) and will be brought down to net zero by 2050.*

Shell produces **1.4%** of the world's total primary energy, but sells around **4.6%** of final energy consumed.

than traditional jet fuel, making it an uncompetitive choice for the airlines."

Shell has adopted an emission reduction target of 20% by 2030, reaching 45% by 2035, and 100% by 2050 (see chart). These include Scope 3 emissions, meaning emissions from the use of energy sold by Shell – i.e. not just the company's own operational emissions.

In absolute terms, this translates into a 1.7bn metric ton/year reduction by 2030, 765mn mt/yr by in 2035 and 1.7bn mt/yr in 2050. Global greenhouse gas emissions are around 52bn mt/yr, so Shell's contribution is around 3.25%.

LEVERS OF DECARBONISATION

So how does this translate into concrete activities? In addition to pursuing "operational efficiency" in its own assets, Shell has five "levers" to help the company and its customers "decarbonise energy in the short, medium and long term".

More natural gas

Shell notes that its oil production peaked in 2019 and is expected to decline 1-2%/year. The company anticipates "no new frontier exploration entries after 2025". It will reduce the number of refineries from 13 sites today to six "high-value chemicals and energy parks", and "reduce production of traditional fuels by 55% by 2030, from around 100mn mt/yr to 45mn mt/yr."

At the same time, Shell intends "to grow volumes from our chemicals portfolio and increase cash generation from chemicals by $1-2bn/yr by 2030." It will "produce chemicals from recycled waste, and by 2025 aim to process 1mn mt/yr of plastic waste."

Shell sees the share of natural gas in its hydrocarbon production grow to 55% in 2030. "We intend to extend our leadership in LNG volumes and markets, with selective investments in competitive LNG assets to deliver more than 7mn mt/yr of new capacity on-stream by the middle of the decade," says the report. "We will continue to support customers with their own net-zero ambitions, with offers such as carbon-neutral LNG, which uses nature-based carbon credits to offset full life-cycle emissions, including methane." Shell's LNG production in 2020 was 33.2mn mt, a decline of 2.2mn mt compared to 2019.

CCS

CCS is an important part of Shell's transition strategy. Today, Shell is involved in seven of the 51 large-scale CCS projects listed in 2019 by the Global CCS Institute, including for example the Quest CCS project in Canada and the Northern Lights project in Norway.

In 2020, Shell invested around $70mn in CCS. "This included progressing opportunities and operating costs for CCS assets in which Shell has an interest. We seek to have access to 25mn mt/yr of CCS capacity by 2035 – equal to 25 CCS facilities the size of our Quest project, or around 20% of the capacity of all CCS projects being studied around the world today."

Natural sinks

"Investing in nature" is another pillar of Shell's strategy. "The market for nature-based solutions and the number and type of projects which are being developed to meet this market demand is growing rapidly," notes the company. "McKinsey Nature Analytics estimates that there is the potential for nature-based projects to store an additional 6.7 Gt [6.7bn mt] of CO_2 every year by 2030. …. The Taskforce on Scaling Voluntary Carbon Markets (TSVCM), sponsored by the Institute of International Finance (IIF), estimates that the market for carbon credits could be worth more than $50bn in 2030."

Shell vows to use "high-quality nature-based solutions, independently verified to determine their carbon impact and their social and biodiversity benefits. In line with our approach of avoid, reduce and only then mitigate, we expect to offer our customers nature-based solutions to offset around 120mn mt/yr of our Scope 3 emissions by 2030."

Shell is already offering its customers "carbon-neutral driving using nature-based carbon offsets in seven countries. We also offer carbon-neutral LNG cargoes, which use nature-based carbon credits to offset full life-cycle emissions, including methane."

In 2020, Shell invested around $90mn in the future development and purchase of nature-based offsets, and the company expects to invest an additional $100mn/yr in similar projects. In 2020, it acquired Select Carbon in Australia, "which runs more than 70 carbon farming projects that span an area of around 10mn hectares."

Low-carbon fuels

Shell expects to grow its biofuels production and distribution business, which in 2020 sold 9.5bn litres of biofuels. Its joint venture Raízen, which produces low-carbon biofuels from sugar cane in Brazil, recently announced the acquisition of Biosev. This is set to increase Raizen's bioethanol production capacity by 50%, to 3.75bn litres/yr, around 3% of global production.

> *"This is the first time that an energy company has asked shareholders to vote on its energy transition strategy."*
>
> **Shell**

With regard to hydrogen, Shell intends to develop "integrated hydrogen hubs initially to serve industry and heavy-duty transport. We will begin by producing and supplying hydrogen for our own manufacturing sites, especially refineries. … We will also continue to extend our network of hydrogen retail stations, with an increasing focus on heavy-duty transport."

The clean hydrogen market is still in the early stages, notes Shell, and the volumes are still modest. "But we see strong potential for growth especially in hard-to-abate sectors of the economy. We aim to achieve a double-digit market share of global clean hydrogen sales by 2030."

Low-carbon power

Shell aims for its power business "to sell around 560 TWh/yr of electricity by 2030, which is twice as much electricity as we sell today, and for the electricity we sell to have lower carbon intensity than the grid average within the markets where we operate."

The company is also increasing "the number of electric vehicle charging points globally – for homeowners and businesses and for use on our forecourts – from more than 60,000 today to more than 500,000 by 2025 and to 2.5mn by 2030. By comparison, that is around 7% of the total number of public and private charge points expected in Europe alone by 2030, according to research by Bloomberg."

Shell currently has around 1mn customers of integrated home energy solutions (Shell Energy Retail), more than 80,000 operated electric vehicle charge points (primarily through NewMotion), 60,000 intelligent home battery energy storage systems (Sonnen). Shell is also "a leading player in the UK distributed energy market" (Limejump) and has a "growing power trading business across Europe".

It has 160 MW of renewable generation capacity in operation (in the Netherlands) and 1.6 GW in development across solar and wind.

CAPITAL ALLOCATION

Shell's strategic shift will of course have an impact on the way it spends its money. The Energy Transition Strategy looks at this from the bright side. It notes that "compared with our conventional upstream assets, investments in low- and zero-carbon solutions can require lower amounts of capital…. The levels of capital investment needed to maintain a renewable energy business are also likely to be lower than in capital-intensive complex engineering projects common in the oil and gas industry."

What is more, Shell notes that "we can grow our sales of low-carbon energy without necessarily investing in producing it ourselves by buying it from third parties and selling it to our customers. This model is part of our business today, we sell more than three times the energy we produce ourselves."

Shell also sees an opportunity to "enter into different types of financial arrangements that enable renewable generation capacity to be built, without bearing the full capital cost of the project. For example, developing renewable production as part of joint ventures allows us to reduce the capital investment needed, while giving us access to valuable expertise from other partners. It also gives us the opportunity to secure a substantial portion of the energy produced, allowing us to grow customer sales."

By contrast, the company's investment in the upstream, in particular the oil business, will gradually be reduced. "Our planned capital investment of $8bn in our upstream business in the near term is well below the investment level required to offset the natural decline in production of our oil and gas reservoirs, and will not sustain current levels of production. As a result of this planned level of capital investment, we expect a gradual decline of about 1-2%/yr in total oil production through to 2030, including divestments."

INTERVIEW

"At the core of our strategy is our ability to *trade between products and markets*"

DAVID HONE, CHIEF CLIMATE CHANGE ADVISOR, SHELL

"With our *Energy Transition Strategy*, we are making it clear that we will continue to be an integrated player in the global energy sector," says David Hone, chief climate change advisor at Shell, in an interview with *NGW*. According to Hone, people tend to underestimate the importance of trading and retail for Shell. "We supply much more energy than we produce. Our ability to trade is at the core of our strategy. We will continue to use that ability as we transition towards a net-zero emission society."

David Hone, a chemical engineer by education who started his career at Shell in 1980 as a refinery engineer in Australia, has been the company's chief climate change advisor since 2001. He is mostly known to the outside world as the author of the Shell Climate Change Blog, but he is also a member of the Shell Scenarios Team, who has provided key inputs for the company's strategy since the 1970s. The findings of Shell's latest scenarios, Sky 1.5, Waves and Islands, all published this year, have gone into the making of the *Energy Transition Strategy* which was published in April.

"Our scenarios help us to understand the changing energy landscapes," explains Hone. "They enable us to adapt ourselves as a company irrespective of how the world evolves." This holds true just as much today, says Hone, as in the days when fossil fuels were paramount. "We see the world moving towards net-zero emissions. We intend to be part of that transition. This means that as a company we are in transition as well."

Hone notes that given the constraints of climate policy, "there are many strategies a company take. You can decide to be the last man standing in oil if you want to. We decided we want to continue to be a relevant global player."

> ***"Natural gas will play an increasingly important role. It is still the best option to achieve short-term emission reductions as an alternative to coal."***
>
> **David Hone**
> CHIEF CLIMATE CHANGE ADVISOR, SHELL

David Hone works for Shell International and is the chief climate change advisor in the Shell Scenarios Team. He joined Shell in 1980 after graduating as a chemical engineer from the University of Adelaide in Australia. He has worked in refinery technology, oil trading and shipping areas for Shell.

David is a board member of the International Emissions Trading Association (IETA), was chairman of IETA from 2011-2013 and is a board member of C2ES in Washington and GCCSI in Melbourne. David is a regular climate blogger and is the author of a 2017 book on climate change, *Putting the Genie Back: Solving the Climate and Energy Dilemma.*

This means that Shell will be exploring many new activities in the years to come. Hone: "What we see is an increasingly important role for electricity. But we also see a continuing role for molecular fuels, although the nature of those molecules can change. They could be synthetic, bio-based, hydrogen."

But the role of natural gas has not ended yet. On the contrary. "Natural gas will play an increasingly important role," says Hone. "It is still the best option to achieve short-term emission reductions as an alternative to coal. There is also increasing interest in natural gas in the transport sector, for example in shipping. Natural gas is readily available and scalable today. Hydrogen is still some time away."

Shell will continue to invest in the LNG market in the 2020s, says Hone. "Most of the energy infrastructure in the world is still geared to oil and gas. There is a peak for gas, but it's further away than for oil."

Shell is also expanding its renewable energy portfolio, for example in offshore wind. Whether Shell will become as big in the generation of renewable energy as it is in oil and gas, is not clear, but according to Hone that is not as important as people might think. "We don't necessarily need to produce all the renewable energy that we will be selling. In the UK, where I live, I buy renewable electricity from Shell, even though it is not produced by Shell."

According to Hone, "the role trade and retail plays in our strategy is often underestimated. We produce around 1% of the world's oil and gas, but we sell 4.6% of the primary energy in the world. Our supply of products is much bigger than our production. At the core of our strategy is our ability to trade between products and markets."

It would be a mistake to think that Shell will evolve into a utility company, says Hone. "We are an energy supply and trading company. This means for example, that as electricity becomes more important, we will expand our electricity trading activities, which are already big in some countries. To trade successfully you do need to have an asset base but you don't have to produce everything yourself."

This is also how the company is approaching the "management of CO_2 emissions", through nature-based solutions and carbon capture and storage (CCS), which Hone says will become "a big market". "We will be offering our customers CO_2-management options, but we won't be carrying out all the projects ourselves, although we will participate in them."

Why do "natural sinks" contribute much more to Shell's 2030 reduction targets than CCS? Hone explains that this is because CCS is more difficult to scale up and has longer lead times. "To get to 10mn mt of CO_2-reduction through CCS takes seven or eight 10-year projects. Nature-based solutions also take time, but they can be realised quicker and are more scalable in the shorter term. 100mn mt of CO_2-reductions through CCS is beyond the current capacity of Shell but 100mn mt through natural sinks is achievable."

Long lead times of projects are also one of the reasons why there is a such a big jump in the reduction of carbon intensity from 2030 (-20%) to 2035 (-45%). "We are starting many projects and making investments that will take years to come to fruition. Many projects will be delivered after 2030. That's when we will see a pronounced shift. Reductions are still relatively modest in the 2020s, but will accelerate rapidly thereafter." •

EU to overhaul gas rules to fulfill green ambitions

THE EUROPEAN COMMISSION WILL PROPOSE AND ADOPT A NUMBER OF MARKET REFORMS THIS SPRING AND AUTUMN WHICH WILL SIGNAL HOW IT EXPECTS GAS MARKETS TO EVOLVE IN THE FUTURE

Andreas Walstad

THE EUROPEAN COMMISSION will this autumn outline a proposal for a new set of gas market rules which will revamp the existing Gas Directive and Regulation adopted in 2009, now considered outdated. The new Hydrogen and Decarbonised Gas Package will outline how renewable, synthetic and decarbonised gases will be incorporated into the gas market. It falls under the Fit for 55 package which is a move by Brussels to better align legislation with the EU's recently adopted target of cutting greenhouse gas (GHG) emissions by 55% compared with 1990 levels. A public consultation is open until June 18 and has already triggered plenty of reactions from major industry players including Shell, Total, Eni and Equinor.

The existing Gas Directive and Regulation set out rules for third party access and ownership unbundling of gas pipelines and storage facilities. Back then, the EU was keen to break up monopolistic behaviour in gas markets to foster competition and strengthen security of supply, not at least after 2006 disruption in Russian gas flows to Europe via Ukraine for several days. Notably, the Directive and Regulation were adopted by the EU institutions six months after the second Russia-Ukraine gas crisis in 2009.

Today, the EU gas market is much better functioning and resilient to supply shocks, with gas flowing more freely across borders. This is also illustrated by the emergence of the Dutch TTF as a liquid benchmark hub. The new Gas Package is therefore expected to be built on the same principles of competition and fair access to infrastructure. Brussels, and many industry players alike, want to avoid a situation whereby hydrogen networks are owned and operated by monopolies potentially denying access for new entrants. For example, the European Commission, in its impact assessment, raised the question if gas transmission system operators (TSOs) should be allowed to operate electrolysers.

Brussels has set a target of 40 GW electrolyser capacity in EU countries by 2030. For producers of renewable electricity, it will be key to get access to this capacity in order to convert the electricity they produce to hydrogen and ship it through networks. Some see it as problematic that TSOs own both the networks and the electrolyser capacity. Others believe TSOs are in a good position to build and operate this capacity as long as the EU designs a fair access regime for third parties.

"There is little appetite from commercial operators to build electrolysers as the demand outlook for hydrogen is uncertain. TSOs are ready to make those investments, and I do not think it is at odds with the unbundling regime if they own and operate electrolysers. TSOs are needed to accelerate the process," Walter Boltz, a senior independent energy advisor, tells *NGW*.

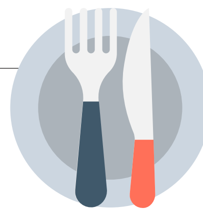
INDUSTRIAL CLUSTERS

A number of countries including the UK, the Netherlands and Germany are planning to develop industrial clusters to decarbonise hard-to-abate sectors such as steel and petrochemicals. Shell said in its response to the public consultation that gas TSOs should be allowed to develop dedicated hydrogen and CO_2 pipelines for CCS infrastructure in such clusters. The involvement of gas TSOs should not result in crowding-out of commercial investment and competition in production and supply, it added.

"Over time, renewable and low-carbon hydrogen should become a tradeable commodity in a liquid European wide internal market," said Shell. "To start the hydrogen market and enable commercial players to invest with confidence, the regulatory framework should mirror the main features of the gas regulatory framework: unbundling, third-party access and cost-efficient non-discriminatory tariffs."

But one challenge with industrial clusters is that they may be disconnected from networks, with only one single hydrogen producer within the cluster, effectively eliminating competition.

"The risk with hydrogen clusters is that one hydrogen producer may have a dominant position in supplying the industrial consumers. If the cluster is not linked to another network, then the hydrogen producer can set the price without competition from other producers," explains Boltz.



"There is little appetite from commercial operators to build electrolysers as the demand outlook for hydrogen is uncertain. TSOs are needed to accelerate the process."

Walter Boltz
SENIOR INDEPENDENT ENERGY ADVISOR

The EU has adopted a target of reducing its greenhouse gas emissions by
55%
by 2030 versus the level in 1990.

A revamp of the existing legislation is also an opportunity to revisit the access regime for LNG terminals. LNG terminals are, broadly speaking, much less regulated than pipelines meaning it can be difficult for shippers to obtain third party access on a non-discriminatory basis and that transparency is often lacking. Rendering the operation of LNG terminals more transparent and accessible, the commission said, would "ready for imports of renewable and low carbon gases." Germany, for example, has signed collaboration agreements with Saudi Arabia, Canada and Australia for potential imports of hydrogen and ammonia at its planned LNG terminals.

BINDING TARGETS FOR CLEAN GAS

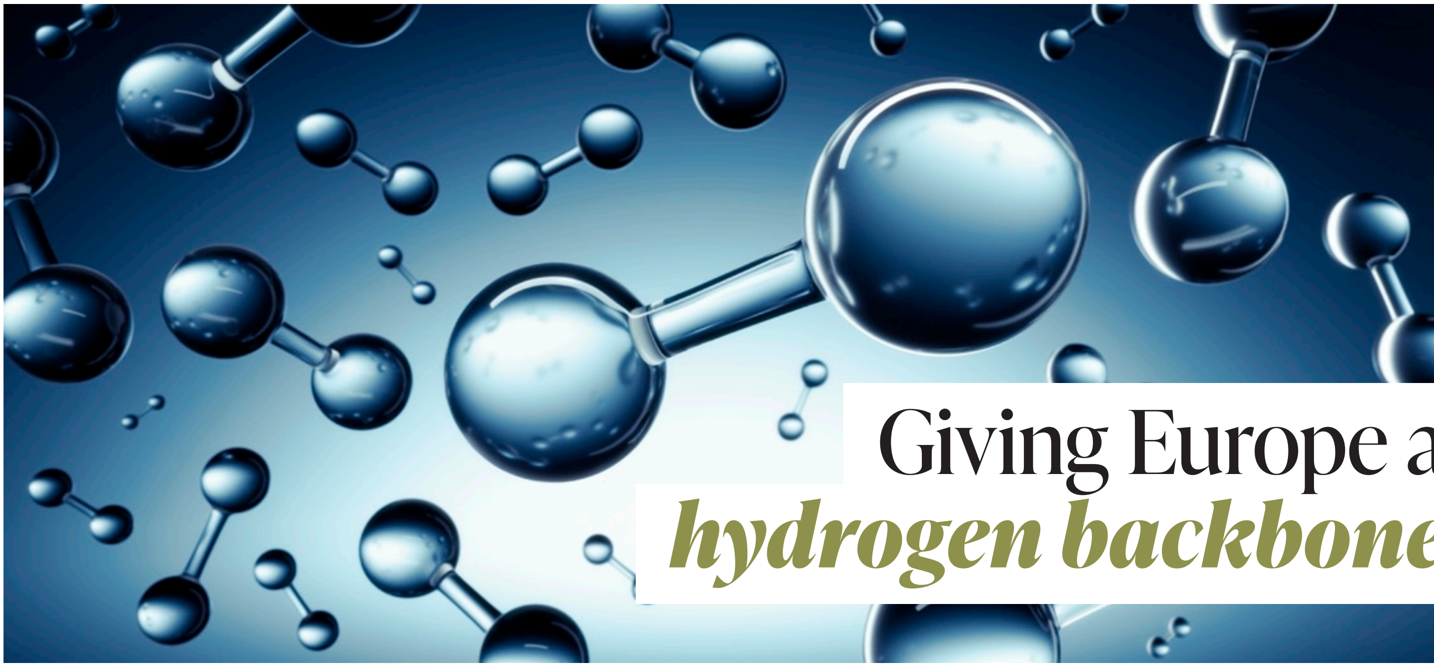
Security of demand also needs to be addressed. In the stakeholder consultation, French major Total called for a binding 2030 EU target of renewable gas by energy content in the natural gas grid for 2030. European gas lobby Eurogas specifically called for a binding target of at least 11% of renewable gas. A number of stakeholders – Total, Engie, and Shell among them – also called for an EU-wide Guarantees of Origin (GOs) market to replace the current, fragmented national markets. GOs would give traders and end-users the opportunity to check the origin of the gas, whether renewable, decarbonised, synthetic or blended. However, industry players acknowledged that GOs and binding targets for renewable gases should be tackled by the Renewable Energy Directive (RED) which is also under revision this year.

The revised RED will align the EU's renewables target with the new 55% by 2030 GHG emissions reduction target. That means the current renewables target of 32% by 2030 will have to be scaled up to around 40%, or possibly more. Players in the gas industry want decarbonised gases utilising CCS to count towards the renewables target, but this is meeting strong opposition from green groups, a number of MEPs and some utilities such as Enel and Iberdrola.

As for EU grants, the revised TEN-E regulation will set out new rules for eligibility. Under the new regulation, natural gas pipelines will no longer be eligible for status as Projects of Common Interest (PCI) which excludes them from receiving grants under the Connecting Europe Facility infrastructure fund. On the contrary, hydrogen and CO_2 transportation projects will be eligible for PCI status and financial support. The new rules are expected to enter into force in 2023. Meanwhile, the Taxonomy Regulation is key for financing from the private sector. Yet the EC has still not decided to what extent gas fired-power plants can be classified as a green investment under Taxonomy, for example if they replace coal plants. It is expected to make that decision later this year.

The EU's flagship climate tool, the Emissions Trading System (ETS), has favoured gas over coal in power generation. Whereas coal has been squeezed out in several countries, the UK and Spain among them, gas has defended or expanded its market share despite a sharp increase in prices for carbon allowances. Further ETS reforms, a tightening of the cap on allowances and the possible inclusion of the shipping sector, are expected to be agreed later this year. If prices for carbon allowances move higher, as many expect they will, coal plants look set to lose further market share while modern and efficient CCGT plants will be much better positioned.

All eyes are also on the upcoming proposal for a methane regulation later this year, which is an effort to strengthen reporting and monitoring requirements of methane emissions for oil and gas companies. Addressing methane leakage will be key for natural gas to position itself as a credible bridge fuel in the energy transition. One challenge for the EU, however, is that methane emissions from gas production in Europe are modest compared with third countries such as Russia, Algeria and the US, which export plenty of gas to Europe. •



Giving Europe a *hydrogen backbone*

THE 40,000-KM NETWORK WOULD BE COST EFFECTIVE, TRANSMISSION SYSTEMS ARGUE, LARGELY BECAUSE OVER TWO THIRDS WOULD COMPRISE EXISTING GAS PIPELINES

Karel Beckman

THE 40,000-KM so-called European Hydrogen Backbone would be "an attractive and cost-effective option for long-distance hydrogen transport", according to a study by 23 transmission system operators (TSOs) from 21 European countries coordinated by consultancy Guidehouse. Co-author Daan Peters, a director at Guidehouse, is very positive about the outcome of the study. "What we have shown is that long-distance transport of hydrogen in Europe can be done relatively cheaply, thanks to the excellent existing gas infrastructure network," he tells *NGW*.

The new report, *Extending the European Hydrogen Backbone*, is an expanded version of a study issued last year, in which 11 gas TSOs were involved. The new study involves 21 countries and presents a full-scale hydrogen transmission network with a length of 39,700 km running from Finland to Spain and from the UK to Italy and Greece, which could be ready by 2040. 69% of the hydrogen backbone would consist of repurposed natural gas pipelines and 31% would be newly built.

Total investment cost would be between €43bn and €81bn ($52-98bn), the researchers estimate. Transport costs are estimated to be €0.11-0.21/kg/'000 km, which the report describes as "attractive and cost-effective, taking into account an estimated future production cost of €1.00-2.00 per kg of hydrogen."

The comparatively limited costs owe much to the fact that over two-thirds of the network will be based on existing gas pipelines. "Building new hydrogen pipelines is much more expensive than converting them," notes Peters, who managed the production of the study for the consortium. The study shows that the capital investment for new hydrogen pipelines is roughly five times as high as for converting natural gas pipelines to hydrogen.

PARALLEL PIPELINES

The network's development would have quite a limited impact on natural gas transport capacity and flows in Europe, according to Peters. "Our plan assumes that most of the repurposed pipelines will be parallel ones which will not be in use by the time they are converted."

He explains that there is parallel capacity on many transmission routes. "From Tunisia to Italy there are five import lines of which only two or three are in use. From Ukraine via Slovakia and the Czech Republic to Germany there are also several routes, which are already being used less since Nord Stream 1 was built, and will see further reduction in use after Nord Stream 2 will be ready."

In Hungary, some of the transmission capacity is also used much less after the LNG terminal in Croatia came into operation, notes Peters. However, creating a route from Spain, where large-scale solar-based hydrogen production is planned, to France and Germany, will require quite a few new stretches, by 2035 when it is expected to come into operation.

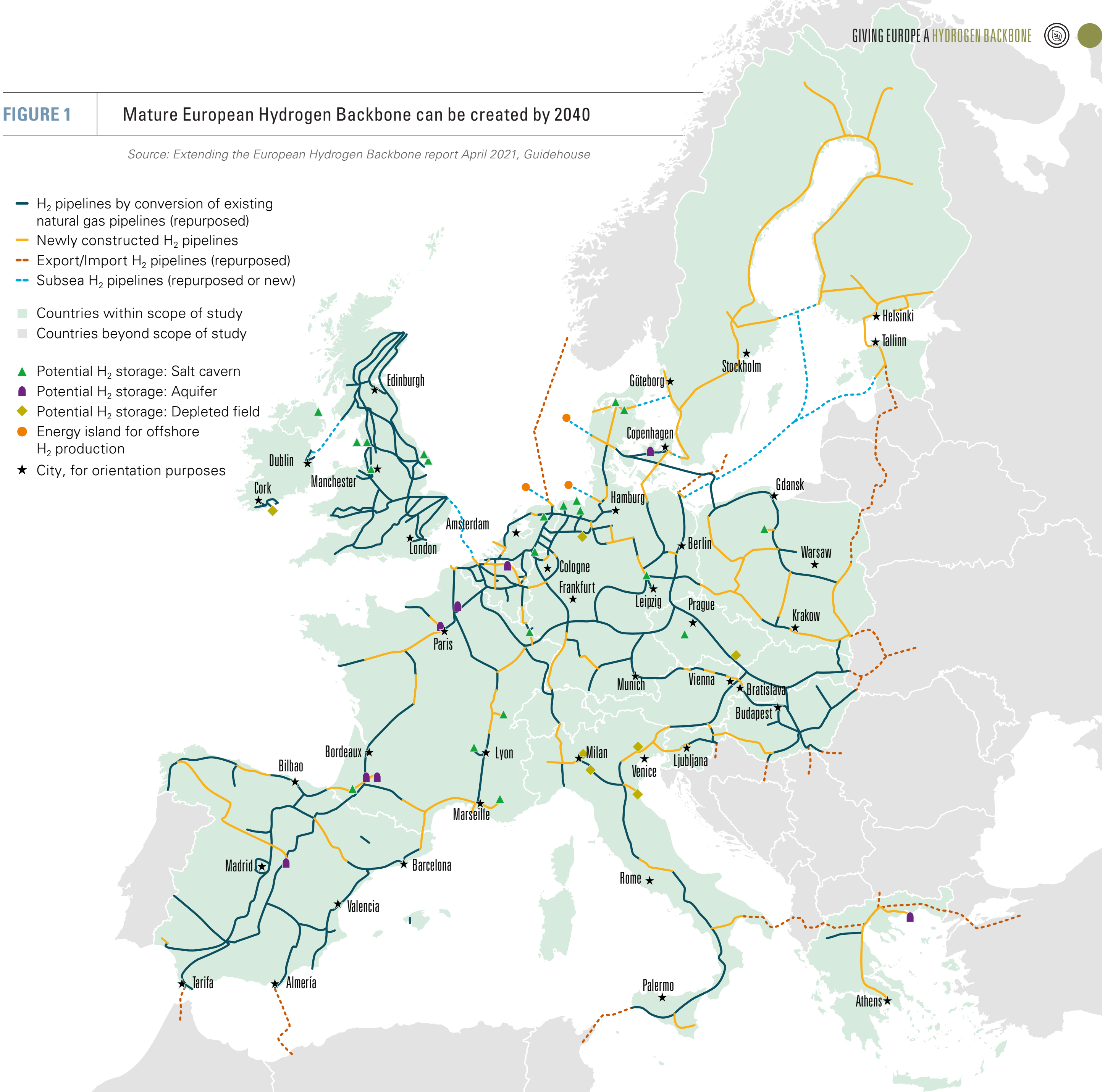
The researchers took into account existing long-term contracts, which they assume will be fulfilled completely, says Peters. "There are only some places where a choice will have to be made between natural gas and hydrogen, where market players or policy-makers will need to make an active decision to phase out natural gas or to build new hydrogen pipelines."

MODEST SIZE

Peters notes the 2040 hydrogen backbone is modest in size compared to the 200,000 km of natural gas

FIGURE 1 Mature European Hydrogen Backbone can be created by 2040

Source: Extending the European Hydrogen Backbone report April 2021, Guidehouse



A new plan proposes a hydrogen pipeline that would span Europe north to south and east to west, at a cost of nearly

$100bn

transmission capacity available in Europe today. "We analysed the amount of hydrogen that will be needed in 2040 to serve industrial hubs, heavy transport and electricity generation. That amounted to 1,100 TWh or just over 100bn m³. By 2050, the requirement may be around 1,700 TWh or 180bn m³. So the backbone will still need to be extended considerably after 2040."

The researchers did not take into account the possible need for distribution networks to serve homes and buildings. "We are not certain as yet how this segment will evolve."

What is needed next, says Peters, "is a good flow simulation study, to give us more insight into the dimensioning of the pipelines and the pathway." The initial plan, presented last year, included only cost estimates for 48-inch pipelines. The new version assumes that a large part of the network will consist of smaller 24- or 36-inch pipelines. These are cheaper to repurpose, leading to lower investment costs, but more expensive to operate.

There are no major technical obstacles that the researchers encountered. "Pipelines will need to be inspected. If they contain cracks, they may need to

FIGURE 2 Estimated investment and operating cost of the European Hydrogen Backbone (2040)

Source: Extending the European Hydrogen Backbone report April 2021, Guidehouse

		LOW	MEDIUM	HIGH
Pipeline cost	€ billion	33	41	51
Compression cost	€ billion	10	15	30
Total investment cost	**€ billion**	**43**	**56**	**81**
OPEX (excluding electricity)	€ billion/year	0.8	1.1	1.8
Electricity costs	€ billion/year	0.9	1.1	2.0
Total OPEX	**€ billion/year**	**1.7**	**2.2**	**3.8**

Daan Peters is a director in Guidehouse's energy, sustainability, and infrastructure segment. He provides strategic advice on the future role of gas and gas infrastructure both in Europe and the US. He worked at the Dutch infrastructure and environment ministry and as policy advisor in the European Parliament for the rapporteur on the Fuel Quality Directive (FQD). In 2011, he joined Dutch energy consultancy Ecofys, which was later acquired by US-based international consultancy Navigant, which last year changed its name to Guidehouse.

be given a coating on the inside. Otherwise, simple cleaning with nitrogen will suffice. New pipelines will probably need to be built with higher quality grade steel that's 10% to 20% more expensive than is used now."

Peters notes that the amount of hydrogen that is expected to be transported through a pipeline is substantially less than that of natural gas. "Hydrogen has one-third the density of natural gas, although it flows faster. Hydrogen capacity is around 80% of natural gas capacity in the same pipeline. However, we have calculated that it's most cost-effective to use around 60% of the capacity. This has to do with the costs of compression, which are higher for hydrogen. So this means that we assume a hydrogen pipeline will transport 60% of 80%, i.e. around half, of the amount the same natural gas pipeline would transport."

GIGANTIC VOLUMES

The researchers did not consider the possibility of blending hydrogen into the natural gas system. "Blending is possible, but we don't see it as a long-term solution."

Peters is in favour of scaling up the supply of "blue hydrogen", based on natural gas with CCS, if the remaining greenhouse gas emissions associated with this technology are compensated. However, he adds that blue hydrogen is likely to be only a medium-term solution. "What we see now is that by 2040, green hydrogen will become cheaper than blue. At a certain point, green will overwhelm blue with gigantic volumes, although remaining SMR and ATR units may continue to operate."

Guidehouse will publish new research on the supply side of the European hydrogen market in June, says Peters. These will include import figures.

Some environmental organisations are critical of the hydrogen pipeline plans. They argue that there is a risk that Europe's hydrogen strategy is used as "an excuse to prop up the gas industry and subsidise obsolete gas pipelines," as one critic put it.

But Peters believes this is misguided. "Our analyses show that if you want to be climate neutral by 2050, you can't do it without hydrogen. You need it to balance the grid, for your heavy transport and for high-temperature industrial processes."

"We have this great natural gas infrastructure that we can repurpose relatively easily," he continues. "You can try to do everything with electricity, but then you won't recognize the continent, so many power lines would be required.

Gas infrastructure, as electricity infrastructure, is used to transport fossil energy today and will be used to transport renewable and low carbon energy tomorrow." •

The European Hydrogen Backbone would be 39,700 km in total length, 69% comprised of repurposed existing infrastructure and 31% of new hydrogen pipelines. It would run from Ireland to Hungary, and from Spain to the Nordic countries, linking different regions with different renewable energy profiles. Its proponents say it offers a cost-effective way to transport large volumes of renewable energy to demand centres, creating security of supply and a liquid European market for hydrogen. It would also enable hydrogen pipeline imports from Europe's eastern and southern neighbours, as well as liquid hydrogen imports from other continents via Europe's main harbours.

GAS IN TRANSITION

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