GAS IN TRANSITION

BY THE INTERNATIONAL GAS UNION IGU

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ENERGISING A SUSTAINABLE FUTURE

WGC2025 | BEIJING 19 - 23 MAY

Natural gas: strong growth today, strong growth tomorrow

Affordability is paramount for Asia Pacific and LNG

Molecules of change: Introducing the top low-carbon gas technologies

Efficacy of policy in shaping a low carbon energy future

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Message from the President

This will be my last message to you, as the President of the International Gas Union. The past three years of the Chinese Presidency of the International Gas Union have been, one could argue, some of the most complex years – if not the most complex – both the Union and our global Gas industry had to face:

- The remnants of a global pandemic in which immediately available, reliable and affordable energy sources had to meet an intense demand from household consumption as the restrictions imposed by the world's governments saw millions of people confined to their homes throughout the year;
- A war breaking out in Europe, which tested the European countries' preparedness and readiness for the energy crisis that soon ensued;
- Gas stepping in to meet and plug the energy demand gaps caused by a rapid economic recovery across developing economies, particularly in Asia.

At the height of the COVID-19 pandemic, many of us working in the Gas industry did not know what the future would bring, nor what it would look like. There was one thing we knew for sure: we would be ready to tackle the uncertainties of Gas demand, supply and consumption. And we did.

The International Gas Union stayed true to its mission and purpose: to improve the quality of life by advancing Gas as a key contributor to a sustainable energy future. Our members across the globe made that possible and continue to do so relentlessly, and with a renewed determination to demonstrate the essential role of Gas for human progress and global growth.

As such:

- According to IEA's preliminary data, natural gas consumption increased by 2.8% year-on-year (y-o-y) in the first three quarters of 2024 (Q1-Q3 2024) – well above the 2% average growth rate between 2010 and 2020. For the entire 2024, global gas demand is forecast to have reached a new all-time high of 4,200 bcm;
- Estimated to surpass USD 600 billion for the first time in a decade, oil and gas upstream investment in 2024 is expected to be more than double 2020's low of USD 300 billion, according to the International Energy Forum, and be well above the 2015-2019 levels of USD 425 billion, showing a strong recovery of investments in critical oil and gas infrastructure;
- The global biomethane production is gaining momentum, with new centres of production emerging beyond the traditional market leaders of the EU and the US, experiencing a significant growth in the past three years, reaching 7.7 billion cubic meters (bcm) in 2022, representing a 20% increase from 2021, with further projected growth to 9.5 bcm in 2023, marking a 23% increase;
- The global hydrogen project investments have grown seven-fold since 2020, from 228 projects in 2021 to 1,572 projects in 2024 across the entire value chain, and it is currently estimated that the direct hydrogen investments will reach 370 billion USD by 2030;

I am very excited about the future of our Gas industry, about its potential and endless innovation capabilities but, irrespective of this progress curve, I am mindful of one thing that matters a lot to me, to the IGU and to our global Gas industry: our decarbonisation efforts must be ramped up, and all our organisations should adopt a zero-methane emissions culture, focused on the deployment of monitoring, verification, and emissions reduction technologies.

We are the buffer between high carbon-emitting fuels and renewable energy sources, and our efforts to do more, do better, and do so efficiently should never stop.

I find it hard to believe that this will be the last time I have the honour and privilege to address each and every one of you reading this magazine and, if you permit me, I'd like to share with you some of our most remarkable achievements over the past three years, achievements that could have never happened without the fantastic support I received from our Vice President – Mr Andrea Stegher – and the IGU Secretariat led by our Secretary General, Menelaos (Mel) Ydreos:

- The IGU Charter and Articles of Association have been revised to ensure full Gas maximisation benefits and a much closer collaboration with our members;
- In terms of global and institutional outreach, over the past three years, we have hosted side events at the COP in Azerbaijan (2024) and UAE (2023); and co-hosted the G7 Energy Security Forum meetings highlighting the unique and vital role of natural gas in achieving energy security and climate objectives;
- Multiple high-level industry and diplomatic events were held in China, events whose purpose was to reinforce IGU's position as the spokesperson of the global Gas industry, and to demonstrate the significant commitment and dedication of the Chinese Gas industry to global co-operation and knowledge-exchange;
- We launched our first public Manifesto earlier this year, a powerful fact-based statement on the role of Gas (in all its forms and types) in a sustainable, just and orderly energy transition;
- We improved the IGU governance meetings by adding a strategic discussion session to the Executive Committee and Council meetings, providing members with deep insights into the Gas industry;
- The Membership Retention and Growth Report has been formulated, and a series of measures to enhance the IGU governance meeting experience, as well as increase member value, have been discussed.
- We established a permanent and professionally staffed IGU Secretariat based in London to ensure we maximise the value, support and services we provide to our members;

I am also very optimistic about the future of our industry as, globally, more than USD 720 billion is to be spent on Gas pipelines under construction or planned, and an additional USD 190 billion is to be put into facilities to handle liquefied natural gas (LNG) imports, while an additional USD 969.8 billion will be allocated to facilities handling LNG exports.

In less than two months' time, at WGC2025 taking place in Beijing, I shall pass the relay of the IGU Presidency to Andrea Stegher of Italy. I know that under his leadership IGU will thrive and continue on its current path of advocacy and representation of our members and our global Gas industry.

Progress, just like it happens in any of the organisations we work for, must be built on and consolidated. Our industry is facing multiple challenges on a multitude of fronts, out of which the most complex of them all is the geopolitical one which leads, as we have seen so many times in the past, to market instability and a significant delay in FIDs.

Market volatility creates challenges, indeed, but it also forces us to identify opportunities where there are, seemingly, none – we did it before, and we can certainly do so in the future. We know that Gas is essential to human progress and global growth, and we have to make sure that our message is heard loud and clear. We need to ensure, together, that energy choices are made available to those who need them the most.

If you attend the largest World Gas Conference ever organised by the IGU in its almost 100 years of existence – WGC2025 in Beijing – please come and share your thoughts with us on what we need to do more and do better for the IGU, for our members and for our global Gas industry.

And, as a final remark, I would like to thank all of you for the support you have shown to our "*Gas In Transition*" magazine and to me, personally, as the first female President of the IGU!

Li Yalan
President, International Gas Union

GAS IN TRANSITION. MARCH 2025

Editor's Note

In just a few weeks, the International Gas Union (IGU) will convene its 29th World Gas Conference, WGC2025, in Beijing. Hosted by Beijing Gas during May 19-23, WGC2025 carries the theme Energising a Sustainable Future, with more than 400 speakers addressing key issues facing the global Gas industry, from energy security and the integration of Gas and renewable energy sources to advances in the deployment of hydrogen and digital transformations coursing through the industry.

But ahead of WGC2025, global energy markets are roiling in the wake of geopolitical events in Europe and US President Donald Trump's fast-evolving domestic and international policies that impact both energy and the environment.

In Europe, the finality of the end of gas transit in Ukraine and the impact this has had on the availability of Russian piped gas has brought into question the security and affordability of natural gas throughout the EU.

And more recently, missile strikes by Russia against its gas storage and production facilities in February prompted Ukraine to ask its allies for help in increasing its gas imports by a third.

In North America, President Trump unleashed a flood of executive orders that, among other things, declared a national energy emergency and pulled the US out of the Paris Agreement. His moves have grabbed attention on the global oil and gas stage, and were brought into sharp focus in early March, at CERAWeek by S&P Global in Houston, as world energy leaders moved to position themselves against the backdrop of an aggressive American stance on both energy and the environment.

In what was perhaps the starkest reversal, International Energy Agency (IEA) director Faith Birol told delegates there was a need for new oil and gas investments to support energy security. In 2021, Paris-based agency said companies should not invest in new oil, gas and coal projects if net zero by 2050 aspirations were to be reached.

In Houston, however, Birol emphasised that underinvestment in existing oil and gas fields is a problem as fossil fuels are needed to meet global energy demand. Of the total $400bn in investments in global oil and gas, about $360bn goes into offsetting the decline in existing oil and gas fields.

"I want to make it clear...there would be a need for investment, especially to address the decline in the existing fields. There is a need for oil and gas upstream investments, full stop."

Saudi Aramco CEO Amin Nasser offered much of the same sentiments, saying policymakers and energy executives need to stop doubling down on things that don't move the transition needle and return instead to investing in fossil fuels to meet demand.

"It is time to stop reinforcing failure," Nasser said. "In fact, there is more chance of Elvis speaking next than the current plan working."

Newly-installed US Energy Secretary Chris Wright pumped the tires of the global natural gas industry and pointed out that his predecessor, Michigan Democrat Jennifer Granholm, had stood on the CERAWeek stage a year earlier predicting that US LNG exports would soon be in the rear-view mirror.

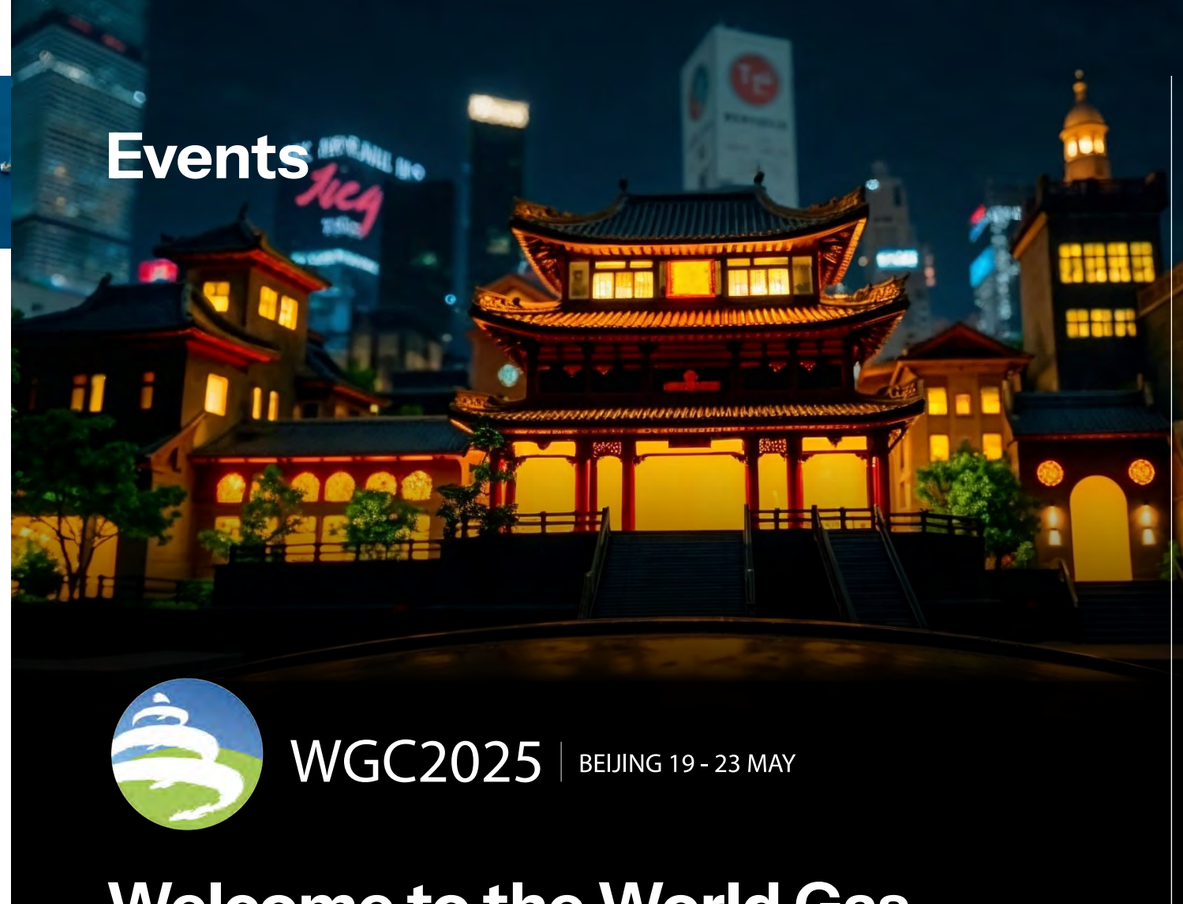
"Think about that for a moment," he said. "Natural gas today supplies 25% of global primary energy and has been the fastest growing source of energy over the last 15 years."

Natural gas, he said, is the largest source of home heating in the US, the largest supplier of processed heat for many industries and the fuel of choice for 43% of US power generation.

At the same time, the blinkered focus of the previous administration on developing wind and solar for power grids has resulted only in higher grid prices and reduced grid stability, he added. "Is this pathway really going to put natural gas in the rear-view mirror?"

As the global Gas industry gathers in Beijing, President Trump's actions, Russia's imperatives and the Gas market's response to both – not to mention to other pressures – will be critical in laying out a pathway to a sustainable energy future.

Dale Lunan
Editor, *Gas in Transition*



Events

WGC2025 | BEIJING 19 - 23 MAY

Welcome to the World Gas Conference 2025!

There is one place where the world's policy makers, industry stakeholders, delegates, speakers, exhibitors and sponsors gather every three years, as they have done so for the last almost 100 years, and that is the International Gas Union's World Energy Conference which, this year, is held in Beijing, China!!!

Over four days, this remarkable global Conference and Exhibition will feature strategic, commercial and technical sessions where more than 400 industry leaders will debate and discuss the role of Gas in building a more prosperous, secure, and sustainable society for all.

With an impressive line-up of expert speakers and a world-class exhibition showing cutting-edge innovations, WGC2025 will be an event to remember as it is the first time ever that is hosted in Beijing, China!

Over a week, you'll have the opportunity to take part in a series of exclusive networking sessions, perfect for connecting with your peers, exchanging ideas, and establishing meaningful business relationships and successful partnerships.

In a purposely built and state-of-the-art venue - China National Convention Center – the facilities of this unparalleled Conference on the triennial global Gas events agenda are unmatched. With very few opportunities left to register, we urge you not to miss what WGC2025 has to offer, including a direct and unmitigated access to the world's largest consumer and Gas market! All the details you need are at: www.wgc2025.com.

We also invite you to visit us at the IGU booth onsite at WGC2025, as the entire IGU Secretariat team will be there to share with you why, even after almost 100 years, we still remain the spokesperson of the global Gas industry and the special benefits and opportunities only our members have!

See you in Beijing!

Regional Updates

Europe

Didier Holleaux
Executive Vice President Engie and IGU Regional Coordinator.

1. Natural Gas

The Russian war in Ukraine and its consequences were still the main factors influencing the natural gas market in Europe during the past six months.

The main new element was the interruption of the flow of Russian gas through Ukraine at the end of the contract between Gazprom and Naftogaz/Ukrtransgaz on December 31, 2024. This flow represented between 13 and 15 bcm/year in both 2023 and 2024.

That means that the flow of Russian gas to Europe is now well below 40 bcm/year (two thirds as LNG from Yamal LNG, one third by pipe through Turkstream) compared with nearly 155 bcm/year in 2021.

The market reacted to the announcement of this interruption, combined with a relatively cold weather in December and January, by increasing the price of gas in Europe from around 40 EUR/MWh to around 50 EUR/MWh (equivalent to US$13-$16/mmBtu).

The interruption impacted mostly Eastern European countries like Moldova, Slovakia, Austria and Hungary. Austria had already diversified its supplies following the interruption by Gazprom of its contract with OMV in November (following an international arbitration won by OMV). Slovakia and Hungary have alternative sources of supply available even if they may be more expensive than their past Gazprom contracts. But the case of Moldova is very difficult both on gas and power, as the country is poor and divided, with a pro-Russian province (Transnistria) which was so convinced that Russia will continue to supply cheap gas to them that they never prepared an alternative solution. With the support of European institutions, an alternative supply from the West is being called up as a matter of emergency for Moldova (including Transnistria).

In addition, the new US sanctions against GazpromBank made it more difficult to transit Russian gas (delivered through Turkstream) across Europe and reinforced the feeling that the European gas market was tight.

LNG

In an unprecedented effort since 2022, a dozen floating LNG terminals have been installed in Europe. If the Netherlands were the first to react to the invasion of Ukraine, by installing one as early as September 2022, since then France, Germany, Italy, Greece etc. have each added one or several FSRUs and connected them to their grids. The resulting additional LNG import capacity is more than 60 bcm/year. In addition, some LNG could also be regasified in Turkey and imported in Europe (Greece, Bulgaria).

This allows the European industry to import LNG even in Central and Eastern Europe.

But at the same time, few new long term LNG contracts are being signed by European players. This seems to be the result of a combination of factors:

- Some reluctance of European players to commit long term when EU wants to put an end to fossil fuels by 2049 at the latest,
- Uncertainties about the availability of additional US LNG (itself a combination of the “pause” decided by the former US administration, of the unpredictability of the new US administration, and of the bad experience of European customers with one of the US LNG plant operators who is still not delivering according to contract),
- and, more recently, uncertainties about the willingness of Qatar to deliver LNG to Europe (considering the legal constraints imposed by Europe upon its suppliers).

On the spot market, and taking into account the price increase mentioned above, Europe was able to attract more LNG in the past three months than on average in 2024.

The situation will remain very tight on the LNG market in 2025 and 2026, and if the winter is cold in Europe, or if there is a production accident (like the interruption of Snohvit LNG in January 2025), the prices may increase even further.

Markets

The industrial market for gas remains depressed in Europe: with prices 4 to 6 times higher than in the US, many industries cannot produce at full capacity or are even forced to close down.

On the domestic heating market, it appears that some of the countries who had decided to ban gas heating from homes (mainly new homes, but in some cases old ones) are realizing that this policy was ill-founded and inapplicable, and are changing it.

2. Green gases

The green gas production in Europe is progressing, unfortunately the systems (including the Union DataBase) which should allow this green gas to find the best markets (i.e. the customers who are the keenest to pay for this particular green gas, wherever they are in Europe) aren’t yet in place. This situation results in a suboptimal allocation of resources and a fragmented European market.

Renewable methane

The production of biogas and biomethane is nevertheless very dynamic, and the final 2023 figures for the EU show a total of 22 bcm (equivalent to one fifth of the missing Russian gas).

The production of biomethane (i.e. gas produced by anaerobic digestion, then purified and injected in the network) alone was more than 5 bcm and growing fast (expectations are between 20 and 30%/year). The targets of 35 bcm by 2030, 74 bcm by 2040, 151 bcm by 2050 seem reachable.

Gasification of timber and waste (mostly pyrogasification) is also progressing, but more modestly. The target remains 37 bcm by 2040.

Hydrogen

Hydrogen has been progressing in Europe more slowly than anticipated.

A combination of high costs (inflation), customers reluctant to commit because of these costs, producers being attracted to the US by IRA promises and slow subsidies decision process in EU explains this slow development.

It is unclear how the decisions of the new US administration on IRA will impact the green and blue hydrogen projects.

At the same time, the hydrogen infrastructures projects are still progressing. Germany announced 525 kms of H2-pipes in 2025, and the local or regional hydrogen pipe projects receive a lot of interest. On the storage side, 12 European TSOs created the H2eart organization to develop hydrogen projects and some salt cavities are being converted to H2.

Natural Hydrogen (usually known as “white”) is a topic of growing interest: the Hnat world congress in Paris in November attracted more than 250 people from all continents and numerous exploration projects are ongoing. Generally speaking, because of the slow development of the green H2 projects, more people are looking into other colors (including methane pyrolysis to produce hydrogen (known as “turquoise”) and black carbon).

Conclusion

More and more people in Europe are realizing that electricity alone cannot solve the problem of energy transition, and that gas will be needed in the long term as a part of the energy system. Biogas and biomethane are already scaling up to play a major role, when natural gas+CCUS, and different colors of hydrogen, are still at an early stage, but attract more and more interest in Europe. The tightness of the natural gas market, with its associated volatility and high price, reinforces this interest for green and low carbon gases. ●

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Regional Updates

GAS NEWS FROM AROUND THE WORLD

Africa

Eng. Cav. Khaled AbuBakr
Chairman, Egyptian Gas & Energy Association
Chairman, TAQA Arabia
IGU Regional coordinator

North Africa: Egypt helps in promoting and releasing Cypriot gas to the global market.

During the opening of EGYPES 2025, Eni has signed an agreement with Egypt and Cyprus to develop and export gas from Cyprus' Cronos Block 6, leveraging Egypt's existing hydrocarbon infrastructure. The agreement aims to establish a gas hub in the Eastern Mediterranean, transporting gas to Egypt's Zohr facilities before liquefaction at the Damietta LNG plant for export to Europe. Cronos, discovered in 2022 and appraised in 2024, holds over 3 trillion cubic feet (tcf) of gas, with further potential in Block 6.

Moreover, during the last three months, Egypt has been progressing its gas sector with new investments and initiatives to bolster production. One of the latest is the beginning of production from the Raven field's second development phase offshore Egypt by bp, tying back additional subsea wells to its onshore infrastructure under the West Nile Delta (WND) project. The new wells are expected to yield 220 billion cubic feet (bcf) of gas and 7 million barrels (mmbbl) of condensates.

Also, Shell has brought online two of three wells drilled as part of Phase 10 of the West Delta Deep Marine (WDDM) Project, adding 86 mmcf/d to production. The project's total output is now 286 mmcf/d.

Besides, ExxonMobil has struck gas at its Neferatari-1 exploration well in Egypt's frontier Herodotus basin. Meanwhile, Eni plans to begin drilling two wells at one of Egypt's largest gas discoveries, the Zohr gas field, in 2025. Additionally, Badr Petroleum Company plans to drill three exploratory wells, four development wells, and the re-completion of 12 existing wells for the next two years to increase production from its Badr-1 field. Badr-1 field has already seen success with the 10-2X exploratory well, which currently produces approximately 20 mmcf/d of gas.

Morocco is set to launch tenders in 2025 for the initial phases of the Nigeria-Morocco Gas Pipeline (NMGP) as part of the 2025 Action Plan from the National Office of Hydrocarbons and Mines (ONHYM). The tenders will cover the Moroccan sections of the pipeline, which is a key player as it will connect 16 countries, primarily along the Atlantic coast and eventually to Europe. The first phase will involve Morocco, Mauritania, and Senegal, with additional agreements for gas transport expected to be signed in 2025. A private company will be established to manage the construction, operation, and maintenance of the project.

East Africa: Mozambique Announces New Natural Gas Discovery in Inhambane Province and Tanzania Expands Natural Gas Development with New Wells and LNG Project

The Mozambican government announced in November 2024 a natural gas discovery in the Inhambane Province. The new find is a result of the first well, drilled by Sasol in the Pande and Temane onshore area (PT5-C) located in the Mozambique Basin. This discovery adds to Mozambique's existing gas resources, including those from the Coral South and Rovuma LNG projects. The government confirmed the presence of natural gas during the operation of the first borehole in the PT5-C area and noted that additional evaluations will follow to determine the size and viability of the discovery.

Tanzania: Maurel et Prom Exploration Production Tanzania (M&P) is finalizing plans to drill three new wells in the Mnazi Bay Block expected in early 2025. This project includes two production wells (MB5 and MS2) and one exploration well (Kasa), with an estimated budget of $80.2 million. The drilling aims to maintain the production plateau and gather more geological data about the reservoir. Currently, the Mnazi Bay block has five operational wells producing an average of 74.24 mmcf/d, accounting for 48% of Tanzania's total natural gas production. Additionally, Positive progress is underway on the $42-billion Shell-Equinor LNG project in Tanzania, which will contribute to domestic energy needs while supporting global LNG exports.

West Africa: BP Begins Gas Flow at GTA Phase 1 LNG Project offshore Mauritania and Senegal: Nigeria Grants License for First Floating LNG Facility to Reduce Gas Flaring and Enhance Supply, and TotalEnergies Plans $750 Million Gas Project to Expand Production in Nigeria

BP has begun gas flow from the wells at the Greater Tortue Ahmeyim (GTA) Phase 1 liquefied natural gas (LNG) project to its floating production storage and offloading (FPSO) vessel for the next stage of commissioning. The gas from GTA Phase 1 is being transported to the GTA FPSO, approximately 40 km offshore Mauritania and Senegal, where water, condensate, and impurities are removed. Subsequently, the gas will be transferred via pipeline to a floating liquefied natural gas (FLNG) vessel located 10 km offshore to be cooled and stored for export and the domestic energy demand in Mauritania and Senegal. GTA Phase 1 is expected to produce around 2.3 MTPA of LNG.

Nigeria advances FLNG Project to Curb Gas Flaring as it has approved UTM Offshore Limited to build its first Floating LNG facility, capturing flared gas from ExxonMobil's Yoho field. The 2.8 MTPA plant will reduce gas flaring, boost domestic supply, and enhance LNG exports. It will deliver 500,000 metric tons of LPG locally, with LNG designated for export. Engineering will finish by 2028, with production starting in 2029. Afreximbank is financing the project with $2.1 billion for phase one and a $3 billion commitment for phase two.

Moreover, TotalEnergies is planning a $750 million gas project in Nigeria next year to expand its hydrocarbon production in Africa. Mike Sangster, Senior Vice President Africa at TotalEnergies, announced in December the Ima dry gas project at a France-Nigeria business forum in Paris. Since President Bola Tinubu took office in May 2023, Nigeria has focused on addressing oil and gas sector challenges and aims to attract up to $10 billion in new investment through tax breaks and other measures. Sangster noted that regulatory changes have encouraged TotalEnergies to renew its investments in Nigeria to increase production.

South and Central Africa: Eni Begins Production at Baleine Field, Africa's First Net Zero Emission Upstream Project, Angola's New Gas Consortium to Commence Production from Quiluma and Maboqueiro Gas Fields by 2025, and Chevron Starts Production at Sanha Lean Gas Connection Project in Angola.

Eni has started production at phase 2 of the Baleine field offshore Cote d'Ivoire, the first net zero emission Upstream project (Scope 1 and 2) in Africa. The second phase is expected to reach production of 60,000 barrels per day (bbl/d) of oil and 70 thousand cubic feet (mcf)/d of associated gas (equivalent to 2 million cubic meters). The oil will be exported through Petrojarl Kong and Yamoussoukro vessels while 100% of the processed gas will be allocated to secure the country's local energy demand through the connection with the pipeline built during the Baleine's first Phase. Currently, phase 3 is under study and is anticipated to boost production alongside phase 2 to reach 150,000 bbl/d of oil and 200 mcf/d of associated gas.

Angola's New Gas Consortium (NGC), led by Azule Energy (a joint venture between Shell and Eni), has announced plans to commence production from the Quiluma and Maboqueiro gas fields by 2025. This $4 billion project aims to develop Angola's first non-associated gas project, enhancing the country's energy security and diversifying its energy mix. The project will supply 5.2 MTPA of gas to the Angola LNG plant, ensuring it operates at optimal efficiency. Additionally, the increased gas production will support domestic needs, including the Soyo Combined Cycle Power Plant, and promote self-sufficiency in cooking gas production.

Furthermore, Chevron commenced production of natural gas from the Sanha Lean Gas Connection Project in shallow water Block 0. The first stage of the project will deliver 80 mmcf/d of gas to the Angola Liquefied Natural Gas (ALNG) plant. The second phase will add a further 220 mmcf/d of gas with the commissioning of the Booster Compression module. Besides supplying gas to the 5 MTPA ALNG plant, the project will also supply gas from the Sanha field to the 750 MW Soyo power plant. Chevron aims to increase gas production by a further 300 mmcf/d, bringing the total amount to 600 mmcf/d. ●

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GAS NEWS FROM AROUND THE WORLD

Northeast Asia and Australia

Satoshi Yoshida
Senior Adviser, Japan Gas Association, and IGU Regional Coordinator.

Australia

On October 6, 2024, at the LNG Producer-Consumer Conference (LNG PCC) 2024 held in Hiroshima Japan, the Japan Organization for Metals and Energy Security (JOGMEC) and Woodside Energy signed a Memorandum of Understanding (MOU) creating the Methane Emissions Technology Reduction and Innovation Collaboration (METRIC), which supports collaboration on methane emissions management.

Under the MOU, JOGMEC and Woodside will promote collaboration on methane management with Japanese companies to collaborate on technologies related to the detection and quantification of methane emissions.

This MOU will strengthen the relationship of both importers and exporters, upstream to downstream, to support future decarbonisation of the LNG value chain.

This highlights the strengthening collaborations among and across borders along the natural gas value chain to reduce methane emissions.

Reducing methane emission along the natural gas value chain is critical for the natural gas industry to continue to play an important role towards 2050 and beyond.

China

Sinopec forecasts China's petroleum consumption to peak by 2027 as diesel and gasoline demand weakens. Broader use of LNG and electric vehicles would reduce demand for gasoline and diesel. By 2030, China's natural gas consumption is expected to reach 570 bcm and plateau at around 620 bcm between 2035 and 2040.

Energy-related carbon emissions are expected to peak before 2030 at between 10.8 billion and 11.12 billion tons as gasoline and diesel fuel is converted to natural gas and the region sees strong growth of renewable energy.

Chinese Taipei

A series of new LNG contracts have been signed to secure the stable supply of LNG, a mainstay of energy for Chinese Taipei.

In June 2024, Qatar Energy signed definitive agreements with CPC Corporation covering the long-term supply of LNG and a partnership in the North Field East (NFE) LNG expansion project.

The same two parties signed a sale and purchase agreement (SPA) for the delivery of 4 MTPA of LNG from the NFE project to CPC over a period of 27 years.

Additionally, they signed a share sale and purchase agreement under which QatarEnergy will transfer a 5% interest in one NFE train, which has a capacity of 8 MTPA, to CPC.

CPC Corporation announced on August 16, 2024 that it has received approval from Australian authorities for its acquisition of a 10% stake in Carnarvon Energy's Bedout sub-basin exploration permits, offshore Western Australia, from Carnarvon Energy.

Japan

The Ministry of Economy, Trade and Industry (METI) unveiled a draft of its revised Basic Energy Plan in December 2024.

The Basic Energy Plan defines the medium- to long-term direction of Japan's energy policy. It is formulated by the government based on the Basic Act on Energy Policy and revised every three years.

Some highlights concerning the gas industry are as follows:

1. LNG-fired power is positioned as a necessary means of energy transition to cleaner energy.
2. The plan stresses the needs of the government and the private sector to jointly secure the long-term LNG contracts to enhance energy security and invest in upstream natural gas infrastructure.
3. JOGMEC, a government agency under the jurisdiction of METI, provides various financial supports for resources exploration, new gas infrastructure and offers liability guarantees to companies.

New Zealand

Natural gas is back in focus as New Zealand faces an energy crisis. New Zealand passed legislation to reverse the ban on offshore and oil and gas exploration early in 2025, allowing new exploration projects to proceed. This change aims to boost energy security for the nation and attract investment in the sector. The government aims to balance energy needs and environmental concerns.

A previous government halted the new oil and gas exploration permits in 2018, aiming to achieve 100% renewables electricity by 2030.

Due to the recent spike in wholesale power prices caused by dry weather, the government is returning to natural gas for a reliable source of power generation.

New Zealand has proven reserves equivalent to seven times its annual consumption.

South Korea

In its 11th Basic Plan for Electricity Supply and Demand, Seoul confirmed its return to nuclear expansion, reversing the previous administration's policies.

South Korea is expanding its nuclear power capacity. By 2038, the country plans to increase its nuclear fleet from 26 to 30 reactors. This includes constructing up to three large new reactors and small modular reactors (SMR) as part of its nuclear expansion strategy.

The government is investing in SMR development to enhance energy security and support decarbonisation.

The return to nuclear power will affect the country's imports of LNG. South Korea is expected to reduce reliance on fossil fuel imports and aims to cut fossil fuel imports from 81.8% in 2021 to 60% by 2030.

Currently, South Korea is the third largest market for LNG after China and Japan, importing 60.6 bcm of the fuel in 2023, equivalent to 11% of the global market. ●

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New Member Focus

A SPOTLIGHT ON OUR NEWEST MEMBERS

ONHYM

The National Office of Hydrocarbons and Mines (ONHYM) is a Moroccan public institution, established on August 17, 2005, through the merger of BRPM and ONAREP. With legal and financial autonomy, ONHYM leads the exploration, exploitation, and midstream activities of hydrocarbons, alongside the development of mineral resources, excluding phosphates. It promotes investment and partnerships, develops databases on Morocco's subsurface potential, and negotiates agreements to foster collaboration. Focused on innovation and excellence, ONHYM drives exploration projects, supports midstream infrastructure development, attracts investment, and optimizes resource management to position Morocco as a leader in hydrocarbon and mining assets development.

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We're a team focused on providing energy solutions for Mexico and North America. By delivering cleaner energy to the people in Mexico, we help to build a future of sustainable prosperity. Today, we're taking action to make that energy more accessible, more sustainable, and more secure, bringing natural gas to underserved regions and increasing reliability in the regions we already serve. Our presence in Mexico spans around 30 years. Since then, we have built and operated the Naranjos - Tamazunchale; Manzanillo – Guadalajara; Tamazunchale - El Sauz; El Encino – Topolobampo, El Oro – Mazatlán and the Sur de Texas – Tuxpan pipelines, and we are building the Tula – Villa de Reyes pipeline and Southeast Gateway, a marine pipeline in partnership with CFE, to supply natural gas to the south and southeast Mexico. Our company was built to help our partners seize opportunities like these and to provide the energy solutions Mexico needs.

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Argentine Institute of Oil and Gas (IAPG)

The Argentine Institute of Oil and Gas (IAPG) serves as Argentina's official representative to the World Petroleum Council. It has been a charter member of the International Gas Union for many years and collaborates with the Argentine Committee of the World Energy Council (CACME), which represents our nation at the World Energy Council.

Established in June 1957 from the Argentine Section of the South American Oil Institute, IAPG is a non-profit think tank dedicated to supporting the oil and gas industry. Our mission encompasses providing comprehensive technical assistance through extensive research and analysis across various sectors related to these industries, including technical, economic, regulatory, statistical, and environmental domains. The IAPG boasts approximately 200 members comprising national and international oil and gas companies, alongside 700 individual partners.

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Origem

Origem Energia is an integrated energy and infrastructure company focused on Brazil's development through energy integration. It operates 14 onshore oil and gas concessions, including one offshore, in the states of AL, BA, ES, and RN, as well as 18 exploratory blocks in the Sergipe-Alagoas and Tucano Sul basins. In the Alagoas Hub, it operates the country's first privatized Natural Gas Processing Unit (UPGN), two production stations, five collection stations, and a 230 km pipeline system connected to TAMAC and the TAG network. Since February 2025, it has also been operating the MAC11A area in TAMAC. Additionally, in 2025, it is set to launch Brazil's pioneering underground natural gas storage project.

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GAS IN TRANSITION. MARCH 2025

New Member Focus

MudoZangl Limited

At MudoZangl, we leverage our Hybrid Intelligence™ model to ensure the right mix of domain expertise and technology. This approach delivers clarity across the value chain, resolves ongoing challenges, mitigates future risks, and creates lasting value for our clients. Our Integrated Gas Management module with its immutable cryptographic transaction system, for example, is the only commercially available solution that enables you to seamlessly manage your gas portfolio without any gas transaction disputes. Other special features include:

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Natural gas: strong growth today, strong growth tomorrow

MENELAOS (MEL) YDREOS
IGU Secretary General

In a recent interview with Gulf Intelligence, IGU Secretary General Menelaos (Mel) Ydreos discusses the key developments shaping the natural gas sector today, and how the energy transition should not take priority over energy security and affordability in developing countries.

JOSEPH MURPHY

Global gas markets are undergoing a critical period of growth and transformation, driven by rising demand, geopolitical shifts and the push for decarbonisation, Menelaos (Mel) Ydreos, the Secretary General of the International Gas Union, told Gulf Intelligence in a video interview in February. Though markets remain tight, natural gas remains essential for economic development, energy security and emissions reductions, playing a central role in the global energy mix, he said.

In 2024, gas demand increased by 2.6-2.8%, significantly above the pre-COVID 10-year average of around 2% per year. This equated to more than 3.5 trillion cubic feet of additional gas, with half of that increase occurring in Asia-Pacific and further growth in the Middle East.

"Gas markets are looking very positive – gas accounted for about 40% of the increase in total energy demand last year," Ydreos said. "We are very bullish in terms of demand in the future, because of the tremendous flexibility and application of natural gas."

Natural gas is expanding its role in multiple sectors worldwide. In the Middle East, it is increasingly replacing oil in power generation, improving efficiency and cutting emissions, he explained. In China, LNG is making inroads in transportation, particularly with LNG-powered trucks gaining traction. Globally, maritime bunkering of LNG is also expanding, underscoring the versatility of natural gas in lowering emissions, Ydreos said.

Recent geopolitical shifts have reshaped gas trade flows. Europe has turned to LNG from the US and elsewhere to replace lost Russian pipeline supplies. It invested rapidly and heavily in LNG import capacity to do this, leveraging floating storage and regasification units (FSRUs) to enhance flexibility, Ydreos said. If a peace agreement ends the Russia-Ukraine conflict, various factors will determine whether Europe resumes the larger Russian gas imports it once relied on.

Political interventions affecting gas supply – such as the now-ended pause on some US LNG export approvals – cause concern, Ydreos said.

"[But] whether that reflects into a reduced appetite for investment remains to be seen … the outlook is very positive for Gas, and so I think the investment will follow," he said.

The impact of the introduction of US tariffs on Canadian and Mexican imports by the new Trump administration as a negotiating tactic has so far had only a muted impact on natural gas, Ydreos continued. North America's energy system is highly integrated, with gas flowing efficiently between Canada, the US and Mexico. Canada produces about 6 tcf of gas annually, half of which is exported to the US. The US then exports 3.5 tcf as LNG, highlighting the importance of this Canadian gas.

Meanwhile, the way that gas is traded continues to evolve, Ydreos said. Market flexibility is increasing, with nearly 45% of transactions now spot or short-term, compared with a decade ago when long-term contracts dominated. While long-term agreements provide stability, spot markets offer agility, allowing buyers to capitalise on favourable price movements. The US LNG industry has played a key role in this transformation by removing destination clauses, making cargoes more freely tradable, Ydreos said. This shift enhances market liquidity and strengthens the role of natural gas as a responsive global commodity.

South Asia presents a key growth opportunity for natural gas, though affordability remains a challenge. Countries such as Pakistan and Bangladesh have sought to expand LNG imports, but price volatility has pushed some back to coal, Ydreos said. During Europe's energy crisis, high LNG prices effectively priced South Asia out of the market. Recognising this risk, some nations have secured long-term contracts to stabilise costs and enhance energy security. Continued investment in LNG infrastructure and production will be critical to ensuring stable, accessible supply for these fast-growing economies, he said.

All the while, natural gas remains a critical driver of sustainability, Ydreos continued. Its expanded integration into energy systems can accelerate the phasing out of coal, the use of which peaked at nearly 9bn tonnes last year, and half of that was consumed by China.

"That significant growth in coal must be substituted if we are going to have any chance of reaching some of the [climate] targets that have been set."

Natural gas also plays a crucial role in supporting renewables, Ydreos said. Wind and solar power are growing, particularly in Europe and China, but their intermittency presents challenges. Natural gas provides the stability needed to balance fluctuations in renewable output, ensuring a reliable electricity supply. For example, when wind generation in Europe dropped for an extended period earlier this year, gas stepped in to fill the gap. The Gas industry itself is also evolving to become cleaner, with renewable gases and hydrogen gaining traction, he said. Scaling up low-carbon gases will be vital for reducing emissions while maintaining affordable and secure energy supplies.

> **"Gas is a uniquely flexible energy source, meeting diverse needs from electricity generation to industrial applications and residential heating"**
>
> MENELAOS (MEL) YDREOS, IGU SECRETARY GENERAL

Sustainability should not come at too heavy a cost to economic prosperity and living standards, however, Ydreos said. In the developing world, home to 80% of the world's population, "they support reductions in emissions, but they also have other priorities that are important to their societies – security of supply and affordability are critical," he said.

While developed economies can focus more on cutting emissions, developing nations must balance environmental goals with economic development, he said.

Gas is a uniquely flexible energy source, meeting diverse needs from electricity generation to industrial applications and residential heating, Ydreos said. It is also a key feedstock for important products such as fertilisers and chemicals. And given its adaptability and economic importance, significant investment in Gas infrastructure and supply must continue.

Temporary surpluses in Gas supply will occur as large-scale projects come online – "it's the nature of how the market works, because of the long-term commitments and construction cycles that get those assets to the market," he said. "Sometimes the market is very tight, then it's oversupplied for a temporary time, and then it all balances again."

"Gas is a long-term fuel that will be in place well beyond 2050 … because of the value it brings to energy markets," Ydreos concluded, noting he preferred to refer to energy additions rather than energy transitions.

"That's what we've had over the last 100 years – a series of additions to the energy sector and not transitions. And those additions happen when economics are at work that don't impose a burden on the affordability of energy." ●

Stronger international cooperation is needed for secure natural gas supplies

GERGELY MOLNAR
Gas Analyst, International Energy Agency

Although natural gas demand returned to structural growth in 2024, the IEA says the global gas balance remains fragile.

Following the supply shock of 2022/23, natural gas markets moved towards a gradual rebalancing and returned to structural growth last year. Global gas demand reached a new all-time high in 2024 and is expected to expand further in 2025, primarily supported by some fast-growing markets in Asia.

Preliminary data indicate that natural gas consumption increased by 2.8%, or 115 bcm year-on-year in 2024, above the 2% average growth rate between 2010 and 2020. First estimates indicate that natural gas met almost 30% of the increase in global energy demand in 2024. This relatively strong growth was mainly due to the Asia Pacific region, which accounted for almost 45% of incremental gas demand in 2024 on the back of continued economic expansion.

Natural gas demand returned to structural growth in 2024

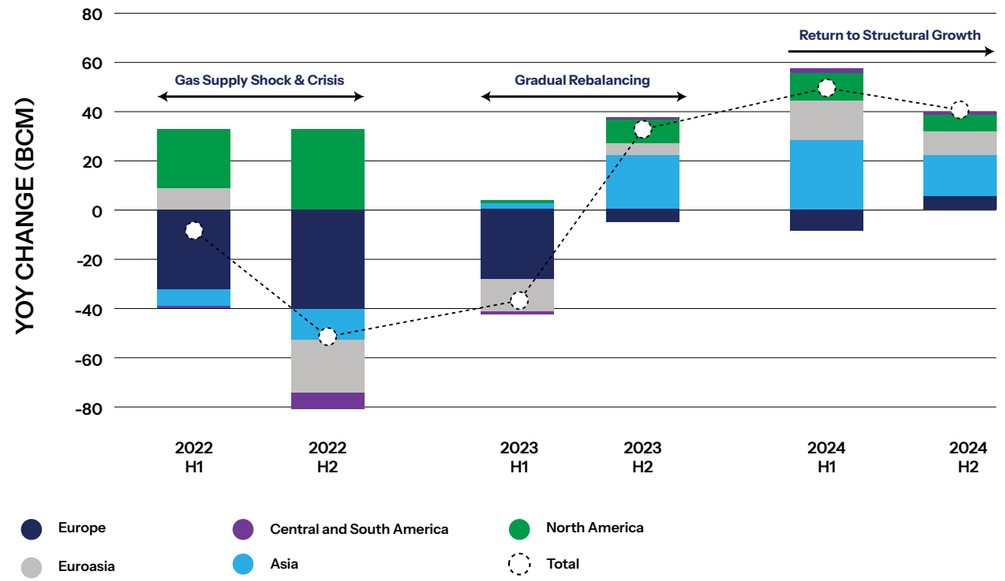
Meanwhile, the global gas market balance remains fragile. Below-average growth in LNG production has kept supply tight, while extreme weather events have added to market strains. Geopolitical uncertainties have continued to fuel price volatility. Lower underground storage levels in the European Union are set to translate to higher injection needs through the summer of 2025 and to fuel a fierce competition for flexible LNG cargos. And while the halt of Russian piped gas transit via Ukraine on January 1, 2025 does not pose an imminent supply security risk for the European Union, it is expected to further tighten market fundamentals in 2025.

Extreme weather highlights need for gas flexibility

Extreme weather events highlighted once again in 2024 the crucial role that gas supply flexibility can play in ensuring electricity and heat security, including in renewables-rich markets, where gas-fired power plants often provide back-up for variable renewables.

In the United States, gas demand surged to an all-time high of 3.9 bcm/day during winter storm Heather in January 2024. Gas demand in the residential and commercial sectors rose by 70% from January 11-16,

ESTIMATED YEAR-ON-YEAR CHANGE IN NATURAL GAS DEMAND IN KEY REGIONS, 2023 - 2024



"The existing gas system will play a key role in enabling the integration of low-emissions gases, including biomethane, hydrogen and e-methane."

2024 as below-average temperatures pushed up space heating requirements, while gas-fired power generation surged by around 40%. Storage withdrawals and pipeline flow optimisation played a key role in ensuring gas supply adequacy, guaranteeing heat and electricity security.

In India, powerful heatwaves during the summer of 2024 drove up gas-fired power generation to multi-year highs. Gas demand for power generation in India rose by 32% in the May-July period y-o-y amid higher cooling needs. Incremental gas demand was primarily met through increased LNG imports.

In South America, both Brazil and Colombia faced extreme droughts last year, limiting their hydropower output. Brazil's gas-fired power generation surged by nearly 600% between June and October, with most incremental gas demand met via LNG.

In Europe, slow wind speeds in the first half of November 2024 led to a sharp decline in wind power output y-o-y. Gas-fired power plants played a key role in providing backup to the power system during this period by increasing their output by nearly 80% y-o-y. Higher gas demand was primarily met through stronger storage draws.

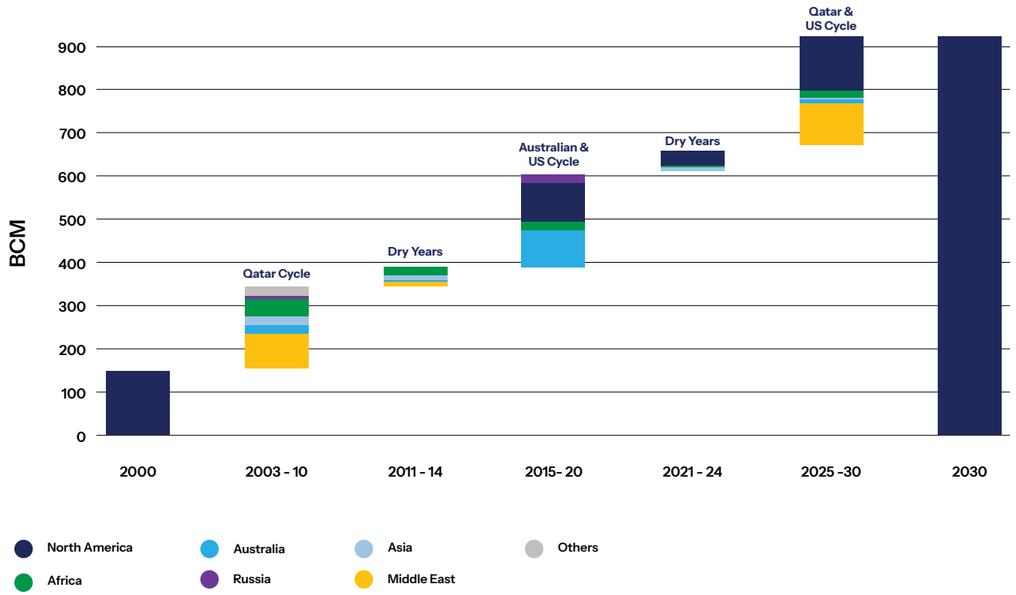
These events highlight the need for a careful assessment of investment in the assets that enable the secure delivery of gas, including gas storage, as well as the development of mechanisms that allow for greater supply flexibility.

Next-wave LNG

Together with Qatar's expansion projects, LNG liquefaction plants that have reached financial investment decision or are under construction could add over 270 bcm per year of export capacity by the end of 2030 – equating to around half of global LNG trade today. This strong increase in LNG production capacity is expected to loosen market fundamental and could pave the way for a balanced growth in natural gas demand in the years ahead. →

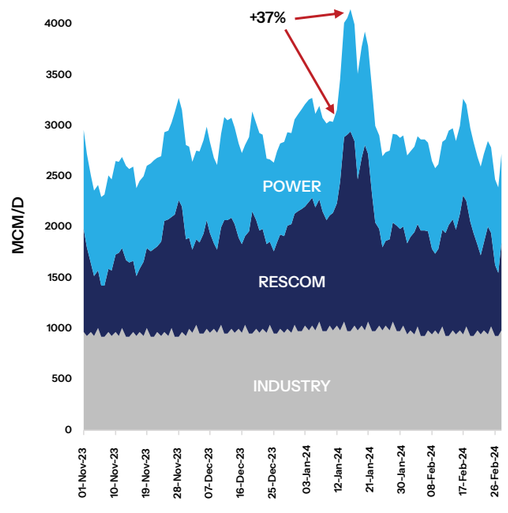
GAS IN TRANSITION. MARCH 2025

EVOLUTION OF GLOBAL LNG SUPPLY (2000 - 2030)

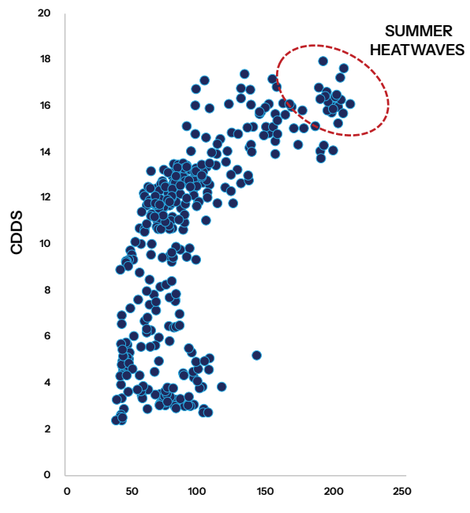


GAS SUPPLY FLEXIBILITY PLAYS A KEY ROLE IN ENSURING HEAT & ELECTRICITY SECURITY

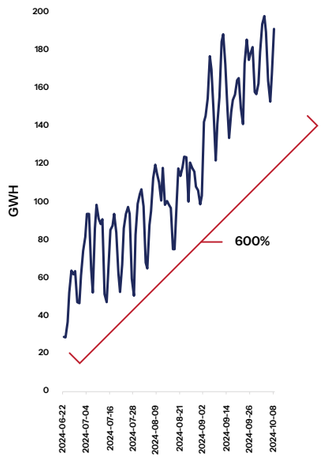
US Daily Gas demand during winter storm Heather



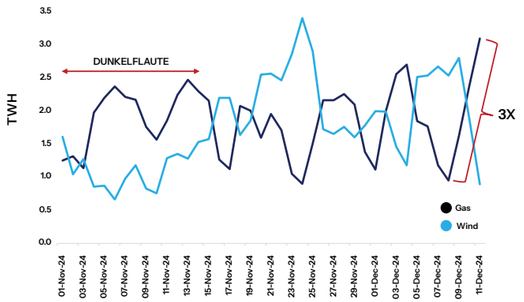
India's gas-fired power generatio in 2024



Brazil's gas-fired power generation in 2024



Europe's gas and wind power generation



Evolution of global LNG supply (2000-2030)

Meanwhile, natural gas is expected to face different demand trajectories and varying roles across regions. In many markets, including Africa, natural gas could play a key role as a "growth fuel" in improving energy access and support economic expansion through the medium-term. In the large Asian markets and the oil-rich Middle Eastern countries natural gas is expected to act as a "switch fuel". The availability of natural gas at competitive prices could effectively support policies in these countries to reduce their reliance on coal and oil and hence lower emissions and improve air quality. Even in markets where the rapid expansion of renewables is weighing on natural gas consumption, natural gas is set to play a growing role as a back-up fuel, providing flexibility in power systems increasingly dominated by weather-dependent and variable renewables.

Moreover, the existing gas system will play a key role in enabling the integration of low-emissions gases, including biomethane, hydrogen and e-methane. The deployment of these low-emissions gases is set to accelerate over the medium term. In the World Energy Outlook's Stated Policies Scenario (STEPS), the combined supply of biomethane and low-emissions hydrogen quadruples by 2030 to reach 42 bcm-eq and expands to near 300 bcm-eq by 2050. In addition, global e-methane production could reach over 1 bcm/y by 2030 based on the projects which are currently being proposed (although no final investment decisions have been reached yet).

While low-emissions gases, along with carbon capture, utilisation and storage (CCUS), can play a crucial role in the decarbonisation of gas supply streams, they will inherently lead to a more complex gas and energy system. Hence, an orderly transition from the current gas system to a model integrating multiple gases will require prudent market design already in the early stages, to take into consideration the network integration challenges and changing supply flexibility of low-emissions gases and ultimately their implications for security of supply.

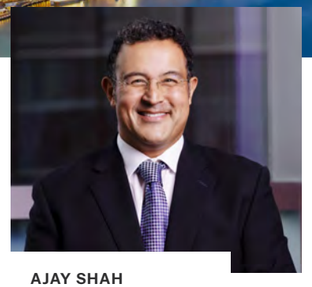
Strengthened international cooperation on gas and LNG

In an uncertain and complex geopolitical context, the IEA has called for greater international cooperation to enhance gas supply security and reduce the emissions intensity of gas value chains. Responsible producers and consumers need to work together to reinforce the architecture for safe and secure gas supplies, while investigating options for reducing the environmental footprint of gaseous fuels.

A number of new initiatives were launched in recent years with the aim of improving market transparency, data exchange and cooperation mechanisms on gas and LNG. This included the Global Early Warning Mechanism established by the European Union and Japan.

Building on the IEA's longstanding work on gas supply security, the IEA established in late 2024 a permanent Working Party on Natural Gas and Sustainable Gases Security (GWP) under the Standing Group on Emergency Questions, which aims to facilitate data and information exchange among its members and to promote dialogue between producers and consumers. In April 2025, the IEA will convene an international Summit on the Future of Energy Security, hosted by the UK government. The Summit will address traditional and emerging risks related to energy security, including for natural gas. ●

Shell Energy Asia: Diversity in detail



AJAY SHAH
Vice President of Shell Energy Asia

Shell Energy Asia, part of global energy major Shell, operates in a suite of very diversified energy markets.

DALE LUNAN

Nearly a decade ago, as it absorbed its massive $70bn acquisition of BG Group to become one of the largest natural gas and LNG traders in the world, Shell recognised that Asia would become a significant contributor to global economic growth as different countries in the region transitioned to a middle- and higher-income future, bringing millions out of energy poverty.

To meet that growing demand for energy in Asia, Shell Energy, Shell's global offer to markets for gas and power – including renewables – created Shell Energy Asia to bring its regional gas and power businesses in India, Japan, Malaysia, Singapore and the Philippines under the same umbrella. Its purpose was to meet customer demand for more and cleaner energy while helping accelerate economic growth in the region.

Right from the creation of Shell Energy Asia, Ajay Shah, its Vice President, tells *Gas in Transition*, the diversity of the markets in the region and the varying stages of market liberalisation presented both challenges and opportunities.

"Asia is a very diverse part of the world, with very developed economies, but also economies that are emerging," he says.

But even with that diversity there were certain themes common to all: significant growth, both in energy demand and GDP, and energy markets which were moving away from the government-owned, monopoly utility models.

"So what you see is that this neck of the woods, the Asian continent, is going to be the main driver of growth in energy demand and the main growth engine of global economics," Shah says.

At the same time, market liberalisation gave companies like Shell a place to compete and customers the flexibility to choose their best energy options. All five of the markets Shell Energy Asia is active in have liberalised, either in gas, in power or in both, and they're all growing.

Regional energy trade

Across the region, Shell trades about 3 MTPA of gas in India, Singapore and Malaysia and in 2024 sold 4.9 TWh of power to over 100 customers in Japan and Philippines. And in India, Shell Energy Asia works closely with affiliate Sprng Energy, a renewable energy platform with some

Shell acquired Nature Energy, Europe's largest renewable natural gas producer, in 2023.

2.3 GW of operating and 5 GW contracted energy.

"It's becoming quite dynamic now, the Asian market," Shah says. "Today, we see hundreds of customer locations. We've got more than 50 suppliers. We see liquidity, which means the ability to trade LNG and gas on a spot basis, really exploding. And then there's much more flexibility between customers and suppliers– in fact, customers often become suppliers because they have excess volume and they want to be able to sell it on."

Singapore may be the smallest of the five markets, but it's growing quickly as tech companies eye global hubs like Singapore. Malaysia, the Philippines and India, with GDPs per capita usually somewhere between 10% and 30% of the developing world, offer "tremendous scope" to grow.

"What we want to do is make sure, in each of those markets, that we bring tailored solutions using our portfolio of gas and power, where we can play with both, but also with renewables," Shah says.

In the Philippines, for example, Shell is in a joint venture with Emerging Power, a subsidiary of Nickel Asia Corporation, to generate solar energy, which Shell Energy Asia then pairs with either batteries or gas-fired generation in a way that best meets customer needs. The development of the JV's first 120 MWp project is in its advanced stages and the JV plans to eventually grow its portfolio to 1 GWp.

In Japan, Shell Energy Asia acquired a small, 80 MW gas-fired peaking power plant in the city of Nagaoka three years ago that can be brought on-line quickly. "That was an asset that we really thought complemented what was emerging in Japan, which was more intermittency from renewables and a peakier gas demand profile."

And in India, it works to supply natural gas to the growing city gas distribution (CGD) system, an initiative by India's regulators to push the supply of compressed natural gas (CNG) into more and smaller urban centres.

The expanded CGD system, Shah says, is "an incredible story" of bringing natural gas supply not just to the major cities of India, with populations of as many as 20mn residents, but to smaller urban centres of perhaps only 100,000.

"The most important thing is how can we serve the customer better, in particular trying to give them help through the energy transition, and we think gas and power are the vectors to help them do that."

AJAY SHAH, VICE PRESIDENT OF SHELL ENERGY ASIA

"CNG is a very important pathway to get to those customers," he says. "We don't actually sell CNG, but we do supply most of the CNG suppliers – they access pipeline gas, and it's most often compressed on location."

By trading in virtually all forms of energy, Shell Energy Asia is able to tailor flexible solutions for its customers, Shah says.

"The most important thing is how can we serve the customer better, in particular trying to give them help through the energy transition, and we think gas and power are the vectors to help them do that."

More than just natural gas

Global major Shell has long had a presence in natural gas production across Asia and is still a significant player in Brunei and Malaysia and less so in the Philippines, where it was the original developer of the Malampaya project, discovered in 1991 and brought online in 2001 to provide gas to four power plants on the island of →

Luzon. Shell exited the project in 2022, selling its 45% interest to Malampaya Energy XP, a subsidiary of Prime Infrastructure Capital.

"We've had a long history and a long presence," Shah says. "But remember, most of that gas, historically, has been turned into LNG because it's been in countries like Malaysia, Brunei, Indonesia, where domestic gas demand has been relatively low, given that there is really no real heating demand."

Shell Energy Asia trades natural gas and LNG throughout the region, drawing on its parent's global portfolio, and is actively involved in power trading and supply in India, Singapore, the Philippines and Japan. It is also building on its February 2023 acquisition of Nature Energy Biogas, Europe's largest renewable natural gas (RNG) producer, by moving into a growing Asian RNG market, especially in Malaysia.

"We're talking about more and more RNG made from waste products being substituted into the gas value chain, and in Asia, it's largely produced from agricultural waste and biomass like rice husks and wheat," Shah says, pointing out the logistics of gathering the required waste feedstocks makes entry into the production end of the RNG value chain quite prohibitive.

Still, Shell Energy Asia is in the space. In Malaysia, anaerobic digesters are producing biomethane to be trucked to nearby pipelines where it is injected. That's where Shell comes in to buy RNG and incorporate into its overall gas supply picture.

"RNG is relatively expensive today compared to conventional natural gas but when you take into account the CO_2 benefits, I think it really has a role to play," Shah says.

Addressing energy poverty

Much of the work Shell Energy Asia does with the International Gas Union (IGU) involves mapping out routes for emerging economies, like those in Asia, to navigate the energy transition, and helping some of those move away from coal to natural gas, Shah notes, is an obvious path forward.

"In these countries, Indonesia is a good example, Philippines is a good example, there's a growing understanding that there should be less emphasis on coal," he says. "But then there's the question 'what's the alternative?' The alternative is, of course, in the immediate future, gas, and then in the medium and longer term, renewables."

At the same time, making energy – whatever its form – more affordable and accessible is top of mind for Shell Energy Asia, Shah says, and it is against that backdrop that it works closely with its customers to determine their needs and their priorities.

"We ask our customers to tell us what they need," he says. "Do you want indexation to your best alternative, for example, so linked to oil or diesel or LPG? Or do you want it linked to Henry Hub or to end products – indexed to what you actually produce?"

Some of these priorities are easier to grasp and work with than others, Shah says, but all are critical to understanding the customer and ensuring its energy needs can be met securely and affordably. ●

The gas-fired 85.8 MW Nagaoka Power Station in Niigata, Japan, which Shell acquired in 2022.

Southeast Asia ramping up methane mitigation efforts

Southeast Asia is a growing centre for energy demand, and a growing source of methane emissions. But the Association of Southeast Asian Nations (ASEAN), through its ASEAN Centre for Energy, is leading a collaborative effort to reduce emissions.

DALE LUNAN

At the 29th Conference of the Parties (COP29) in Baku in November 2024, the issue of global emissions of methane, the most potent of greenhouse gases, was again a major topic of conversation.

As part of the gathering, the ASEAN Centre for Energy led seven signatories (Cambodia, PT Pertamina, PETRONAS, Myanma Oil and Gas Enterprise, Philippine National Oil Company, Singapore LNG and PTT Public Company) in the release of a joint statement calling for a progressive, collaborative and inclusive approach to methane abatement in the ASEAN energy sector.

By agreeing the joint statement, the signatories committed to a variety of initiatives, including creating a Southeast Asian oil and gas sector methane emissions baseline, as early as 2025, and to share best practices and the region's progress on decarbonisation and methane emissions reductions.

The joint statement was a key milestone in methane emissions reduction efforts in Southeast Asia over the past several years, dating back to 2020, when Malaysia's state-owned oil and gas company, PETRONAS, became a signing member of the Methane Guiding Principles (MGP) partnership. The leadership of PETRONAS in developing robust methane reduction initiatives continued in 2022 when it joined the Oil and Gas Methane Partnership 2.0 (OGMP 2.0) and supported the Global Methane Pledge Energy Pathway, which aims to accelerate the deployment of the fastest and most cost-effective methane mitigation solutions available.

Since 2013, PETRONAS has reduced its group-wide greenhouse gas emissions by 14% and methane emissions across its natural gas value chain by 58%. And it has set targets to reduce emissions by 25% in 2024 and by 50% by 2030.

In January, the International Gas Union brought the story of PETRONAS' collaboration with industry partners to mitigate methane emissions to its membership in the form of a knowledge-sharing webinar, moderated by Mark McCrory, the IGU's Director for Strategy and Advocacy, and featuring Syahrul Mohamed, Senior Manager, Alliance and Partnerships at PETRONAS, and Suhana Muhamad, senior manager, delivery excellence with the Malaysian state-owned company.

In his opening comments to the webinar, McCrory noted that while the global gas industry is responsible for just 8.62% of human generated methane emissions, the issue is taken "extremely seriously" by the industry which views action on methane as critical to maximising the economic and the environmental value of gas. He also noted that many IGU members are already committed to reducing their methane emissions by at least 30% and to operate with near-zero leaks by 2030.

In October 2021 PETRONAS launched the ASEAN Energy Sector Methane Roundtable, a five-year programme that convenes two roundtables each year. Seven roundtables have been convened to discuss a variety of topics, from why methane matters to developing robust measurement, monitoring, reporting and verification (MMRV) frameworks.

The roundtables also highlighted the importance of upskilling key practitioners in the sector to address information asymmetry and a need for capacity building. This led to the creation of the ASEAN Energy Sector Methane Leadership Programme (MLP), an 18-month initiative delivered through masterclasses and workshops.

Through the MLP collaborations, PETRONAS achieved the OGMP 2.0 Gold Standard pathway for the 2023 and 2024 reporting years, while Pertamina, Indonesia's state-owned oil and gas company, and Thailand's state-owned PTT Exploration and Production Public Company (PTTEP) have each become OGMP 2.0 signatories.

PETRONAS also worked with Japan Organization for Metals and Energy Security (JOGMEC) and the ASEAN Centre for Energy to launch the Methane Abatement Towards Sustainable Petroleum Industry (MAESTRO) dashboard in October 2024. With technical assistance from the World Bank's Global Flaring and Methane Reduction Partnership, MAESTRO helps stakeholders identify emission sources across ASEAN's oil and gas sector and enables more effective monitoring and abatement strategies.

PETRONAS and JOGMEC have also enhanced their collaboration by establishing the Southeast Asia Methane Emissions Technology Evaluation Center (METEC), which will enable the simulation of conditions suited to the Southeast Asia region and help ASEAN energy players improve regional methane emissions abatement efforts.

Both the MLP and the METEC initiatives are gaining international recognition, with the United Nations Environment Programme (which oversees OGMP 2.0) enquiring about joining METEC and the US Department of Energy reaching out for potential collaborations.

But while the MLP process has accelerated the ability of ASEAN members to bring robust methane mitigation plans into action, it is clear that collaboration must be maintained and conversations continued to ensure the momentum created by the MLP initiative is maintained.

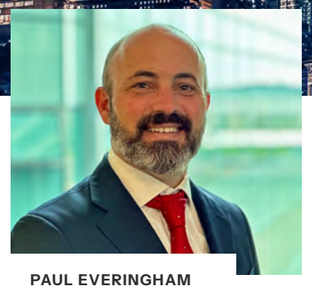
"This is an issue that is going to have to be addressed on a global level by the global natural gas industry," McCrory said. "The industry is open to criticism by its opponents who can and do use selective examples of methane emissions to discredit gas. The most effective way to address this challenge is in a collaborative way via peer-to-peer initiatives such as MLP, which will be absolutely critical in spreading the ambition, the leading practices and the technology needed to do this." ●

"This is an issue that is going to have to be addressed on a global level by the global natural gas industry."

MARK MCCRORY, IGU

GAS IN TRANSITION. MARCH 2025

Affordability is paramount for Asia Pacific and LNG



PAUL EVERINGHAM
CEO, Asia Natural Gas and Energy Association

Nobody doubts that natural gas will play a key role in Asia Pacific's energy future and its transition aspirations, but affordability of LNG is critical to that future.

The future of natural gas in the Asia Pacific is a bright one.

That said, the ability of Asia Pacific to transform its energy systems using gas comes with one very significant caveat: it will require a lot of support from the rest of the world to get there.

Asia Pacific's demand for gas is currently growing strongly and will accelerate even more rapidly through the 2030s and beyond. In a 2024 study commissioned by the Asia Natural Gas and Energy Association (ANGEA), Wood Mackenzie projected that Asian demand for LNG would rise from 270 MTPA in 2024 to 510 MTPA in 2050.

While LNG will continue to play a key role in the energy security of established importing nations – Japan, South Korea, Taiwan, Singapore and China – the biggest part of this growth will come from the emerging economies of South and Southeast Asia.

This includes India, where the US Energy Information Administration has forecast gas consumption to triple by 2050, and Bangladesh, Pakistan, Thailand, the Philippines and Vietnam.

While India will mostly use LNG for industrial purposes, for the remainder of these countries it is a key fuel for producing electricity.

Gas has been a major source of power generation for Pakistan and Bangladesh over the past 25 years, but their domestic reserves are depleted.

Thailand, similarly, is a long-time gas-based economy that is facing declining domestic production. It started using LNG early last decade and has been growing import volumes ever since.

Reduced domestic production of gas has also been an issue for Vietnam and the Philippines, both of which have encountered challenges developing additional sources of supply. Vietnam and the Philippines are currently highly reliant on coal but have energy plans that would see gas-fired power increased significantly to support growing investments in renewable energy.

Asia Pacific lacks the gas resources required to be self-sufficient.

Even if recent significant discoveries off Indonesia and Malaysia are developed and countries like Vietnam and the Philippines are able to locate and exploit new domestic resources, regional demand for gas will still strongly outstrip supply.

Access to imports

Asia Pacific's rising appetite for gas is quite clear. Less clear is the pathway to Asia Pacific being able to access the gas it needs, because this is dependent on external factors.

Asia Pacific lacks the gas resources required to be self-sufficient. Even if recent significant discoveries off Indonesia and Malaysia are developed and countries like Vietnam and the Philippines are able to locate and exploit new domestic resources, regional demand for gas will still strongly outstrip supply.

As a result, LNG will be an essential fuel for driving the energy transition in Asia Pacific. And because much of the demand will come from emerging economies – whose energy decisions are highly price sensitive – it is essential that LNG is affordable.

This is where other regions have a critical role to play in determining Asia's energy future. The simplest pathway to LNG being affordable for emerging Asia Pacific is for key exporting nations around world to produce sufficient volumes to meet the needs of all countries who wish to use it.

This supply equation will depend on continued production from established trading partners in the United States, Australia and the Middle East, new projects coming online in Canada and Mexico and the continued emergence of export industries in Africa and Latin America. Diversity of supply offers the opportunity to safeguard against geopolitical or policy developments that have the potential to impact the availability and affordability of LNG.

Decision makers in Asia Pacific spent most of 2024 dealing with a very real reminder of how policy developments elsewhere in the world can make the already challenging task of energy planning even more complex.

The Biden Administration's 'pause' on the processing of LNG export permit applications cast doubts over the feasibility of projects that nations in Asia were hoping to rely on to meet their future energy needs. Making long-term decisions about national energy systems is next to impossible in an environment of uncertain supply.

The Trump Administration's early move to resume processing of export applications has been well-received in Asia Pacific. A new era of opportunity beckons for US LNG in the region.

But memories of the pause remain fresh for governments, utilities and industries in Asia Pacific.

One of the most notable aspects of the Wood →

Mackenzie study was that they were able to model the likely impacts on global LNG markets if the 'pause' had stayed in place and planned and proposed US export projects did not proceed.

Without LNG, coal rises

The near certain outcome was that more concentrated supply would have resulted in LNG being more expensive than many emerging Asian nations could afford. In this scenario, these countries would inevitably have fallen back on coal use.

Wood Mackenzie estimated that a 30% reduction in emerging Asia's LNG demand because of higher prices would have led to as much as 95 million tonnes of additional coal being used annually by 2035.

The United States, which is projected by Wood Mackenzie to produce a third of global LNG supply in 2035, has an outsized influence on markets. But reducing or limiting production from any significant exporter would have a negative impact on Asia's ability to access gas.

This is particularly important in the context of Australia, where recent policy uncertainty around future gas production is concerning for Asian stakeholders. Australia's Future Gas Strategy acknowledges Asia's growing need for LNG, but the country's domestic energy security challenges have led to speculation that export volumes could be reduced as part of attempts to address problems at home.

It shouldn't be a binary proposition. The reality is that Australia has significant gas resources – backfill and new opportunities – that can be accessed to both improve domestic energy security and ensure LNG is available to help transform energy systems in the Asia Pacific. What Australia has lacked is a policy environment that will provide the necessary confidence for the Australian gas industry and its investors to start progressing major expansions to existing projects or development of new fields.

This ties in with one of the biggest learnings from my three years to date with ANGEA.

LNG import facilities and associated infrastructure require billions of dollars of investment and years of work. This is especially true for emerging nations, which are often less experienced with LNG.

Emerging nations cannot afford to invest this sort of money and time in LNG if future supply is less than assured.

And so, we arrive back at the premise that started this article.

The future of gas in Asia Pacific does indeed look bright. But the ability to turn potential into reality will depend on attitudes and actions outside the region.

Asia Pacific needs the world's support and access to affordable LNG. ●

Paul Everingham is the inaugural CEO of the Asia Natural Gas and Energy Association (ANGEA), which works with governments, society and industry throughout Asia to build effective and integrated energy policies.

Molecules of change: Introducing the top low-carbon gas technologies

JEAN-MARC LEROY
International Gas Union (IGU) former Executive Committee member and current Chair of its Carbon Neutrality Taskforce

The IGU's Introduction to Low Carbon Gas Technologies report outlines the key low-carbon gas technologies available for deployment that support the natural gas industry's decarbonisation efforts.

JOSEPH MURPHY

There is not enough recognition among the public, policymakers and stakeholders of the significant innovations shaping low-carbon gas technologies, Jean-Marc Leroy, a former member of the International Gas Union (IGU)'s executive committee and current chair of its carbon neutrality taskforce, tells *Gas in Transition*.

The IGU's Introduction to Low Carbon Gas Technologies report, released last October with Leroy as lead author, seeks to address this by outlining the key technologies available for deployment. These technologies support the natural gas industry's decarbonisation efforts while enhancing energy security and energy access. They also offer multiple benefits beyond this, such as supporting sustainable waste management and agriculture.

"There is a common misperception that the gas industry is less innovative compared with the electricity sector," Leroy said, citing the visibility of advancements like electrolysers, wind turbines, solar panels and battery storage. "People see electricity as innovative because of technologies like electrolysers and renewables. In contrast, gas is often viewed as an old-fashioned industry. This is far from true."

The report reviews five main technologies for producing low-carbon methane and seven for low-carbon hydrogen. These technologies complement industry efforts to cut emissions through efficiency improvements and reductions across the existing natural gas value chain, Leroy said.

Beyond emissions reductions, the technologies address a key limitation of renewables: the inability to store their low-carbon energy at scale for extended periods. Unlike batteries, "molecules – like methane and hydrogen – can store energy in large volumes and for long durations, making them essential for ensuring energy security."

Moreover, these molecules make use of existing gas infrastructure, limiting costs and facilitating a smoother energy transition. "Gas infrastructure is a highly capital-intensive asset, and much of it is already in place. Efficiently using it can reduce the cost of the energy transition," Leroy said.

Decarbonising the methane chain

The most commonly-used technology for producing low-carbon methane is anaerobic digestion, breaking down organic matter including agricultural wastes, manure and other biowastes, into biogas – a mixture of methane and CO_2 – and digestate. The methane content in biogas can be increased by injecting hydrogen into the reactor or using a light electrical current to enhance microbial efficiency. Biogas can be burned for heat and power or upgraded to biomethane and injected into natural gas grids for broader industrial and domestic uses.

Biogas and biomethane production is considered carbon-neutral since it is based on a virtuous carbon circle. Indeed, the CO_2 released during combustion merely returns what the organic matter previously absorbed from the atmosphere and will be again absorbed by some organic matter. They may also replace the use of higher-carbon fuels..

The digestate that is produced can also serve as a lower-carbon fertiliser alternative to high CO_2 producing chemical fertilisers.

The report examines four more technologies for producing synthetic methane. Like anaerobic digestion, pyrogasification and hydrothermal gasification can help manage waste and curb emissions.

Moreover, e-methane is produced by combining carbon monoxide and CO_2 with hydrogen. The carbon gases can come from a number of sources including biogenic CO_2 from methanisation plants or industrial emissions or direct air capture. The process benefits further when low-carbon hydrogen is used.

Finally, there is the solar photocatalytic process, otherwise known as artificial photosynthesis, which mimics natural photosynthesis by absorbing sunlight using photocatalysts to split water into hydrogen and oxygen. The hydrogen then reacts with CO_2 in the air to form methane. This approach both harnesses free and clean solar energy and produces low-CO_2 methane.

Low-carbon hydrogen pathways

The report notes that low-carbon hydrogen technologies remain limited in widespread deployment and must be scaled up significantly to meet climate targets.

Steam methane reforming (SMR) is by far the most common method for producing hydrogen, involving the use of heat to get steam to react with methane over a catalyst. The result is carbon monoxide and hydrogen. Through a water-gas shift reaction, carbon monoxide is converted into more hydrogen and CO_2. Crucially, the hydrogen can only be considered clean if the CO_2 is captured and sequestered.

Electrolysis, powered by renewable or nuclear energy, splits water into hydrogen and oxygen. The five main electrolysis technologies – alkaline, proton exchange membrane, solid oxide, photoelectrochemical and anion exchange membrane – each have their own benefits and drawbacks in terms of cost, efficiency and durability. Although electrolysis accounts for only a small fraction of global hydrogen production at present, there is a growing project pipeline and research is ongoing to improve performance.

Thermal gasification processes solid organic feedstocks – including biomass, coal, solid recovered fuel and non-recyclable plastics – at high temperatures to produce syngas, comprising hydrogen, carbon monoxide and methane. The syngas is then purified of pollutants and undergoes the water-gas shift reaction to convert more carbon monoxide into hydrogen and →

> **"The idea that our wastes could become a valuable resource is a new way of thinking."**

CO_2. The hydrogen is then extracted from the mix with 99.9% purity. This method yields the same benefits as other methane and hydrogen production methods using biomass, in terms of reducing emissions and managing waste. The CO_2 can also be sequestered for an additional environmental gain.

Methane pyrolysis breaks down the chemical bond between carbon and hydrogen, requiring less energy than electrolysis. Like SMR, this technology benefits from access to existing gas infrastructure. But it has an added advantage of producing solid carbon rather than gaseous CO_2, forgoing the need for carbon capture. That solid carbon can be stored or used.

Solar photocatalysis also applies to hydrogen production, using sunlight to split water without then combining the hydrogen with CO_2 to produce methane.

Biological hydrogen production, meanwhile, can be done by coupling the photo or microbial electrohydrogenesis cell fermentation with dark fermentation of macro-nutrients from biomass, such as organic waste materials. In addition to hydrogen, the process also produces alcohols, simple sugars and volatile fatty acids. Alternatively, biophotolysis uses cyanobacteria and green algae to split water into hydrogen and oxygen. Biological hydrogen production removes CO_2 from the air, requires low energy input and assists with waste recycling.

Lastly, there is the nascent field of geological hydrogen extraction. Currently, only one project in the world – Mali's Bourakebougou field – is operational. But recent discoveries suggest natural hydrogen could be a viable resource. This hydrogen is mainly produced through natural reactions between water and iron-rich minerals in the Earth's crust. It slowly moves through rock layers and can collect in underground pockets, in a similar way to how natural gas accumulates. Extracting it involves finding the right sites, drilling and separating the hydrogen – just like natural gas production.

To give hydrogen extraction a net-negative emissions profile, CO_2 can be mixed with water and injected into rock. The CO_2 stays trapped while the water reacts with iron to create hydrogen. The hydrogen-rich water is then pumped back up through surrounding wells. This process essentially mimics the process by which hydrogen is naturally produced.

Scaling up

The report highlights the pivotal role of low-carbon gas technologies in achieving net-zero emissions while addressing broader societal challenges. "These innovations offer compound benefits," Leroy said, noting how they can improve waste management, reduce reliance on chemical fertilisers and support energy accessibility.

Despite their promise, scaling these technologies faces certain hurdles. Developing supply chains to collect agricultural and industrial waste at low cost is one key challenge. Breaking down institutional "silos," where energy and agriculture policy-makers and industries do not communicate and cooperate enough with one another, is also critical. "Progress is being made, but collaboration must improve to fully realise these solutions," the expert urged.

Thinking about how sustainable energy can be produced is rapidly changing. Technologies like hydrothermal gasification, which were relatively unknown a few years ago, are now gaining traction among water treatment companies, Leroy said. "The idea that this waste could become a valuable resource is a new way of thinking."

Innovation in low-carbon gaseous energy must continue, and access to financing and enabling policy environments are critical for scaling up investments in decarbonising technologies, the report stresses. In parallel, investment in natural gas – both supply and the infrastructure that over time can increasingly carry lower-carbon gases – should also be maintained.

"Only then can we ensure that the priorities of energy security and energy transition do not undermine each other," the report concludes. ●

The IGU's Introduction to Low Carbon Gas Technologies can be read here. It was developed with the support of IGU's Carbon Neutrality Taskforce, Sustainability Committee and Research, Development, and Innovation Committee.

"There is a common misperception that the gas industry is less innovative compared with the electricity sector ... This is far from true."

JEAN-MARC LEROY, INTERNATIONAL GAS UNION (IGU) FORMER EXECUTIVE COMMITTEE MEMBER AND CURRENTLY CHAIR OF ITS CARBON NEUTRALITY TASKFORCE

GAS IN TRANSITION. MARCH 2025

SONATRACH: A Key Player in Global Energy and the Pillar of Algeria's Economy

Algeria’s national oil and gas company operates across the full hydrocarbon value chain and has been driving the country’s economy for more than 60 years.

SONATRACH

SONATRACH, Algeria's national oil and gas company, is a flagship enterprise that operates across the entire hydrocarbon value chain. From exploration and production to transportation, processing, and marketing, SONATRACH has cemented its position as one of the world's leading energy companies. Established in the wake of Algeria's independence in 1963, the company has been driving the country's economic development for over six decades, contributing 26% of Algeria’s GDP and generating 95% of its foreign currency revenues.

A history of leadership

SONATRACH’s history began with a vision to develop and operate Algeria's vast hydrocarbon resources for the nation’s benefit.

A major milestone in its history was the commissioning of the first natural gas liquefaction complex in the world, CAMEL (the Algerian Liquefied Methane Company), on September 27, 1964. This pioneering achievement placed SONATRACH at the forefront of the global LNG industry.

Over the years, the company has expanded its capabilities and infrastructures, becoming a key player in international energy markets. SONATRACH is ranked as the largest African company, the 13th largest oil company at the global scale and the 3rd largest natural gas supplier to Europe. It also stands as the Mediterranean region's top gas supplier and the world’s 10th largest natural gas producer.[1]

Today, SONATRACH stands as the driving engine of the nation's economy. It is the guarantor of energy security, ensuring gas supply in order to allow gas penetration rates of 72% and electricity access for 99% of the population. It is the builder of infrastructure, a major creator of jobs, and a dedicated bedrock to support Algerian progress.

1. Figures are from SONATRACH's internal data.

Exploration and Production

Algeria's vast mining area, of over 1.5 million km², contains significant unexploited hydrocarbon reserves. Despite decades of exploration, the region remains largely unexplored compared to other parts of the world. The average number of wells drilled is about 24 wells per 10,000 km². Besides, the company’s annual number of discoveries is still high, which consistently confirms Algeria's resource-rich potential.

SONATRACH manages nearly 300 exploration and production perimeters, operating its own efforts or in partnership with international energy major companies.

In 2024, SONATRACH’s natural gas production reached 195 bcm.

Some of the world's largest hydrocarbon fields are located in the south of Algeria, where SONATRACH oversees hundreds of production wells and surface treatment facilities.

Strategic Partnerships

Collaborations with international partners have been a cornerstone of SONATRACH's success. Over the decades, the company has established long-term relationships with major players in the global energy industry, including, Eni, Equinor, Repsol, Wintershall Dea, CEPSA, OXY, TotalEnergies, Pertamina, Sinopec, Gazprom, Rosneft-Stroytransgaz, PVEP and PTTEP and others.

Recent Memoranda of Understanding signed with ExxonMobil, Chevron and Oxy aim to examine development opportunities of new hydrocarbon perimeters, further strengthening SONATRACH’s position in the global energy market.

Infrastructure and Transport

SONATRACH operates an extensive energy infrastructure network. Its pipeline transport system spans 21,190 km, comprising 11,735 km of natural gas pipelines, almost 4,980 km of oil pipelines, more than 1,700 km of condensate pipelines and 2,760 km of LPG pipelines. The pipeline transport network can transport 405 million TOE/year including 263 million TOE/year on the North Network and 142 million TOE/year on the South Network. It includes 128 storage tanks for oil and condensate with a total capacity of 4.3 million TOE.

Also, SONATRACH owns and operates a unique gas hub in Hassi R’Mel which is the National Center of Gas Dispatching (CNDG) with a capacity of 390 million cubic metres (mcm)/day, through which transits all the gas produced in the south to intercontinental gas pipelines and LNG facilities, along with domestic market and downstream transformation units. A similar liquid hydrocarbons hub (CDHL) with a capacity of 1.4 →

GAS IN TRANSITION. MARCH 2025

"In response to growing national and global demand for natural gas, SONATRACH is actively pursuing its development plan, which includes significant investments to enhance production capacity and unlock additional resources."

million barrels/day, is located in Haoud El Hamra (Hassi Messaoud).

To supply the European market, two transcontinental pipelines connect Algeria to the European continent:

- MEDGAZ: Directly linking Algeria to Spain
- GEM (Enrico Mattei Pipeline): Connecting Algeria to Italy via Tunisia

The total capacity of both transcontinental pipelines is of 43 bcm/year.

These pipelines are vital for ensuring a stable energy supply to Europe, making SONATRACH a key contributor to regional energy security and a reliable supplier.

Processing

SONATRACH owns four liquefaction plants (LNG complexes) with a combined installed capacity of 56 mcm/year. It also operates another type of gas with two LPG separation units in Arzew, with a total capacity of 10.4 MTPA. The company's industrial zones in Skikda (East Coast) and Arzew (West Coast) house advanced facilities for liquefaction, separation, refining, and petrochemical production, as well as shipping terminals for hydrocarbon exports.

SONATRACH owns five crude oil refineries with a processing capacity of 27 MTPA in addition to a condensate processing unit of 5 MTPA.

Besides, SONATRACH has also petrochemical complexes for the production of methanol, polyethylene, ammonia and urea.

Export

Thanks to Algeria's strategic geographical position, SONATRACH plays a pivotal role in supplying Europe with natural gas through two key pipeline connections: the Trans-Mediterranean Pipeline (GEM) to Italy and the Medgaz pipeline to Spain. Together, these pipelines have a combined capacity exceeding 43 bcm.

Recognized for its flexibility in natural gas (NG) and liquefied natural gas (LNG) operations, as well as its professionalism and operational excellence, SONATRACH has established itself as a trusted and reliable energy partner on the international stage, particularly in Europe.

To strengthen its position in traditional gas markets and expand its reach to new clients, SONATRACH has established two international subsidiaries: Sonatrach Gas Marketing (SGM) and Sonatrach Gas Comercializadora (SGC). These subsidiaries are responsible for marketing regasified Algerian gas at the Isle of Grain terminal, managing SONATRACH's share of Medgaz, and distributing LNG volumes within the Iberian gas market.

In response to growing national and global demand for natural gas, SONATRACH is actively pursuing its development plan, which includes significant investments to enhance production capacity and unlock additional resources. These efforts are focused on both the short- and medium-term development of new gas fields to ensure a steady increase in supply.

As part of its strategy to diversify gas exports, SONATRACH is actively targeting new markets. Recent milestones include the delivery of its first LNG cargo to Croatia at the KRK floating regasification terminal, with part of the regasified gas being transported to Hungary via the Croatian gas network. Additional achievements include the supply of natural gas to the Czech company ČEZ under a newly concluded purchase and sale agreement, the signing of a partnership with Grain LNG to secure gas supplies to the United Kingdom, and new gas purchasing and selling agreements with the Turkish company BOTAS, German Company VNG and the Slovenian company Geoplin.

Major Projects in Development

To meet growing global energy demand and strengthen its market position, SONATRACH is pursuing an ambitious development plan focused on expanding production capacities and diversifying its operations, through:

1. The start-up of new gas fields such as Ain T'sila by the end of 2023 and the connection of the new Tinhert wells to Alrar during 2024. The recompletion of production at Touat Gaz has added 12 mcm/day;
2. Extending the operation of mature fields through the launching of several projects such as the Hassi R'Mel Boosting project - Phase III-Step II, launched in 2024 and to be received by the end of 2026, the Alrar boosting - Phase III, launched in 2024 and to be received in 2027, and the Rhourde Nouss boosting which launching process is underway;
3. Exploiting various gas resources, particularly in partnership to benefit from the experience of major companies in this field;
4. New Hassi Messaoud Refinery: Expected to produce 2.8 MTPA of gasoil, 1.3 MTPA of gasoline and significant annual volumes of propane, butane, and asphalt.
5. Methyl Tert-Butyl Ether (MTBE) Project: With an annual production capacity of 200,000 tons, this project is to be implemented in Arzew and will eliminate the need for MTBE imports and will supply SONTRACH's refineries to produce gasoline.
4. Linear Alkyl Benzene (LAB) Complex: Utilizing kerosene and benzene from the Skikda refinery, this project will enhance petrochemical production.
5. Propane Dehydrogenation and Polypropylene (PDH-PP) Plant: Expected to produce 550,000 tons of polypropylene annually in Arzew.
6. Raw Phosphate Extraction and Enrichment Complex (PPI Project): With an extraction capacity of 10 MTPA. This integrated project will support phosphate and fertilizer production, transportation and marketing.

These projects underscore SONATRACH's commitment to reinforce its industrial infrastructures, to diversify its portfolio and strengthen its role as a key energy player and a reliable supplier.

Focus on Sustainability and Energy Transition

SONATRACH recognizes the importance of sustainability and the global shift towards cleaner energy. The company has integrated energy transition into its long-term strategy, focusing on three main areas:

1. **Energy Efficiency:**
   - Targeting a reduction in gas flaring to less than 1% and eliminating routine flaring by 2030.
   - Implementing advanced monitoring systems to reduce fugitive methane emissions.
   - Conducting energy audits to optimize efficiency across all operations.
2. **Renewable Energy:**
   Developing solar power projects to meet the energy needs of production sites.
3. **Green Hydrogen:**
   Developing the SouthH2 Corridor project, which aims to transport 4 MTPA of green hydrogen from Algeria to Europe.

In this framework, SONATRACH, SONELGAZ (Algeria), VNG (Germany), SNAM (Italy), SEACORRIDOR (Italy) and VERBUND GREEN HYDROGEN (Austria) signed a Memorandum of Understanding to jointly →

"Algeria's abundant natural resources, strategic location, and advanced energy infrastructure position it as a critical player in the global energy market."

conduct necessary studies, throughout the hydrogen value chain, to assess the viability and profitability of an integrated project for the production of green hydrogen in Algeria in order to supply the European market via the SoutH2 Corridor which aims to transport almost 4 MTPA of green hydrogen from Algeria to Germany via Italy and Austria. This important step confirms Algeria's commitment to play a key role in supplying Europe with clean energy.

Climate Strategy and Carbon Neutrality

In 2024, SONATRACH adopted a comprehensive climate strategy aligned with Algeria's commitments under the United Nations Framework Convention. Its efforts are driven by its ambition to achieve a balance between greenhouse gas emissions and absorptions by carbon sinks during the second half of the century. Key initiatives include:

- Reducing greenhouse gas emissions through technological innovations and natural carbon sequestration.
- Planting over 423 million trees to create certified carbon sinks, offsetting emissions and generating carbon credits.
- Investing in research and development to advance carbon capture and storage technologies.

An integrated Group

SONATRACH oversees a diverse portfolio of 152 subsidiaries and affiliates directly & indirectly owned, including 91 in Algeria and 61 abroad. With over 40 years of experience, the group operates across the entire oil and gas value chain from Upstream to Marketing, provides hydrocarbon's industry-specific services and is involved in sectors beyond oil & gas, including agribusiness, seawater desalination, air transportation and insurance.

Domestically, through its three national holding companies, SONATRACH directly owns shares in 42 subsidiaries and affiliates, 21 of which are wholly owned. Internationally, it operates in 17 geomarkets, mainly in Africa, with a broad range of activities.

Conclusion

Algeria's abundant natural resources, strategic location, and advanced energy infrastructure position it as a critical player in the global energy market. SONATRACH plays a central role in this dynamic, ensuring energy security for both domestic and international clients.

SONATRACH's legacy of innovation, its robust infrastructure, and its commitment to sustainability have established it as a leader in the global energy industry. Through strategic investments, international collaborations, and a clear focus on energy transition, SONATRACH continues to shape the future of energy while maintaining its role as a reliable partner for global energy security. ●

The Algerian Gas Industry Association (AIG): One Vision, One Mission For A Clean And Sustainable Energy Future

The Algerian gas industry is one of the oldest in the world, and is generally considered to be the birthplace of the global LNG industry, which was launched in 1964 with the first international cargo to Iceland.

ALGERIAN GAS INDUSTRY ASSOCIATION

The Algerian Gas Industry Association (AIG) has been an active member of the International Gas Union (IGU) since 1968. Initially called the Algerian Gas Union (UAG), it was renamed AIG in 1993.

The Algerian gas industry is one of the oldest in the world, and the largest in Africa both upstream and downstream, with significant reserves including 4,500 bcm in conventional natural gas, and 24,000 bcm in unconventional natural gas, making it the largest producer and exporter of gas in Africa. The Algerian downstream sector is also the highest through its liquefaction and petrochemical infrastructures, the rate of connection to natural gas and electricity of the population and consuming industries, the highest in the world at a rate of 70% with natural gas, and 99% for electricity produced 96% with natural gas.

The AIG represents Algeria within the International Gas Union and actively participates, through professionals from the Algerian gas industry who are members of the AIG, in the work of its technical committees (WOC & PGC), as well as the preparation of its World Gas Conference which is held every three years.

The AIG has consistently contributed to the global dialogue on the evolving role of gas in the energy sector, participating since its creation in the very first International Conference on LNG, organized by the IGT on April 7-12, 1968 in Chicago, United States. At that time, the LNG industry was nascent, with Algeria being the only LNG exporting country, whose first LNG plant was built in Arzew and delivered its first cargo of 12,000 tonnes of LNG to Iceland in 1964.

The AIG has thus maintained its presence and its action within the IGU, through strong participation in all debates and events relating to the development of the gas industry through, among other things, the reception and the organisation by Algeria of the 4th International Conference on LNG (LNG4) in Algiers in 1974, and once again the LNG16 in Oran in 2010. Later, at the monitoring and in preparation for the 2015 World Gas Conference in Paris, the AIG succeeded in organising an important African Conference on Natural Gas in 2014 in Algiers, which brought together most African countries and gas players around a rich program of exchange of knowledge and expertise.

The vision of the AIG is based on a strategy of promotion and development of natural gas as a clean, sustainable energy resource, a key driver of economic growth, and an indisputable support for renewable energies and the energy transition. As a leading organisation within the Algerian gas industry, the AIG is dedicated to promoting gas technologies and the efficient and responsible use of gas resources through the organisation of technical sessions and an international symposium every three years, during which all operators and direct or indirect players in the gas industry come to share their knowledge, expertise, and innovations.

One of the main axes of the AIG also consists of expanding its cooperation with other organisations and institutions, and universities, on a national and international scale, on innovations, technologies, and changes within the energy sector, in terms of decarbonisation of operations and uses, new resources (hydrogen), their use, consumption models, environmental protection, for a sustainable and clean energy future. ●

Unlocking East Mediterranean gas

New Mediterranean-Leviathan

OSAMA MOBAREZ
EMGF Secretary-General

The East Mediterranean Gas Forum (EMGF) is spearheading efforts to unlock the region's natural gas potential by aligning policies, expanding infrastructure, and fostering cooperation between governments, industry, and investors, as Secretary-General Osama Mobarez explains.

JOSEPH MURPHY

The Eastern Mediterranean holds vast natural gas potential that can help deliver secure, affordable and clean energy, particularly for Europe. But fully unlocking that potential requires policy alignment between producing, transit and consuming countries, greater regional integration of infrastructure and collaboration between government, industry, academia and other stakeholders, Osama Mobarez, Secretary-General of the East Mediterranean Gas Forum (EMGF), tells *Gas in Transition*.

This is what the EMGF sets out to achieve. Established in 2019, the forum now comprises eight member countries and three observers, with a gas industry advisory committee of 38 companies.

Securing markets

Development of the East Mediterranean's gas reserves began in the late 1960s, when gas was found in shallow waters off Egypt's coast. But the region has gained significant prominence in the global energy market over the past two decades, with the discovery and development of giant fields like Leviathan and Tamar off Israel, and Zohr in deeper waters off Egypt. Significant reserves have also been found off Cyprus, but are yet to be exploited, and Lebanon too has begun exploring for gas.

More discoveries are likely, with the US Geological Survey estimating the region's undiscovered, technically recoverable gas at close to 300 tcf (8.5 tcm).

A key challenge has always been securing markets for these resources by developing the necessary infrastructure, Mobarez explains. "Egypt is the only country in the region with a large domestic gas market, so most of these gas resources need other markets to go to, whether via LNG or pipeline, and the closest market – Europe – is of course easier."

Egypt has LNG export terminals, and Israel began delivering gas to Egypt through Jordan five years ago, with some of this supply being re-exported via those terminals. But Cyprus is yet to secure a route to market, although plans are underway to pipe gas from the country's Cronos field to Zohr off Egypt, then ship it as LNG. Gas from Aphrodite could also be exported in this way.

High gas prices caused by supply shortages over the past three years have added new impetus to developing the East Mediterranean's gas resources. Europe has been at the epicentre of the global energy crisis, as a result of the loss of most of its Russian pipeline gas supply in 2022.

Exploration activity is on the rise, with new developments progressing across Egypt, Cyprus and Israel. In Egypt, new drilling campaigns are expanding into previously unexplored western offshore areas, reflecting the continued push to unlock additional resources. In Cyprus, ExxonMobil and QatarEnergy began drilling at the Electra prospect, which they believe could hold gas resources comparable to the 4.2-tcf Aphrodite discovery.

An agreement between Eni, TotalEnergies and the governments of Cyprus and Egypt on delivering Cypriot gas from the Cronos field to Zohr facilities offshore Egypt will open up new opportunities for upstream investment, by creating a corridor of pipelines and LNG trade from Cyprus to Egypt and onwards to Europe and other markets, according to Mobarez.

"With a more attractive gas market in Europe with favourable prices, companies and countries will be encouraged to develop these resources and bring them to market," Mobarez says. But investment decisions still depend on having the infrastructure as well as the right policies in place, to ensure profitable returns.

Policy coordination is crucial, and following its creation six years ago, the EMGF sought to facilitate alignment between producing, consuming and transit countries. "We saw that many discoveries remained unmonetised, and a framework was needed to align government policies, attract investment and develop the infrastructure necessary for gas exports."

The Forum's relevance has grown since the Russia-Ukraine conflict, which shifted Europe's approach to gas. "Before the conflict, the European narrative largely downplayed gas as part of the energy mix, discouraging investment. Now, the recognition that gas will be needed for at least 20 years has renewed investor confidence," Mobarez says.

Three pillars of strategy

The EMGF's work is structured around three key pillars: regional integration, the energy transition and climate action and private sector engagement. Regional integration involves infrastructure development and cross-border co-operation, often between multiple countries. "We see this in practice with Israeli gas flowing through Jordan to Egypt for liquefaction and re-export, and in the future, Cypriot gas may follow a similar route."

Policy alignment is essential for facilitating such projects.

The EMGF released an extensive regional gas monetisation study in 2024, carried out by Boston Consulting Group and approved by the Forum's member countries. The study outlines a roadmap for resource monetisation, covering infrastructure development, private sector engagement, and commercial →

Zohr-Nooros

policies. The Forum plans to implement the study's recommendations from this year onward, working with member countries, observers and industry stakeholders to advance gas development and regional integration, Mobarez says.

The Forum's second pillar focuses on making gas a cleaner energy source. "Gas is the cleanest fossil fuel, and not only a transition fuel but a baseload source of electricity that can support renewables," Mobarez says. "But technologies exist to further reduce emissions along the value chain. There are a lot of technologies out there, and most of them are well-established, but some need further advancements to reach scale."

By fostering cooperation among stakeholders, EMGF is working to improve methane emissions abatement, flaring reduction and energy efficiency. It presented its progress in this area at COP29, outlining a strategy to curb greenhouse gas emissions from the region's gas industry. This initiative included the development of a marginal abatement cost curve, prioritising lower-cost energy efficiency improvements and methane emissions abatement, before advancing to capital-intensive technologies requiring greater investment.

Alongside this, the Forum developed two policy roadmaps spanning six and eight years, detailing investment incentives and specific projects that can reduce emissions. EMGF is also working on a carbon intensity certification tailored for the region, while also collaborating with the EU and the US on methane monitoring and reporting frameworks.

The third pillar involves leveraging private sector investment to ensure cost-efficient, low-carbon gas supply. Last year's regional gas monetisation study supports this effort.

"By continuing to align policies, attract investment and enhance integration, we can unlock the full potential of this region – delivering energy security while advancing the energy transition"

OSAMA MOBAREZ
EMGF SECRETARY-GENERAL

A unique platform for dialogue

The EMGF serves as a unique platform bringing together governments, industry players, regulators and academia to coordinate policy and investment strategies. "Unlike other organisations that engage either governments or companies, we integrate all key stakeholders," Mobarez says. "This supports policy alignment and project development. The forum is a great platform for dialogue between government and industry, where governments can understand more about what industry requires and align their policies accordingly."

Members of the Forum's gas industry advisory committee include international oil and gas majors like BP, Chevron, Eni, ExxonMobil and Shell, along with national oil companies, transmission system operators, service and engineering contractors, financial institutions and other organisations.

Mobarez also commended the EMGF's partnership and ongoing collaboration with the International Gas Union (IGU).

"The Eastern Mediterranean has the resources and the proximity to key markets to deliver reliable and sustainable gas supply," Mobarez concludes. "By continuing to align policies, attract investment and enhance integration, we can unlock the full potential of this region – delivering energy security while advancing the energy transition." ●

Efficacy of policy in shaping a low carbon energy future

Three key policy principles need to be kept in mind to ensure policies aimed at reducing carbon emissions are effective

MARK MCCRORY
Strategy and Advocacy Director, International Gas Union

One of the aspects that makes the global energy transition so challenging is the need to view energy systems holistically, looking across organisational, technological and even geographical boundaries to see the system-wide effects.

Shaping a successful energy transition will therefore require an unprecedented level of understanding and co-operation at the nexus between government, business and the consumer. This may require some difficult cultural shifts, but a collaborative approach will be critical if we are to have any chance of navigating the energy transition while maintaining secure and sustainable energy supplies for all.

The global Gas industry can and already is rising to this challenge, innovating and collaborating to deploy lower-carbon and more energy-efficient technologies. But these industry efforts are taking place on the energy supply side.

Low carbon technologies will simply not succeed if demand is not there. “If you build it, they will come” is not a sensible commercial strategy. This is where partnership with policymakers is so critical in driving a low-carbon energy future. Only effective government policy and regulation can change consumer behaviour, drive demand and create new markets in low carbon technology.

Given the fiscal and electoral implications, this process will be neither easy nor comfortable for hard-pressed policymakers. So let me offer three key policy principles to shape our low-carbon future.

First and foremost, focus on the outcomes – not the technology. Policy measures need to be judged solely on what works in reducing CO_2 emissions – and doing that quickly. Time is ticking and net zero ‘carbon budgets’ are ebbing away. Near-term emission reductions are therefore worth far more than theoretical gains in 20 years’ time.

An excellent example of this in action is LNG in shipping. The IMO’s 2023 GHG strategy indeed focuses on outcomes by calling for a reduction in carbon intensity of international shipping by at least 40% by 2030, not by prescribing specific low-carbon fuel technologies. As a result, the order book for LNG fuelled ships – which can reduce marine emissions by up to 28% – continues to grow. According to Clarksons Research, 35% of all new tonnage ordered in 2024 was LNG dual-fuel capable as shipowners and charterers are moving away from theoretical discussions of what might work tomorrow and deploying what works today. LNG, in addition, provides options for even deeper decarbonisation via liquefied biomethane or liquefied synthetic methane.

GHG reductions also need to be considered using a full lifecycle assessment. Low-carbon and zero-carbon fuels have very diverse production pathways which entail significant differences in their overall environmental footprint. Policymakers must assess all →

"no-regrets investments should be prioritised. The future trajectory of the energy transition is highly uncertain, as are the development horizon and commercial viability of many low carbon technologies."

low carbon technologies on their full carbon footprint from production to end-use. The emissions gains in using green hydrogen for steelmaking or driving an EV – for instance – can be completely undermined if the electrolysis or the battery is being powered by coal-fired electricity.

Second, no-regrets investments should be prioritised. The future trajectory of the energy transition is highly uncertain, as are the development horizon and commercial viability of many low carbon technologies. Policy should therefore incentivise those investments that create optionality by opening up viable pathways for deeper decarbonisation in the future – as we have already seen in marine LNG. This is where utilising existing gas infrastructure really comes into play. The energy transition can piggy-back on this existing infrastructure to drive a faster and less costly energy transition – but only the provided policy incentivises such repurposing and the associated capital investment.

Deployment of hydrogen, low-carbon and renewable gases and carbon capture and storage (CCS) are classic examples where such 'no-regrets' investment can happen. Natural gas infrastructure can be used to transport and store hydrogen. Depleted gas reservoirs and gas pipelines can be used to transport and sequester carbon from industrial clusters. Some modifications are needed, but these are far less costly than creating new pipeline networks from scratch. And in the case of biomethane – chemically identical to natural gas – this is a 'drop-in' option which can be blended into natural gas networks, boilers and vehicle fuel tanks without modification.

Net Zero Teesside Power in the UK, for instance, affords a powerful example of the critical role of policy in driving this repurposing, via government funding to underpin the CCS commercial contracts around the Teesside industrial cluster. Construction will begin later this year on this first-of-a-kind project which repurposes existing gas infrastructure to transport CO_2 emissions from a gas-fired power station to be stored in depleted gas reservoirs under the North Sea.

Finally, policy measures must be market-based to create functioning low carbon markets. Most of the required investment in low carbon technology will need to come from the private sector, so creating the right market signals will mean the difference between success or failure. Such policies could include carbon emissions pricing, air quality regulations or emissions standards. The common denominator is that these mechanisms work with the market by creating new consumer demand and enabling a wide range of energy sources, including low-carbon gases, across different applications and in different locations. We can see this in action in the case of renewable natural gas, or biomethane. According to the IEA, global biomethane production rose by 20% in 2024, with 40% of this increase occurring in the United States, where increasingly stringent fuel standards have been driving end-user demand.

But crucially, different markets will require differing policy regimes. "One-size-fits-all" is equally untrue of policy and regulation as it of the wider energy transition. Cross-border policies like sustainable investment criteria or carbon-leakage mitigation measures that have global implications need to be flexible enough to match the range and the varying pace of multiple global energy transitions. For example, blanket restrictions on financing upstream gas via ESG criteria may be desirable in mature markets but simply make no sense in developing markets with little access to energy. Such measures again simply target the energy supply side, jeopardise vital economic development, while doing nothing to enable an energy transition.

Humility, practicality and flexibility are equally valuable as qualities in policymakers, as indeed they are for the rest of us. ●

Tight gas supply weakens Europe's energy security

Tight conditions on the European gas market undermine the continent's energy security, as reduced gas availability and price volatility make it harder for industries and households to access reliable and affordable energy, while increasing the risk of supply disruptions.

JOSEPH MURPHY

Europe's natural gas market faced a turbulent start to 2025, losing approximately 5% of its supply on January 1 following the expiry of the transit contract for Russian gas flow through Ukraine. The continent has managed to draw in additional global LNG supplies to compensate for the shortfall, but colder weather and low wind speeds have exacerbated the situation, driving up prices and leading to record storage withdrawals.

The outlook for summer remains challenging. Refilling Europe's depleted gas stocks will be costly, with governments likely shouldering the expense through subsidies. Further complicating the situation, stringent EU gas storage targets over the coming months weaken buyers' negotiating position against sellers.

The current tight gas market not only threatens the EU's efforts to deindustrialise – a key priority outlined by the European Commission that took office last December – but also undermines energy security. Reduced gas availability and price volatility make it harder for industries and households to access reliable and affordable energy, while increasing the risk of supply disruptions.

To shore up its energy security and affordability, Europe could pursue more long-term gas supply contracts, as recommended by former European Central Bank President Mario Draghi in a report for the European Commission last autumn on enhancing EU competitiveness. However, buyers and member states remain hesitant due to uncertainty about future demand and concerns among regulators and authorities that long-term commitments are anti-competitive and conflict with climate goals.

The market grows tighter

Russian gas transit through Ukraine ceased on January 1 after reaching 14.3 bcm in 2024 – around 5% of the bloc's consumption – despite efforts by Slovakia and other member states to negotiate alternative delivery arrangements.

The potential resumption of these flows remains uncertain and may hinge on peace negotiations between Russia and Ukraine. In the meantime, TurkStream is now the only remaining pipeline route for Russian gas into Europe. The pipeline has the capacity to increase deliveries to Europe to 18 bcma, up from 16.7 bcm last year, but this additional volume is only a fraction of what was previously transported via Ukraine. While the conflict in Ukraine persists, there is a risk of disruptions to TurkStream gas supplies, particularly following Russia's reports of recent attempted drone strikes on the pipeline.

Difficulties have been compounded by an unusually cold end to winter and below-average wind power generation. In February, the EU derived only 13% of its electricity from wind, down from 21% in January.

Robust gas demand and the cessation of Russian flows via Ukraine have pushed up LNG imports. The EU imported 10.7 bcm of LNG in February, marking a 2.7% increase from January and an 11% rise from February 2024. In the first two months of 2025, total LNG imports reached approximately 21.2 bcm, up 4% year on year.

Market conditions have also led to high storage withdrawal rates. By February 28, European gas storage levels had fallen to 38.5% of capacity, 11.57 percentage points below the five-year average. Storage withdrawals were the primary source of gas supply in January and February, accounting for around 44% of total inflows, according to the European Network of Gas Transmission System Operators (ENTSOG). LNG made up 25%, while North Sea gas accounted for 17%.

While European gas storage remains above critical lows seen in past years, the rapid rate of withdrawals raises concerns over supply security.

Tight supply has driven up prices. The front-month price at the TTF hub increased by 5% month on month to an average of over €50/MWh ($559 per 1,000 cubic metres) in February. This is up two-thirds from the price in February 2024. Worse still, prices are expected to remain at this level throughout the summer before declining next winter, deviating from the usual trend in which summer prices are lower than winter prices, encouraging storage injections.

One factor contributing to higher prices over the summer is the EU's gas storage policy, introduced in 2022 to ensure sufficient reserves for winter in the event of further disruptions to Russian supply. All member states must fill their storage to 90% capacity by November 1, with interim targets set for individual member states for February 1, May 1, July 1, and September 1. If targets are not met, national authorities must intervene to boost stockpiles.

This dynamic benefits sellers, who know precisely how much gas buyers need to purchase and when, allowing them to maximise their pricing power. Reports also suggest speculators are exploiting this situation.

With high injection costs over the coming months, expectations are that governments will need to step in with subsidies, adding to fiscal burdens. Higher gas prices weigh on the broader economy, undermining EU efforts to improve competitiveness and revive industries that have suffered from three years of elevated energy costs.

The gas industry is calling for a relaxation of storage targets, but so far the European Commission appears open only to adjustments from 2026 onward, not this year.

Attracting more gas and cheaper

Looking ahead, the EU has introduced several policies to attract more gas supply at affordable prices, though →

their effectiveness remains debated. The AggregateEU platform, launched in 2023 to facilitate joint gas procurement, has largely functioned as a matchmaking service between buyers and suppliers rather than securing additional supply. In September 2024, the Financial Times reported that the platform had facilitated contracts covering just 2% of potential demand.

Despite its shortcomings, the European Commission plans to use AggregateEU as the foundation for a broader procurement platform encompassing not just natural gas but also clean hydrogen and critical minerals. The first auction at this platform, for clean hydrogen procurement, is due to start in September.

The gas industry widely regards long-term supply contracts as essential for supporting new investments and ensuring the energy security of importing nations. However, European buyers remain hesitant to commit for multiple reasons.

For years, European competition authorities have discouraged long-term contracts, imposing fines or forcing revisions on the grounds of antitrust violations, state aid rules and internal market policies. Future gas demand in Europe is also uncertain, with the 2022 REPowerEU strategy forecasting a two-thirds reduction by 2040. Additionally, EU regulations prohibit new long-term contracts for unabated fossil gas beyond 2049, while future methane regulations could further complicate contract negotiations.

Nevertheless, Draghi's report on EU competitiveness in September 2024 advised Europe to secure more long-term contracts with a diverse range of suppliers, shifting away from spot market reliance and towards alternative pricing mechanisms. This, he argued, would help provide lower and more stable prices, thereby strengthening energy security. The former Italian prime minister also called for expanded joint procurement initiatives, enhanced hedging mechanisms and maximised domestic gas production to meet base demand and reduce import dependency over the years to come.

Beyond expanding renewable energy generation, the EU could shore up its energy security by accelerating the development of biomethane, as a domestic energy source that does not need to be imported and utilises existing gas infrastructure. The sector is gaining momentum, with biogas and biomethane production reaching 22 bcm in 2023, according to the European Biogas Association. Put in context, this is equal to around a fifth of the Russian gas that the EU has lost since 2021.

In the near term, the EU has limited opportunities to secure additional global LNG supply. However, the market is expected to ease as new projects come online, namely in North America, followed later by Qatar. Much will depend on the precise timing of Qatar's North Field East project, which is scheduled to start operations sometime in 2026. TTF futures indicate that market tightness will persist for years, with contract prices projected to remain above €30/MWh until the first half of 2027, nearly three times the average TTF price in the pre-pandemic year of 2019. ●

European gas demand and LNG to shape gas infrastructure

Changing landscape on both sides of the Atlantic brings challenges and opportunities for natural gas infrastructure

ANNA KACHKOVA

The picture for natural gas infrastructure has been in flux over the past couple of years, with various dynamics contributing to changes across the landscape. Such changes can be seen in both North America and Europe and recent shifts on both sides of the Atlantic present challenges, but also opportunities, to gas infrastructure companies.

In Europe, the ongoing war in Ukraine continues to reshape gas flows and the infrastructure that enables them. At the same time, the European Union's energy transition goals are contributing to longer-term uncertainty over what the gas demand picture will look like in future years and decades.

In North America, meanwhile, optimism over gas demand from buyers in both Europe and Asia is contributing to the continuing build-out of LNG export infrastructure. Perhaps the most significant recent change is the return to office of US President Donald Trump, whose stance on energy is already resulting in the easing of regulatory barriers for LNG projects. While these and other gas infrastructure projects are expected to continue benefiting from friendly policies, the Trump administration's measures can also have knock-on effects for the industry.

Nonetheless, LNG infrastructure and pipelines linking to LNG terminals have a significant role to play in the gas infrastructure landscape on both sides of the Atlantic over the coming years. Looking ahead, investor appetite and demand patterns will be important factors in shaping development over the longer term, as much as – if not more than – regulatory environments.

Replacing Russian gas

In Europe, the pivot away from Russian gas in the wake of the war in Ukraine has been the major driver behind the development of new gas infrastructure over the past three years. The impact was almost immediate, as Germany and other European countries scrambled to reduce their dependence on Russian gas, especially by expediting the development of new LNG import capacity.

"Europe's gas infrastructure has had to cope with the loss of the bulk of Russian gas exports and the pipelines that delivered those volumes since 2022," the Oxford Institute for Energy Studies' (OIES) head of gas research, Bill Farren-Price, tells *Gas in Transition* (*GiT*). "In essence, Russian gas has been replaced with increased LNG imports, which has required new receiving terminals and improved grid interconnections to allow all European countries to access imported LNG," he says. "Much has been achieved in the last two years and this work continues, in particular for the countries in central/southeastern Europe that were until December reliant on volumes delivered via Ukraine – flows that have now halted."

"As bottlenecks are progressively removed, infrastructure costs will fall, reducing gas import costs for landlocked countries."

BILL FARREN-PRICE, OXFORD INSTITUTE FOR ENERGY STUDIES

The stopping of flows through Ukraine at the start of 2025 relates to the recent expiry of a transit agreement between Russia and Ukraine. Despite Trump's attempts to bring about an end to the war, the conflict is ongoing as of late February and the dynamics stemming from it continue to shape gas flows. And as more infrastructure is added, it creates new – and increasingly affordable – opportunities for gas imports and transit across Europe.

"As bottlenecks are progressively removed, infrastructure costs will fall, reducing gas import costs for landlocked countries," Farren-Price says.

However, he cautions against relying on infrastructure build-out to gauge the state of the European gas market.

"I don't think infrastructure projects and their progress necessarily gives a good read on the strength of the short-term gas market," says Farren-Price. "Germany has been able to fast-track LNG import terminals and a lot of other infrastructure work since 2022 has been carried out with urgency in an effort to alleviate the risk of winter shortfalls. So far that effort has been successful."

Challenges loom over the coming years, however. While there are expectations that the EU could struggle to meet its medium-term energy transition targets, the bloc also continues to build out its renewable energy capacity in an effort to reduce its gas dependence. Whatever happens with the war, this is likely to weigh on gas demand over the longer term.

"While the pivot away from Russian gas is unlikely to change significantly unless there is a dramatic volte face in the Ukraine war, the growth of renewable power continues to reduce the demand for gas in the power sector – even though gas remains critical to grid balancing due to renewable intermittency," Farren-Price says. "What is not likely to change in the near term is European dependence on gas for heating in the residential and commercial sectors."

Meeting demand

Despite longer-term uncertainty, North American infrastructure players are still betting on LNG demand from Europe – and also from Asia – which underpins the drive to build yet more LNG export terminals. Meanwhile, another source of demand has emerged closer to home.

"Infrastructure growth in North America has two main themes that we have seen recently: LNG export demand and data centres," Energy Aspects' head of North American natural gas, David Seduski, tells *GiT*.

These two sources of demand are playing a major role in determining where new pipeline capacity is being built.

"Most of the large pipelines expected online this year, or moving towards FID, will directly serve new LNG facilities," Seduski says. He adds that there were several other Louisiana pipelines due online in 2025 that would not directly service LNG facilities but would expand takeaway capacity from the Haynesville shale.

Seduski goes on to point to projects being developed to serve customers powering data centres – a recent trend that is expected to continue given the considerable power demand of such facilities.

"This was directly cited as part of the initial plans for SONAT's South System Expansion and Tennessee Gas' Mississippi Crossing pipelines," Seduski says. "Energy Transfer recently booked a long-term gas supply deal with CloudBurst Data for 500 million cubic feet per day →

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(mmcfd) of gas on its Oasis Pipeline, with further such deals likely to inspire additional pipeline capacity near future data centres."

This will play out as pre-FID LNG terminals also move forward again.

"We expect a boom year for new project approvals now that President Trump's Department of Energy has dropped the previous administration's halt to approving licences for export projects," Seduski says. "Already, Commonwealth LNG has received DoE permission to export to countries that the US does not have a free-trade agreement with. We expect several more approvals like Commonwealth following minimal activity in 2024, which should allow these projects to take FID, begin construction activities and potentially enter service by the end of the decade."

Seduski sees cost as the main challenge, while regulatory hurdles at the federal level are expected to keep easing.

"Costs due to the inflation of the past few years were already a challenge for LNG projects," he says, citing the bankruptcy of Zachry Holdings, the contractor for Golden Pass LNG. "The recently imposed steel and aluminium tariffs will only exacerbate that issue," Seduski continues. "The US does not produce enough steel to meet the demands of the domestic market plus all the LNG terminals and pipeline in development. That means higher-cost foreign imports will be needed if these projects are to move ahead. That shifts the financial calculus for such projects and could mean longer development timelines to drum up additional financing (especially on the LNG side)."

Supply-demand dynamics

Ultimately, while regulatory and permitting challenges are expected to diminish, supply-demand dynamics are still expected to be a more significant driver of gas infrastructure build-out, both in specific regions and more broadly.

"I do not believe the Trump administration easing permitting and regulations on pipelines will drive the infrastructure build-out," Seduski says. "It will still be based on regional supply-demand dynamics. That's why we have seen such an expansive buildout of Louisiana and Haynesville projects recently, because the LNG export expansion is the lynchpin for several new pipeline projects."

Seduski adds, however, that this does not mean a more lax regulatory regime is less beneficial.

Farren-Price also sees Trump's stance on permitting as helpful to the development of LNG export projects but notes that other dynamics will also come into play.

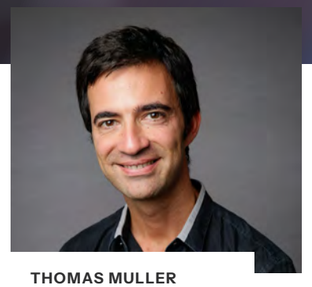
"The challenge for new projects will be establishing new markets as major consumers steadily seek to decarbonise their energy systems and reduce their use of gas," Farren-Price says. "So rather than eased regulation, it will be investor enthusiasm and availability of finance that will be tested after the current wave of LNG is delivered." ●

"Infrastructure growth in North America has two main themes that we have seen recently: LNG export demand and data centres."

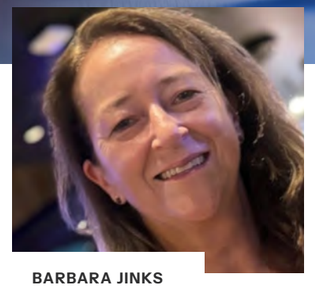
DAVID SEDUSKI, ENERGY ASPECTS

Europe needs more than the European Hydrogen Backbone

Recent research on behalf of the Ready4H2 project suggests distributions grids are key to achieving the deployment of hydrogen across Europe.



THOMAS MULLER
Hydrogen Director, GRDF



BARBARA JINKS
Director, Ready4H2

Despite a complicated context, Europe still has great ambitions for hydrogen, seen as a promising energy carrier that could facilitate the integration of intermittent or remote renewable energy sources. The development of the new hydrogen supply chain is underway, including projects for domestic production, imports, transportation, storage and end use. But how do we get the hydrogen to the final customers?

Historically, natural gas consumed in Europe is transported through the 200,000 km network of transmission pipelines, typically 8-inch diameter and above, at high pressure and volume, but these deliver only about half of the gas directly to the consumer. The other half is transported through an extensive 2.2 million km network of lower-pressure gas distribution pipeline grids that connect 99% of gas customers.

As part of the energy transition in Europe to meet net zero plans, renewable and low carbon gases will be used to decarbonise energy use. The production of biomethane is increasing throughout many countries, leading to structural changes such as decentralised injection and real-time operation. Plans are also being made to use gas transmission and distribution networks to transport hydrogen, partly by repurposing pipelines, also by building new. Whereas the creation of the European Hydrogen Backbone transmission network (EHB) is well known, plans to transport hydrogen through the distribution grids are less widely recognised. Yet they are crucial to bring hydrogen to a large base of customers, with the potential to reduce vast quantities of CO_2 emissions.

To fill this gap, the Ready4H2 project was established in 2022 to share the expertise and experience of Distribution System Operators (DSOs) across Europe and build a common knowledge base to highlight the role of distribution networks in the deployment of hydrogen.

In its fourth year, the project comprises more than

FIGURE 1: READY4H2 MEMBERS AND PARTNERS

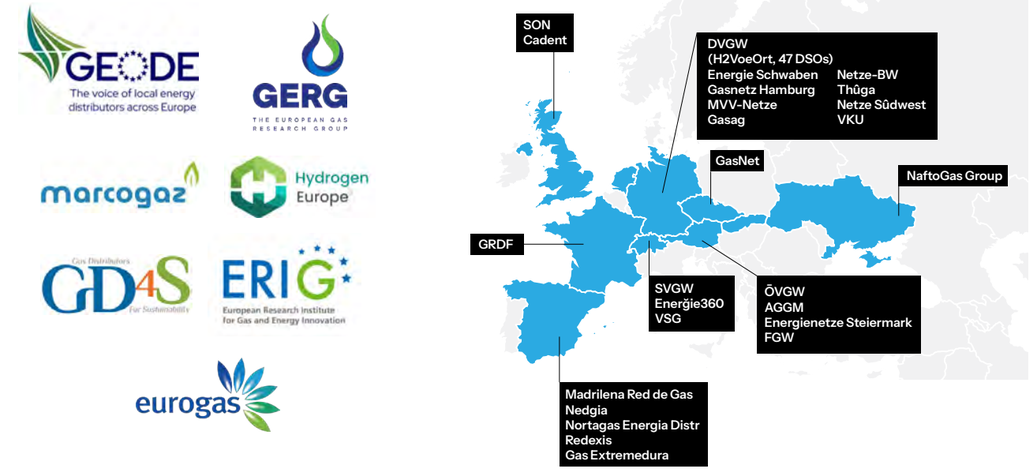
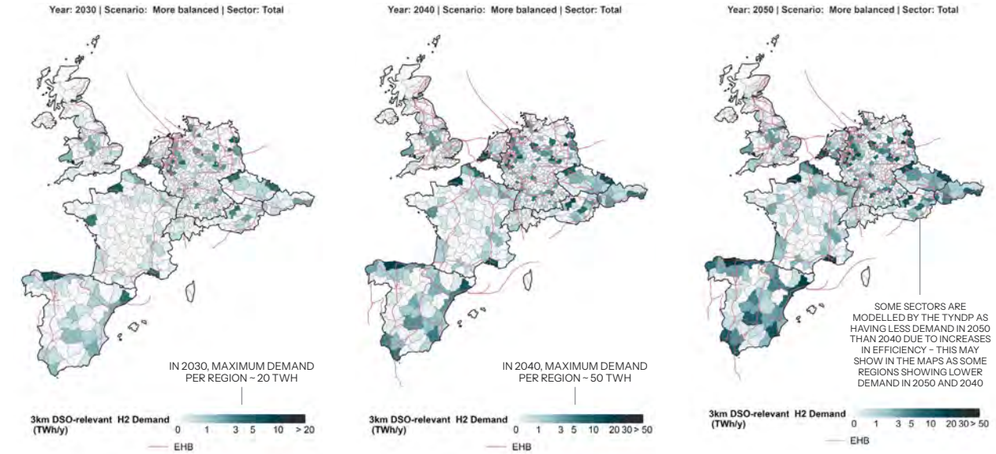


FIGURE 2: DSO-RELEVANT H2 DEMAND (TOTAL ACROSS ALL SECTORS): THE NEED FOR H2 DISTRIBUTION GROWS STRONGLY OVER TIME AND IS DRIVEN BY LARGE GEOGRAPHICAL DISPERSION IN H2 DEMAND



Disclaimer: This analysis is not intended to reflect and may deviate from network development plans. It is based on national hydrogen demand predicted by TYNDP and public regionalisation data, such that it may not reflect actual future regional hydrogen consumption or current natural gas consumption.

70 gas DSOs and national associations in 10 countries in Europe (Fig 1). Members operate a total of 1.6 million km of distribution systems, supplying 19 million customers. Members in the EU27 operate 55% of the total EU27 gas distribution grid.

Research in 2024

In order to assess the overall role of DSOs in delivering hydrogen – both in terms of physical need for connection and how much hydrogen volume will need to be delivered – the forecast hydrogen supply and demand across the sectors above were mapped (Fig 2). This was done for 2030, 2040, and 2050 using two contrasting scenarios in terms of electrification, technological innovation, policy and economic developments at both sector and country levels, based on publicly available TYNDP2024 data[1]. Hydrogen consumption heat maps where developed, using exact coordinates where possible or at a geospatial NUTS-3 level[2]. A DSO was deemed to be needed, depending on the distance of the →

1. TYNDP2024 : ENTSO-E and ENTSOG TYNDP 2024 Draft Scenarios Report
2. NUTS - Nomenclature of territorial units for statistics link

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FIGURE 3: DISTANCE FROM EHB USED TO CALCULATE DSO-RELEVANT DEMAND, UNDER MORE BALANCED SCENARIO

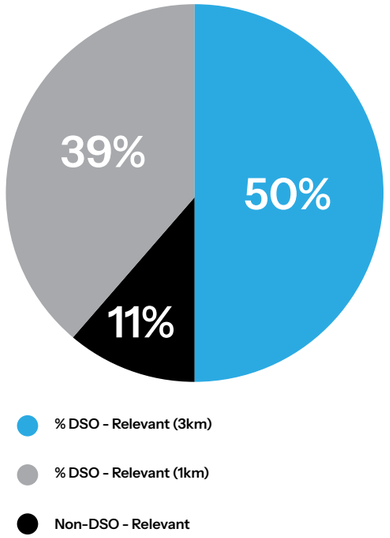
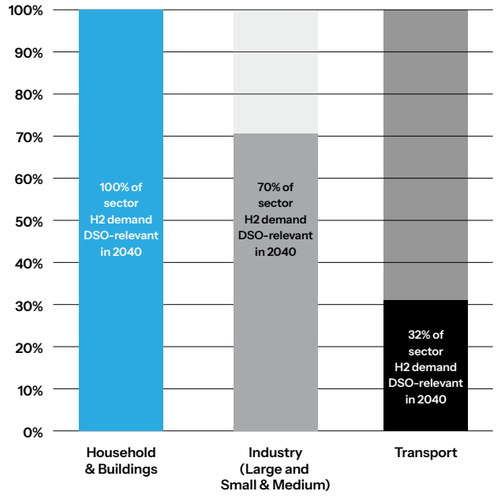


FIGURE 4: DSO-RELEVANT DEMAND AS % OF TOTAL DEMAND IN SECTOR



hydrogen consumer from the EHB or a green hydrogen production facility. The study was conducted by Frontier Economics.

The study highlights the importance of European gas DSOs in linking hydrogen supply to widespread demand in all sectors, for both demand scenarios (Fig 3). Around half the hydrogen needed by consumers located more than 3 km from the EHB will need to be connected by a distribution pipeline, and an additional 11% between 1 and 3 km. A significant number of consumers that are located within 1 km of the EHB will also require a pipeline but due to high connection costs amongst other factors, this figure is uncertain.

Estimates of hydrogen demand that needs to be transported through a distribution grid range from 160 TWh in 2030 to 580-840 TWh in 2050. The percentage of total hydrogen needed to be transported through the distribution grid varies by sector (Fig 4): all hydrogen into households and buildings (for heating and to provide flexibility during winter) will be delivered through the distribution grids, as it is for gas today; 70% for all industrial consumers (large, medium and small); and 32% for transportation (including EC plans for a hydrogen refuel stations at least at 200-km intervals along motorways).

The need to transport hydrogen as feedstock for e-fuels, power and e-methane plants was considered, but the role of distribution grids was not estimated due to significant uncertainties around the location and requirements of these plants.

The study concluded that most developments in hydrogen distribution networks will be no-regret investments due to the forecasted large ramp-up in hydrogen demand over time. The use of distribution grids might also offer faster regional development as they can connect remote green hydrogen production sites to local consumers without the need to connect to a transmission pipeline system, offering opportunities for hydrogen islands, hydrogen valleys and river ports. In addition, gas distribution grids that are made hydrogen-ready can be used for methane and hydrogen and for blended or pure gases - offering flexibility in emission reduction solutions as well as ramping up biomethane and hydrogen production.

The cost of repurposing distribution grids for hydrogen or building new was conducted with current data on assets, materials and costs[3]. A typical distribution system consists of pipelines, valves, meters, control and measuring equipment, and Gas Pressure Reduction and Metering Stations (GPRMS). The study shows that it is a relatively fast and straightforward process to repurpose distribution grids to hydrogen and that both repurposing and new-build are extremely cost-effective options. Repurposing a pipeline system costs 9% compared to the cost of building new, attributable to the fact that most distribution pipelines are made from plastic materials (polyethylene) and are compatible with both natural gas and hydrogen. The cost of converting a GPRMS from gas to hydrogen is 50% compared to building new, with the majority of cost being the replacement of diaphragm meters.

The process of transforming a gas distribution grid can moreover be faster compared to new-build and, in areas where existing grids are not planned to transport biomethane, the conversion of gas grids to hydrogen is a cheap option allowing the valorisation of existing assets.

Complimentary to these two studies, a survey was conducted within the Ready4H2 membership on the progress of DSOs along the 2023 Ready4H2 Transformation Roadmap. It sets out nine key areas for a DSO to be hydrogen-ready, comprising:

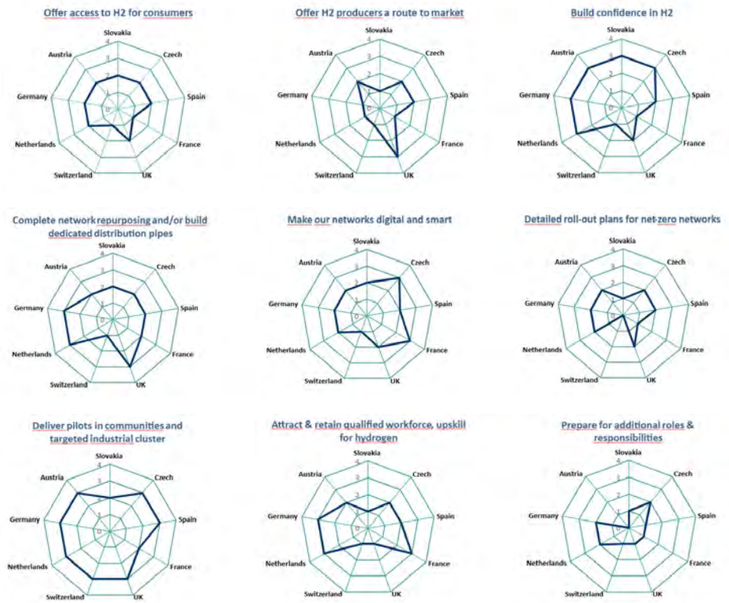
- Facilitating the development of the hydrogen market - offering customers access to hydrogen, offering hydrogen suppliers a route to the market, and building confidence in hydrogen.
- Transforming the distribution network - repurposing the distribution grid or building new grids for hydrogen, making the networks digital and smart, and developing roll out plans.
- Delivering hydrogen at scale - conducting pilot plants in communities and targeted industrial clusters, attracting and retaining qualified workforce, and preparing for additional roles and responsibilities.

The results demonstrate that participants actively support the transition to hydrogen. Planning for this transformation is well underway, and the distribution of hydrogen via distribution grids has been shown to be both feasible and safe at the forecasted volumes.

While the prerequisites for gas DSO transformation to hydrogen are in place, there are external uncertainties that need to be addressed. These include the lack of hydrogen supply forecasts, which weakens the hydrogen value proposition to investors and consumers, and the fact that gas customers are often unaware of the options available to them for using hydrogen in their processes (Fig 5).

Finally, a database was created of the 57 projects being conducted by Ready4H2 members to test the feasibility of hydrogen in distribution grids (Fig. 6) and 20% are complete. Key activities, challenges and lessons learned have been shared between Ready4H2 members; these fall under the categories of technical and safety, operational, organisational, commercial and stakeholder management. Some of these projects will be included in →

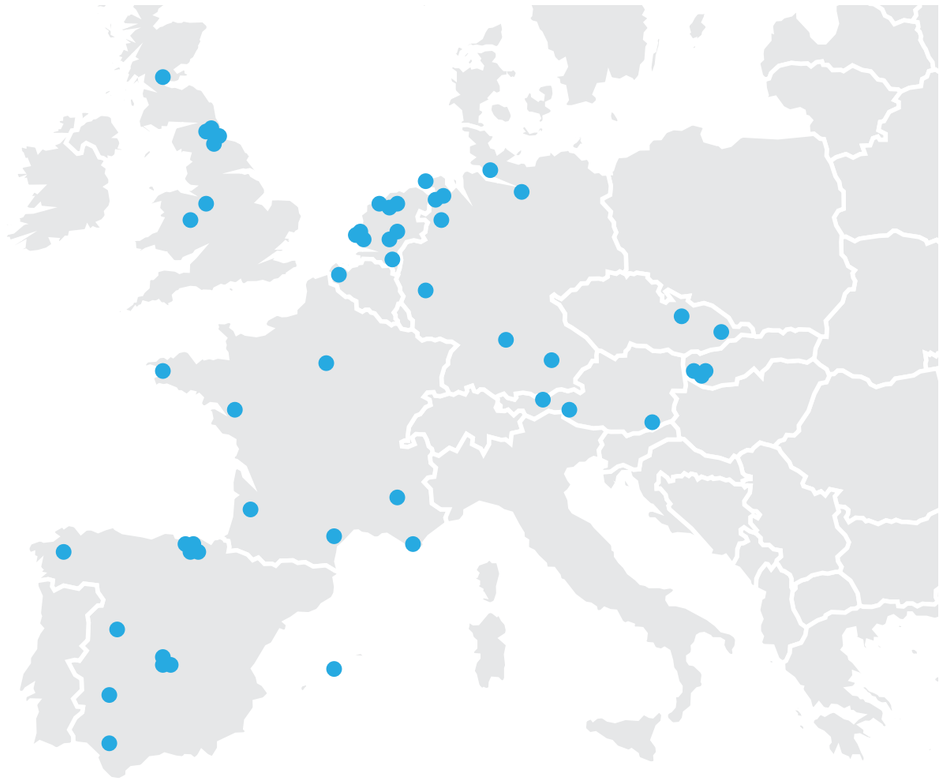
FIGURE 5: PREEQUISITES FOR TRANSFORMATION PLANS ARE IN PLACE, BUT CLARIFICATION IN REGULATORY FRAMEWORK AND FINANCE MODELS ARE NEEDED TO ENSURE AN INTEGRATED GAS AND ELECTRICITY LOW-CARBON ECONOMY



3. Revision to 2023 MARCOGAZ study

GAS IN TRANSITION. MARCH 2025

FIGURE 6: READY4H2 PROJECT MAP SHOWING MEMBER PROJECTS IN TRANSFORMING GAS DISTRIBUTION GRIDS TO HYDROGEN



A WIDE RANGE OF PROJECTS:

74% – Repurposed network
68% – 100% H2
79% – Field projects, 1/2 will scale up
32% – Completed projects

ACROSS READY4H2 COUNTRIES

Austria (4)
Czech R (2)
France (7)
Germany (8)
Netherlands (11)
Slovakia (3)
Spain (14)
UK (9)

58 TOTAL PROJECTS

the IGU Distribution Committee report at the World Gas Conference 2025.

Conclusions

The work of Ready4H2 shows evidence that the energy transition in Europe would clearly benefit from using gas distribution grids as the enabler to deliver hydrogen to end users. Gas DSOs offer cost effective, fast ways to deliver hydrogen.

Industry leaders, investors and policy makers need to be more aware of the essential role of gas distribution grids to make informed decisions about the future of the energy system in Europe. In addition, coordination is needed between the gas transmission and distribution sectors to enable the best planning of the future energy network. Without this, Europe will not be able to reach its ambition, nor will the EHB to function at capacity, as around half the hydrogen needs to be passed on to the customer through distribution grids.

Works conducted by the Ready4H2 project show that such industry initiatives are important to fill gaps in knowledge of the whole suite of solutions that are available to achieve the energy transition. The project is open to new members from gas distribution and related industries. ●

Glut or supply gap? LNG market forecasts chart different futures

The global LNG market has gone through multiple phases of expansion, but the one now looming will be the largest yet. Some observers see glut amid peaking global gas demand, others a supply gap by 2040 as more affordable prices stimulate consumption. Both narratives can't be right. Both, of course, could be wrong.

ROSS MCCRACKEN

LNG prices in Europe and Asia are high and freight rates have slumped. The northern hemisphere winter has proven colder than its two predecessors, pumping up European demand for LNG as Russian pipeline imports have fallen to a new low. Restocking should keep prices firm over the summer. And US LNG producers now have a champion in the White House, who rarely fails to remind friends and foes alike of the need to buy more US LNG.

Nonetheless, harder times may be coming. Low freight rates – negative for older vessels – are a harbinger. The LNG fleet is growing in anticipation of a surge in new liquefaction capacity. Even so, for the moment, the current situation indicates only that there are more LNG carriers than cargoes, not that there is insufficient demand were more cargoes available.

The glut narrative

LNG volumes have increased only incrementally in the past five years, reflecting the industry's long investment cycle and earlier periods of uncertainty which led to a lack of investment. However, the next five years will be very different.

Based on projects under construction, North American liquefaction capacity is set to grow from 86.6 MTPA in 2023 to 184 MTPA in 2028. Most of this growth will be in the US (73.7 MTPA), but also in Canada (19 MTPA) and Mexico (6 MTPA), much of it on the west coast.

LNG production will also boom in Qatar, where capacity will jump from 77 MTPA to 126 MTPA in 2026-27 and to 142 MTPA by 2030. Just as with west coast Canadian and Mexican LNG supply, Qatar's position, located between the Asian and Atlantic basins, presents a competitive challenge to US LNG. Qatari costs, offset by associated liquids production, are expected to be the cheapest globally.

In total, global LNG production will leap by more than 160 MTPA by 2030, an increase of 40%, the fastest rate of expansion in volume terms ever. This expansion suggests glut is coming to the market.

Europe – a demand centre in decline

High LNG prices in the last three years reflect largely Europe's sudden and dramatic shift from Russian pipeline imports to much higher LNG import levels. Following Russia's invasion of Ukraine in late February 2022, European LNG imports jumped from 79mn mt in 2021 to 126.5mn mt. At 124.3mn mt in 2023, Europe accounted for 30.1% of global LNG demand.

However, the Ukraine war and high gas import bills have only served to accelerate Europe's energy transition ambitions. The UK, for example, has set a target of achieving a fully decarbonised electricity system by 2030, which, while unlikely to be achieved in full on time, still implies a sharp decline in gas for power consumption.

Similarly, Germany, the largest gas market in Europe, has plans to achieve carbon neutrality by 2045, which again implies a sharp decline in its demand for gas. Overall, energy transition plans suggest Western European gas demand will fall sharply post-2030, eradicating the surge in demand for LNG seen since the start of the Ukraine war.

Peace in Ukraine would also present major uncertainties. US President Donald Trump has made ending the conflict a major foreign policy objective. Although there is little clarity on how this will be achieved, after three years of war both Kiev and Moscow appear receptive to some kind of peace.

The question for the LNG market is to what degree, if any, the resumption of Russian pipeline gas flows to Europe plays a part.

Europe is not united in its stance. Some European governments are resolutely opposed to any resumption of Russian gas imports, others protest the latest suspension of gas flows through Ukraine, while others may accept low-cost Russian gas as a temporary measure, in the knowledge that their energy transition plans will eventually end their dependence on Russian gas.

The future role of Russian gas in European gas supply is also a conundrum for Trump: while he has gambled political capital on ending the Ukraine war, peace could erode US LNG export volumes to Europe.

Demand growth shifts back to Asia

Trump's trade policy also seems at odds with his support for the further expansion of US LNG. With European LNG demand potentially on the cusp of decline, the markets of Asia will again become the centre of global LNG demand growth.

Trump has put an additional 10% tariff on all Chinese imports, to which Beijing has responded with a 15% tariff on US LNG, amongst other measures. US LNG already →

In the period to 2030, the LNG market should certainly become much more competitive.

faces cost challenges in competing with west coast North American LNG and Qatari LNG, while north Asia will always be the main consumer of Australian LNG. A 15% tariff imposed by the world's largest LNG importer, and where demand is expected to rise to 2030 and beyond, puts US LNG at a major disadvantage at the very moment at which supply is expected to leap ahead of demand.

Meanwhile, the energy transition is also having an impact in Asia. LNG demand in Japan and South Korea appears to be in structural decline, as nuclear power makes a comeback and renewable energy capacity expands. Even in China, which continues to add LNG import infrastructure and sign long-term supply deals, gas demand has been forecast as peaking as early as 2040. China is well advanced in its energy transition, leading the world in almost every aspect of energy transition technology deployment.

Counter narrative sees demand rebound

The counter narrative to impending glut is that demand and supply growth cycles are rarely in sync but reactive. The imminent expansion of supply reflects earlier scarcity and high prices – aspects of the market already evident in the six months before Russia invaded Ukraine.

Surplus supply will cause prices to fall and in turn stimulate demand, almost immediately in areas such as South Asia, where the short-term problem is not so much infrastructure but affordability. China, too, has the capacity to absorb much more LNG, if prices are more attractive. LNG still has a major role to play in the displacement of coal – a complimentary role in the energy transition – but can do so only if it is more competitive.

This should occur as supply temporarily outstrips demand. LNG market analysts, typically within the industry rather than without, see LNG demand rising to as much as 600 MTPA by 2040. This would create not a glut, but a supply gap of more than 100 MTPA, even if LNG producers have to ride out a pricing trough, while the demand side catches up.

So, glut or supply gap? There are many uncertainties in both narratives; both cannot be right, and both could be wrong.

However, in the period to 2030, the LNG market should certainly become much more competitive. This bodes ill for the US as swing producer. US producers will be hard pressed to compete with Qatar on cost, are geographically disadvantaged in terms of the shift in demand growth to Asia, may suffer from peace in Europe and face a 15% tariff on entry into the world's largest and most dynamic LNG import ●

Fulfilling Nigeria's natural gas potential

AKACHUKWU ADEYINKA NWOKEDI
President, Nigeria Gas Association

Gas in Transition discusses the challenges and opportunities facing Nigeria's natural gas sector with the Nigerian Gas Association

Nigeria's gas potential is vast, yet financing remains a major challenge. What specific policy, regulatory or financial mechanisms do you believe are critical to unlocking capital for gas infrastructure and development?

It is important to acknowledge the significant policy interventions of the Nigerian government aimed at unlocking the latent potential in its vast gas resources, and although robust fiscal incentives have been put in place to attract the required investments, there is the opportunity to do more to overcome the enduring challenges to accessing financing. A multifaceted combination of interventions including predictable and favourable policies, legislative and regulatory frameworks; promotion of innovative financial models; effective risk mitigation strategies; and the improvement of existing fiscal incentives by way of extended tax holidays and accelerated depreciation for gas assets among other things will be required, while a transparent and stable legislative environment characterised by strict adherence to the rule of law and sanctity of contracts will assure investors. Finally, creativity and innovation will be required in optimizing existing financial models such as international capital targeted infrastructure bonds, enhanced public-private-partnerships and multilateral/blended funding. The courage to develop innovative solutions such as prepayment and forward sale arrangements will also be required where time tested models do not deliver on expectations.

Given the global push for a just energy transition, how can Nigeria and other African nations balance the need for climate action with leveraging natural gas as a critical driver of industrialisation and economic growth?

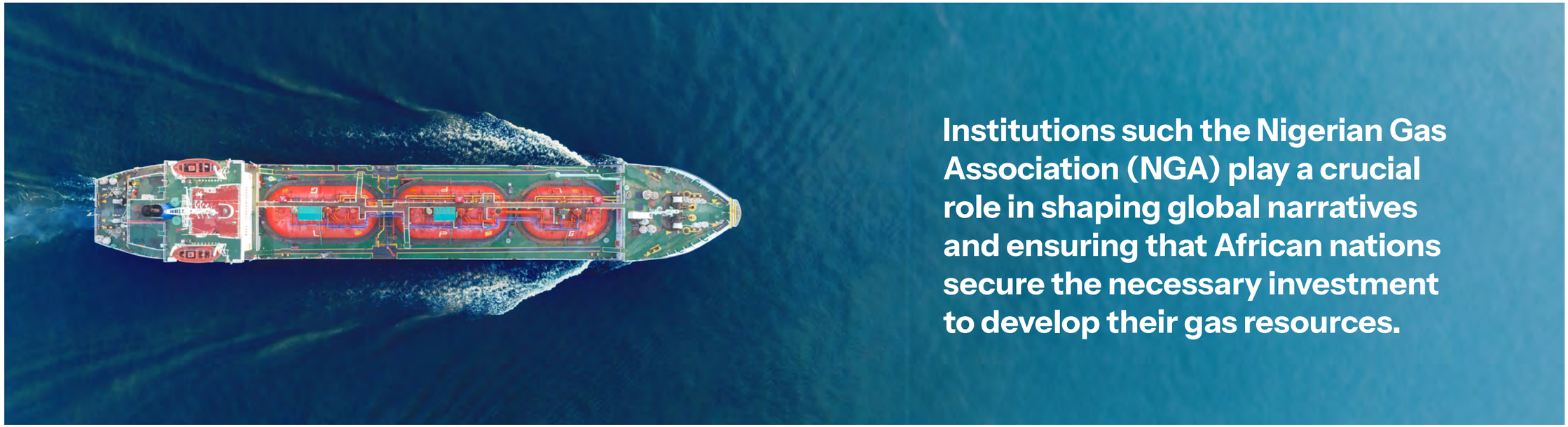
Nigeria and other energy producers in the global south are faced with the challenge of balancing climate action with the need for poverty eradication, economic growth and wealth creation. Natural gas being the cleanest fossil fuel is well positioned as the transition fuel source with a critical role to play in the systematic displacement of dirtier fuels such as solid biomass, coal, petrol and diesel in everyday use for cooking, power and transportation to more sustainable and renewable sources. The solution for African countries lies in properly phasing their respective pathways to energy transition, prioritizing the pervasive energy poverty among their populations, before energy security, and ultimately developing home-grown energy transition plans uniquely tailored to their national development goals underpinned by long-term strategies that clearly define the balance between energy access, industrial growth, and climate action. International support is required to accelerate progress toward sustainability, and to this end ambitious yet credible, realistic and measurable emission reduction targets will be required. Gas projects will need to demonstrate emission mitigation considerations such as Carbon Capture and Storage (CCS), with active steps aimed at developing the required regulatory frameworks for safe deployment. Finally, engaging local communities, civil society, and the private sector in the energy transition process is crucial, as the people most affected by energy policies must be able to take ownership of decision-making for policy to be effective. African nations must continue to engage on the national, regional and global stage to contribute and integrate their unique perspectives on energy poverty and energy security to the energy transition narrative.

Multilateral lenders have been shifting focus away from fossil fuel investments, including gas. How can Nigeria and other African nations attract alternative financing sources, such as domestic capital markets, private equity or blended finance models, to sustain gas development?

The shift in focus by traditional providers of finance from fossil fuels has made it imperative for Nigeria and indeed other African countries to seek innovative solutions to fund natural gas development and use, to avoid derailing their energy security objectives whilst keeping their climate change and energy transition commitments in mind. There should not be much concern as domestic and/or regional capital markets, pension funds and insurance companies can be leveraged through public-private partnerships (PPPs). Dedicated infrastructure funds such as the Nigerian Midstream and Downstream Gas Infrastructure Fund (MDGIF) are another step in the right direction, which can be complemented by regional and continental initiatives such as the African Energy Bank. Private equity firms with an emerging markets and energy sector focus, can also be attracted by a combination of competitive returns, stable regulatory environments, fiscal incentives, investment-friendly policies and risk mitigation instruments. Innovative blended finance models that leverage multilateral and bilateral development finance from a combination of development finance institutions (DFIs), philanthropic organizations and private capital are another viable method of reducing risks and improving the financial viability of gas projects. I believe these options demonstrate that Nigeria and Africa will be able to continue to finance gas projects but must stress that replacing the traditional financing routes in no way suggests an abandonment of climate change considerations as alignment with climate goals and ensuring projects are supported by carbon offset strategies or renewable energy integration will continue to preserve access to available international funding sources such as impact investors that prioritize social, environmental, and governance (ESG). By positioning gas as part of a broader 'balanced' or 'just' energy transition strategy that includes renewable energy and energy access goals and committing to gas projects with a clear path to reducing emissions over time, Nigeria and other African countries will attract new funding sources while preserving access to international funding sources that support climate action and economic development.

The Decade of Gas initiative underscores Nigeria's ambition to harness its gas resources for economic transformation. What financing strategies would be most effective in fast-tracking gas-to-power projects and domestic gas utilisation?

The Decade of Gas initiative which aims to transform Nigeria into a gas-based economy by 2030 will benefit from financing strategies tailored to Nigeria's unique economic context, energy needs, and development objectives. Some strategy considerations that could significantly move the needle include developing policies directed at deepening the market by closing identified gaps in relation to metering, cost-reflective tariffing, upgrading aging and obsolete gas supply and power transmission infrastructure and price liberalization on a willing buyer-willing seller basis will significantly boost investor confidence. A regime of targeted incentives for domestic gas use and regional cooperation could prove very helpful for accelerating the development of the gas sector, and these could unlock capital market funding. For example, Nigeria's capital market capitalisation as an example is expected to reach over USD 50 billion in 2025, and it is critical to make the domestic gas utilisation projects attractive enough to capture a significant share of this available capital. Issues around bankability of offtake and other non-technical risk factors require attention, and clear and transparent →



Institutions such the Nigerian Gas Association (NGA) play a crucial role in shaping global narratives and ensuring that African nations secure the necessary investment to develop their gas resources.

policy, legal and regulatory frameworks are necessary to reassure investors. Challenges with traditional financing sources have brought about alternative financing which need to be matured and supported by concise contractual structures that effectively allocate risk between government, development finance institution and the private sector. There is no gain saying that the development and deployment of key gas infrastructure such as the AKK and OB3 pipelines are critical to the Decade of Gas aspirations, and the sustained high priority the Nigerian government has given these infrastructure projects to ensure timely completion is most commendable. Finally, while the initiative focuses on Nigeria's economic transformation, it must be understood that this will have direct and indirect positive impacts on the West-African sub-region in particular, and the African continent in general. There is therefore value in deliberately fostering the necessary cooperation to fast-track projects that have potential for regional impact and expanding regional gas markets.

Infrastructure bottlenecks, such as pipeline development and processing capacity, have slowed the expansion of the gas sector in Nigeria and other African nations. How can strategic partnerships and innovative funding models help address these challenges?

Strategic partnerships and innovative funding models are essential for addressing infrastructure challenges in the gas industry across Africa, with Public-Private Partnerships (PPPs) and Regional Cooperation and Cross-Border Infrastructure representing useful tools for resolving some of the obvious issues. Through PPPs, governments can share the financial and operational risks with private investors, reduce the burden on public finances and allow private sector partners focus on their areas of expertise while benefiting from long-term contracts with guaranteed revenues. International Players are also able to provide the capital, technology, and experience required for complex gas infrastructure projects through joint ventures. African countries can also collaborate regionally to develop cross-border gas pipelines that serve multiple countries which would increase the scale of infrastructure projects, making them more attractive to investors and help address supply and demand challenges. Regional investment funds will greatly enhance such cross-border collaboration and facilitate the creation of regional hubs and centres of excellence, and the innovative funding models we have talked about will further reduce risk and ensure more efficient employment of available capital from a multiplicity of sources including domestic and/or regional capital markets, infrastructure or energy funds or bonds, and multilateral support from Development Finance Institutions (DFIs) to provide long-term, low-cost financing, technical assistance and guarantees that will help overcome the high capital costs of gas infrastructure development. By leveraging strategic partnerships, innovative funding models and technology, Nigeria and other African Nations can unlock capital for much-needed gas pipeline and processing infrastructure. However, the right balance of financial instruments, de-risking strategies, and collaborative approaches will be needed to fast-track the development of the gas sector and achieving energy security, economic growth, and sustainable development across the region.

With African nations increasingly advocating for gas as a transitional fuel, what role should institutions like the Nigerian Gas Association play in shaping global narratives and ensuring Africa secures the necessary investment to develop its gas resources?

Institutions such the Nigerian Gas Association (NGA) play a crucial role in shaping global narratives and ensuring that African nations secure the necessary investment to develop their gas resources. As Africa increasingly advocates for natural gas as a transitional fuel to facilitate economic growth while moving toward renewable energy sources, the NGA and other similar institutions can drive several key actions to ensure the continent's gas potential is recognized and adequately financed, including:

- **National and Global Advocacy:** This entails collaboration with the government and other stakeholders to develop liberalised, competitive and efficient gas markets underpinned by transparent and stable regulatory frameworks as investors are more likely to invest in projects in a predictable investment environment. It also entails shaping a more favourable global narrative in the ongoing advocacy for a Just Energy Transition, promoting gas in global energy dialogues and climate summits as a pathway for Africa to support the achievement of global climate targets and energy equity.
- **Investment Promotion:** Making a case for alternative funding and investment sources while attracting available international capital by promoting the viability of the African gas sector and highlighting the strategic role of gas in diversifying energy sources, ensuring energy security, and driving economic growth. The NGA will, for instance, host a Nigeria Pavilion at the 2025 World Gas Conference in Beijing, China, showcasing the vast opportunities in Nigerian gas to a global audience. Gas achievements and opportunities at WGC 2025.
- **Capacity Development:** It is important that African countries develop the local capacity to take ownership of their gas industries as part of a broader energy security framework. NGA actively promotes workforce development initiatives that ensure that local industries are ready to manage and operate gas infrastructure efficiently. Building local capacity will not only create jobs but also reduce dependence on foreign expertise and attract domestic investors. Capacity initiatives also include promoting the development and adoption of cutting-edge technologies which can help optimize the use of gas and reduce its environmental footprint. ●

GAS IN TRANSITION. MARCH 2025

Sustainable and Efficient Ethane Transportation

In the evolving landscape of ethane transportation, GTT has pushed the boundaries with the largest Very Large Ethane Carriers (VLECs) and has long developed and promoted Ultra Large Ethane Carriers (ULECs).

2024 marks the beginning of a new era in ship types with the Ultra Large Ethane Carrier (ULEC), a 150,000 cubic meter liquefied gas carrier. The Chinese chemical giant "Zhejiang Satellite" has decided to charter eight (with an option for two additional) ULECs, with EPS as the shipowner and Jiangnan shipyard (JN) and Hyundai Heavy Industries (HHI) as the shipbuilders. These eight carriers are expected to be delivered in 2027.

In early 2025, Thailand's Siem Cement Group decided to move ahead with its half dozen VLEC shipping programs, with SHI as the shipyard, utilizing the world's largest VLEC size of 100,000 cubic meters. This growing preference for GTT technologies is driven by several key advantages that enhance operational efficiency, reduce costs, and improve overall vessel performance.

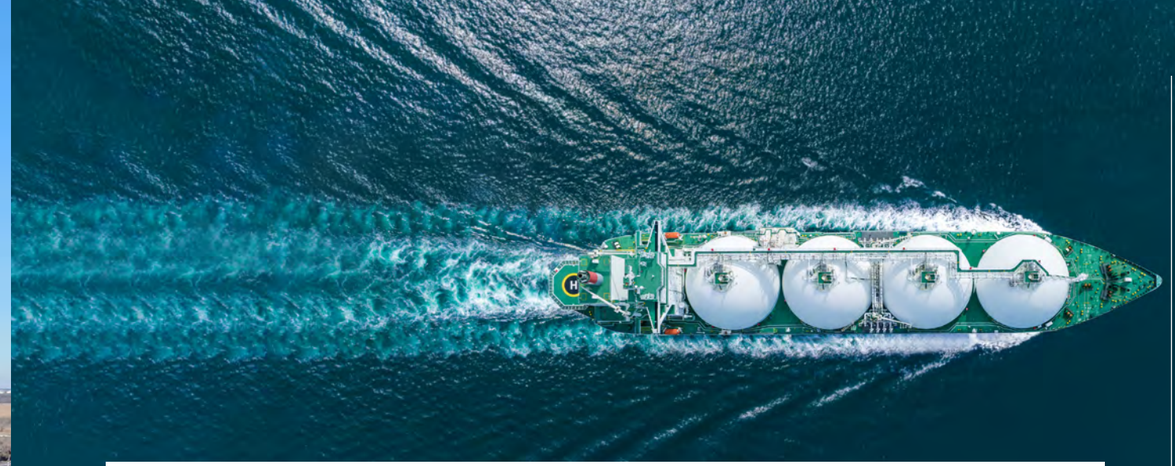
Key Advantages of GTT Technology

GTT technologies offer unparalleled cargo flexibility. Unlike self-supporting IMO tanks, which are restricted to ethane, ethylene, and LPG cargoes, membrane tanks can accommodate a broader spectrum of liquefied gases, including ethane, ethylene, propane, propylene, butane, LNG, and ammonia (with loading limitations due to its 25% higher density).

This multi-cargo capability enables shipowners to diversify operations, adapt to market fluctuations, and maximize fleet profitability. One of the most significant benefits of GTT's technologies is its lower Boil-Off Gas (BOG) rate. Advanced insulation reduces BOG generation, minimizing the need for reliquefication plants. Unlike LNG carriers, where BOG is burned in the engines for propulsion, ethane carriers run on liquid fuel, requiring full reliquefication of the BOG. GTT's thermal insulation performance not only lowers operating costs (OPEX) but also enhances energy efficiency. Additionally, its increased design pressure (compared to the conventional 250 mbarg) further reduces reliance on reliquefication units, providing greater operational flexibility and enhanced energy savings.

The GTT technology systems also provide a significant lightship advantage. Weighing approximately 1,650 tons, the membrane technology is considerably lighter than self-supporting IMO tanks, which can reach up to 5,000 tons in their nickel alloy version. This weight reduction results in lower fuel consumption or faster service speeds, and better compliance with Carbon Intensity Indicator regulations.

Regarding operational efficiency, GTT's VLECs and ULECs are capable of loading cargo more quickly. At major terminals, self-supporting IMO tanks VLECs experience a 25% longer loading time for ethane cargo due to higher BOG generation as well as thermal inertia,



which both combined conflicts with the reliquefication unit capacity. In contrast, GTT's superior insulation prevents excessive BOG, enabling quicker loading times and increased efficiency.

Given its construction philosophy and International Gas Codes requirements, GTT cargo containment systems come with easier inspection and maintenance plans compared to self-supporting IMO tanks, which often require welding repairs and scaffolding installation. Continuous monitoring of GTT cargo containment system tanks ensure higher reliability, safety for the crew, and lower maintenance costs over the vessel's lifetime.

Recent Design Breakthroughs

In recent months, GTT and its partners have introduced a series of ship design optimizations. Korean shipyard partners, Samsung Heavy Industries (SHI) and Hyundai Heavy Industries (HHI), have both refined their latest designs developed in 2025, increasing cargo tank capacity from 98,000 cubic meters to 100,000 cubic meters. Additionally, GTT has collaborated with its Chinese partner CMHI-JS and ship designer Delta Marin to develop a three-tank GTT Mark III VLEC, enabling a cargo capacity of 103,000 cubic meters. This layout further reduces construction costs (CAPEX), enhances hull integration, and optimizes cargo space utilization. Lastly, GTT and ship designer MARIC have developed a 155,000 cubic meter ULEC design. This work was granted Approval in Principle by Bureau Veritas in late March 2025.

Lastly, GTT is developing a new portfolio of dedicated cargo containment systems, both Mark III and NO96 technologies—for LPG and LEG cargoes that are warmer than LNG. Not only will the cost be lower, but the cargo volume will be increased by nearly 2% thanks to a thinner insulation system.

Conclusion

GTT technologies offer superior operational efficiency and cargo flexibility, larger cargo volume, and reduced maintenance costs compared to self-supporting IMO tanks. These advantages make it an optimal choice for both ULECs and VLECs, supporting the industry's shift toward sustainability, adaptability, and cost-effectiveness. ●

Albania continues reaching for natural gas

Natural gas could provide stable, dispatchable energy to complement renewable energy buildout and mitigate the volatility of hydroelectric generation, while spurring economic growth and industrial development.

JOSEPH MURPHY

Albania has long sought to expand natural gas use, leveraging its role as a transit country for supplies from Azerbaijan and potentially global LNG supply to enhance its energy security and spur industrial and broader economic development.

The small Balkan nation relies heavily on hydropower, with some 2,500 MW of dams in operation. While clean, hydropower is unreliable and in some years, severe droughts have forced Albania to import part of its electricity, at considerable expense. Most dams are also located in the north of the country, leading to transmission losses when the power is sent to the south. And given the country's low energy consumption per capita, more than 70% below the EU average, there is significant room for its energy needs to grow in the future, requiring more supply to meet them.

Albania produces only a small amount of solar, up to 500 GWh per year or 7% or its total electricity generation. Currently, it does not generate any wind power, although last year it held a successful auction for the construction of 225 MW of onshore wind capacity. It plans to build up these sectors, harnessing an estimated 7 GW of potential. But progress has been slow, and the intermittency of these sources means the country still needs a stable form of baseload power, to mitigate fluctuations in hydroelectric supply. The government sees natural gas as a solution, but first the necessary infrastructure must be built, for the most part from scratch.

Albania, one of the world's oldest oil producers, began natural gas production in 1963 at the Patos-Marinza oilfield, with national output peaking at 1 bcm in 1985. Since then, natural gas production has dwindled to negligible levels. The country has 840 mcm in remaining reserves, although new onshore hydrocarbon prospects like Shpiragu may yield additional volumes, and offshore exploration could also hold potential. Currently, Shell and Italy's Eni continue to explore the potential of onshore projects.

Without domestic supply or import options, Albania's consumption of gas is also negligible. The country has a 400-km domestic gas grid – a legacy asset from when gas was more significantly in use – but much of it is inoperable.

Imports and regional integration

The most important development for Albania's gas aspirations was the launch in late 2020 of the Trans-Adriatic Pipeline (TAP), which runs through Albania on route to Italy. The pipeline does not yet supply Albania itself. But in 2021, the government and state gas transmission and distribution operator Albgaz agreed with TAP's consortium on constructing an exit point from the pipeline at Fier.

Under the host government agreement, TAP is responsible for building the Fier exit point and transferring it through a formal handover arrangement. Initially designed for 0.7-1.8 bcma of gas, the facility is undergoing design revisions to support increased transmission of up to 5 bcma. To facilitate this, the 46-km Vlora-Fier pipeline will be adapted to align with higher capacity needs. Albgaz aims to secure a substantial stake in the pipeline and will jointly operate it with selected partners under a certified transmission licence.

"With these projects moving forward, we expect to become an energy-exporting country in the region soon."

MAKSIM SHULI, GAS COMMISSIONER AT ERE

Though TAP's current 10-bcma capacity is almost fully booked, it will be expanded by a further 1.2 bcm by the end of 2025, Azerbaijan's energy ministry said in February 2024. This will make 200 mcma of gas available for Albania in the future, according to the ministry. Longer term, TAP may be expanded to flow as much as 20 bcma of gas to Europe.

Another key project is the Ionian-Adriatic pipeline (IAP), which would extend from Fier to Croatia via Montenegro and Bosnia, linking TAP to the Croatian gas network. The pipeline would extend the reach of Azeri gas into southeast Europe, supplying up to 5 bcma, with 1 bcm designated for Albania, 0.5 bcm for Montenegro, 1 bcm for Bosnia and 2.5 bcm for Croatia. It will also be capable of flowing in reverse, potentially delivering LNG imported in Croatia and other sources of supply. However, there are no firm targets for the start of construction and completion.

Albania has also looked at the opportunity for importing LNG at the port of Vlora. The Vlora-Fier pipeline would help integrate supply from such a project. In 2021, ExxonMobil and Excelerate Energy agreed to study the development of a regasification terminal at the site, along with the conversion of the Vlora's thermal power plant (TPP) to run on gas and small- →

scale LNG distribution, a viable solution for countries lacking extensive pipeline networks. Vlora TPP was completed as an oil-fired generator in 2005, but was never commissioned owing to problems with its cooling system. The same year, Excelerate Energy, Italian company Snam and Albgaz agreed to explore a pipeline linking the proposed Vlora terminal to Fier and the TAP system.

Excelerate had intended to deploy the FSRU Excelsior to Albania, but by October 2022, the vessel was redirected to Germany under a five-year rental agreement, leaving the Vlore LNG project's status uncertain.

Albania has also explored new gas pipeline links with Kosovo and North Macedonia, to expand regional integration. Plans for the 240-km Albania-Kosovo pipeline have been finalised and commissioning is expected around 2029-2030. Meanwhile, integrating the networks of Albania and North Macedonia will require a 60-km pipeline to be built. Albgaz intends to undertake the project between 2025 and 2028, with capacity expected to reach 0.3 bcma in the long term.

Storage and gasification

Any well-functioning gas market needs storage capacity, and Albania has been studying the use of the Dumre salt dome for this purpose. Two options exist: Dumre Alternative 1, with a 260-300 mcm storage capacity, a 1 mcm per day withdrawal rate, and an estimated investment of €68mn; and Dumre Alternative 2, with a much larger capacity of 1-1.2 bcm, a 6 mcm per day withdrawal rate and a projected investment of €73mn. Alternative 2 would have a lower cost per cubic metre. Depleted hydrocarbon fields have also been considered for additional gas storage.

To enhance energy capacity and diversify supply sources, the Albanian government has approved a project for a 170-MW thermal power plant in Fier, scheduled to begin operations in 2029.

Azerbaijan's national oil company SOCAR is also assisting in Albania's gasification initiatives. This February, it announced a cooperation agreement with Albgaz on a pilot project to build a gas distribution network for the city of Korce. A feasibility study on the €21mn ($22mn) project has been undertaken, and construction should be completed in 2027.

Policy

The direction of policymaking for Albania's gas sector has been guided by the country's Gas Master Plan, although this was presented almost a decade ago, in 2016. As such, it will have to undergo revision. The Albanian government has conducted a comprehensive review of the Master Plan, incorporating detailed studies to identify and approve priority projects.

The original plan projected that gas consumption could potentially reach 2.454 bcm by 2040, including 893 mcm by households, 438 mcm from services, 489 mcm from industry and 568 mcm from anchor consumers. But that same plan projected 1.4 bcm of potential demand by 2020 – a target now expected to be reached in a few years.

Albania has also laid down some of the necessary legislative groundwork for a natural gas market over the past decade. It passed a 2015 Gas Law, aimed at paving the way for a liberalised market that provided supplier choice, established the universal supplier concept and public service obligations and increased the strength and independence of the regulator.

The law also led to the unbundling of the transmission system operator. Albgaz was unbundled, certified and licensed as an independent company separate from Albpetrol, operating in compliance with EU regulation. Albgaz is also to be divided into a physical asset operator and a market operator managing gas contracts.

Albgaz has signed a memorandum of understanding with TAP and the Albanian government to support the development of the country's gas market. TAP has also reached an agreement with Albanian Gas Service (AGS) to provide maintenance services for its pipeline system and stations in Albania. AGS is a 75:25 joint venture between Albgaz and Snam. The agreement expires in October this year but TAP is set to begin negotiations soon for its renewal.

Opportunities from gas

Developing a natural gas market in Albania presents opportunities for the country's economic growth and energy security. It can provide the stable, dispatchable energy needed to complement Albania's renewable energy buildout and mitigate the volatility of hydroelectric generation, to create a more resilient energy system. Beyond energy security, the introduction of natural gas can act as a catalyst for industrial development, with reliable and competitively priced gas potentially attracting new industries that depend on stable energy access. But success depends on accelerated progress at key infrastructure projects.

"The delay in implementing the Gas Master Plan has been primarily due to insufficient investment and project preparation," Maksim Shuli, Gas Commissioner at Albanian energy regulator ERE, told *Gas in Transition*. "But now we have identified priority projects – starting with the gasification of Korca and the construction of a 170-MW power plant in central Albania."

"We have completed all the necessary by-laws to open Albania's gas market in line with EU directives and regulations," he continued. "With these projects moving forward, we expect to become an energy-exporting country in the region soon." ●

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