European gas takes hit from Covid-19 crisis
Cheniere set to ride out the storm
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Nigeria’s Year of Gas
The Role of Gas, a view from IGU’s Wise Person Nobuo Tanaka

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Dear reader,

Welcome to the inaugural issue of the Global Voice of Gas magazine, brought to you by the International Gas Union. This issue of the Global Voice of Gas magazine will be the first in a quarterly digital series, bringing key global gas discourse insights and analysis to the global energy community. It will select the latest, most relevant, critical issues; explore challenges; and highlight opportunities facing the industry. It will also feature key projects and unveil technology and market trends, showcasing how gas can be a key tool in the sustainable energy future for generations to come.

This issue comes out at an unprecedented time of a century-proportion global health and economic crisis, as countries around the world cope with the devastating impacts of Covid-19. It is also high time for good policy, as the pressure on governments to deliver post-pandemic recovery is mounting.

When it comes to energy, the challenge is especially tough, because decisions made in this economic sphere will have implications for decades to come, and the choices made today will translate into energy mix and environmental consequences we leave to the future generations. It is therefore imperative that governments carefully choose projects that simultaneously support economic recovery and sustainable, long-term energy policies. That will require an objective assessment of all costs, benefits, and importantly - trade-offs - that come with every choice. I could not stress this point enough – as financial resources are limited, every choice will have trade-offs – and these trade-offs will need to be carefully weighted to avoid unintended consequences at the system level. Governments have a hard task of toeing the fine line between “choosing winners” and investing strategically.

I believe that this presents an opportunity for the gas industry to make its case, showcasing gas projects that can help advance this long-term goal, since gas is well placed to support the economic recovery and the focus on sustainable energy. Gas technologies, existing and emerging, hold great promise to make a significant contribution towards emissions and air pollutant reductions, consistent with the long-term climate and air quality ambitions. It is critically important for the industry to work with governments and demonstrate its commitment to the sustainable energy future, ability to help economies recover, and value in creating healthy environments and achieving reductions in emissions and eliminating air pollution.

This will be a testing time, because under huge economic pressure to reduce direct costs, there is a real risk of a coal renaissance. If that happens, the world will have no hope of meeting its climate commitments.

Gas can help to avoid that, as it is the most flexible lowest emissions hydrocarbon that can supporting stable economic development and providing a versatile, reliable, and secure source of energy. Existing and emerging technologies and innovations will further reduce the carbon intensity of gas particularly in the areas of efficiency, methane emissions reduction, renewable gas, blue-hydrogen and CCUS.

On behalf of the entire Korea Presidency team who continue to work diligently towards organizing the biggest gas conference in 2021, the World Gas Conference in Daegu, Korea, from 21-25 June, 2021 I hope you will enjoy reading this inaugural issue of Global Voice of Gas.

— Prof. Joe M. Kang
President, International Gas Union
From the Secretary General

The IGU Secretariat is based in Barcelona, Spain, thanks to the sponsorship of Naturgy, and we are now preparing an exciting transition to new permanent office in London, UK.

The IGU Council made this historic decision last October, in Yogyakarta, Indonesia, approving the process that is now underway to prepare for the move to the permanent office which will be fully operational by July 2021. This will provide the strong foundation and administrative longevity, necessary for the Global Voice of Gas to keep growing.

Established in 1931, the International Gas Union is a worldwide non-profit organisation representing the entire gas sector. Our global membership includes over 95% of the global gas market, with more than 160 members in 85 countries. The IGU is the only organisation of such reach, which covers all industry segments, from exploration and production, transit via pipelines and liquefied natural gas (LNG), as well as distribution and use of gas, including importing and exporting participants.

As such, the IGU’s mission is to advocate for gas as an integral part of a sustainable global energy system, and to promote the political, technical and economic progress of the gas industry. We seek to promote the competitiveness of gas, enhance transparency, grow public engagement, to remove barriers to progress, innovation, access, and development.

Our Charter members are national organisations, companies, or government bodies, that are able to represent their respective national industry, and through them, the IGU is present in all five continents. All other gas sector participants participate via associate and premium associate membership options. If you are interested in joining our extensive global network and contribute to the mission of a sustainable energy future and improving the quality of life, please get in touch with the Secretariat, or visit our membership section at igu.org.

IGU is responsible for organizing the World Gas Conference every three year under the leadership of the IGU President and the Secretary General. The next edition will be in Daegu, South Korea, in June 2021 where WGC2021 will be held.

Also, jointly with Gas Tech Institute (GTI) and International Institute of Refrigeration (IIR) we conduct the LNG International Conference and Exhibition, with the next edition in St. Petersburg, Russia in 2022.

To complete the IGU flagship events, the IGU also organizes the International Gas Research Conference (IGRC), with next edition scheduled for 2023.

Among the many membership benefits, IGU members have the advantage to support and participate in theses IGU flagship events. For more details, please contact the IGU Secretariat.

— Luis Bertrán Rafecas
Secretary General, International Gas Union
Welcome to the first issue of *Global Voice of Gas (GVG)*, an International Gas Union publication that sets a new standard in communication for the natural gas community worldwide.

This IGU publication is produced in collaboration with Natural Gas World, and in this edition we look at the key issues affecting the industry today.

The gas sector faces unprecedented challenges in the wake of the coronavirus pandemic. In 2019 supply continued its positive trajectory before governments began imposing travel restrictions and other measures to stem the virus’ spread. This has weighed down heavily on gas demand. The International Energy Agency (IEA) warns that global consumption could contract by 4% in 2020 – double the rate of decline seen after the 2008 economic crash.

Suppliers have had to make drastic cuts to both capital and operational expenditure to shore up their finances. At present low prices, some production has had to be mothballed and might not return. But the market is recovering slowly but surely as lockdowns are eased and economies reopen.

On the upside, the low gas price environment is of course good for consumers, helping to spur the post-coronavirus recovery. Policymakers will have added incentive to expand the role of gas in national energy mixes, largely at the expense of coal, as part of efforts to further reduce emissions and air pollutants. Urban air quality improvements have been significant as a result of the pandemic and there will be a further incentive to increase the use of gas so as not to return to pre-pandemic levels. In this edition we look at how this trend could play out in Europe.

Some suppliers have shown resilience in the face of current difficulties. Also, as part of this edition we profile US LNG producer Cheniere, which is comparatively well-positioned to weather the downturn in LNG market, thanks to the nature of its offtake contracts.

While there is presently a market glut, long-term demand prospects are firm and investment in supply must continue. As we report, the world’s top LNG exporter Qatar has demonstrated its confidence in long-term growth by pushing ahead with a massive expansion at its North Field. The project will raise the low-cost supplier’s liquefaction capacity by almost two thirds by 2027, to 126mn mt/yr.

Meanwhile other gas-rich countries are taking steps to capitalise more on their resources. Having declared 2020 as the “year of gas,” Nigeria appears closer, than ever before, to introducing a new legal regime that will give outside investors a better foundation for investing in gas projects. As we document, the government wants to use gas as an engine for economic growth, by expanding its share in the national power mix and ramping up exports.

Uzbekistan is also looking to capitalise more on its gas resources. It has taken steps to attract more upstream investors while advancing new downstream projects to add value to its gas, as we investigate.

Elsewhere, Canada is trying to strike the right balance between meeting its environmental targets and supporting its economy, in which energy plays a major role. We look at how, despite the current market upheaval, Canada’s gas industry is hoping to play a key role in delivering this goal in the longer term.

We also feature an interview with the Australian Petroleum Production & Exploration Association, discussing how Australia’s gas sector is facing up to the challenges of slowing investment and supply shortfalls on the East Coast.

Methane leakage is rightly a pressing concern for the gas industry, and we explore the work ExxonMobil is doing to address this issue, including its Project Astra, aimed at developing an innovative sensor network to detect and repair leaks quickly and efficiently.

— *Menelaos (Mel) Ydreos*,
Executive Public Affairs Director, IGU

— *Joseph Murphy*
Editor, Natural Gas World
Events

From the IGU
Events Director

For ninety years the International Gas Union has hosted the world’s most highly regarded events, with our current portfolio setting the strategic, commercial, technical and research benchmark for the natural gas and LNG industry.

Importantly, IGU events not only provide our attendees with direct benefits such as knowledge and networking but through your participation you are contributing to something much bigger - the IGU’s ongoing role as the Global Voice of Gas. Check out our publications, information and messaging that support the development the natural gas industry at igu.org

When it comes time to consider which events offer you the best opportunity to contribute and to learn, while supporting the IGU’s ongoing advocacy of gas, then make sure that WGC2021 and LNG2022 are top of your list.

If you want to know more about the IGU visit our website igu.org or for information on our portfolio of global gas events email me, Rodney Cox, IGU Event Director.

Our History is Creating the Future:

June 2, 1931: The 1st International Gas Conference opened in the Great Hall of the Institution of Civil Engineers in London ~ June 24, 2018 the 27th World Gas Conference returns to Washington DC. Check out the history of the World Gas Conference in the IGU 80 Year Celebrations.

April 7, 1968: The 1st International Conference on LNG (LNG1) opened in Chicago ~ April 1 2019: The 19th International Conference and Exhibition on Liquefied Natural Gas came to China for the first time. Look out later this year for the full release of the 1,400+ papers from LNG1 until LNG2019.

June 9, 1980: The 1st International Gas Research Conference was held in Chicago ~ February 24, 2020: Oman hosted the 16th International Gas Union Research Conference in Muscat. Visit IGRC2020 for our gallery of highlights.

And Looking Ahead:

The host country for the World Gas Conference in 2027 (WGC2027) will be either Columbia or Italy with a decision by IGU members at the end of this year. This will follow WGC2024 in China and WGC2021 in South Korea.
28th World Gas Conference
21-25 June, 2021 | Daegu, Korea

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LNG2022: Half a Century as Industry Leader

After more than 50 years the world’s premier LNG event comes to Russia for the first time with St. Petersburg hosting LNG2022. Following the success of LNG2019 Shanghai the event moves from one of the dynamically growing importers of LNG to a top ranking innovative LNG exporter – see the IGU 2020 World LNG Report.

There has never been a more important time for the LNG industry to come together to discuss and debate the strategic prospects, the commercial opportunities and the technical innovations that will power our future for the next 50 years. And there is no better place to meet than LNG2022 which will continue to both create and capture the path of our industry.

Event owners, the International Gas Union, GTI and the International Institute of Refrigeration together with Gazprom as a Host are delighted to invite you to the 20th Anniversary edition of the International Conference & Exhibition on Liquefied Natural Gas - LNG2022 to be held on April 4-8, 2022 in St. Petersburg, Russia.

Want to know more? Visit our website at LNG2022 or email us.

Looking forward to welcoming you in St. Petersburg!
The Covid-19 crisis and the fall in oil and gas prices have been major themes impacting the region. The previous downward trend in LNG prices was accelerated further by the Covid crisis, which is challenging exporters.

Some major LNG buyers are reported to be seeking to reduce their contracted volumes. However, thus far there has been no material fall in LNG cargoes from Australia to North Asia, for which Australia is the largest LNG supplier. In April Australian projects delivered 89 LNG cargoes to buyers in North Asia, which was an increase, compared with 79 cargoes in April 2019.
Increased restrictions on shipping and ship crews, necessary to prevent the spread of Covid-19 at ports imposed new operational constraints for LNG cargoes; however, the industry adapted successfully and is meeting its commitments and delivering shipments securely and reliably.

China has resumed its normal operation in receiving Australian cargoes.

- In February 12 Australian cargoes destined for China were delayed or diverted, but cargoes were back on track during March with no further delays or diversions.
- Lower LNG prices are expected to facilitate Chinese demand, as will structural reforms, such as the establishment of the National Pipeline Corporation. The Chinese gas market currently suffers from infrastructure bottlenecks. In 2019 26% of LNG from receiving terminals was transported by truck, particularly in winter to meet peak demand.
- Despite the short-term economic uncertainties, companies are still investing in long-term gas development for the Chinese market.

Australia: the collapse in oil prices is slashing revenues for LNG producers and leading to deferral of new projects. Australian LNG export revenue is expected to fall by a third - from around US$30 billion this financial year to less than US$20 billion next year.

- Woodside and Santos deferred around US$40 billion of investment in proposed LNG projects.
- On the upside, PetroChina and Shell recently committed US$6 billion to an upstream gas development in the Australian state of Queensland through their jointly-owned company, Arrow Energy. This will underpin ongoing LNG shipments to China, as well as gas supplies for the Australian domestic market.

The tide may be turning on attitudes towards onshore gas development in Victoria and New South Wales, both states where onshore development was banned. Policymakers are beginning to consider the risk of possible gas shortages and high gas prices, in the absence of new gas development. As such, Victoria has announced that exploration for conventional gas will be allowed from July 2021, although fracture stimulation, or exploration for coal bed methane (CBM), will still be not allowed. In the NSW, the prospects for approval of a significant CBM project operated by Santos are improving, following financial incentives offered to the state by the federal government.

As governments around the world are starting to think through restarting their economies and develop stimulus packages in response to Covid-19, Australian experience from the 2008-09 Global Financial Crisis offers valuable lessons. At the time of the GFC, Australia was fortunate to have a pipeline of US$200 billion worth of shovel-ready LNG projects, and public support, coupled with private sector investments in these projects played a major role in insulating Australia from the worst impacts of the GFC.
South & South-East Asia

HAZLI SHAM KASSIM
President, Malaysian Gas Association, Malaysia

The lockdown measures came with reduced demand in the region, consistent with the global trends.

- Malaysia saw a 30% decrease in gas consumption, driven largely by the power sector and industrial activity.
- India experienced roughly a 25-35% drop in gas consumption.
- Return to the normal levels of consumption is going to be tied with the restoration of economic activity.

ASEAN stimulus packages to alleviate financial stress of the lockdown measures has primarily focused on providing consumption and service cost subsidies to the end users. Indonesia, for example, introduced a fixed gas tariff of USD $6/mmbtu for power & strategic industries.

- Slowdown in the overall economic activity can have negative implications for infrastructure capital expenditure plans, and policy support will be crucial.
- A reduction of LNG import volumes due to Covid 19 is likely in the order of 2.0 - 2.5 MT, relative to 2019 levels.

India’s complete lockdown had a significant impact on the gas industry development.

- There was a severe slowdown in pipeline and city gas distribution project activities, due to logistical challenges for the movement of workers and materials. Additionally, there may be liquidity challenges for meeting working capital requirements.
- Energy affordability is a priority concern for the recovery agenda, and as such, coal power plant projects may be favoured over gas and renewables, due to direct cost considerations.

Thailand is proceeding with gas market liberalization; maintaining ambition as regional LNG hub.

Recovering Better will require critical policy decisions to ensure crisis recovery investments choices are not detrimental to the environmental goals.
Impact on gas demand in the region has been significant, due to lockdown measures. Key regional economies, including Algeria, Egypt, Nigeria, UAE, Jordan, and Qatar, use natural gas as the main fuel for factories, commercial facilities and businesses, and their closure resulted in large consumption drop. It is expected that demand will return back to pre-crisis levels gradually, as economies restart.

On the supply side, the reduced prices, combined with a slowdown of global business activity and reduced export volumes is creating a challenge for large LNG producers, including Qatar, Oman, Nigeria, Egypt, and Algeria.

Domestically, the gas sector has been exempted from lockdown measures as an essential service; however, operations have deeply challenged by demand disruptions.

Egypt is continuing to fulfill the role of a regional hub - inter-regional projects are running and operating well, and gas is still flowing between Israel and Egypt and Jordan, although volumes have dropped.

Impact on investment and new projects is strongly felt, as uncertainty from the low-price environment is causing delays and postponements. Projects that are potentially challenged:

- Qatar’s North Field LNG project
- Several new pipelines in West Africa are facing financial burden
- New Pipeline connecting Israel-Cyprus-Greece-Italy

There are also positive developments, however, including:

- $14.4 billion funding for Total’s Mozambique LNG has been secured
- Private Equity is surfaced as meaningful source of funding gas projects, as in Ghana’s TEMA LNG terminal
- There has been a major boost in investing and developing CNG and Mobile CNG in West Africa, East Africa and Egypt, which will help to improve air quality and reduce emissions
- In the short term, the economic impact of Covid-19 could curb the expansion of the region gas sector; however, in the medium-term, natural gas development will continue to be an important source of economic growth in the region
- Additionally, African government policies are beginning to include gas as a major tool in displacing pollutant fuels, like coal and enhancing air quality.
Europe East, Russia, Black Sea, Caspian

MARCEL KRAMER
President,
Energy Delta Institute,
The Netherlands

The consequences of the Covid-19 pandemic and related measures by governments and companies, in combination with heightened competition on the global supply side, have a serious impact on Russian exporters (warmer winter and ample stocks had already dampened demand).

- These negative impacts seem somewhat mitigated by competitively priced gas replacing coal for power generation in some markets.
- The result of these developments for the first half of 2020 is most likely to be a measurable net reduction of export volumes compared to the records of 2018/2019.
- Meanwhile, a strong focus on building the medium to longer term gas export capacity remains and significant capital continues to be injected. The planned investment program for 2020 totals almost 1.1 trillion Rubles (~15 billion USD).
- New export infrastructure projects have either come on stream (e.g. TurkStream through the Black Sea) or are being constructed, with some at an advanced stage of development.
- Nord Stream 2 reportedly has 160 km of offshore pipeline remaining to complete (of the total 1200 km route), it is as yet unclear what the schedule impact will be of recent German regulatory decisions.
- Among the other infrastructure projects, further development of the vast resources of the Yamal Peninsula is expected to help meet the growing future demand in both European and Asian markets.
- To ensure Asian supply, the projects Power of Siberia (has come on stream, focus Eastern China, 30-year contract with CNPC) and Power of Siberia 2 (pre-investment phase, focus Mongolia/Western China) are essential and require major pipeline/compression projects as well as upstream field development outside the Yamal area.
- Novatek and partners (Total, CNPC and the Silk Road Fund) are moving forward with Yamal2 LNG development. 15 new ice-class tankers have been received by the JV. In February 2020 Yamal reached a 30 million tons export milestone, since the start of Yamal 1 Train 1 at the end of 2017. Novatek stated in April that the new projects (including the major LNG2 and the smaller Ob LNG also in Yamal) will proceed without major changes, despite an almost 30% year-on-year drop in exports in Q1 2020.
Overall, the North American gas markets have been less affected than oil markets. This is a time when seasonal consumption normally trends in the region, so the crisis hit at a lower risk time.

A significant drop in industrial consumption is the biggest risk for the sector. Many construction and development projects across the value chain are on hold and all are hoping for an early return to robust economic activity.

Some producers may see an upside from the reduced associated gas output in the abundant gas supply picture in North America.

The crisis has also resulted in a positive implication – highlighting the value of gas as a reliable and flexible fuel and the infrastructure as affordable, resilient, and necessary for a rebuild strong economies.

It is incumbent on the industry to think about how to build on that newfound appreciation and to maximize its contribution to the recovery.
Post-COVID recovery measures are expected to link economic stimulus to the promotion of the green agenda, and it is very important for the gas industry to engage in the conversation about its critical contribution to making it possible.

European Commission is considering new legislative measures, developing documents, studies, and procedures under the “European Green Deal” and the “Just Transition”. Specifically, some of the key topics are:

- **European Taxonomy**, to provide a context for energy financing
- **Alternative Fuels Directive and EUFUEL Maritime consultations** (important for the potential utilization of both CNG and LNG – also in their “bio” forms)
- **Smart Sector Integration consultation**: how to best achieve energy emissions targets with alternative approaches (the gas industry focus needs to be on moving away from the “full electrification” narrative)
- **Energy Taxation Directive consultation**: interest from the Commission to stimulate more green-driven approaches
- **Strong attention on methane emissions regulations** – of particular importance is EC interest in developing an import tax, based on an emission score of the gas
- **High interest in hydrogen potential and possible support schemes** (also considering blending and use of existing gas infrastructures)

Given demand reduction, there is an unprecedented price evolution with significant downward pressures and – for some – the potential for negative prices during the coming summer season.

- As a matter of comparison, the TTF benchmark shrunk by around 50% from January to May, while Henry Hub faced a reduction of less than 20%.
- Also, for the first time ever, Europe imported more LNG, than piped gas, given the newest favourable price environment.
Latin America & Caribbean

ORLANDO CABRALES SEGOVIA
President, Naturgas
Colombian Gas Association, Colombia

Regional Impacts of Covid Crisis

The natural gas industry in Latin America has suffered from the consequences of the pandemic, and has been working hard to ensure the continuous delivery of natural gas throughout the value chain, while at the same time adapting to mitigate the impact coming from the significant decrease in consumption.

In most countries in the region (like Chile, Bolivia, and Colombia), there has been a significant reduction in dues collection by utilities, because of the social economic effects of the lockdown. The industry has also faced delays in planned operations, because the restrictions in mobility.

Measures are being introduced throughout the region to provide rate relief to customers and help offset the economic hardship faced by the communities; however, it is a challenge for the sector.

The industry is adapting and preparing itself to become an engine for economic and social revival.

PHOTO: PETROPERU
Regional Markets Background and Review of Key Recent Milestones

COLOMBIA

This year, gas users have reached 10 million (representing coverage of 70% of Colombia’s population). Natural gas has become the preferred and most competitive clean fuel for commercial, industrial and residential users, generating a true social revolution by playing a growing role in the development of businesses and transport.

Some 20% of current production in Colombia comes from discoveries made in recent years onshore in the Caribbean. In addition, the Cartagena LNG regasification terminal, which was inaugurated in December 2016, has proven to be a reliable and safe back-up for the power generation system. In 2018, the terminal received seven shipments of natural gas and delivered 10 bcf (28 mcm) to the national transport system, while during 2019, six shipments were received delivering 5 bcf (140 mcm).

The industry continues to advance and modernise. In the last five years, the country’s gas pipeline network has been extended by 278 km to reach 7,499 km. In terms of transmission, the expansion of the transport infrastructure in 2019 represented an investment of $300 million, which added 220 mcf/d (6 mcm/d) to the system. A new plan to expand the country’s infrastructure has been published recently which envisages an investment of US$1 billion, including a second regasification terminal on the Pacific coast in the next five years.

According to the Ministry of Mines and Energy, by the end of 2019, more than 600,000 cars have switched to natural gas as a more economical and efficient fuel.

2019 ended with more than 1,500 heavy-duty dedicated vehicles in service, including: buses, trucks, dumpers and refuse trucks. Additionally, in 2019 the number of vehicles converted to hybrids (to run on compressed natural gas [CNG] and gasoline) increased by almost 40% over 2018.

ARGENTINA

Globally, Argentina ranks third in technically recoverable shale gas resources and fourth in technically recoverable shale oil. The Vaca Muerta shale play, which covers an area of 30,000 km2, delivered an increase in gas production of 17% in the last two years, which in turn lowered fuel prices.

Argentina is expected to return to the path of gas self-sufficiency achieved in previous decades, reducing imports from Bolivia considerably.

BOLIVIA

Bolivia’s natural gas reserves guarantee supply to the local market and have allowed exports to Argentina and Brazil.

The largest domestic consumers are the power, industrial and transportation sectors and together they represent about 65% of the total internal demand for natural gas.

The development of new gas resources in Argentina and Brazil is forcing the Bolivian Government to seek alternative markets. Bolivia’s trade balance and its fiscal stability depend on gas exports which represent about 85% of the country’s revenues from hydrocarbons.

Gas integration and access to new markets will depend on the ability to secure export routes.
through neighboring countries and to attract investment in exploration and the construction of new infrastructure.

**BRAZIL**

- Despite its potential, natural gas has a relatively small share in Brazil’s energy mix. Hydroelectricity plays a big role, with gas acting as back-up in the dry season.

- Associated natural gas in the offshore pre-salt fields is expected to break even in the medium term and could become a significant source of supply to the region and the world. The production of natural gas associated with these fields is expected to enter the Brazilian market as the infrastructure is built to connect offshore operations.

**PERU**

- Recently, Perúpetro reported that Peru has enough natural gas reserves to meet internal and external demand for the next 35 years. Approximately two-thirds of current production from the Camisea region supplies domestic consumers with one-third exported as LNG, principally to customers in Asia and Europe.

**CHILE**

- The main consumer of natural gas is the power generation sector, where it is used in combined-cycle thermoelectric plants. Other users of gas, although in smaller volumes, are the industrial and mining sector, the commercial, residential and public sector, and the transportation sector.

- In 2018, Chile resumed imports of natural gas from Argentina after a decade of supply interruption which led the country to build two LNG regasification terminals.

**GUYANA**

- Guyana is a new player in the region’s gas industry due to its new massive offshore discoveries. This might allow it to become a game changer in the region and an important source of supply to gas markets in the long term.

PHOTO: PETROPERU
Covid-19 spread around the world with an enormous speed thanks to the globalization of business and tourism. It’s not only the worst pandemic current population has ever experienced but it triggered the worst economic recession since the Great Depression of 1929. The oil sector was hit hardest because transportation sectors’ demand collapsed due to the lockdown of major cities and international travel bans. Institute of energy Economics, Japan (IEEJ) analyzed that two months of global lockdown reduced the demand of oil by 20% in 2020. In fact, April’s oil demand declined by 29 million barrels per day, almost 30% of global demand. Dr. Fatih Birol, Executive Director of the International Energy Agency (IEA), said that it made for a historic “Black April” for the oil markets. The spot price even went to the negative territory for the first time due to the shortage of storage capacity. OPEC + Russia and some G20 nations including the US were forced to show solidarity facing the historical challenge and reduced production. As China contained the expansion of Covid-19 and re-started economic activities, the price level has come back to mid $30s. The market wishes to see rapid reopening of lockdowns but the Covid-19 epicenter has moved to emerging countries and there are risks of the second and third waves in the opening countries until the effective vaccines be developed.

However, the world is moving forward even during the pandemic. Indeed, telecommunication technology makes...
remote-working as a new normal. Teleworking, webinars, telemedicine, online shopping, entertainment; everything is now available on line, even a party with friends. The skies become cleaner due to less air pollution. CO₂ emission will be 8% lower in 2020 relative to the previous year due to the IEA. Shall we go back to the life before Covid19 when it is contained. Nobody knows when and the “war” with new Coronavirus could continue much longer than we hope. IEA and Danish Government hosted the Ministerial videoconference to promote “green stimulus” when countries take economic stimulus packages. Dr. Birol said “Putting clean energy at the heart of stimulus plans is an excellent strategy for revitalising economies while building a more secure and sustainable energy future.” Coronavirus accelerates societal changes together with the energy transition towards more sustainable and secured power system using much more renewables. I personally think that Covid19 may bring the end of the Oil Age much earlier than we expect. In the future, 2019 may be looked back upon as the peak of global oil demand. Tom Friedman says, “There is the world B.C. — Before Corona — and the world A.C. — After Corona: Our new historical divide.” It may very well be the case for OIL.

Natural gas may suffer less than the oil sector. The IEA projected that global gas demand would decline 5% while oil demand declines 9% and coal 8% for 2020. Renewable energy is the sole winner which increases 1%. (Global Energy Review 2020). Gas spot price at Henry Hub is falling. Supply glut may inevitably be prolonged and many new projects are postponed or aborted. Meanwhile, the fight between the US and China about the origin of Covid19 has been escalating and involving the whole world. Trade and technology conflict has reached the level of a new Cold War. Geopolitical fights between the largest importer and the largest exporter of LNG may undermine the stability of the international gas market. As a cleaner fuel, gas should play an important bridging role to replace coal for cleaner and stable electricity supply even after Corona era. But without further investment in technologies for decarbonization such as blue hydrogen with CCUS natural gas cannot survive in the longer-term.

Establishing the new paradigm is essential for energy sector. A recent article in Forbes magazine observed that many of the countries that have had the most successful Covid19 control measures are run by female leaders. Germany, Taiwan, New Zealand, Iceland, Denmark, Finland, and Norway are all led by powerful female prime ministers and presidents. But Forbes also admits that a huge amount of evidence is emerging that the Coronavirus will have an outsized negative economic impact on women than men.

As for the sustainability and climate change, Ms. Christiana Figueres, former SG of UNFCCC once said, “There is a clear parallel between the progress we’ve seen on gender equality and climate change.” Women suffer more by climate change, for example, Sub-Saharan African women have to fetch water over longer distances, but on the other hand women can influence government or corporate decisions by voting or becoming leaders. Climate Change is NOT gender neutral, neither is Coronavirus. Energy sector has shown weaker performance on gender equality in terms of number of managers and pay gaps relative to other sectors. Women should be more empowered to overcome the Corona outbreak by working at home while protecting loved ones, while corporations should prepare hard and soft infrastructure to facilitate total changes in work style as well as life style. CEOs of the energy sector now face a real opportunity to accelerate gender equality and enhancing sustainability and safety.
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European gas takes hit from Covid-19 crisis

However, depressed prices strengthen the case for gas as an affordable solution for Europe to deliver on its energy transition goals

JOSEPH MURPHY
The Covid-19 pandemic and measures to slow its spread have triggered a sharp decline in European gas demand, which was already weighed down earlier this year by milder weather. The crisis has also exacerbated a global LNG supply glut, which began emerging last year amid weak demand in Asia and extra production coming on stream.

These factors have driven gas prices to historic lows, putting unprecedented pressure on suppliers. In some European countries, though, low prices have led to gas displacing higher-cost coal in power generation. And with the market expected to remain depressed for some time, governments have more incentive to pursue gas as an affordable solution for achieving energy transition goals.

Demand destruction

Warmer temperatures caused gas consumption in Europe to fall by 2.6% year on year (yr/yr) in the first quarter, data published by transmission system operators show, with this decline driven by a 5% drop in gas-fired power generation.

US demand also decreased by 4.5%, on the back of a 18% slump in residential and commercial demand, according to the IEA, and mature Asian markets also experienced a contraction.

Italy was the first European country to declare a nationwide lockdown in early March to combat Covid-19’s spread, imposing travel restrictions and shutting down factories, businesses and public places. Other major economies soon followed course.

Edinburgh-based Wood Mackenzie estimated at the end of May that demand in Europe’s eight biggest gas markets excluding Turkey – Germany, the UK, Italy, France, Spain, the Netherlands, Belgium and Poland – had fallen 12bn m³ over two months because of the restrictions. As these countries account for three-quarters of Europe’s total demand, this would imply an overall loss of 16bn m³. These losses mainly came from the commercial, industrial and power sectors, while residential demand stayed firm.

Lockdowns are one thing and the broader economic fallout from the pandemic is another. Factoring in the weaker economic outlook, WoodMac expects full-year European demand to come to 505bn m³, down from a pre-pandemic forecast of 536bn m³ and around the same level as in 2018.

“This is a heavy loss of course but not catastrophic,” WoodMac’s research director for European gas Murray Douglas tells Global Voice of Gas (GVG).

In some countries with significant coal-burning capabilities like Germany, gas demand has been propped by increased coal-to-gas switching, continuing a trend seen last year. German gas imports notably rose 6.5% yr/yr in the first three months of 2020, state statistics show. Supplies in March surged 23.3% despite lockdowns coming into force in the latter half of the month.
However, other countries which produce little electricity from coal have seen dramatic declines in power-sector gas consumption. “Gas is very competitive against coal at the moment, but with power demand falling, gas is taking a proportionate hit from the loss in electricity demand,” Douglas says. “This is especially true in the UK, where we don’t produce any power from coal anyway, so all that pain falls on gas demand.”

Suppliers’ response
The scale of the demand losses in Europe and the short space of time in which they occurred have come as a shock to suppliers.

Pipeline gas suppliers have borne the brunt of the market collapse so far. Russia’s Gazprom, which supplies around a third of Europe’s gas, has slashed its forecast for shipments in 2020 to 166.6bn m³ – their lowest level since 2015 and down from 199.3bn m³ last year. As recently as February it had expected to deliver around 200bn m³ in 2020.

Norway is also scaling back supply, while European sales by Algeria, which slumped 36% last year, are projected to remain at more or less the take-or-pay level for the rest of 2020.

Pipeline suppliers were already seeing weaker sales before the crisis, not only because of warmer weather but also competition from LNG. Gazprom still sells a third of its gas in Europe at oil-indexed or partially oil-indexed prices, sometimes making its supplies uncompetitive next to LNG.

“Gazprom was always going to be constrained about what it could get through to the market,” Douglas said. “But they are continuing to demonstrate their willingness to fight for market share; they’re still selling aggressively through their electricity sales platform.”

LNG suppliers have fared better so far but are also facing pressure, with Oslo-based Rystad Energy forecasting that European LNG imports will decline 6.6% in 2020 to around 100bn m³.

Some of the supply glut in Europe last year was absorbed into storage, and there was an incentive to store more gas in preparation for a potential disruption in Russian gas transit via Ukraine. This disruption was ultimately averted, after Russia and Ukraine ended a standoff and signed a new five-year transit contract in late December.

Europe now has more than 70bn m³ of gas in storage, which for this time of year is unprecedented. The continent’s total available capacity is around 105bn m³.

There are risks that in some countries, gas storage capacity could run out, as happened last year, according to Douglas. Ukraine could play a key role in soaking up the extra supply, though, with Douglas estimating that the country could provide an additional 9bn m³ of storage for the coming winter. Ukraine has lowered tariffs, ended customs charges and taken other steps to make its storage more attractive to European traders.

Opportunities
The July contract at the Netherlands’ TTF platform – Europe’s main gas trading hub – is currently trading at €5.5-6.0/MWh ($1.8-2.0/mn Btu), having shed more than half of its value since the start of the year.

“It’s pretty clear we’re not going to get anywhere near $3/mn Btu until November at the earliest,” Douglas said. “Even getting to $3 by the end of the year will be a challenge and we’d need some cold snaps for that to happen.”
But while a prolonged period of depressed gas prices will put strain on suppliers, there is an upside. Cheap gas will help support post-crisis economic growth. It will also provide governments and countries with a greater incentive to develop new gas-fired power, largely at the expense of coal, as an affordable means of lowering their carbon emissions.

“For a lot of countries gas will be an affordable option to facilitate their energy transitions, by moving from coal, by moving from oil,” James Watson, the secretary general of European gas association Eurogas told GVG. “We think gas will play a major role in the next ten years because it will deliver a lot of the decarbonisation work at an affordable price, while costs for renewables and hydrogen come down.”

Another driving force behind coal-to-gas switching has been the EU carbon allowance system, which involves emitters paying for permits to cover their emissions in a given year. The price of these permits peaked last year at close to €30/mt of CO2, pushing operators to replace more coal with cleaner sources of energy such as gas.

The pandemic, and the resulting slump in emissions has weakened demand for these permits, causing the price to dip back to under €20/mt. But the reopening of economies should spur a recovery.

In terms of policy, Germany has already pledged to phase out coal power by 2038 or sooner if possible, replacing some of the plants with gas-fired capacity.

“They are likely to accelerate this considering the current trend of prices,” Rystad analyst Carlos Torres Diaz told GVG. “It doesn’t just make environmental sense but also economic sense.”

Watson at Eurogas agrees that Germany may try and push out coal faster than its official target.

“The Germans are to set to have a very strong natural gas and renewables electricity sector,” he said. “The next step is how they envisage decarbonising the gas grid; I think it’s very clear they are moving towards the hydrogen system.”

Even Poland, which generates 80% of its electricity from coal, shows signs of looking more favourably towards gas. State-owned PKN Orlen has recently said it will only invest in the new 1-GW Ostroleka power plant if it runs on gas instead of coal. The project was expected to be the last coal-fired power plant to be built in the country.

At the same time, Poland is advancing a number of new gas import projects, including a pipeline from Norway, new links with its neighbours and increased LNG regasification capacity. These investments will provide more opportunities for gas-fired power.

Belgium and Greece are also looking to expand the role of gas in their power mix. The former is preparing to phase out its nuclear capacity and replace it with a mix of gas and renewables, with plans to build as many as five new gas-burning stations.

“It’s pretty clear we’re not going to get anywhere near $3/mn Btu until November at the earliest,” — Murray Douglas

research director, European Gas
Cheniere set to ride out the storm

US LNG producer Cheniere Energy is comparatively well-positioned to weather the downturn in the LNG market despite being hit by a growing number of cargo cancellations

ANNA KACHKOVA

Cheniere Energy, the US’ leading LNG producer, is seeing a growing number of cancellations of cargo loadings scheduled for its two terminals. However, the nature of the company’s offtake contracts and its share of the market puts it in a comparatively strong position to weather the storm as the LNG industry grapples with the impact of Covid-19 on a pre-existing supply glut.

Reports of the number of cargo cancellations have been unconfirmed. Cheniere does not comment on contracts and individual arrangements with its customers, and was unable to respond to Global Voice of Gas (GVG)’s questions on the topic. And the numbers reported by media vary. Nonetheless, Cheniere is reported to have had 10-16 cargoes scheduled for loading in June cancelled, and up to 30 due for loading in July.

Other US LNG producers are also seeing cargo cancellations, but as the largest, Cheniere accounts for a significant proportion. However, this may not hurt the company as much as could be assumed at first glance.

“The majority of their volumes are secured under long term take-or-pay contracts so the financial hit to Cheniere from the cancellations is negligible. Even if the contracts are cancelled the offtakers are still on the hook for their liquefaction fee,” a Tudor, Pickering, Holt & Co. (TPH) director of equity research, Jordan McNiven, told GVG. Indeed, Cheniere reported that in the first quarter of
2020, it had revenues of around $50mn associated with cancelled cargoes, and the figure is set to be higher in the second quarter.

“The impact to Cheniere occurs on the uncontracted volumes, as they market these through their marketing affiliate,” McNiven continued. “If price spreads between the US and Europe/Asia are in the money this can be a meaningful portion of Ebitda for Cheniere.”

TPH also expects contracted cargoes to bounce back quicker than uncontracted volumes.

“Unfortunately the price spreads for spot uncommitted cargoes are currently out of the money and the forward strip suggests they will remain out of the money until Q4’21,” McNiven said. “Committed cargoes have more of the costs of lifting sunk, so they face a lower threshold and we see those spreads being back in the money by November of this year.”

A Morningstar senior equity analyst, Stephen Ellis, also expects the conditions leading to cargo cancellations to be a relatively short-lived phenomenon that Cheniere can withstand with comparative ease.

“In the short run, Cheniere is essentially made whole as its customers still have to pay its fees, and Cheniere has the ability to remarket the cargo globally,” Ellis told GVG. “We don’t expect these conditions to persist over the long run,” he continued. “The root cause of the cargo cancellations is spot market shipments for oil-linked contracts, which is how much of the world’s LNG is priced, are cheaper than US gas-linked contracts, which as oil prices recover will no longer be the case.”

Feedstock issues
One factor that stands to affect US LNG producers in the coming months is the price of the natural gas they use as feedstock. With seven liquefaction trains operating across its two Gulf Coast terminals, Cheniere has been the largest single consumer of US gas for some time, and, as with cargo cancellations, stands to be affected more than other exporters.

“Gas price fluctuations are expected – at least in the short term – because a significant proportion of the US’ shale gas output is a by-product of drilling for oil in the Permian Basin, where activity has been scaled back significantly owing to the oil price collapse. “The natural gas picture is complicated in the short run, as we expect associated gas out of the Permian to fall, but the decline in LNG feedstock demand is crimping demand for Appalachian producers’ gas,” Ellis said. “Natural gas prices are increasing, in my view, because investors expect the decline in associated gas out of the Permian to be substantial, and thus prices need to rise to incentivise higher production out of more costly basins.”

He added, however, that he does not expect this to remain the case over the long run. “When oil prices recover towards our long-term expectations, the spot market arb on LNG will also disappear, and the pressure on associated gas production will also ease,” he noted.

In the short term, however, the changing gas price could have implications for Cheniere and its peers

“In the short run, Cheniere is essentially made whole as its customers still have to pay its fees, and Cheniere has the ability to remarket the cargo globally”

— Stephen Ellis
senior equity analyst, Morningstar
depending on how dramatic the fluctuations are and how the US picture evolves compared with what plays out internationally.

“The impact of higher US prices also impacts the committed and uncommitted cargoes differently,” said McNiven. “For the committed volumes, Cheniere’s offtakers pay Henry Hub +15% for the feed gas, so gas sourcing costs are effectively passed through to the offtaker. However, if US prices rise and global prices don’t move commensurately then the export arb will narrow and squeeze the arb available for the marketing cargoes; in more extreme situations like we see currently it can also make the committed arb go negative and drive cancellations of committed cargoes.”

Looking ahead
In the longer term, Cheniere is among the LNG producers planning capacity expansions whose pace could be affected by the impact of Covid-19 on the market. The company sounded a cautious note during its first-quarter earnings call when discussing its proposed Stage 3 expansion at Corpus Christi LNG, saying it would be dependent on obtaining sufficient commercial support, among other factors.

Cheniere was previously reported to be negotiating a long-term supply deal with China’s Sinopec, though this was stalled by the US-China trade war. These negotiations – or those with other parties – are unlikely to resume until international travel is less restricted, based on comments from Cheniere’s president and CEO, Jack Fusco, in the company’s last earnings call.

“These are negotiations for long-term energy contracts that require face-to-face combat, for lack of a better word,” Fusco said, adding that reaching this point appeared to be some way away.

When that point does arrive, it seems likely that US LNG producers will still target China as a major market for their LNG, assuming that trade relations between the two countries allow it.

“China is extremely important to the LNG market, in our forecast they make up about 30% of global demand growth through 2030,” said McNiven. “It’s certainly not the only market that matters but it is the one that matters most.” He added that while European demand growth had been “remarkable”, this had a lot to do with the continent’s flexibility to absorb the oversupply of LNG.

“However, from this point forward we don’t see Europe being a major growth driver and are currently forecasting ~20% demand growth from current levels by 2030,” he said. “In contrast, we see Asian demand (led by China) growing 60% through 2030 and this off a much higher base as well as the Asian market currently is >3x European demand. So Asia is the big opportunity – after China we see largest demand growth from India, Pakistan, and Thailand.”

If negotiating with Chinese buyers remains challenging, there could thus be other options elsewhere. Indeed, Ellis said that he did not believe the expansion of Corpus Christi LNG was dependent solely on Chinese customers.

“Cheniere mentioned it planned to move forward with a [final investment decision] on Stage 3 based on contracts with US producers such as EOG and Apache in 2020 late last year. It has shown substantial ability to be creative with contract types to attract new customers, so I don’t think it’s reliant on China here,” Ellis said. “However, its latest update suggested that moving forward with an FID was more up in the air given the obvious market turmoil. I would still expect it to move forward perhaps later this year or in early 2021, once the market has had a chance to get more near-term clarity around demand/supply dynamics for LNG, but also oil.”

Ellis’ expectation is that as the market improves, so should conditions for Cheniere to move forward with new liquefaction capacity. And indeed there have been some early signs of a recovery, though it would need to be sustained and not derailed by any further lockdowns in response to potential new spikes in Covid-19 infections. At the moment this cannot be guaranteed.
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Qatar pushes ahead with LNG growth strategy

Qatar says its low-cost base means it can withstand market shocks and move forward with consolidating its position as market leader

JOSEPH MURPHY
Qatar is pressing ahead with a massive expansion of its LNG production capacity, despite market uncertainty created by the Covid-19 pandemic.

The Gulf state retained its position as the world’s biggest LNG exporter last year, shipping 77.8mn mt. It was closely followed by Australia, which exported 75.4mn mt. Qatar is set to consolidate its top spot with an ambitious plan to expand its liquefaction capacity to 126mn mt/yr by 2027.

The expansion comprises two stages. The first, North Field East (NFE), will add four more trains to the offshore North Field, raising Qatar’s output to 110mn mt/yr by 2025. The second, North Field South (NFS), involves two more trains that will bring capacity to the 126mn mt/yr target two years later.

There had been speculation that Qatar would downsize its ambitious in the face of a growing LNG supply glut, exacerbated by the impact of the Covid-19 crisis on demand. However, state-owned Qatar Petroleum (QP) has hit back against these suggestions.

QP’s CEO and Qatar’s energy minister, Saad Sherida al-Kaabi, stressed on May 22 that work on the project was going “full steam ahead,” despite challenging market conditions.

“We are in it for the long haul. We are the most cost-effective producer and can withstand market shocks,” he said in a statement. “We are in very good financial shape and we are still looking for good investment opportunities.”

This confidence is demonstrated in QP’s actions. A final investment decision on NFE is not yet in place, but the company is already undertaking upstream development work.

QP began drilling NFE’s 80 development wells in late March and has started insulating offshore well-head jackets. It has also reserved capacity.
at several shipyards to build a new fleet of LNG carriers (LNGCs). In April, QP said it had reserved a “significant” share of the LNGC construction capability of China’s Hudong-Zhonghua shipyard through 2027 – a deal potentially worth more than Qatari riyals 11bn (US$3bn). It followed this up with three more deals worth $19.2bn at the start of June to book capacity over the next 7-8 years at South Korea’s top three yards, Daewoo Shipbuilding and Marine Engineering, Hyundai Heavy Industries and Samsung Heavy Industries. These yards could build up to 100 vessels for QP.

Even so, some delays have been inevitable. QP has given contractors until September to file bids for NFE’s main onshore engineering, procurement and construction contracts. Earlier QP had set an April deadline for offers. Awards are expected in the fourth quarter of this year. NFE’s completion has also been pushed back, from 2024 previously to 2025, although NFS remains on track under the original schedule.

**Determination**

Experts are confident that Qatar will realise its growth plans.

“The Qataris are ideally located geographically with very competitive gas, and the expansion of their facilities is a core part of their wish to expand their energy sector,” David Ledesma, chairman of the gas programme at the Oxford Institute for Energy Studies (OIES), and energy and strategy consultant, tells Global Voice of Gas (GVG). “We will see these expansion projects proceeding, but it will be challenging given demand uncertainty in their targets.”

Sara Vakhshouri, founder of Washington-based consulting firm SVB Energy International, sees Qatar moving forward with the expansion “with the same enthusiasm and effort as before the Covid-19 pandemic.”

Keeping the project on schedule will depend on progress in negotiations with buyers, however, and Qatar will need to be flexible.
“They will need to be responsive to buyers’ demands for price flexibility, volume flexibility and potentially cargo destination flexibility,” Ledesma said, predicting that Qatar would meet these expectations.

It may also decide to sell some of the extra supply on a short-term or mid-term basis, instead of under long-term contracts.

Qatar has cemented its foothold in the European market by securing regasification capacity in countries like the UK, the Netherlands and France. It may pursue a similar strategy to sell gas from the expansion projects, while targeting markets without access to pipeline gas, such as those in Asia and South America, according to Ledesma.

QP has said before it is willing to proceed with the expansion alone, but it has also mooted bringing in potential investment partners. To develop its present production capacity, the company teamed up with ExxonMobil, ConocoPhillips and Shell, among others. Last autumn al-Kaabi said the company had shortlisted a “select few” investment partners for its new projects. It likely plans to base its final decision on what additional opportunities they offer besides investment, such as market access or offtake deals.

Before finalising partnerships, though, QP will need to firm up the expansion’s capital expenditure budget. The company has not given guidance on potential costs yet. But in March, Oslo-based Rystad Energy projected that the first phase alone would cost $35bn, with the second’s price tag coming in at $15bn.

Despite its low-cost advantage, Qatar has not been immune to the sharp downturn in LNG market. QP plans to reduce its capital and operating expenses by 30% this year, al-Kaabi said in May. Not only do its LNG expansion plans remain on track, though, but the company intends to continue growing its international business, the CEO said.

QP has been acquiring interests in offshore exploration projects across the world over the past year. It made its latest move in mid-May, agreeing to farm into two exploration blocks operated by France’s Total off the coast of Cote d’Ivoire.

QP also has no intention at this stage of cutting production, al-Kaabi said, noting that Qatar’s low costs meant it would never be compelled to take such a step because of low prices.

Some producers could in theory agree on OPEC+-style coordinated action to reduce supply to rebalance the market, but Ledesma views this is unlikely.

“In such a scenario of forced production curtailment because of price, many other producers would be forced to shut down before Qatar due to their high production cost; therefore there is absolutely no way that we would curtail production,” al-Kaabi said.

“Qatar may have had to delay some of its LNG cargoes for a week due to lower demand among its customers, but this will be a temporarily practice, as the market expects the demand to pick up by the end of the second quarter of this year,” Vakhshouri said.

In the mid- to long-term, gas demand will be supported by many countries increasing its share in their energy baskets as part of their energy transition plans, at the expense of dirtier fuels, she said.
Nigeria’s Year of Gas

Nigeria appears closer than ever before to introducing a new legal regime that will give outside investors a better foundation for investing in gas projects

JENNIFER DELAY
Nigeria became a prominent player in the global energy industry because of oil. It has long been the largest crude producer in Africa, and its proven oil reserves are, at 37.2bn barrels, the 10th largest in the world. But the West African state also has huge potential in the realm of gas. At more than 180 trillion ft³ (5.1 trillion m³), its gas reserves are the ninth largest in the world and the largest in Africa. They are certainly large enough to justify the repeated contention of Tony Attah, the head of the Nigeria LNG (NLNG) consortium, that Nigeria is “a gas nation with some oil” rather than an oil producer with some gas.

Attah is not alone in his thinking. Nigeria’s current government is also eager to develop domestic gas reserves, and Timipre Sylva, the minister of state for petroleum resources, has declared 2020 to be the “Year of Gas.” Sylva and his colleagues are having to adjust their outlook somewhat in light of the coronavirus pandemic and other recent events, but they remain keen on proposals for turning gas into an engine of economic growth.

**Foundation for growth**

This does not mean starting from scratch. Nigeria has already put some of its gas to work.

Thanks to NLNG, which processes natural and associated gas from various onshore and offshore fields in the Niger River Delta region, it is one of the five largest exporters of LNG in the world. The consortium has built six production trains that are capable of turning out around 22mn mt/yr of LNG, and it recently approved plans to build a seventh train that, together with the debottlenecking of existing trains, will push output up to 30mn mt/yr.

Closer to home, Nigerian gas consumption is on the rise. The country has gone from using about 71.9bn ft³ (2.04bn m³) of gas in 1999 to consuming about 618bn ft³ (17.5bn m³) in 2019. During the same period, gas became an increasingly important fuel for Nigeria’s power-generating sector. According to the International Energy Agency (IEA), gas-burning thermal power plants (TPPs) accounted for fully 80% of the country’s electricity production as of 2019.

**Room for improvement**

Nevertheless, Nigeria is far from realising its full potential.

For one thing, the country is still treating a significant share of its gas yields as a waste product. Despite Abuja’s pledge to end routine flaring, many crude oil producers still burn their associated gas just to get it out of the way. As Justice Terefaka, programme director of the Nigerian Gas Flare Commercialisation...
Programme (NGFCP), noted in May, local oil operators reported that they burned off 325bn ft³ (9.2bn m³) of gas in 2019, or 11% of domestic gas output. The number may be even higher, he said, as satellite data from the Gas Flare Tracker (GFT) system put burn-offs at 475bn ft³ (13.45bn m³), or more than 16% of output.

Moreover, gas flaring has actually increased in recent years. According to Terefaka, Nigerian operators flared 282bn ft³ (7.99bn m³) of associated gas in 2018, or 10% of production, and GCF data indicate that the total may be as much as 472.4bn ft³ (13.4bn m³) or 16.75% of production.

For another, even though Nigeria’s power-generating sector has moved quickly to expand the use of gas, it is still not producing enough electricity to meet the needs of the population. As of 2019, about half of the country’s 201mn citizens were living in rural areas that had no access to electric power, and the other half were experiencing frequent blackouts – and using diesel-fired generators as back-up sources of energy.

This supply gap stems partly from Abuja’s failure to implement plans to add at least 10,000 MW of new gas-fired generating capacity between 2015 and 2020. (That plan was part of a wider effort to bring the country’s total generating capacity up to 40,000 MW, more than double the current level, between 2015 and 2020.) But it also stems from gaps in the legal regime, especially with respect to the laws governing hydrocarbon development. Nigeria’s government has been trying to pass a new oil and gas law since 2008, and the failure of its efforts has cost the country about $15bn worth of investment each year, according to the Department of Petroleum Resources.

Next steps
Officials in Abuja hope to remedy the situation this year, though. Sylva has said repeatedly in recent months that the government is determined to pass a new Petroleum Industry Bill (PIB) in 2020; he has also reported that members of the National Assembly are largely satisfied with the provisions of the draft law. In May, he went further, telling Naija 247 News that the general structure of the bill was ready and would be submitted to the legislature following a review by President Muhamadu Buhari and other high-ranking officials.

It still remains to be seen when legislators will hold a vote on the PIB, but Abuja does appear to be closer than it has ever been before to introducing a new legal regime that will give outside investors a better foundation for investing in gas projects. At the same time, it is also taking practical steps to strengthen the gas sector, such as:

- offering companies the chance to invest in 45 flare sites – that is, oilfields that contain large amounts of associated gas that could be directed to the domestic market
- working with NLNG to build up the domestic gas market by promoting the use of liquid petroleum gas (LPG) produced from gas as a fuel for cooking and other domestic purposes
- agreeing to provide sovereign guarantees for the construction of the Ajaokuta-Kaduna-Kano (AKK) pipeline, which will serve as the first section of the Trans-Nigeria Gas Pipeline (TNGP), delivering gas to local TPPs
- exploring non-pipeline delivery options for gas, including but not limited to truck shipments of compressed natural gas (CNG)

Projects such as these are concrete symbols of progress in the gas sector. They demonstrate that Nigerian authorities are truly committed to reducing associated gas flaring, facilitating the delivery of gas to local markets and building up demand for gas. As such, they will help Nigeria move forward quickly once the PIB secures passage – and just in time for the start of work on NLNG’s Train 7 project.
Uzbekistan’s government has taken steps in recent years to bring its oil and gas industry out of stagnation and capitalise on its gas wealth.

JOSEPH MURPHY

Uzbekistan is looking to maximise the value from its gas resources, by attracting more foreign investment, undertaking reforms and advancing new downstream projects.

The central Asian state is endowed with 1.2 trillion m³ in proven gas reserves, according to BP data. In recent years the government has taken steps to bring its oil and gas industry out of stagnation and capitalise on this wealth.

The immediate priority is the post-coronavirus (Covid-19) recovery. National gas production came to 60.7bn m³ last year, but is projected to fall in 2020 to 51.7bn m³, in the wake of the pandemic. Uzbekistan and other central Asian gas exporters had to cut shipments to China earlier this year, after Beijing imposed lockdowns to combat the virus, weakening gas demand.

“The global economy is experiencing a sharp decrease in demand due to the coronavirus pandemic. There has also been a decline in oil and natural gas prices,” Uzbekistan’s energy ministry told Global Voice of Gas (GVG). “Due to these unstable conditions, our partners have temporarily limited gas intake and as a result Uzbekistan’s natural gas exports to China have been reduced.”

By 2030, though, the energy ministry projects that production will increase to 66bn m³. This target will
be achieved by developing the country’s resource base, bringing on stream new fields and restarting others that were previously mothballed. Uzbekistan is reaching out to international oil and gas companies to make this happen.

**Spurring development**

Uzbekistan is taking various steps to try to galvanise development of its resources.

Its reserves are being regularly audited in line with international PRMS standards, to help attract outside interest. Geological data on deposits and investment blocks are also being updated and digitalised. Previously much of this data was kept only on paper and in the Russian language.

“Technological development is important also and the concept of the digital field is being implemented, where the digital data is optimally processed and analysed, increasing efficiency,” the ministry says.

Foreign experts have also been recruited to assist in planning activities and international capital has been attracted. Uzbek president Shavkat Mirziyoyev issued a decree in early April, under which Tashkent plans to borrow $650mn from foreign financiers this year for oil and gas projects, including $250mn in loans from China’s Silk Road Fund.

Uzbekistan’s second biggest gas producer after state-owned Uzbekneftegaz (UNG) is Russia’s Lukoil, which works under production-sharing agreements (PSAs) at its key projects Southwest Gissar and Kandym. Russia’s Gazprom and China’s CNPC are the two other major foreign companies working in the country’s upstream sector.

Over the past few years, Uzbekistan has reached out not only to these established players but also newcomers to develop additional projects. In May, Uzbekistan’s energy ministry and UNG signed a letter of intent on a future production-sharing agreement (PSA) with BP and Azerbaijan’s Socar. The contract envisages the group exploring the Samsk-Kasbulak and Baiterek blocks in the western Ustyurt region.

Negotiations are underway on exploration in Ustyurt with the UAE’s Mubadala, France’s Total and Russia’s Novatek, the ministry said.

Uzbekistan has traditionally offered international companies PSAs, under which they share profits from production with the government after recouping their costs. But Tashkent is now pushing for the use of risk-service agreements (RSAs) instead, Bobur Shamseiv, a partner at Dentons’ Tashkent office, told GVG.

Under RSAs, partners do not receive rights to resources but are instead paid in baseline and incremental fees for the services they provide to enhance production, typically based on how much more oil and gas is yielded.

“We assume that PSAs are no longer on offer in Uzbekistan,” Shamsiev said, noting that RSAs can be effective at mature fields where production is declining. UNG has many such fields.

However, Uzbekistan is yet to finalise a legal framework governing RSAs – a step it had aimed to take last year. At the same time, the new tax code enacted in December has made the special tax regime for PSAs less predictable. This means that, at present, Uzbekistan lacks a clear framework for attracting investors to its upstream sector. ►

**“By 2025, measures will be taken to stop the export of natural gas and expand processing within the country, as well as increase production of value-added products”**

— Abdulla Aripov
Uzbek prime minister
RSAs are “being studied” as an option for increasing production, the ministry said. The ministry added that, together with the state committee for geology and UNG, it is developing other draft laws to attract international investment.

Mirziyoyev also issued a decree last year on UNG’s restructuring in line with international standards. Under this programme, some of the company’s activities will be unbundled to improve the efficiency, transparency and regulation of Uzbekistan’s oil and gas industry.

Uzbekistan’s gas pipeline operator Uztransgaz has been separated from UNG, and a company called Khududgaztaminot has been set up to operate the country’s gas distribution networks. The state may sell a stake in UNG in 2022-2024, depending on progress in UNG’s transformation. An initial public offering (IPO) and a Eurobonds issue are also being considered.

International experts have been commissioned to help with the process. UNG’s hydrocarbon reserves and assets are also to be assessed by DeGolyer & MacNaughton and KPMG respectively. Its financial statements will be audited by EY in accordance with international standards.

Adding value
Uzbekistan currently exports gas, selling 5.1bn m³ to China and a further 6.8bn m³ to Russia last year, as well as small volumes to other central Asian states. Rather than step up overseas shipments, the government wants to use more domestically to produce higher-value products. Uzbek prime minister Abdulla Aripov even suggested in January that the government would seek to bring exports down to zero within the next five years.

“By 2025, measures will be taken to stop the export of natural gas and expand processing within the country, as well as increase production of value-added products,” he was quoted as saying by the local press.

Under this strategy, the country is advancing several key downstream projects. The two main ones are the Oltin Yo’l gas-to-liquids (GTL) project, scheduled for completion this year, and a petrochemical expansion at the adjacent Shurtan gas processing complex.

The $3.6bn GTL plant will convert up to 3.6bn m³/yr of gas into 1.5mn mt/yr of kerosene, diesel, naphtha and LPG, all of which will be consumed domestically. The naphtha will be used at the Shurtan complex to produce an extra 280,000 mt/yr of polyethylene and 100,000 mt/yr of polypropylene.

Uzbekistan is also looking to produce 500,000 mt/yr of polymer products at the M-25 field, and develop a methanol-to-olefins complex that will turn out up to 1.1mn mt/yr of gas chemical products.

A major consumer of gas is Uzbekistan’s power industry, with the country’s mostly gas-fired thermal power plants (TPP) account for 85% of national electricity generation. The ministry projects that energy demand in Uzbekistan will almost double by 2030, necessitating a more than doubling of generation capacity from 12.9 GW to 29.3 GW. As part of this plan, 15.6 GW of TPP capacity will be built or modernised, while 6.4 GW of obsolete capacity will be decommissioned.

Thanks to this boost to efficiency, Uzbekistan hopes to lower power-sector gas consumption from 16.5bn to 12.1bn m³. This will free up more supplies for use elsewhere.

A key challenge for Uzbekistan has been the poor state of its national gas grid, built more than 50 years ago. According to the Asian Development Bank (ADB), physically degraded compressors work at under 35% capacity, and many transmission pipelines have not been tested or inspected for the past 25 years. This has resulted in technical losses of more than 15% of export volumes.

Uzbekistan is implementing a programme to modernise the system in two stages running to 2025. As part of this initiative, it is establishing a centre for dispatching, monitoring and managing gas infrastructure facilities. Seven compressor stations and more than 900 km of gas pipelines will also be reconstructed and modernised under the initiative.
Canada’s balancing act
Under Prime Minister Justin Trudeau, Canada is trying to strike the right balance between meeting its environmental targets and supporting its economy, in which energy plays a significant role

ANNA KACHKOVA

Recently re-elected Canadian Prime Minister Justin Trudeau has sought to balance growing the Canadian economy – in which energy plays a major role – with meeting climate change mitigation targets since taking office in 2015. This approach, however, will always attract criticism from interest groups on both sides of the equation for not going far enough in their direction.

In addition to trying to strike the right balance between environmental and economic aims, where major energy projects are concerned, Canadian policy increasingly has to take indigenous rights and concerns into account. This is illustrated most recently by the way in which opposition to the Coastal GasLink gas pipeline by some members of a First Nation in British Columbia (BC) escalated into nationwide blockades of roads and railways at the start of this year.

On top of all of this, the Covid-19 pandemic has wreaked havoc on energy demand both domestically and internationally. As the pandemic is still playing out, its full impact is unknown. In the short term, there are worries that it may threaten Canada’s ambitions to open up overseas markets for its natural gas. However, Canada’s gas industry still hopes to have a significant role to play in the longer term, and indeed believes it could help strike the right balance between the country’s environmental and economic goals.

Major role

The energy industry accounts for a considerable part of Canada’s economy, with the most recent government data showing it represented over 10% of nominal GDP in 2018. By the government’s estimates, Canada is the world’s sixth largest energy producer, eighth largest consumer and fourth largest net exporter.

“Given how [Canada’s] economic growth is so highly correlated with energy development, you can’t talk about one without the other,” Dinara Millington, the vice president of research at the Canadian Energy Research Institute (CERI), told Global Voice of Gas (GVG). “A lot of that economic activity and GDP growth is tied to continuous extraction and production of hydrocarbon resources that specifically Western Canada is so abundant in.”

However, Canada’s natural resources and energy mix need to be viewed in the context of the country’s commitment to reducing greenhouse gas (GHG)
emissions under the Paris Agreement. Canada has pledged to reduce its GHG emissions by 30% below 2005 levels – which have been estimated at 730mn mt – by 2030.

Thus, the country is faced with the challenge of further developing its energy industry in pursuit of economic growth, while simultaneously figuring out where it can significantly reduce emissions.

Millington noted that there was no single policy or approach that Ottawa and the provinces could take to balancing these goals.

“There’s just a lot of moving parts,” she said. And thus far, she has not seen any research assessing the cumulative impact of these various policies and approaches.

One area where this conflict has played out particularly prominently is in the Canadian oil sands. Concerns about the GHG intensity of the oil sands resource are thought to have played a role in the exit of numerous foreign investors in recent years. And when former US President Barack Obama rejected the now-approved cross-border Keystone XL pipeline he did so largely on concerns that significant new oil sands takeaway capacity would cause production, and therefore emissions, to rise.

Canadian natural gas development, despite also running into opposition, has proved to be less contentious – at least on environmental grounds.

“Canada is a large net exporter, and one way to tie it to more international audiences is through natural gas,” said Millington. She cited a CERI study that found future Canadian LNG to result in some of the lowest GHG emissions compared with other fuels. “You could potentially see a business case and even an environmental case to be made where Canadian natural gas replaces the coal power plants in jurisdictions like Asia Pacific, in China and India.”

Indigenous issues
Even if more LNG projects do go ahead, however, their developers will have to factor indigenous issues into how they proceed. This has become increasingly clear from a number of recent projects. The protests and blockades that stemmed from opposition to the Coastal GasLink pipeline recently proved incredibly disruptive for commuter and commercial transport across the country.

The case involves a disagreement within a First Nation – the Wet’suwet’en – whose elected chiefs support Coastal GasLink while hereditary chiefs oppose it.

Though federal and BC provincial officials have made progress in talks with the Wet’suwet’en, the
issue has not been fully resolved and the hereditary chiefs remain against the project. The spread of Covid-19 in Canada coincided with spring break-up – when much oil and gas activity stops owing to melting snow that makes the terrain unstable – and work on the pipeline slowed as a result.

As construction work ramps up again and measures to contain Covid-19 are eased, there is a risk that more protests could flare up unless an agreement is reached with the Wet’suwet’en hereditary chiefs.

“I think the resolution here has to come internally first within their own nation,” Millington said.

The question of indigenous rights needs to be considered by the Canadian government as well as the developers of a given energy project. This can be illustrated by the fact that federal approval for the Trans Mountain expansion – an oil sands pipeline – was withdrawn by a court in 2018 on the grounds that the government had failed to adequately consult First Nations before approving the project.

The approval has since been reinstated and the federal government – which owns the Trans Mountain project and its expansion – will seek to sell it back to the private sector after construction has been completed. The question of whether First Nations can take an equity stake in the pipeline is being examined, and this could set a precedent for other energy projects that could make it easier for them to proceed without high levels of opposition.

“That might entice better, closer partnerships and relationships, and consent at the end of the day,” Millington said. “There’s still a duty to consult and a duty on the behalf of Canadian government and project proponents to do that.”

How work on Coastal GasLink – which will supply feed gas to LNG Canada when it is in service – progresses will be closely watched and could help inform how other LNG developers on the BC coast proceed if they build their terminals.

Ottawa, meanwhile, will also come under increasing pressure to factor indigenous issues into its efforts to balance environmental and economic concerns.

“You could potentially see a business case and even an environmental case to be made where Canadian natural gas replaces the coal power plants in jurisdictions like Asia Pacific, in China and India.”

— Dinara Millington
vice president of research at CERI
Interview with

Andrew McConville

CEO, Australian Petroleum Production & Exploration Association
Q: The Australian Energy Market Operator has warned that gas supply shortfalls on the East Coast market could emerge as soon as 2023. Is there a risk that, between the oil price crash and Covid-19, investment might dry up and exacerbate that issue?

AEMO’s most recent analysis confirms the actions taken by the industry to bring more gas into the domestic market will ensure domestic gas supply to at least 2023 – but we need continued development of existing and new resources to ensure supply beyond that point. We also need policy stability to help support the investment needed for that development.

While AEMO’s analysis has in many cases been overtaken by the onset of the Covid-19 pandemic, the industry has increased substantially the flow of gas to the east coast domestic market and this will continue into the future.

APPEA members are taking all steps necessary to ensure the production and delivery of gas supplies continues, even as the domestic market spot prices have fallen to multi-year lows.

But further action by both industry and governments will be required to bring more gas into the east coast domestic gas market beyond 2023.

Supply is reducing in the major consumer states of Victoria and NSW over the next few years as legacy fields decline. While Queensland and the Northern Territory are increasing supply, more needs to be done closer to the major demand centres of Melbourne and Sydney.

That will require substantial and ongoing industry investment to commercialise existing reserves and resources and finding new sources of supply.

With exploration at record low levels, low oil prices and the Covid-19 pandemic meaning both gas demand and gas supply face challenges, AEMO’s analysis reinforces how vital it is for all governments to support developing new gas supplies as quickly and as cheaply as possible.

What upstream measures can Australia embrace to help push back supply shortages for as long as possible?

At the risk of stating the obvious the solution to any possible supply challenges is more supply.

The good news is that in Queensland, South Australia, the Northern Territory, New South Wales and Victoria, there are identified gas resources waiting development once regulatory approvals are in place and the investment climate improves. There are challenges on both fronts. ▶
We are arguing strongly against measures that threaten new development, or work against further investment in existing projects. Our governments, at State and Federal level, are coming to realise that that anything that distorts or fails to recognise the cost structure of gas delivery in Australia must be rejected.

Increasing local supply remains the single most important and economically sensible way to deliver competitively priced gas to consumers and industry on the east coast.

Given Australia’s abundant natural gas resources there is absolutely no reason the country should face domestic gas shortages, even while we maintain our role as a leading LNG exporter.

Investment in LNG projects (barring Arrow) has slowed or stopped altogether. Is this a by-product of the current global situation or a symptom of LNG market oversupply and the greater adoption of renewables?

The current slowing in upstream investment was inevitable after the development boom of the last decade, but also reflects barriers that have slowed more recent projects.

Australia’s upstream oil and gas industry needs long-term regulatory stability to create attractive investment opportunities for the sector and maintain industry’s strong economic contribution.

A report we commissioned this year, undertaken by energy research and consultancy Wood Mackenzie, highlights the Australian industry’s success from 2009 to 2012 was predicated on relatively few regulatory and fiscal changes in the previous decade, which provided a strong foundation for a wave of unprecedented investment.

It is important to recognise the scale of this investment, including the establishment of LNG projects, worth approximately A$350 billion, has delivered direct and indirect economic benefits to the Australian economy – and enabled us to forge stronger commercial ties with our customers in Asia.

The period since 2012 has not been as stable with almost double the number of regulatory changes affecting investor confidence and development. The long-term outlook remains strong with rising demand for gas globally, particularly in major developing markets to our north, and gas playing a critical role in supporting Australian manufacturing and in lowering our emissions from power generation. So we need a fiscal and regulatory policy environment that supports investment and the further development of Australia’s substantial natural gas resources.

The greater adoption of renewables in Australia is actually strengthening the need for more gas-fired power to support the integration of intermittent technologies like wind and solar into our energy mix. The existing fleet of aging coal-fired power plants is unable to play that role.

Have we seen the last of multi-billion-dollar greenfield LNG developments in favour of brownfield expansions?

We expect investment in both greenfield and expansion of supply existing projects. The slump in oil and gas prices this year, compounded by the disruption of Covid-19, has inevitably led to project delays but we see that as a short-term impact – provided we keep the policy settings in place to attract investment.

The WoodMac report showed Australia has an opportunity to secure the next wave of investment which has the potential to deliver upwards of $50 billion in capital expenditure, and secure up to 6,300 jobs across the life of a project and an estimated $80 billion in taxation receipts.
“A better solution is to support investment that helps to increase supply. Markets work best without intervention.”

But, the right policy environment is essential to future development and success and governments must resist the temptation to intervene in markets.

There are several LNG import projects in the works, attracting some criticism given the country’s status as the world’s largest exporter. Can Australian gas production meet local demand without the need for FSU projects?

There should be no need to import gas into Australia, but given recent delays in advancing new projects targeted at the domestic market it may be the case that one or two import facilities are established. These would all be privately funded and would reflect the market dynamic we now face.

While there are, of course, a number of countries that both export and import gas, we understand this seems somewhat bizarre when viewed from outside Australia, but it does reflect the delay and disruption to a number of planned projects. Thankfully a moratorium on hydraulic fracturing in Northern Territory was lifted last year and the development of substantial shale gas resources in the NT’s Beetaloo Basin is now possible. The sanctioning of Arrow Energy’s Surat Basin Project in Queensland will create additional supply for the state’s LNG projects and the domestic market. And in NSW, a coal seam gas project around the regional community of Narrabri is in the final stages of regulatory approvals after lengthy delays.

If these projects all proceed it is hard to see the commercial case for Australian import terminals, but that’s a matter for investors in those projects.

The upstream industry has pushed back against the idea of the government intervention to reserve gas supply for the domestic market. Given the current economic climate and projected supply shortages, isn’t it to be expected that government will want to guarantee local supply?

As we look to economic recovery in all sectors of the economy — not just oil and gas — maintaining access to open and competitive markets is in Australia’s best interest.

We strongly argue that governments must resist calls coming from some for intervention in the gas market that force non-commercial outcomes. Such approaches act as a tax on gas production, raising costs and can discourage long-term investment, reducing production and undermining long-term energy security.

A better solution is to support investment that helps to increase supply. Markets work best without intervention.

In the current challenging environment, governments can help ease pressures by releasing more acreage for gas exploration and development and removing unscientific bans on onshore gas development.

Transparent, open and secure access to resources for exploration and development and developing access to domestic and international markets on globally competitive terms is the key for long-term industry development.
Going after a vigorous reform agenda, ensuring open and competitive markets and a tax system that helps us maintain our international competitiveness can see industry and governments work together to support the positive role the oil and gas industry can play in contributing to Australia’s economic recovery.

The government is increasingly focused on new technologies to help reduce emissions and has talked up the role of gas in power generation. Could gas completely replace coal in the power mix and how long might it take to transition fully?

Australia has traditionally relied on coal-fired power generation, but the role of both gas and renewables is increasing.

In 2019, natural gas accounted for 21 per cent of electricity generation in Australia. This is in line with all renewables (bioenergy, wind, hydro, solar and geothermal) combined. Electricity generation from natural gas increased by 6 per cent in 2019 as compared with 2018. At the same time, coal-fired generation accounted for 56 per cent of the power mix, after falling progressively from traditional levels closer to 80 per cent.

While we expect coal will continue to be part of our energy mix for many years to come, we expect the growth of gas and renewables to continue.

Natural gas is the most significant fuel for electricity in Western Australia, Northern Territory and South Australia accounting for 61 per cent, 58 per cent and 49 per cent of generation, respectively.

The state of South Australia is a great example of an area where gas and renewables work side-by-side to deliver lower-emissions energy. The state gets about half of its power from gas and the rest from solar and wind.

This data shows the critical role natural gas plays in the electricity market by enabling more renewable power generation to be integrated into the grid and keeping it stable and reliable.

“There is tremendous interest globally in hydrogen as a new, cleaner fuel. Australia is well placed to capitalise on our already abundant natural advantage.”

Natural gas allows for more renewables to be integrated into the grid due to its short response time. Gas-fired power generation can ramp up and down very quickly to support renewable generation and provide emissions reduction along with it.

Experts in Australia and globally have repeatedly suggested the quickest way to reduce emissions from the electricity sector is to switch traditional coal generation to natural gas-powered generation, which has less than half the emissions associated with it.

As the world’s largest exporter of LNG, Australia will continue to capitalise on this important low emissions export opportunity. Some of our key trading partners, including Japan and South Korea, have indicated that LNG will play an important role in decarbonising their electricity systems. LNG represents a continuing opportunity for Australia.

Reducing global emissions is a global effort, and as an energy exporter Australia is doing its part through many channels. Our LNG exports can substitute gas for more emissions-intensive fuels and have the potential to reduce greenhouse gas emissions by 164 million tonnes in our trading.
partners. That’s equivalent to 30 per cent of Australia’s total annual emissions.

Blue Hydrogen pilot projects appear to be on the rise. Do you envisage Blue Hydrogen playing a meaningful role in the Australian gas industry’s future?

The natural gas industry is well-placed to assist in and be a key part of the development of a large-scale and innovative commercial hydrogen industry, both in using natural gas to produce hydrogen and using gas infrastructure to process and transport hydrogen.

Australia’s LNG export success story means our industry has the technology, expertise and commercial and trade relationships to make hydrogen exports a reality.

There is tremendous interest globally in hydrogen as a new, cleaner fuel. Australia is well placed to capitalise on our already abundant natural advantage.

Hydrogen is already being produced from Australian LNG exports. In the United States, natural gas is the dominant source of its growing “blue hydrogen” industry.

Natural gas can provide a fuel source for hydrogen made through the process of steam methane reforming (SMR), with any greenhouse gas emissions generated during SMR managed through market offset or technical abatement (such as CCS) to offer a carbon-neutral product.

A number of APPEA members are already exploring these opportunities.

We support strong partnerships across government, industry and the research community to ensure Australia makes the most of the opportunity arising from this emerging technology. A good example of this is APPEA’s recent commitment to be a part of the Future Energy Exports Cooperative Research Centre. ■

Andrew McConville is the Chief Executive Officer of the Australian Petroleum Production & Exploration Association (APPEA), a position he has occupied since April 2019.

APPEA is the peak national body for Australia’s oil and gas exploration and production industry. APPEA represents almost 200 companies involved in oil and gas exploration and production as well as the provision of goods and services to the upstream industry.

As Chief Executive, Andrew is responsible for leading the Association and its members to be the effective voice the Australian oil and gas industry, building community trust and support, driving advocacy and engagement, developing the industry’s key policy positions and executing a strategy for growth of the Association.

Andrew is an advocacy and corporate affairs professional with more than 25 years’ experience across the oil and gas, agribusiness, banking and finance, FMCG and government sectors.

Andrew holds a first class honours degree in Agricultural Economics from the University of New England, a Master of Science in Agricultural Economics from Oxford University and is a Member of the Australian Institute of Company Directors.

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ExxonMobil is committed to methane reductions in our operations and across industry, and our operational experience informs our perspectives on policy, regulations and technology development. The correct mix of emission-reduction technologies, policies and appropriate regulations can help efficiently reduce methane emissions.

**Methane emission reductions in our operations:**
As of year-end 2019, we have reduced methane emissions by nearly 20 percent in our U.S. unconventional operations compared to 2016 levels, and we remain on track to meet our corporate-wide commitments to reduce methane emissions by 15 percent and reduce flaring by 25 percent by year-end 2020. Our successful voluntary methane management program includes structured leak detection and repair protocols, prioritized replacement of high-bleed pneumatic devices, technology enhancements to infrastructure and substantial data gathering and research.

**Regulation addressing oil & gas related methane emissions:**
ExxonMobil supports the development of reasonable and cost-effective regulations addressing oil and gas related methane emissions. While voluntary efforts by individual companies are important, they only capture a fraction of industry’s overall emissions. Full industry participation is required to maximize the benefits to society.

In this regard, in March 2020, we introduced a model framework for industry-wide methane regulations and urged stakeholders, policymakers and governments to develop comprehensive, enhanced rules to reduce methane emissions in all phases of production. This framework is the product of intensive study and implementation of controls for the major sources of methane emissions in our own operations. Notably, it builds on the actual mitigation measures that ExxonMobil has been applying to our operations as noted above, resulting in improvements that
Technology Development:
We also continue to undertake extensive research to understand methane emissions sources, and help develop and test new detection and mitigation technologies. We are helping to identify the best performing and most efficient technologies – including satellite instruments – that can be adopted by all producers to detect, repair and accurately measure methane.

However, no one-size-fits-all solution exists. For this reason, ExxonMobil is leading testing for the most promising next-generation methane detection technologies at 1,000 sites in two U.S. states, Texas and New Mexico, with the aim of identifying effective, scalable solutions. Additionally, we also just announced a new collaboration involving academia, environmental groups and other industry partners. Called “Project Astra,” the effort is focused on developing an innovative sensor network to continuously monitor methane emissions across large areas to enable quick and efficient detection and repair of leaks. If successful, the project could provide a more affordable, efficient solution to reduce methane emissions. (See accompanying video.)

We believe these efforts show great promise in developing new technologies that could improve fugitive methane emissions detection and mitigation in the near future.
Developing biogas in our towns to fuel the agricultural sector in our rural communities.

ENGIE, solutions to support your zero-carbon transition.

Alongside our partners, we are investing €800 million in green gas between now and 2022 in France. We are banking on biogas, in particular by working with farmers whose waste products we recycle, thus contributing to the agro-ecological transition.

For more information, visit engie.com