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Number 395
May | June 2025

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Urea markets
LNG and gas pricing
Ammonia cracking
Reformer tube life

NITROGEN+SYNGAS
ISSUE 395
MAY-JUNE 2025

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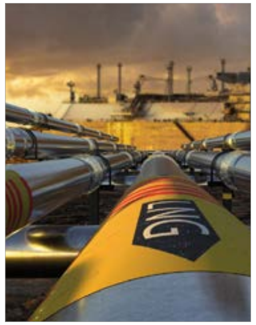
Cover: Pipelines leading to a LNG terminal.
Image: Mike Mareen/Shutterstock


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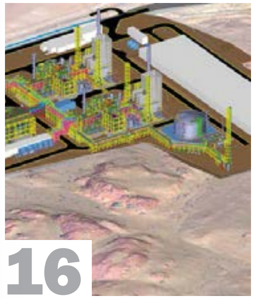
India's challenges

Meeting the country's changing need for fertilizer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Ammonia storage in gravity based structures

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Sailing on...

> **"Changes to the IMO's IGC and IGF codes were crucial to ammonia's adoption as a marine fuel..."**

With future demand for both low carbon methanol and ammonia depending to a considerable extent on their take-up as low carbon shipping fuels, recent developments in the EU and IMO may help accelerate that process, as detailed in CRU's most recent Low Carbon Hydrogen and Ammonia Outlook.

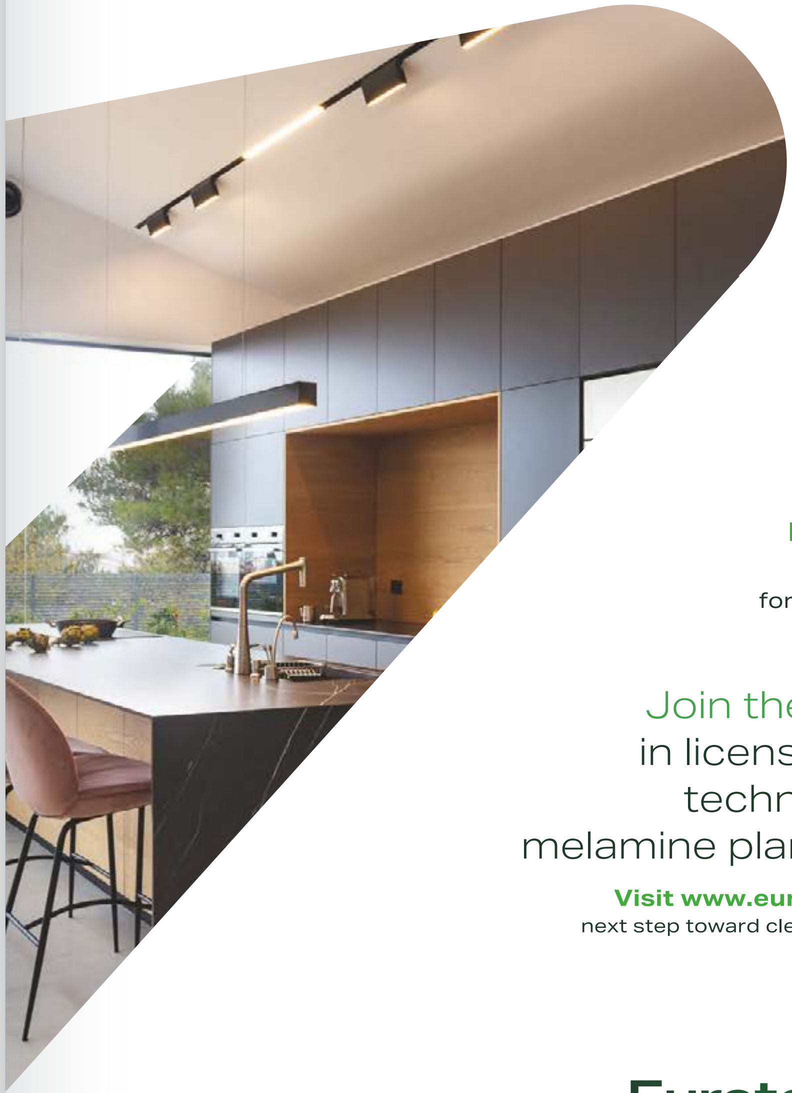
In December, the International Maritime Organisation (IMO) Maritime Safety Committee (MSC) adopted amendments to the International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code) which lifts the existing prohibition on the use of ammonia cargo as fuel as from July 1st 2026, establishing a regulatory pathway for future ammonia carrier operation using ammonia fuel, and a "voluntary early implementation provision" can allow for its use before that if the regulations are followed. In parallel, the interim guidelines provide international safety standards for using ammonia as fuel; the International Code of Safety for Ships using Gases or other Low-flashpoint Fuels (IGF code) is amended as from January 1st 2028, which will allow ammonia powered vessels of all kinds. Further regulatory support for alternative marine fuels is anticipated through upcoming discussions at the Maritime Safety Committee in June this year, which aims to advance policies accommodating emerging fuel types.

The EU has extended its emissions trading system (ETS) to cover maritime transport, which accounts for approximately 3-4% of the EU's total CO_2 emissions. Shipping companies must surrender allowances for 40% of 2024 emissions in 2025, 70% in 2026, and 100% from 2027 onwards. Alongside this, the FuelEU Maritime regulations introduce specific compliance obligations for ship operators by setting mandatory reduction targets and supporting the uptake of low-carbon maritime fuels, such as ammonia. Those who fail to meet the emissions requirements may incur a penalty of €2,400/t of VLSFO-equivalent energy for any emissions shortfall. In particular it encourages the use of "renewable fuels of non-biological origin" (RNFBO), such as low carbon methanol or ammonia, and will impose a 2% mandatory use of such in the 2030s if uptake has been insufficient.

Changes to the IMO's IGC and IGF codes were crucial to ammonia's adoption as a marine fuel, but it still faces challenges in terms of cost, safety, and NOx-related challenges which must be addressed before widespread adoption. Energy density is lower than for conventional fuels, and while ammonia is a carbon-free fuel, its combustion in marine engines can still produce NOx emissions. To manage these, selective catalytic reduction (SCR) technology is being integrated as a standard emissions control solution in ammonia-fuelled engine designs. Major engine manufacturers have demonstrated that SCR systems can achieve over 90% reduction in nitrogen oxides, enabling compliance with IMO Tier III regulations without compromising engine performance.

At the moment shipowners are still looking towards LNG and possibly biogas as a transition fuel, with ammonia a longer term prospect. But adoption is anticipated to increase steadily, supported by stricter emissions regulations, decreasing ammonia production costs and higher carbon prices. In the medium term, ammonia-ready vessels are expected to represent a greater share of newbuild capacity, as it gives greater flexibility and help shipowners hedge against future transitions. Over time, the uptake of ammonia-fuelled ships is anticipated to surpass ammonia-ready vessels as the preferred choice for newbuilds. Within a decade, CRU anticipates ammonia use for ships will have reached 10 million t/a, and could be as high as 70 million t/a by 2050. Around 4.8 million t/a of green and 4.7 million t/a of blue ammonia capacity is expected to be on-stream by 2030, with China having already approved 1.6 million t/a of green ammonia capacity. Ammonia's cousin methanol has had some setbacks of late in its quest to be the next major shipping fuel, as our article on pages 26-28 indicates, but there seems to be a willingness by ship owners and operators to overcome this and push on with adoption as well.. ■

Richard Hands, Editor



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Price Trends

In mid-April, Ammonia prices both east and west of Suez remained firmly oriented to the downside, with supply still heavily outweighing demand and suppliers scrambling to place excess tonnage. Bearish market sentiment was exemplified by a Trammo sale to OCP at $415/t c.fr Morocco, $20/t short of Tampa's c.fr settlement for April and around $44/t down on February.

Across the Atlantic, exports continue from the US Gulf, where prices are now suggested below $400/t f.o.b. and possibly as low as $350/t, amid healthy availability from regional suppliers. Suggestions that the 1.3 million t/a Gulf Coast Ammonia facility in Texas, which loaded its first export cargo in March, is facing further production hiccups, are yet to be confirmed.

East of Suez, Ma'aden announced that it would be taking its 1.1 million t/a No.1 unit offline for seven weeks as of early May, likely removing around 120,000 tonnes of output from the market, though observers see the curtailment as having little impact on Middle East fundamentals. In Iran, PPC tendered for and sold around 23,000 tonnes of material in the $250s/t f.o.b. range, to be split between Turkey and India. Import demand from the latter remains lacklustre. Mitsui is shipping a Kaltim cargo from Indonesia to the Americas, demonstrating the ongoing length seen in Southeast Asia and poor demand from nearby markets. Industrial appetite from the Far East remains limited, with contract prices in South Korea and Taiwan, China steadily slipping closer towards the $300/t c.fr mark.

In urea markets, India is still believed to be in need of 1.5 million tonnes of urea, and with spot interest emerging from Australia, suppliers see this as an opportunity to gain ground. It remains unclear if IPL will secure anywhere close to the tonnage it required with just short of 400,000 tonnes so far accepted from the initial low bids and counters. The Middle East saw a netback of $370-380/t f.o.b. for the Indian tender with the east coast counter offering a much higher return than the west. When Australian interest emerged for end April/May, an opportunity arose to push the spot price back towards the $390/t f.o.b. secured earlier by Sabic. Fertiglobe is the supplier said to be behind the latest sale to Australia which traded at $387-389/t.

European prices have risen in France and Italy although the latter appears to have quite a line up of ships heading its way. With the market running way behind however and Yara failing as yet to fire up its Ferrara plant, the tonnes could be quickly absorbed and prices maintained. Algeria looked set to see the US market cut off with the very high duty of 32% set last week in the Trump Tariffs. However the tariff debacle continues and this has now been pushed back to 10%. NOLA prices unsurprisingly have been volatile as the tariffs come and go. As high as $425/st has been secured for 1H April but further forward prices slipped below $400/st. Upriver barges could command quite a premium with a two week delay in securing transport to move loaded barges out of NOLA. ■

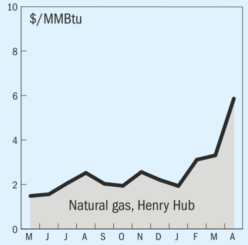
Table 1: **Price indications**

Cash equivalent	**mid-Apr**	**mid-Feb**	**mid-Dec**	**mid-Oct**
Ammonia ($/t)				
f.o.b. Black Sea	n.m.	n.m.	n.m.	n.m.
f.o.b. Caribbean	395	460	530	520
f.o.b. Arab Gulf	270-305	330-360	350-430	350-430
c.fr N.W. Europe	470-520	550-600	610-620	600-610
Urea ($/t)				
f.o.b. bulk Black Sea	350-355	385-395	305-320	320-330
f.o.b. bulk Arab Gulf*	345-389	402-445	319-358	350-370
f.o.b. NOLA barge (metric tonnes)	300-315	402-418	326-338	330-339
f.o.b. bagged China	n.m.	n.m.	n.m.	253-261
DAP ($/t)				
f.o.b. bulk US Gulf	628-640	588-595	n.m.	550-570
UAN (€/tonne)				
f.o.t. ex-tank Rouen, 30%N	340-345	330	278-280	265-270

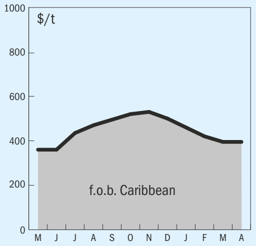
*Notes: n.a. price not available at time of going to press. n.m. no market. * high-end granular.*

END OF MONTH SPOT PRICES

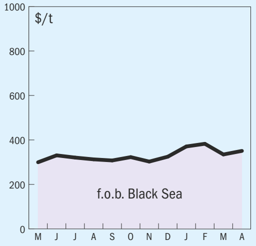
natural gas



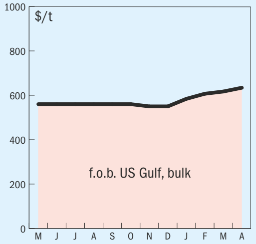
ammonia



urea

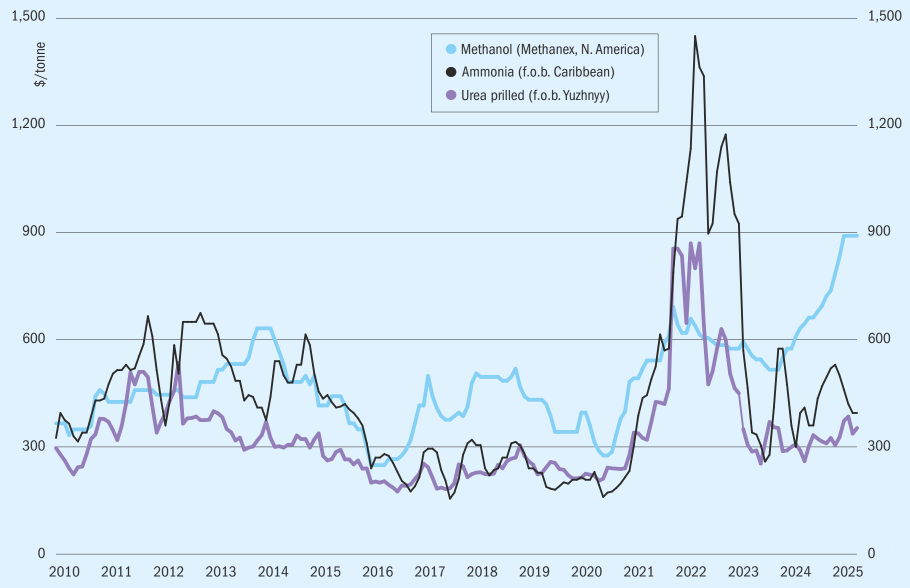


diammonium phosphate



Market Outlook

Historical price trends $/tonne



Source: BCInsight

AMMONIA

- Continuing oversupply means that ammonia prices should continue to come under pressure moving into 2H April, though it remains to be seen just how much further values in Asia can decline before producers begin to shutter output.
- Conversely, questions remain as to how much of an upside impact US 10% tariffs will have on imports of Trinidadian ammonia for the next Tampa settlement.
- The seven week Ma'aden turnaround announced for May-June should also help to put a floor under ammonia prices out of the Arab Gulf.
- The netback to the Caribbean will be adjusted down $43.50/t this week to $351.50/t FOB, taking into account the 10% US tariff on imports from Trinidad. Mosaic and Yara are understood not to have agreed a way forward yet for the Tampa contract in May and the Caribbean export price is calculated on Tampa at $435/t CFR less the 10% tariff and assuming a $40/t freight.

UREA

- The meltdown in global financial markets unleashed by the US last week showed few signs of abating. Even as President Trump paused his "reciprocal tariffs" for 90 days, and cut them all back to 10%, he ramped up the pressure on China. All fertilizer producers that export urea to the US will now face a baseline 10% rate, excluding Canada, Mexico and Russia.
- Amid the turmoil, India held its first urea tender for nearly two months and had secured less than a third of its stated aim of 1.5 million t/a at the time of writing. The very short term could therefore see urea prices stabilise, as India may well have to tender again. Not all benchmarks may increase, however, as fading interest in Europe could take its toll on Algeria and Egypt.

METHANOL

- Methanex, the world's largest producer and supplier of methanol, maintained its Asian contract price (ACP) for April 2025 unchanged at $420/t, with China $20/t lower at $400/t.
- There are concerns that US tariffs on China, the major importer of methanol, may lead to slower demand growth in industrial sectors. Chinese MTO demand also appears to be falling, with lower operating rates and delays to new capacity. The tariffs may also lead to lower methanol demand in the US as spending slows.
- Falling oil prices due to concerns about recession will also likely play on methanol markets, bringing prices lower.
- This, taken together with some new capacity in Iran and the US, means that the outlook for the short to medium term is for lower prices for both Atlantic and Pacific methanol. ■

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Nitrogen Industry News

PARAGUAY

EPC contract awarded for green fertilizer project

ATOME says that it has signed a $465 million fixed-price, lump-sum engineering, procurement and construction contract with Casale for its 260,000 t/a green fertiliser plant at Villeta, Paraguay. ATOME believes that this is the first dedicated green fertiliser facility of this scale worldwide. The plant will use 100% renewable baseload power to generate hydrogen for ammonia to supply low carbon fertilizer for the Mercosur region. The project timeline is 38 months, with start-up and first ammonia production expected in 2028. Casale joins Yara, Hy24, AECOM, Natixis, IDB Invest and ANDE as partners to the project. In March ATOME signed non-binding heads of terms with Hy24's managed Clean H2 Infra Fund for an up to $115 million investment in the project. A full definitive equity agreement is expected in Q2 2025, with final investment decision and full financial closure targeted by the end of the quarter. The full terms envisage a total funding for the project of approximately $625 million which includes not only the cost of construction but also financing, interest, transaction and supervision costs during the build period, with at least 60% coming from debt finance with the balance represented by project equity. ATOME says that negotiations on the definitive full offtake agreement with Yara International are "proceeding well", with senior Yara representatives having had a successful visit to Paraguay at the end of January. It is anticipated that the definitive agreement will be signed by early Q2 2025, subject to necessary approvals.

Olivier Mussat, CEO of ATOME, commented: "ATOME is delighted to announce the signing of our EPC Contract with Casale, on time and on track to our project schedule. This underscores our ability to deliver final agreements and marks another milestone achieved as we advance to reach FID for the Villeta Project towards the end of H1 2025. Casale is a world leader in ammonia and fertiliser engineering, and I have every confidence in the team as the right partners to deliver our flagship project in Paraguay, the first green fertiliser facility of its kind."

Federico Zardi, CEO of Casale, commented: "We at Casale are immensely proud to be an integral part of ATOME's world-first green fertiliser Villeta project in Paraguay. For over a decade, Casale has been advancing the development of CO_2 emissions-reduction technologies in fertiliser production. Through these technological advancements, we are delivering an extremely optimised design at Villeta, setting a precedent for sustainable fertiliser production at costs that are competitive with, or even lower than, conventional 'grey' fertilisers, paving the way to a sustainable agricultural future." ■

INDIA

Contract awarded for new nitric acid plant

thyssenkrupp Uhde has been awarded a contract by Gujarat Narmada Valley Fertilizers & Chemicals Ltd. (GNFC) for the construction of a weak nitric acid plant in Bharuch, Gujarat state. The scope of work includes license, basic engineering, detailed engineering, procurement, construction, commissioning, and start-up services. The plant will have a capacity of 600 t/d of weak nitric acid, and will use Uhde's proven EnviNOx® technology to reduce greenhouse gas emissions by eliminating nitrogen oxides from nitric acid production. This will be the third weak nitric acid plant licensed by Uhde to GNFC's Bharuch site, in a partnership going back more than three decades.

Dr. T. Natarajan, managing director of GNFC said: "We are delighted to further strengthen our market presence for Weak Nitric Acid in India by installation of new plant based on thyssenkrupp Uhde technology. At present, we are operating two nitric acid plants licensed by thyssenkrupp Uhde. The third plant will enhance the capacity and fulfil the [Indian government's] 'Make in India Campaign' with a commitment to environment conservation."

The project will be carried out by thyssenkrupp Uhde's local subsidiary in India, a leading EPC and engineering consultancy offering solutions across different sectors such as petrochemicals and refining, fertilizers, cryogenic storage and more, which has executed more than 850 projects in the past four decades.

CHINA

Order for ammonia powered gas carriers

Alfa Laval says that its ammonia fuel supply system, FCM Ammonia, will be installed in seven LPG/ammonia carriers for Tianjin Southwest Maritime (TSM). The installation will commence with three 25,000m3 vessels, followed by four 41,000m3 vessels. The first FCM Ammonia unit for TSM is scheduled for delivery at the end of 2025. The contract follows extensive testing and development conducted in close collaboration with Swiss engine designer WinGD at its Engine & Research Innovation Centre (ERIC) in Winterthur, Switzerland. Alfa Laval says that the research and development project with WinGD has laid a strong foundation for FCM Ammonia's commercial adoption, as evidenced by K Shipbuilding receiving approval in principle in December 2024 dfrom the American Bureau of Shipping for the design of an ammonia dual-fuel MR1 tanker. Alfa Laval contributed to the design of the entire fuel system, including the ammonia fuel supply system, fuel valves train, and vent treatment system, as well as an Aalborg ammonia dual-fuel boiler system.

"Through research, product development, and strategic partnerships, we are building the solutions needed for a safe and efficient transition to low-carbon alternative fuels," said Peter Sahlen, Head of Marine Separation, Fuel Supply System & Heat Transfer, Alfa Laval. "Our deep experience with fuels like methanol and LPG has given us a head start with ammonia, and this first contract validates our commitment to driving decarbonization in shipping with reliable and innovative solutions."

"Collaborating with trusted partners such as Alfa Laval has been instrumental in bringing these new clean-fuel technologies to market, making ammonia-powered shipping a reality. This partnership, along with our joint R&D efforts, underscores our shared commitment to the clean energy transition to enable a sustainable future for shipping," said Sebastian Hensel, Vice President, Research & Development, WinGD.

JAPAN

Ammonia ship completes demonstration voyage

Japan's New Energy and Industrial Technology Development Organization (NEDO) says that the world's first commercial-use ammonia-fuelled vessel, Sakigake, has successfully completed a three-month demonstration voyage, during which the vessel engaged in tugboat operations in Tokyo Bay, while achieving greenhouse gas (GHG) emission reductions of up to 95%. The vessel was completed by Nippon Yusen Kabushiki Kaisha (NYK) and IHI Power Systems in August 2024, in cooperation with Nippon Kaiji Kyokai (ClassNK) as part of a Green Innovation Fund Project. NEDO says that the vessel will continue to be used for tugboat operations in Tokyo Bay, and the organisation will continue to promote research and development of next-generation fuel vessels, including developing an ammonia-fuelled ammonia gas carrier, in conjunction with NYK, Japan Engine Corporation, IPS, and Nippon Shipyard. This vessel is scheduled to be delivered in November 2026.

CANADA

Green ammonia plant submitted for environmental approval

Hy2gen says that it has submitted its Courant renewable ammonia project to Quebec's Minister of the Environment, marking the end of the planning stage. The Ministry will now define an impact study that Hy2gen must carry out to ensure that the project meets safety and environmental impact requirements. Project Courant aims to produce 230,000 t/a of low carbon ammonia for the local mining industry and region around Baie-Comeau, Quebec, using 300 MW of electrolyser capacity to generate renewable hydrogen in what Hy2gen says will be one of the largest renewable ammonia projects in North America. The plant is due to become operational in 2030.

EUROPEAN UNION

EC starts tracking of industrial chemicals

The European Commission (EC) says it has begun tracking European imports of certain ethylene and ammonia products, to allow it to react quickly to level the playing field if the monitoring points to a surge of imports causing or threatening to cause injury to the EU industry. This surveillance has been put in place in response to evidence of a significant and potentially injurious increase in the EU market share of imports of the chemicals. It covers imports of copolymers of ethylene and alpha olefin, urea containing more than 45% (by weight) of nitrogen, and ammonium sulphate from all countries, and should remain in place for a period of three years.

The EC is also considering tariffs on Russian fertilizer imports into the EU, including via Belarus, with a vote in the Trade Committee expected in May, followed by a vote in the European Parliament in June before final approval by the European Council. The tariffs on nitrogen-based fertilisers would increase over a transition period of three years and aim to support EU domestic production of fertiliser. EU production reached only 14 million t/a in 2023, down from an average of 18 million t/a in the previous 5 years.

UNITED STATES

Deferral for green ammonia project

Hydrogen Insight reports that Atlas Agro, which has been developing a $1.5 billion green fertilizer project in Washington state, has deferred a final investment decision on the project due to uncertainties resulting from the Trump administration's tariffs, particularly on steel and key equipment items such as solar panels and batteries. The FID had been planned for early 2025.

CF Industries in blue ammonia JV with JERA and Mitsui

CF Industries has formed a joint venture with JERA, Japan's largest energy company, and Mitsui & Co, a leading global investment and trading company, for the construction, production and offtake of low-carbon ammonia. CF Industries will hold 40% ownership in the new company, JERA 35%, and Mitsui 25%. The joint venture will construct at CF Industries' Blue Point Complex in Louisiana an autothermal reforming ammonia production facility with a carbon dioxide dehydration and compression unit at the site to prepare captured CO_2 for transportation and sequestration. The estimated cost for the ammonia production facility is approximately $4 billion, and the plant will have an annual nameplate capacity of approximately 1.4 million t/a, making it the largest single train ammonia plant in the world. Pre-construction activities and engineering evaluations will begin in 2025 at CF Industries' Blue Point Complex in Ascension Parish, Louisiana. Construction of the ammonia production facility is expected to begin in 2026, with low-carbon ammonia production expected in 2029.

CF Industries will build and operate scalable infrastructure at the Blue Point site to supply the ammonia production facility with services, including product storage and loading, and will be responsible for the operation and maintenance of the ammonia production facility. Product offtake will be handled independently by the three companies according to their ownership percentage. 1PointFive, a carbon capture, utilisation, and sequestration (CCUS) company and subsidiary of Occidental will transport and sequester approximately 2.3 million metric t/a of CO_2 annually at 1PointFive's Pelican Sequestration Hub in Louisiana.

"CF Industries is proud to partner with global leaders JERA and Mitsui to build the leading low-carbon ammonia production facility in the world," said Tony Will, president and chief executive officer, CF Industries Holdings, Inc. "Our joint venture represents tangible progress towards building a reliable and affordable low-carbon ammonia value chain to meet what we expect to be robust global demand for low-carbon ammonia for both traditional and new applications."

LITHUANIA

Achema to suspend ammonia production

Achema says that it plans to "temporarily" suspend ammonia production at its site at Jonava from May 15th, due to the volatility of natural gas prices and competition from cheaper foreign imports. It currently plans to resume production in 3Q 2025. The facility has been operating at reduced capacity since 2021, and Lithuanian lawmakers have discussed converting the site to explosive grade ammonium nitrate production as part of a European rearmament programme.

In a press statement, Achema CEO Audronė Kuskytė said: "Third-country producers competing with European producers have a significant advantage - access to cheap natural gas resources, do not have to comply with strict environmental requirements and pay for emission permits. Imports have increased several times, because the European market is

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currently attractive to both African and Russian producers, who manage to earn large profits here. For European producers, working according to the European TTF gas price index and paying additionally for CO_2 emissions, production costs are significantly higher. We see that one after another, large European producers are reducing their ammonia production capacities, replacing them with imported products."

KAZAKHSTAN

New ammonia-urea complex

The Kazakh government has approved the construction of a new ammonia and urea plant in the country's Mangistau region, on the eastern shore of the Caspian Sea. Construction will be carried out by a joint venture between QazaqGaz National Company and ESTA Construction under Qazesta Fertilizers Ltd. The total investment for the project is $1.35 billion, with construction expected to be completed within three and a half years. The plant's annual production capacity is projected to reach up to 700,000 t/a of urea and 420,000 t/a of ammonia, adding value to the country's natural gas production and helping to substitute domestic production for foreign imports of nitrogen fertilizer. Despite a national demand of 3.2 million t/a, domestic production currently only meets about half of that need.

INDIA

Japanese investment interest in renewable ammonia project

Six Japanese companies have agreed to explore investment opportunities for a large-scale green ammonia plant in Odisha, India, being planned by Acme Group. Last year, IHI Corporation agreed to import up to 400,000 t/a from Acme's project. IHI has now signed a memorandum of understanding with Hokkaido Electric Power, Mitsubishi Gas Chemical Company, Mitsui OSK Lines (MOL), Mizuho Bank, and Tokyo Century Corporate. The partners plan to create a special-purpose company for ammonia production and investment participation. Hokkaido Electric is testing ammonia co-firing at its coal-fired power plant and studying infrastructure needs, while Mitsubishi Gas Chemical wants to decarbonise its ammonia use. Mizuho Bank is planning to invest up to $13 billion in hydrogen and ammonia supply chains by 2030, and Tokyo Century is exploring green ammonia as part of its shift beyond solar to support carbon neutrality.


PHOTO: ACHEMA

Achema's fertilizer plant, Lithuania

BRAZIL

Land secured for green ammonia plant

The Port of Açu and renewable fuels company Sempen have signed a contract to reserve an area in the low-carbon hydrogen hub at the port, in the north of the state of Rio de Janeiro, for the construction of a green ammonia plant. The projected facility would have a production capacity of 1 million t/a of green ammonia. A final investment decision (FID) is expected for 2027-2028, with production of the first green ammonia beginning in 2030.

"The partnership with Porto do Açu represents an important milestone in our journey to boost the production of green ammonia and sustainable fuels in Brazil. We are excited about the potential to contribute to the global energy transition and to be part of a strategic low-carbon hub that will support the sustainable development of the renewable energy and green hydrogen industry in the country." – Juan Pablo Freijo, CEO of Sempen.

NORWAY

Offtake deal for Barents Blue project

Horisont Energi says that it has secured a non-binding offtake deal with "a European energy group" for ammonia sales from its Barents Blue clean ammonia plant at Markoppnes in northern Norway. Sales and purchase agreements are targeted for completion in 2026. Horisont is pressing ahead with the 1 million t/a project in spite of the withdrawal of project partner Fertiberia, and the exit of Polish company Orlen from a related CCS project. Front end engineering and design work has not yet been completed, but the project has been working on commercial agreements for the supply of gas, offtake of clean ammonia and storage of CO_2. Carbon capture is projected to be above 99%, and it is expected to be the most energy-efficient clean ammonia plant in the world. Barents Blue is supported by a $48 million grant as part of the EU IPCEI hydrogen program, Hy2Use. The project is targeting a final investment decision (FID) in 2026 and estimated production start in 2029/2030.

BRUNEI

Sustainability and digital services for Brunei Fertilizer Industries

thyssenkrupp Uhde has signed a 5-year framework service agreement with Brunei Fertilizer Industries, aimed at advancing digitalisation and implementing clean technologies in the fertilizer industry. Central to these efforts is the set-up and implementation of a digital twin, which will provide a virtual representation of the plant to enable real-time monitoring, predictive maintenance, and data-driven decision-making. This technology, together with specialized trainings, will allow BFI to enhance operational safety, reduce downtime, and achieve greater energy efficiency.

In addition to that, Uhde says that it will evaluate opportunities to reduce the carbon footprint of a potential second BFI fertilizer complex, ensuring that operations meet the highest environmental standards. This includes evaluating the feasibility of expanding into sustainable ammonia production such as incorporating blue ammonia by adding carbon capture technologies, and green ammonia derived from renewable energy sources.

Brunei Fertilizer Industries commented: "This agreement is a testament to the excellent cooperation between BFI and thyssenkrupp Uhde. Together, we are committed to driving innovation and sustainability in the fertilizer industry. The development of a digital twin and the exploration of low-emission ammonia projects are key steps towards achieving our environmental objectives." BFI's CEO, Dr. Harri Kiiski added: "Reducing our environmental impact is at the core of our efforts, particularly in improving the carbon footprint of our products. We are identifying strategies to cut emissions during production and transportation. With one of the most advanced plants globally, we inherently operate at a lower carbon footprint than older facilities, which typically average 50 years in operation."

Nadja Håkansson, CEO of thyssenkrupp Uhde, commented: "We are proud to support BFI in its ambitious journey towards innovation and sustainability. By leveraging our technology and implementation expertise, we create lasting value for our customer and set new standards in operational excellence."

The BFI plant was built by thyssenkrupp Uhde as a fully integrated fertilizer complex, and comprises an ammonia plant with a capacity of 2,200 t/d as well as a urea plant and a urea granulation plant, both with a capacity of 3,900 t/d.

CHILE

Green ammonia project 'paused'

Spanish company Ignis has decided to pause work on the renewable energy generation projects it had planned in Chile's Magallanes region. In a press statement, Ignis said that: "even though we firmly believe that this industry will develop and mature, the company is considering a longer time frame than initially planned and a reduction in the project to adapt it to this new reality." The company was developing a wind farm to supply the green ammonia plant with hydrogen, but reportedly found the process of leasing the land area to build the turbines slower and more difficult than it had hoped. ■

OBITUARY

Umberto Zardi

It is with great sadness that we report the death of Dr. Umberto Zardi, who passed away on March 17th 2025 at his home in Breganzona, Lugano, Switzerland. Dr Zardi was an innovator in the nitrogen industry and for many years the president and driving force behind Ammonia Casale, now simply Casale SA, becoming responsible for its revival and transformation into the global engineering and technology giant that it is today.

Born in Bologna in 1929, Umberto Zardi graduated in mechanical engineering, before beginning his career with Montecatini in Milan in 1954 to handle the development, engineering and marketing of urea technology as part of the company's inorganic division. For a decade he worked in research and technological development there, before moving in 1964 to Snamprogetti, where he successfully developed the total recycle stripping technology for the urea process, helping to make Snamprogetti one of the largest licensees for urea in the world.

He remained head of the company's inorganic engineering division until 1978 when, together with former Snamprogetti CEO Francesco Salimbeni, he was part of the refinancing of Ammonia Casale after its purchase by Salimbeni's new Ingeco Group, and put in charge of the company's revitalisation. Luigi Casale had been one of the pioneers of ammonia technology back in the 1920s, developing his own high pressure variant on the Haber-Bosch process in 1920, and in 1921 he founded Ammonia Casale at Lugano in Switzerland. The company had been very successful in ammonia licensing, with 120 plants built using its technology, but Luigi Casale had died an untimely death in 1927 and after the war the company had drifted with a lack of investment and had seen its lead overtaken by the newer higher capacity plants using the Kellogg ammonia process.

Zardi surrounded himself with a group of nearly two dozen talented young engineers and specialists in ammonia and fertilizer technology at Via della Posta no.4 in Lugano, and together with "the boys of Via della Posta", he formed the core of a revival in the company based on a renewed focus on technological development. In 1983 Casale patented its axial-radial flow reactor, which became a key offering, with more than 250 reactors of this type eventually built all over the world. Zardi and his group pushed hard at innovating across a range of related technologies, eventually forming Urea Casale in 1991, Methanol Casale in 1994 and Casale Chemicals in 1995, all eventually consolidated into Casale SA in 2014, which continues to promote the modernisation and construction of new plants, as licensee, designer, and builder, branching into nitric acid, NPKs, melamine and, via its 2014 acquisition of Chemoprojekt AS, engineering, procurement and construction contracting.

Following the success of the axial-radial flow reactor, Casale, Zardi and collaborator Giorgio Pagani filed numerous industrial patents, including 27 for ammonia and 18 for urea. Even after his formal retirement, Zardi still held the position of honorary president of Casale SA, and was frequently seen in the company's offices, an example to and stimulus for all Casale personnel.

Speaking from personal experience, he was also a highly personable and generous man, and I can only echo the sentiments expressed in Casale's own obituary of Dr Zardi, that: "Umberto Zardi's qualities of inventiveness, passion, business acumen, and tenacity were profound, yet it was his generosity and ethical standards that truly distinguished him. His commitment to innovation and quality has set new standards, driving us toward a more sustainable and efficient future. He was a beacon for many, and his teachings continue to inspire our corporate identity. The values he instilled- integrity, perseverance, excellence, and innovation - are the pillars upon which we stand to meet future challenges. His legacy is furthered by the leadership of his son, Federico Zardi, the current CEO of Casale, who continues to guide our company with the same passion and vision." ■

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Syngas News

MEXICO

NextChem to supply technology for low carbon methanol plant

NextChem subsidiary KT Tech has been awarded a licensing contract for the implementation of NextChem's proprietary NX AdWinMethanol® Zero technology for Pacifico Mexinol, an ultra-low carbon methanol facility near Los Mochis, Sinaloa, on the Pacific coast of Mexico, which will have a planned output in excess of 2.1 million t/a. Transition Industries LLC, based in Houston, Texas, is developing Pacifico Mexinol with the International Finance Corporation (IFC), a member of the World Bank Group. When it initiates operation in 2028, Pacifico Mexinol is expected to be the largest single ultra-low carbon methanol facility in the world – producing approximately 350,000 t/a of green methanol and 1.8 million t/a of blue methanol annually from natural gas with carbon capture.The value of the licensing award is in the low tens of million euros, with the whole package estimated to be about €250 million, including basic engineering, proprietary and critical equipment supply, as well as assistance to commissioning, start-up and operation of the facility.

NX AdWinMethanol® Zero technology has been developed by GasConTec, NextChem's subsidiary dedicated to low-carbon hydrogen and methanol solutions, and integrates a proprietary autothermal reforming (ATR) process and methanol synthesis loop and proprietary CO_2 capture technologies. It further minimises carbon emissions to nearly zero by converting captured CO_2 and green hydrogen into ultra-low-carbon methanol. This approach increases the sustainability of the methanol production process, reflecting Pacifico Mexinol's commitment to addressing climate change. Rommel Gallo, Chief Executive Officer of Transition Industries, commented: "We are pleased to enter into this strategic relationship with NextChem and implement a world-class technology for the largest ultra-low carbon methanol facility in the world. We look forward to working together with NextChem to accelerate and lead the decarbonisation of the global methanol and chemicals sectors." ■

GERMANY

Mabanaft and HIF Global to accelerate methanol adoption in the shipping industry

Energy company Mabanaft and HIF Global have signed a heads of agreement for the offtake of e-methanol from, HIF's planned e-Fuels facilities, reinforcing their commitment to advancing carbon-reducing fuels for the shipping industry. The initial offtake would be of up to 100,000 t/a of e-methanol produced from renewable electricity and captured CO_2 per year. As HIF Global moves forward with the development of its e-Fuels facilities, Mabanaft says that it will further explore demand for different methanol applications jointly with its customers.

Volker Ebeling, Senior Vice President New Energy, Supply & Infrastructure at Mabanaft said: "We strongly believe in the potential of e-methanol as a key enabler of the energy transition, and we are proud to deepen our partnership with HIF Global. This agreement is a further step forward in providing our shipping customers with a viable, alternative fuel. In parallel we are now in the process of making methanol storage available at our Hamburg tank terminal and possibly further global locations. Our combined efforts help bridging the gap towards a broader adoption of methanol in the maritime sector."

Diego Fettweis, Chief Commercial Officer of HIF Global, stated, "Today we take another step in leading the e-Fuels industry, joining forces to break into a key market: shipping. Drop-in fuels can make a relevant difference ensuring a secure energy supply while leveraging existing infrastructure."

HIF has a pilot green methanol facility at its HIF Haru Oni e-Fuels facility in southern Chile and is developing commercial-scale e-Fuels facilities in the United States, Uruguay, Australia, and Chile.

DENMARK

Start-up for green methanol plant

Clariant says that its MegaMax 900 methanol synthesis catalyst has been used in the successful startup of European Energy's green methanol plant at Kasso, Denmark. The facility uses biogenic CO_2 and green hydrogen to produce up to 42,000 t/a of green methanol. Clariant's Applied Catalyst Technology (ACT) technical service team provided on-site support throughout the startup procedure, overseeing the catalyst loading, reduction, and startup. Clariant says that the catalyst is operating with excellent activity and stability despite the challenging conditions of CO_2-to-methanol conversion.

Georg Anfang, Vice President Syngas and Fuels at Clariant Catalysts, commented, "We are excited about the successful startup of European Energy's pioneering e-methanol plant. The project is an important milestone in deploying and upscaling green methanol production and we are proud that our catalysts are already producing sustainable methanol at commercial scale. At Clariant, we are committed to catalysing the energy transition – not only tomorrow but starting today."

Anders Brendstrup, Vice President at European Energy, added, "We are thrilled to have produced one of the world's first e-methanol at our Kasso facility. This is a pivotal moment on the journey that started four years ago. We thank Clariant not only for providing their high-performance methanol synthesis catalyst but especially for their comprehensive on-site support. We look forward to continuing this successful partnership in future projects."

European Energy was founded in 2004 with the goal of driving the green transition and developing sustainable, fossil-free energy solutions. The multinational company has major investments in solar and wind energy projects, as well as Power-to-X and carbon capture technologies.

SPAIN

Design contract for new methanol plant

Tecnicas Reunidas and Siemens Energy have been awarded the contract to carry out front-end engineering design (FEED) for a major green methanol project in La Robla, Spain. The consortium will work on the project for Spanish developer Reolum, part of a partnership that says it is building the largest green methanol plant in Europe. The La Robla Nueva Energia facility will combine biogenic CO_2 from a co-located biomass-based cogeneration plant with green hydrogen to produce 140,000 t/a of low carbon methanol. Tecnicas Reunidas will focus on the biogenic carbon capture and methanol production units, while Siemens Energy will handle the renewable hydrogen unit. Johnson Matthey has been selected to supply its eMERALD methanol technology, while Mitsubishi Heavy Industries will license it CO_2 capture technology for the project.

The methanol and 50MW biomass-based cogeneration form the La Robla Green hub, a broader project led by industrial engineering firm Tresca Ingenieria and investor Incus Capital alongside Reolum. In February the project was awarded euro 180 million ($196 million) in EU funding allocated by the Spanish ministry for ecological transition under the H2 Valles programme.

BASF and Forestal collaborate on green methanol production

BASF and Forestal de Atlántico SA (Forestal) have signed an early disclosure agreement (EDA) aimed at advancing the production of low carbon methanol via carbon capture solutions. Under this strategic partnership, BASF has been selected to share its proprietary OASE® blue technology, designed for the efficient removal of CO_2 from flue gases, for use in Forestal's Triskelion project in Galicia, Spain. The Triskelion project has a design capacity of 156 t/d of ethanol production. The CO_2 captured from the exhaust gases of electricity generating turbines will be transformed into methanol by reacting it with renewable hydrogen, highlighting an innovative approach to a more sustainable fuel production.

The agreement paves the way for the front end engineering design (FEED) phase, which will be developed by a third-party contractor hired by Forestal. This will enable Forestal to assess the project's clarity, vision, technical feasibility and economic viability, allowing them to share the design with other contractors for competitive construction bids.

"This partnership addresses the critical need for innovative solutions in carbon capture and utilization, marking a significant stride towards reducing global emissions," said Torsten Katz, Global Business Director, OASE Gas Treating Technologies, in BASF's Intermediates division. "By collaborating with Forestal, we are setting the foundation for one of the first plants to produce e-methanol using our OASE technology, entering into an innovative sustainable application area for our OASE blue technology."

"By utilizing CO_2 captured from our production processes, we are embracing a more sustainable approach to fuel production," stated Andrés Fuentes, CEO of Forestal del Atlántico. "This partnership with BASF not only enhances our capabilities but also contributes to the development of sustainable fuels, particularly in the maritime industry."

UNITED KINGDOM

Hybrid hydrogen-diesel retrofits for greener shipping

lomarlabs, the innovation arm of Lomar Shipping, has announced a strategic collaboration with Newlight, a technology company specialising in hybrid hydrogen-diesel engine retrofits, to accelerate the adoption of cost-effective, lower-emission solutions for the shipping industry. This collaboration will focus on retrofitting conventional diesel engines to operate on a hydrogen-diesel mix, reducing fuel consumption on average by 20% and significantly lowering greenhouse gas emissions. Savings of up to 30% have already been demonstrated in workshop trials and this new collaboration will seek to replicate this onboard vessels.

As the maritime sector works toward meeting IMO decarbonisation targets, shipowners are searching for solutions to extend the service lives of their existing vessels and future proof new vessels they build. Newlight claims that its dual-fuel retrofit technology is a low capex solution that enables existing vessels to integrate hydrogen as a cleaner fuel source, improving energy efficiency while maintaining operational flexibility.

Stylianos Papageorgiou, Managing director of lomarlabs commented: "We believe in accelerating progress through energy efficiency improvements, emissions treatment and leveraging clean energy sources, always with a focus on maintaining costs at sensible levels. Newlight's solution fits right into this approach. Decarbonisation isn't about waiting for the perfect fuel; it's about acting now with every viable tool at our disposal. Newlight's dual-fuel retrofit technology promises an immediate, scalable and cost-effective way to reduce fuel consumption and emissions. This is exactly the kind of practical innovation that will bridge the gap between today's operational realities and the long-term vision of a net-zero maritime industry."

"Hydrogen has enormous potential as a maritime fuel, but transitioning entire fleets to pure hydrogen is a long-term challenge. We believe the industry cannot afford to wait. By taking immediate steps with the current fleet, we can decarbonise ship by ship—delivering real impact today," said Haran Cohen Hillel, CEO of Newlight. "By retrofitting existing diesel engines to operate on a hydrogen blend, we provide an immediate, scalable solution that cuts emissions without requiring a complete overhaul of the propulsion systems."

UNITED ARAB EMIRATES

Record-breaking growth in renewable power capacity

Renewable capacity statistics 2025 released by the International Renewable Energy Agency (IRENA) shows a massive increase in renewable power capacity during 2024, reaching 4,448 gigawatts (GW). The 585 GW addition last year indicates that renewables claimed a 92.5% share of the total capacity expansion in power generation, and a record rate of annual growth (15.1%). Even so, progress still falls just short of the 16.6% growth needed to be producing 11.2 terawatts of energy by 2030. Progress also reflects significant geographic disparities. As in previous years, most of the increase occurred in Asia, with the greatest share being contributed by China- almost 64% of the global added capacity. G7 and G20 countries respectively accounted for 14.3% and 90.3% of new capacity in 2024.

IRENA Director-General, Francesco La Camera said: "The continuous growth of renewables we witness each year is evidence that renewables are economically viable and readily deployable. Each year they keep breaking their own expansion records, but we also face the same challenges of great regional disparities and the ticking clock as the 2030 deadline is imminent."

Solar and wind energy continued to expand the most, jointly accounting for 96.6% of all net renewable additions in 2024. Over three-quarters of the capacity expansion was in solar energy which increased by 32.2%, reaching 1,865 GW, followed by wind energy which grew by 11.1%. The large net decommissioning of non-renewable power in some regions has contributed to the upward trend of renewables capacity. However, more needs to be done to reach the goal of tripling renewables capacity by 2030 as per the Paris Agreement. ■

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People


Heather Remley

BASF Corporation has appointed **Heather Remley** as its new president and chief executive officer, effective April 1, 2025. She takes the helm of the North American arm of BASF SE, one of the world's largest chemical companies. Remley has a background in global leadership and operations. Most recently, she was president of BASF's global engineering services division in Ludwigshafen, Germany. Before that, she led the company's North American petrochemicals business as senior vice president in Houston. Since joining BASF in 2016, she has held key positions across the US, China, and Germany.

Prior to her tenure with the company, Remley spent nearly 20 years at Air Products & Chemicals Inc., holding executive roles in industrial gases and global engineering across the U.S. and Asia. Her career has included oversight of commercial operations, manufacturing, and engineering in multiple markets.

"Heather's industry expertise and leadership make her the right person to drive our U.S. business forward," said Anup Kothari, a member of BASF SE's board of executive directors responsible for North America. "She will play a critical role in strengthening our market position while advancing the company's global strategy."

Magnus Krogh Ankarstrand has been appointed executive vice president and Chief Financial Officer at Yara. Ankarstrand has been a member of Yara's Group Executive Board since 2023 as EVP Corporate Development. He has previously held positions as CEO Yara Clean Ammonia, SVP Yara North America, CFO of the Industrial segment and Director of Strategy & Business Development in Yara. **Thor Giæver** has been appointed as acting EVP Corporate Strategy & Business Development until August and will thereafter serve as SVP Strategic Advisor to the CEO. Giæver has served as Yara CFO since 2021.

In other changes at Yara, **Fernanda Lopes Larsen** has been named as EVP Corporate Development. Lopes Larsen has been a member of Yara's Group Executive Board since 2020 in the position of EVP Africa & Asia. Lopes Larsen has held several other senior positions since she joined Yara in 2012. The process to identify Lopes Larsen´s successor as EVP Africa & Asia has been initiated, and during a transition phase Lopes Larsen will retain this responsibility until August 2025. **Hanna Opsahl-Ben Ammar** has been appointed EVP People & External Affairs, Chief of staff. Opsahl-Ben Ammar joined Yara in 2021, and comes from the role as VP CEO Office, working closely with the CEO on corporate affairs, strategic positioning, partnerships and as Company Secretary. Finally, **Solveig Hellebust**, EVP & Chief HR Officer has decided to leave Yara to pursue opportunities outside the company.

"I want to thank Hellebust for her significant effort during a time of volatility and rapid change," said Holsether. "Amidst a volatile business environment, delivering on the strategy with a sharpened focus is our main priority. I am pleased to strengthen the Group Executive Board with Opsahl-Ben Ammar and making use of the extensive experience held by Lopes Larsen and Ankarstrand in new roles that are key to strategy execution."

Joy Archer has been confirmed as CRU's Chief Financial Officer (CFO) from 1 April 2025. Having joined CRU in 2020, Joy has successfully overseen multiple areas at CRU such as Finance, Enterprise Systems and Programme Management (PGMO) teams. Since October 2024 Joy has taken the full remit of global finance, PGMO and customer care functions for the business, working successfully with members of the board and executive committee to drive the company's financial strategy and in particular to partner with the business to achieve this through the newly created Business Partnering Team. ■

Calendar 2025

MAY

12-14

IFA Annual Conference, MONTE CARLO, Monaco
Contact: IFA Conference Service,
Paris, France
Tel: +33 1 53 93 05 00
Email: ifa@fertilizer.org

JUNE

15-18

International Methanol Technology Operators Forum, LONDON, UK
Contact: Polly Murray, Johnson Matthey
Email: polly.murray@matthey.com

SEPTEMBER

8-11

69th AIChE Ammonia Safety Symposium, ATLANTA, Georgia, USA
Contact: Ilia Kileen, AIChE
Tel: +1 800 242 4363
Web: www.aiche.org/ammonia

OCTOBER

12-15

Global Syngas Technologies Conference, SAN DIEGO, California, USA
Contact: Global Syngas Technologies Council,
PO Box 18456, Sugar Land, TX 77496
USA
Tel: +1 713 703 8196
Email: info@globalsyngas.org

13-17

Ammonium Nitrate/Nitric Acid Conference, OMAHA, Nebraska, USA
Contact: Sam Correnti, DynoNobel,
Karl Hohenwarter, Borealis
Email: sam.correnti@am.dynonobel.com,
karl.hohenwarter@borealisgroup.com,
annaconferencehelp@gmail.com
Web: annawebsite.squarespace.com/

JANUARY 2026

26-28

Fertilizer Latino Americano, MIAMI, Florida, USA
Contact: CRU Events
Tel: +44 (0) 20 7903 2444
Email: conferences@crugroup.com

FEBRUARY

10-12

Nitrogen+Syngas Expoconference 2026, BARCELONA, Spain
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Plant Manager+

Problem No. 74 Is green urea really green?

Green urea is urea based on green ammonia produced from renewable power via electrolysers and bio-based carbon dioxide and its colour is the same as normal urea. But in this round table discussion we discuss the possible causes for urea turning a green colour as found by the initiator of this discussion. We will learn that the colour of urea can be reddish or brownish in certain conditions where corrosion rates are high and/or oil fouling is high. But what can cause urea to turn green? ■

Ali Ançaza from Igsas in Turkey kicks off this round table discussion: Our synthesis section was blocked during a 12-hour shutdown. The synthesis section was then drained and emptied. While recycling the urea solution in the urea solution tank via the evaporation section, we noticed that the colour of the solution was green as you can see in the pictures below. I wonder what could be the reason for this? Has anyone experienced such an event?

Mark Brouwer of UreaKnowHow.com in the Netherlands replies and asks a question: As you know, normally the urea melt and product can become reddish after blocking in. Did you analyse for metals (Ni, Cr, Fe, Cu, …) ?

Ali replies: We did the analyses and obtained the following results.
The first sample result: Cu: 0 ppm; Fe: 0 ppm; Ni: 0.9 ppm; Cr: 9.6 ppm, Na: 0.7 ppm; Mo: 0.9 ppm, N: 2.75%.
2nd sample result (after 15 minutes): Cu: 0 ppm, Fe: 0 ppm, Ni: 1.7 ppm, Cr: 17.8 ppm, Na: 1.3 ppm, Mo: 0.74 ppm, N: 4.08%.
3nd sample result (after 30 minutes): Cu: 0 ppm, Fe: 0 ppm, Ni: 3.1 ppm, Cr: 28 ppm, Na: 2.3 ppm, Mo: 1.24 ppm.

Mark responds: What are the normal Ni levels? In case you see a rising trend of nickel (days) you are experiencing active corrosion. The next step is take more samples upstream and see where the delta-Ni over an equipment item or section is rising. Then shut down and inspect that equipment/section.

Rama Raghava Kumar Kotti, freelance operations consultant and expert of UreaKnowHow.com joins the discussion: To further investigate this incident, I'd like to clarify a few points:

- Sampling procedure: Were the samples taken sequentially during the draining process of the synthesis section, or were they collected after the draining was complete and the tank level stabilised?
- Off-spec urea recycling: Are you recycling any off-spec urea into the system? If so, what are the known contaminants in this off-spec urea?
- Urea storage tank cleaning: When was the last time the urea storage tank was cleaned? Prolonged periods without cleaning can lead to the accumulation of impurities.
- Other tank draining: During the 12-hour shutdown, were any other tanks, such as the ammonia receiver or carbonate solution tank, drained alongside the synthesis section?
- CO_2 removal section: Could potential carbon components or byproducts from the CO_2 removal section in the ammonia plant be contributing to the green coloration?
- Equipment inspection: If you have already inspected the relevant equipment, could you please share the findings?

Ali replies: We had a stop for about one month. During this stop, all synthesis lines were technically checked by Stamicarbon. The urea solution tank was completely emptied and cleaned. We put the system back into operation. Stripper, rectifying column (left picture below) and melt urea pump (right picture below) samples were taken from the first solution coming from the synthesis. We observed a visible green solution. We took samples and analysed them. Chromium nickel values were high. After about two hours, the colour of the solution started to return to normal. Analysis values also started to return to normal. The system is still working. Ni values continue to be around 0.5 to 0.6 ppm.

Mark suggests a possible cause: I think the green colour is a result of the larger amounts of chromium oxides, which seem to have a green-blue colour according to the following: "The

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prevalence of chromium oxides resulted in greenish or bluish shades, whereas iron oxides' dominance produced brownish and reddish hues." Source: https://www.sciencedirect.com/science/article/abs/pii/S0030399223013622?via%3Dihub

Kumar makes further enquiries to find a cause: A one month shutdown was a good interval for conducting a detailed inspection of the equipment and pipelines for the entire urea plant. Was any thickness reduction observed in the main HP loop synthesis equipment e.g. the urea reactor, stripper, etc. or the pipelines? What was the oxygen percentage in CO_2 maintained before shutdown? Was the online oxygen analyser or air flow meter calibrated? Did you observe anything while cleaning urea solution tank bottom?

Ali replies: Our facility has completed 50 years. Work began to change the synthesis lines approximately two years ago. New lines will come this year.

What we are curious about is that the green solution is first activated or blocked and then returns to normal after two hours. If there is active corrosion, why doesn't it continue?

- Iron oxide residues were found in the sediment at the bottom of the urea solution tank.
- Oxygen values in CO_2 are 0.8 to 0.9 vol-% before the stripper.
- We do not have an instantaneous tracking analyser for hydrogen and oxygen. We follow the hydrogen converter inlet-outlet temperature difference and additional air.

Kumar provides a possible suggestion for the temporary green colour: A possible explanation for corrosion not continuing could be due to dynamic passivation. The formation of a passive layer on the metal surface is dynamic. If there is a deficiency of oxygen or a lack of oxygen for a certain period, it can lead to temporary corrosion and potentially result in material loss. Once oxygen is restored, the passive layer can reform, inhibiting further corrosion. However, this is just one possible explanation and cannot be confirmed without further investigation and analysis of relevant parameters.

Ali replies: Actually, this green solution incident occurred after pipe replacement with 316L pipe (with Stamicarbon approval) in February 2024 because the HP scrubber GCB line thickness value was too low and the pipe could not be supplied for replacement. After that, the first solution coming from the synthesis was seen to be green in the subsequent commissioning and exits. In the technical control made after the last stop, no excessive corrosion was detected in the 316L pipe. Do you think this is possible due to the 316L material?

Mark replies: Yes, I think applying 316L instead of 316L UG will lead to higher corrosion rates under synthesis conditions. But whether one line can make this difference, I doubt.

You also had a blocking in situation didn't you? That leads to accumulation of chromium oxides in the blocked in liquid.

Dynamic passivation is an interesting topic. The formation of a passive chromium-oxide layer is an equilibrium with the dissolving rate of chromium oxides in the acid ammonium carbamate solution. But once active corrosion starts it cannot be stopped by adding more oxygen. One has to stop the plant, drain and re-passivate the surface.

Kumar comes back with some follow up questions: How long was the solution held in the urea reactor before start-up? Was this holding time longer than the licensor's recommendation? Can you confirm that chromium levels are stable while nickel levels are elevated?

Blocking urea solution in the urea reactor for an extended period can indeed lead to the accumulation of chromium oxides in the blocked-in liquid.

Referring to the potential impact of using 316L instead of 316L UG, I fully agree with the earlier assessment. As correctly pointed out, a smooth metallic surface generally indicates that the passive layer is intact and active corrosion has not yet significantly progressed. Once the metallic surface becomes rough, for example inside the urea reactor, it signifies that active corrosion has already taken place, and the passive layer has been compromised.

Ali provides more details of the incident: On 03-12-2024 at 08:30 due to a problem in the ammonia unit, we stopped the system. We waited for about 12 hours with the synthesis block. After 12 hours, while restarting the system, we went out of service due to a different malfunction and drained and emptied the synthesis.

On 10-12-2024, we started to restart the system, while the synthesis was heating.

While rotating the evaporation in circulation with the solution in the urea solution tank (the solution we drained the synthesis), we noticed that the solution in the observation glass was green. When we took samples from the solution in the urea solution tank and analysed them, we saw the analysis results reported earlier.

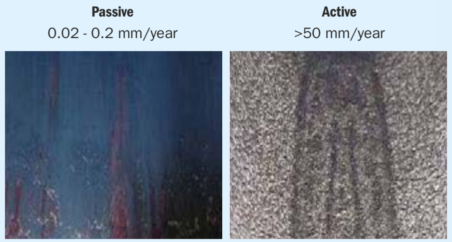
We stopped commissioning the system. We completely emptied and cleaned the urea solution tank. Corrosion inspection of the synthesis lines was performed. It was reported that there was no situation preventing operation (Stamicarbon).

We re-commissioned the synthesis on 20-01-2025 (ammonia was fed after 4 hours of passivation and the level in the reactor was reached after 2 hours. No waiting was done).

The rest is as already mentioned.

Mark replies: The pictures below show passive and active corrosion. Passive corrosion is typically a blueish, reddish or grey colour, while active corrosion gives a silver shiny surface.

Fig. 1: **Corrosion phenomena: passive and active corrosion (depending on oxygen level)**



Passive
0.02 - 0.2 mm/year

Active
>50 mm/year

a minimum oxygen level in liquid phase is critical
corrosion rates valid for 316L UG
25-22-2 sees lower rates but also active corrosion risks

Source: Fertilizer Academy/UreaKnowHow.com

Kumar replies: The images along with the corrosion rates are truly informative and a valuable learning experience.

Please find my observations as mentioned below:

- A 12-hour block of urea solution may not be the sole cause of this issue unless proper MOC is in place.
- The replacement of the HP scrubber GCB line with 316L in February 2024 suggests that corrosion concerns were already identified in this specific area. This incident highlights the potential for localised corrosion in other critical components within the system.
- The age of the plant (50 years) raises concerns about the suitability of existing materials for the current operating conditions. A comprehensive equipment/pipe lines materials suitability review, considering factors such as operating temperature, pressure, and the presence of corrosive species, is crucial. What is the capacity of your plant? You may calculate how much chromium is lost during the incident and considering parameters at that time.
- Can you confirm that the oxygen meter before the stripper was calibrated before and after the December 2024 shutdown? Accurate oxygen measurements are critical for understanding and controlling corrosion processes.
- A thorough investigation is recommended, including a detailed review of operating logs, material analysis of corroded components, and potentially a review of the original design specifications to identify potential areas for improvement.

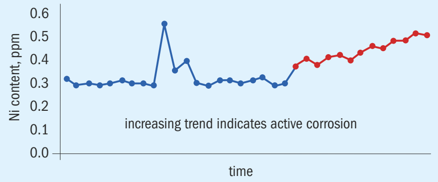
Ali comes back: We do not have a continuous oxygen meter in our system. We take samples from CO_2 before the stripper and analyse it. The oxygen value is around 0.8 – 0.9 – 1 vol-%.

The last corrosion inspection we had on the synthesis lines reported no problem preventing the start-up. The new lines were ordered and the delivery process is ongoing.

Mark replies: It is recommended to install a continuous O_2 analyser to ensure sufficient oxygen is supplied to prevent active corrosion. Once active corrosion occurs it cannot be stopped by adding extra oxygen.

It is good practice to take daily samples of the final product, analyse nickel and watch for rising trends indicating active corrosion (see figure below).

Fig. 2: **How to detect active corrosion?**



Source: Fertilizer Academy/UreaKnowHow.com

Another benefit of a continuous O_2 analyser is that one can control the oxygen content more closely to the minimum required 0.6 vol-% (in case the stripper has 25-22-2 tubes).

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Urea production at Gazprom Neftekhim Salavat. Russia is claiming a rising share of urea markets.

Urea market developments

Urea markets are well supplied at present in spite of Chinese export restrictions, but face volatility due to a number of trade barriers and other non-market pressures.

Tariff and other trade restrictions continue to impact on urea market volatility. Supply is seeing another round of capacity additions which will theoretically take the market into oversupply from about 2027, after a couple of tighter years due to increasing demand, but Chinese export restrictions remain a wild card.

Supply

Urea markets face a significant period of supply additions, particularly in China and Russia. After a period of industry consolidation, China has entered a new round of capacity additions and leads capacity growth in 2024. Chinese production increased by 4 million t/a to reach 67 million t/a in

2024 on the back of new capacity additions and improved utilisation rates, and in 2025, production is forecast to grow further to 67.8 million t/a, with a net capacity increase of 2.4 million t/a. However, poor margins and falling domestic prices coupled with restricted means that actual production increases will be somewhat lower than this. Nevertheless, Chinese urea capacity is expected to increase by 16.4 million t/a over the period 2025–2029, balanced only slightly by around 4.1 million t/a of expected closures, taking capacity to 83.8 million t/a in 2029, the highest on record. Most new capacity is based on lower cost bituminous coal, while the closures are fed by more expensive anthracite, taking the bituminous share of capacity from 53% at present to 63%, and lowering overall production costs.

Elsewhere, there are a number of projects coming to fruition around the world, with Russia leading large scale project announcements. There are also new projects in Africa, Central Asia and the Middle East, as shown in Table 1, adding a potential 12.1 million t/a to the 16.4 million t/a of new capacity in China.

China has imposed export restrictions on urea, significantly reducing exports in recent years, primarily to stabilize domestic prices and support food security. These restrictions have had a notable impact on the global urea market, causing some exporters to seek alternative markets and prompting importers to diversify their supply sources. In late 2023, China implemented export restrictions, limiting total urea exports in 2024 to around 944,000 tonnes. In June 2024, China introduced additional restrictions, further reducing urea exports by 83% compared to the previous year. As a result of these restrictions, urea exports from China have plummeted, with some reports indicating a 92% year-over-year decline in August 2024. Conversely, Russian exports are soaring, rising 11% in 2024 to reach 9.5 million t/a. The absence of Chinese urea has allowed Russia to increase its market share to 17.7% in 2024, with capacity reported to be running flat out.

Demand

On the demand side, nitrogen demand is expected to rise, but concerns remain around affordability for farmers. Increasing planted areas are expected through the medium term, with Asia, Africa and

Latin America leading the growth. Corn production in the US is expected to increase in 2025 as strong early exports draw down availability. Additionally, shrinking herd cattle and high cattle prices are likely to promote slaughtering rather than breeding, thus increasing crop acreage.

The outlook for Brazil's corn and soy crops are set to hit a new record despite all the complications faced during the season. However, the demand for soybeans remains in questions with a less supportive Chinese outlook.

Wheat supply is expected to take a hit due to the unfavourable weather conditions in Russia, France and the US impacting output. Rice production is estimated at an all time high due to growing area in Asia and the Americas, thus making the market oversupplied.

Overall, growing global population will continue to fuel increased crop demand, with expectations of average global food availability growth at a CAGR of 4% over the period 2024–2030. Expectations of fast-paced intensification of livestock production in emerging markets will fuel a steady increase of crop use for animal feed manufacturing. The push for higher quality meat and dairy products has led to more corn- and soybean-based feed. The global energy transition has also led to increased use of crops as feedstock for energy products, with nearly 40% of US corn being used for ethanol and nearly 50% of US soybeans being used for biofuel.

Chinese agricultural demand for urea grew by 4%, to 38.3 million t/a in 2024 due to rising planting area and use of high-density planting technology. It is expected to remain stable at 38 million t/a in 2025 but the government continues to try and curb growth in fertilizer use and overapplication over medium term. Consumption is therefore expected to peak in 2026 and decline to 36 million t/a by 2029.

Overall global nitrogen demand is forecast by CRU to rise from 117 million tonnes N in 2024 to 123 million tonnes N in 2029, with urea demand ex-China rising from 123 million tonnes product in 2024 to 137 million tonnes product in 2029.

Trade and tariff issues

There are however a number of trade and tariff issues which may impact upon urea markets. While the tariff implementation by the US on Canadian imports remains uncertain, the impact on nitrogen is expected to be minimal. However, a possible duty on Russian imports into the EU will alter trade flows as preference for African sources emerge. Persisting gas prices remain a hurdle to overcome for the EU, but an imminent threat is the emergence of polices around emissions. Additionally, the EU has imposed a duty on Chinese melamine imports.

US tariffs on imports from Canada were set to be implemented from 4 Feb 2025, but the implementation was delayed until 2 Apr 2025, and an executive order that exempts all products qualifying for USMCA preference status was later issued in early March, thus suggesting a possible exemption of nitrogen. However, the uncertainty around the implementation remains.

Canada is wholly dependent on the US for offtake of its ammonia and urea produced in excess of domestic consumption, leaving little recourse in the event of tariffs being imposed. However, net imports from Canada have shrunk over the past three years. Less than 15% of US imports originated from Canada, primarily to suffice the needs of Northern Plains. A potential tariff on Canadian imports is likely to raise the premium for the Northern Plains market, encouraging more domestic sourcing of nitrogen.

In Europe, the European Commission (EC) has proposed import tariffs on fertilizers arriving from Russia and Belarus in a drive to reduce import dependence on those countries and support domestic European production. Tariffs are to be applied to material not previously covered under existing tariffs, while the material on which the tariffs will be applied represented 15% of Europe's agricultural imports from Russia in 2023, the EC said in a 28 January document.

The EC noted that buying and selling of Russian agricultural product is to remain unchanged as well as its storage in EU warehouses, transportation on EU vessels or any insurance and financing services if the material is in transit to third countries.

Table 1: **New urea capacity ex-China, 2024-29**

Company	Location	Capacity, million t/a	Year commissioned
Pemex	Cosoleacaque, Mexico	0.5	2024
Shchekinoazot	Shchekino, Russia	0.7	2025
Acron	Novgorod, Russia	0.4	2025
Gemlik Gubre	Gemlik, Turkey	0.5	2025
Hengam Petchem	Hengam, Iran	1.1	2025
Indorama	Eleme, Nigeria	1.3	2026
United Capital Fert	Zambia	0.3	2026
Talcher Fertilizers	Talcher, India	1.3	2027
EuroChem	Kingisepp, Russia	1.3	2027
Perdaman	Karratha, Australia	2.0	2027
Ferkensco	Yangiyer, Uzbekistan	0.6	2028
NCIC	Ain Sokhna, Egypt	0.4	2028
Pusri	Pupuk, Indonesia	0.9	2028
KazAzot	Aktau, Kazakhstan	0.8	2029
Total		12.1	

Source: CRU

The proposal will now be considered by the European Parliament and the Council where it requires majority voting for its approval. There are already 'anti-dumping' duties on Russian UAN, along with duties on UAN from the US and Trinidad & Tobago.

EU tariffs on Russia are likely to divert more Russian product towards the Americas, thus replacing the Egyptian and Algerian supply. This diversion could potentially lead to Algeria and Egypt filling the gap created from missing Russian supply to Europe. Additionally, new capacity in Turkey and increasing exports out of Iran will further allow Egypt to focus on the European market from 2025 H_2.

Reduced EU reliance on Russia for urea will necessitate increased reliance on Egypt and Algeria, who comprise more than two-thirds of EU imports in 2024.

There is also the question of the EU Carbon Border Adjustment Mechanism (CBAM). This attempts to ensure that imported goods are treated similarly to EU products and fairly taking into account embedded carbon emissions, enforcing the same EU emission trading scheme carbon price, and considering effective carbon prices paid outside the EU. Embedded emissions for CBAM goods will be gradually covered by the CBAM obligation, with costs increasing over the period 2026-33. The total CBAM tax liability in 2026 is estimated at $58/t urea, followed by an increase to $108/t in 2029, on the back of rising carbon prices and a gradual phase-out of free allowances.

Lastly, in February the EU imposed a definitive anti-dumping duty on imports of melamine from China, in a move to protect the domestic downstream industry. The anti-dumping duty for Xinjiang XLX is 12%, rising to 44.9%– 49% for the other melamine producers. All other China exports will be levied at 65.2%. China exported 578,000 tonnes of melamine in 2024, of which 16% was exported to the EU. Anti-dumping duties are expected to reduce Chinese melamine exports to the EU. Although the equivalent amount of urea is just under 300,000 tonnes, relatively insignificant to China's demand, the duties are likely to exacerbate the oversupply situation.

Urea trade

Traded volumes of urea are set to rise this year after a dip in 2024. India continues to be the main buyer as the gap from missing Chinese supply is filled by exports from Russia. Lower prices in 2024 will climb through 2025–26 on the back of rising Indian purchases, but will be limited by returning Chinese exports and sporadic demand globally. However, as noted above, a glut of new capacity set to hit the market in 2027, which will put a cap on rising prices over the 2025-26 period. ■

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Gas pricing and the LNG market

Global gas demand has returned to growth after the supply shock of 2022-23, but geopolitical tensions and short supply in LNG markets.

Natural gas continues to be a major energy source for the world, representing about one quarter of all energy demand in 2024, and particularly for the ammonia and methanol industries, where gas feedstock accounts for about 70% of all ammonia production and around 65% of all methanol production. Gas pricing remains a key determinant of ammonia and methanol profitability. In addition, while coal and oil are seen as fossil fuels whose demand is on the wane, gas is a cleaner burning fuel and seen by many as a key transition fuel alongside renewables over the coming decades.

The past few years have been a highly volatile time for gas markets, with the coronavirus pandemic and the surge in demand caused by easing of restrictions leading to a gas price spike, exacerbated in early 2022 by the Russian invasion of Ukraine and the gradual restriction of gas supply to Europe, resulting in a price spike that has been followed by an easing in markets as gas flows were redirected around the world, and now gradual tightening again as demand recovers.

Global natural gas consumption increased by 2.8%, or 115 bcm year on year in 2024, above the 2% average growth rate between 2010-20. Natural gas met around 40% of the increase in global energy demand in 2024 – a greater share than any other fuel. This relatively strong growth was mainly due to the Asia Pacific region, which accounted for almost 45% of incremental gas demand in 2024 on the back of continued economic expansion.

Europe

The European gas market continues to suffer as a result of the Russian invasion of Ukraine and the reduction of Russian pipeline gas flows to Europe. The last pipeline supplies across Ukraine ended in December 2024, and Russian gas is now only reaching Europe via Turkey (ca 13 bcm) and as LNG shipped from Yamal. The attempt to replace the loss of 160 bcm of Russian gas supply by opening new LNG terminals and running existing ones to capacity has been remarkable; European LNG imports went from 108 bcm in 2021 to 170 bcm in 2023, and actually dropped in 2024 due to lower gas demand. While LNG, particularly from the US, has kept the lights on in Europe, perhaps as big a story over the past three years has been one of demand destruction, both due to increased use of renewables for electricity generation, a return in some cases to coal-based power, and lower use of gas overall, particularly for industrial uses, where high prices have forced reduced running rates and idling of plants. While European gas prices have stabilised since the 2022 price shock, they have done so at an elevated level. Overall, European gas prices based on the Dutch TTF benchmark have risen from an average of around $5-10/MMBtu prior to 2022 to around $10-15/MMBtu in 2024-25.

The ammonia industry has been a particular casualty, and the continued elevated levels of gas pricing compared to the levels of a few years ago pose an ongoing threat to European ammonia competitiveness. A number of plants are now operating on imported ammonia and more may switch, though the Carbon Border Adjustment Mechanism may provide some relief over the coming years. Europe's reliance on LNG imports means that wholesale gas prices are generally determined by global LNG rates now, which tend to be higher than the pipeline gas that Europe has traditionally relied upon, especially given competition between Europe and various Asian economies for LNG cargoes.

Other notable features of Europe's gas picture include the rapid ramp up in production of biomethane and biogas, reaching 22 bcm in 2023, up from 17 bcm in 2022, and forecast to reach 35 bcm by 2030. There is also increased gasification of biomass and domestic waste, which is targeted to supply 37 bcm of gas equivalent by 2040. Green hydrogen targets remain unmet for now, however, mostly due to cost.

North America

US natural gas production continues to increase, with steady demand coming from new LNG facilities. Natural gas demand in the US is forecast to rise by 4% in 2025, with a significant portion attributed to a 18% increase in exports, including both pipeline and LNG shipments. The expansion of LNG export facilities, like Plaquemines LNG Phase 1, will contribute to a notable increase in U.S. LNG exports, but growth in the power sector as US power generation continues to shift away from coal, and increasing demand due to investment in data centres and other industries, will contribute to higher natural gas demand. The US Energy Information Administration (EIA) forecasts that the US gas market – not taking into account weather related fluctuations - will tighten somewhat this year, with the Henry Hub price likely to average around $4.30/MMBtu in 2025 and nearly $4.60/MMBtu in 2026, compared to an average of $2.20/MMBtu in 2024 and $2.50/MMBtu in 2023, but these prices remain low by global standards.

South America

The South American natural gas market is characterised by a widening deficit and growing LNG imports, with a focus on regional integration and infrastructure development. While the region holds substantial gas reserves, particularly in Brazil and Argentina, challenges in production and distribution, along with potential geopolitical factors, could hinder its full development. Colombia's natural gas reserves are declining, and the country faces challenges in meeting its projected consumption needs, while Argentina's oil and gas sector requires significant investment to develop its Vaca Muerta shale gas resources. Trinidad & Tobago continues to face challenges in mitigating a decline in natural gas production. South American gas demand for power production is expected to grow significantly, with a CAGR of 17.2% from 2024 to 2030. In order to meet this, the LNG market in Latin America is expected to grow by an annual average of 6.7% from 2021 to 2030.

PHOTO: SHELL GLOBAL

The Hazira LNG terminal, India.

Africa

Africa's gas production has stagnated since 2021, rising only incrementally from 267 bcm to 268 bcm in 2023, and forecast to reach 272 bcm in 2025. At issue has been a lack of investment in new production and falling production from older fields. This has been a particular issue for Egypt, where production has dropped from 68 bcm to around 43 bcm. However, there are signs that this trend may be belatedly reversing, with investment in the African oil and gas sector increasing by 23% in 2024 according to the African Energy Chamber. In North Africa, Egypt recently signed a deal with Cyprus to import gas from the Cronos block to feed LNG production at Damietta, and is seeing new wells drilled in the West Nile Delta area by Shell and others. ExxonMobil has made a gas find in the Herodotus basin, and Eni is Eni begins drilling this year at the Zohr field. There are also prospects for the domestic Badr Petroleum Company. Further west, Morocco is due to tender in 2025 for the Moroccan section of the proposed Nigeria-Morocco Gas Pipeline (NMGP), which is planned to eventually connect 16 countries, primarily along the Atlantic coast and eventually to Europe. The first phase will involve Morocco, Mauritania, and Senegal, with additional agreements for gas transport expected to be signed in 2025. BP has also begun gas flows from offshore Mauritania to a floating production and storage vessel, and subsequently to a floating LNG vessel for onward transit to Mauritania and Senegal, totalling around 2.3 million t/a.

In Sub-Saharan Africa, Mozambique and Tanzania are increasing gas production, with LNG export planned from Mozambique. Nigeria continues to develop projects to utilise flared gas from its offshore production; a 2.8 million t/a LNG facility is scheduled for production to begin in 2029. Angola is also developing its Quiluma and Maboqueiro gas fields to supply 5.2 million t/a of gas to the Angola LNG plant and the Soyo Combined Cycle Power Plant.

African domestic consumption remains relatively low, and much of the new African gas is destined for export, mainly to Europe via Algeria and Egypt, as well as via an increasing number of new LNG projects.

Asia

Gas demand continues to rise in China, with increasing use of LNG as a vehicle fuel, particularly for heavy duty vehicles, where around 10% of the truck market is now accounted for by LNG-powered vehicles. Electricity generation via natural gas is projected to amount to 232 terawatt hours in 2025, with an average annual

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growth rate of 6.12% for the period from 2025 to 2029, as China tries to pivot away from coal towards lower carbon forms of energy. By 2030, China's natural gas consumption is expected to reach 570 bcm and plateau at around 620 bcm between 2035 and 2040. Energy-related carbon emissions are expected to peak before 2030 at between 10.8 billion and 11.1 billion t/a as gasoline and diesel fuel is converted to natural gas and the region sees strong growth of renewable energy.

Elsewhere, Japan's Ministry of Economy, Trade and Industry (METI) unveiled a draft of its revised Basic Energy Plan in December 2024, which acknowledges that LNG-fired power is a necessary

means of energy transition to cleaner energy and says that the government needs to work with private companies to secure the long-term LNG contracts to enhance energy security and invest in upstream natural gas infrastructure. South Korea, conversely, is aiming to meet its future energy needs using nuclear power. By 2038, the country plans to increase its nuclear fleet from 26 to 30 reactors. This will affect the country's imports of LNG; South Korea aims to cut its fossil fuel imports from 81.8% of its energy requirements in 2021 to 60% by 2030. Currently, South Korea is the third largest market for LNG after China and Japan, importing 60.6 bcm of the fuel in 2023, equivalent to 11% of the global market.

India's domestic gas production, which met 50% of demand in 2023, is projected to grow gradually, reaching just under 38 bcm by 2030. This would put it around 8% above 2023 levels. The limited growth in domestic supply means India's LNG imports will need to more than double to around 65 bcm a year by 2030 to meet rising demand.

Middle East

The Middle East gas market is predicted to experience significant growth in both production and consumption, driven by increasing demand for cleaner energy sources and industrial expansion. The Middle East is experiencing substantial growth in energy demand, particularly for electricity, which is expected to triple by 2050. LNG exports from the Middle East, particularly from Qatar, are projected to remain strong, with Qatar being the world's third-largest LNG exporter. The expansion of Qatar's North Field, the world's largest gas field, will be a key driver of increased production and export capacity. However, rising domestic demand within the Middle East could potentially strain supply and impact export volumes if not managed effectively.

LNG

Most of the foregoing has emphasised the increasing role that LNG is playing in the global gas market. Production and consumption of liquefied natural gas reached 562 bcm in 2024, representing 14% of the global gas market, and 60% of internationally traded gas. LNG trade has increased by 70% over the past decade, and growth continues, as we have discussed above. Europe and Japan in particular will continue to require LNG to fill a widening gap between energy diversification ambitions and actual investment levels. The global trade in LNG is set to rise significantly by 2040, driven by Asian economic growth, the need to decarbonise heavy industry and transport and the emerging growth in the energy-intense tech sector. It is also becoming a cost-effective fuel for shipping and road transport that can bring down emissions. LNG vessels represent the bulk of lower carbon emission fuelled vessel orders at present. Overall, more than 230 bcm of new LNG supply is forecast to come on stream by 2030, although there is uncertainty over the timing of particular projects. There is also likely to be an increasing use of liquefied biomethane, production of which is seeing 13% growth year on year. Tanker capacity is plentiful at present, keeping shipping rates low in spite of canal bottlenecks.

LNG growth is particularly strong in the US, with over 120 bcm of exports already in place and that much again already under construction or closing on a final investment decision. The US became the largest LNG exporter in 2023, just surpassing Qatar and Australia, but this could take the country to 1/3 of all LNG exports by 2035, and together with Qatar's planned expansions, the two nations could represent 60% of all LNG supply. But even in spite of all of this construction, there is a potential forecast gap between supply and demand after about 2033 if more new investment does not materialise soon.

LNG's continued rise is also continuing to change the LNG market away from the traditional long-term oil indexed contracts that it relied upon in its earlier days to justify the costs of liquefaction and regasification terminals. The decoupling of LNG and oil prices is still not complete and varies across regions, but the rise of spot markets and unconventional energy sources like shale gas in the US have contributed to this decoupling, especially in Europe. However, oil-indexed pricing still influences some long-term LNG contracts, particularly in Asia. Overall, around 40% of LNG is now bought on a spot basis.

Gas pricing

Natural gas is priced in different ways. The International Gas Union, in its annual survey of wholesale gas price fixing mechanisms, distinguishes between: 'GOG' – gas-on-gas competition - where there are multiple producers selling into a price unregulated market via trading hubs; OPE – oil price escalation – where the price of gas contracts is tied to oil prices by an escalation factor; and various forms of regulated prices: regulated cost of service (RCS), where a company is allowed to make back costs plus a fixed increment; regulated social and political (RSP) and regulated below cost (RBC), where a company, usually state-owned, sells gas below the cost of delivery for political or other reasons.

At present, North America (including Mexico) and Europe, Australasia and Argentina, Nigeria, Colombia and Morocco are categorised as gas on gas markets. India, China, Brazil, most of northeast and southeast Asia are classed as working on an oil price escalator method, while Russia, Central Asia, the Middle East and North Africa, as well as much of sub-Saharan Africa and the rest of South America are all regulated gas markets. LNG varies, with around half traded on a gas on gas basis, and the rest on oil-indexed pricing.

A tighter gas market this year means that prices will rise in gas on gas regions, with US gas costs up around 40% year on year and European costs up about 25%. By contrast, the average Indian pooled gas price, as it remains tied to oil pricing, is forecast to be slightly lower as the crude oil market remains sufficiently supplied, thereby keeping oil prices partly subdued. As such, the $50/t or so gap between the European average cost per tonne of producing ammonia and South Asia's is likely to be completely eroded in 2025, and may instead see Europe incurring a premium over South Asian costs instead. ■

The future of India's fertilizer market

Dr M.P. Sukumaran Nair, Director of the Centre for Green Technology & Management, Cochin, India and former Secretary to the Chief Minister of Kerala discusses the challenges facing India's agriculture and fertilizer industry.

India, now the world's most populous country, with a population of 1.45 billion people, depends heavily on mineral fertilizers to sustain its agricultural output and feed its people. Food grain production in 2024 was 332 million t/a, of which 55-60% can be attributed directly to chemical fertilizers. India is also the second largest producer of fertilizers globally and the market is primarily driven by government subsidies, increasing demand for agriculture, and the need for efficient farming practices.

Challenges

The major hurdles for Indian agriculture are declining crop response, imbalanced fertilizer usage, the subsidy burden to the exchequer to keep the price of fertilizers affordable for farmers, geopolitical uncertainties caused by wars and warlike situations in importing countries, and supply chain disruptions arising out of port and traffic restrictions.

Urea is the most consumed fertilizer in Indian farms. It is heavily subsidised to the level of one sixth of its current market price and is available cheaply across the country. Some of the Indian farm sectors have experienced declining crop response due to over-application of chemical fertilizers, especially urea, highlighting the need for balanced fertilizer use and an effective action plan to manage soil health. Excessive use of urea has led to upsets in the soil nutrient ratio, aggravated degradation and leaching which damage water bodies.

A major challenge before the government is the rising cost of fertilizers and occasional availability issues, particularly for subsistence farmers. Imports are often subjected to price rises and supply chain disruptions. Both of the above lead to increase in subsidies and cause a heavy burden on the state exchequer. Annual fertilizer subsidy expenditure has hovered around $15-20 billion for the past few years, and peaked to $29 billion in 2022-23. The union budget for 2025-26 carries a provision for $19.4 billion.

Geopolitical uncertainties including political events and geopolitical tensions are disrupting fertilizer trade and supply chains, affecting availability and prices, impacting farmers and agricultural production. This is exacerbated by transportation and logistical challenges caused by port closures and traffic disruptions.

Overcoming the challenges

Government initiatives include adequate provision for subsidies on fertilizers to make them affordable for farmers, efforts for promoting balanced fertilization and sustainable agricultural practices and launching several schemes to promote domestic fertilizer production and reduce dependency on imports.

Increasing domestic production

To counter supply chain disruption, the first step is to increase domestic production. Efforts towards rebuilding five brownfield urea plants – Ramagundam (in Andhra Pradesh state), Gorakhpur (Uttar Pradesh), Sindri and Barauni (Bihar) and Talcher (Odisha) – with a combined output of 6.35 million t/a of urea with natural gas as feedstock, have been a success story. Only FCI's Talcher coal gasification-based ammonia-urea complex is yet to be commissioned. In addition, the government has also approved an 860,000 t/a urea plant for the public sector Brahmaputra Valley Fertilizer Corporation Ltd (BVFCL) as a replacement for two


Rice fields at Chiplun, India.

PHOTO: SATISH PARASHAR/ISTOCK

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Table 1: **Production, import and consumption of fertilizers, million t/a**

	2022-23				2023-24			
Nutrient	N	P_2O_5	K_2O	Total	N	P_2O_5	K_2O	Total
Production	15.74	5.01	-	20.75	17.11	4.88	-	21.99
Import	5.22	3.76	1.46	10.44	4.65	3.14	1.97	9.75
Consumption	20.21	7.92	1.72	29.85	20.46	8.31	1.88	30.65

Source: Fertilizer Association of India

lower capacity old plants. The 2025 Union budget has proposed a new urea plant at the BVFCL site in Namrup (Assam) with a capacity of 1.27 million t/a.

Revamping existing plants

Most fertilizer manufacturers have already adopted and implemented projects and schemes intended for increasing of capacity utilisation, operational reliability, and energy efficiency so as to achieve the best onstream factor. Retrofit and revamp options, when available, are economically feasible, including improved equipment design, new materials of construction, and better performing catalysts, and can be easily incorporated into existing plants. Some have adopted advanced operational practices such as rigorous plant monitoring, digitised process control and online corrosion monitoring.

Joint ventures abroad

As mentioned earlier, India's import dependency is around 25% of its urea requirement, rising to 90% in case of phosphates, either as raw material or finished fertilizers and 100% for potassium fertilizers. The government has been encouraging Indian producers to establish joint venture manufacturing facilities abroad in countries that are rich in fertilizer resources with buy back arrangements and to enter into long term agreements for the supply of fertilizer inputs or finished products to India. Producing urea and phosphoric acid in countries where natural gas is cheaply available was a successful option considered by the government to ensure the availability of urea (see Table 2).

There were also proposals for acquisition of fertilizer assets – production units, mines of raw materials etc - especially potash and phosphate mines in Russia, Canada, and Belarus. However, as the Department of Fertilizers could not formulate viable incentive schemes, such acquisition proposals have not yet taken off.

Import of fertilizers

India is heavily dependent on imports in the fertilizer sector and therefore maintaining a steady supply chain is important for the country's agricultural productivity. The deficit in production - nearly 30% of consumption - is met by imports of raw materials, intermediates and finished products. During the 2023-24 fertilizer year, India imported 15.5 million t/a of fertilizer materials in addition to raw materials such as sulphur, phosphate rock and intermediates such as ammonia, phosphoric and sulphuric acid. The details are given in Table 3.

Table 2: **Joint venture fertilizer projects abroad**

Project	Year	Partners	Product	Capacity
ICS, Senegal	1980	ICS (93.22%) IFFCO (6.78%)	Phosphoric acid	0.55 million t/a
IMACID, Morocco	1999	OCP (50%) Chambal (25%) TCL (25%)	Phosphoric Acid	0.43 million t/a
OMIFCO, Oman	2005	SAOC-50%, Kribhco 25% IFFCO 25%	Urea	1.7 million t/a
TIFERT, Tunisia	2013	GCT (70%) CIL (15%) GSFC (15%)	Phosphoric acid	0.36 million t/a
JIFCO, Jordan	2014	JPMC (48%) IFFCO (52%)	Phosphoric acid	0.48 million t/a

Source: Fertilizer Association of India

Better nutrient efficiency

Efficient use of fertilizers is important to optimal crop productivity, and economic gain to farmers and for avoiding pollution from leaching and farmland runoff due to excessive application. Serious efforts are required to achieve better nutrient use efficiency of applied fertilizers in the field based on nationwide soil testing and balanced administration of fertilizers. The government nowadays insists on a scientific administration of plant nutrients and promotes site and crop-specific nutrient management, the use of coated and delayed-release materials.

An optimal supply of soil nutrients over time and space to match the requirements of crops through the 4R principles can be achieved through crop and site-specific nutrient management (Right Product, Right Rate, Right Time, Right Place). These broad principles of such kind of a nutrient administration to the soil were developed by the International Plant Nutrition Institute in 1988.

Coating of urea with ingredients like sulphur, neem oil or polymers and the addition of micronutrients allow the controlled release of nutrients to the soil over an extended period. Nutrient release rate and duration are guided by coating thickness and soil temperature. Farmers are also being educated on the benefits of advanced techniques such as fertigation and integrated nutrient management.

Large-scale use of compost and farmland manure, biofertilizers, fortified fertilizers, and micronutrients must be promoted. The fertilizer sector, over the years, has undergone all the strains associated with the neo-liberal policies of the government. It needs to undergo a transformation by absorbing the new trends, scientific advancements and strategies that are associated with the production, crop nutrition and use of mineral fertilizers around the world.

Table 3: **Import of fertilizer materials 2023-24**

Item	Total (million t/a)	Countries of Origin
Fertilizers		
Urea	7.04	Oman, China, Russia, UAE, Saudi Arabia, Qatar.
DAP	5.57	China, Saudi Arabia, Morocco, Russia and Jordan.
Potash	2.87	Russia, Canada, Israel and Jordan.
Intermediates		
Ammonia	2.18	Saudi Arabia, Oman, Indonesia, Bahrain and Qatar.
Phosphoric acid	2.26	Morocco, Jordan, Senegal,Tunisia, China and USA.
Raw materials		
Phosphate rock	8.81	Jordan, Morocco, Togo and Egypt.
Sulphur	1.71	UAE, Oman, Qatar, Kuwait and S. Arabia.

Source: Fertilizer Association of India

Specialty fertilizers

Only a part of the nitrogen administered to the soil as fertilizers is absorbed by the plant and the rest leaches to the environment as nitrate or is lost to the atmosphere as ammonia or nitrous oxide, a potential climate distorting greenhouse gas. Various techniques are available to improve the nitrogen efficiency of applied fertilizers by product modifications. Controlling the release of nutrients to the soil by coating the product, stabilising the product with additives, delivery of product in a water soluble or in liquid form, and chelation with crop specific micro nutrients are all ways to add more value to common fertilizers to significantly improve nitrogen use efficiency. The International Fertilizer Association (IFA) lists controlled release fertilizers, slow-release fertilizers, sulphur coated urea, stabilised nitrogen fertilizers, water soluble fertilizers, liquid NPKs, and chelated micronutrients and boron as specialty fertilizers.

'Nano-urea'

India's fertilizer major IFFCO has developed 'nano' fertilizer grade urea and DAP which is expected to revolutionise the application of nitrogen fertilizers. Nano urea in liquid form has particles of 20-50 nm which, when sprayed on the plant leaf, are readily absorbed by the plant through the leaf stomata and releases nitrogen inside the plant. They also stimulate the enzymes involved in nitrogen metabolism inside the plant cells. They are also expected to minimise the environmental footprint by reducing the loss of nutrients from fields in the form of leaching and gaseous emissions which used to cause environmental pollution leading to climate change. They are available in liquid form as 500 ml bottles in India. The long-term crop response of nano fertilizers is awaited. If accepted widely, it will be a game changer to significantly reduce the necessity for massive future imports of granular urea.

Conclusion

Government efforts, though successful in transforming Indian agriculture, are yet to achieve its full scale intended objectives due to difficulties encountered in implementation. The following observations and suggestions are relevant as regards the future market for fertilizers in the country.

Consumption of plant nutrients per hectare of arable/agricultural land is still lower in India compared to major agricultural countries. Consumption of phosphate and complex fertilizers have registered an upward trend and this is projected to grow at approximately 6% through 2024-2029. An average 2-3% increase in overall consumption is expected in the near term, anticipating normal monsoon.

- Therefore, it will become necessary to increase the domestic production of fertilizers, particularly in the context of the ongoing energy transition as ammonia, the major fertilizer input material, is also slated to become a fuel of the future for long-distance hauling of ships etc. The government has announced a National Green Hydrogen Mission, which aims to make India a global hub for green hydrogen and ammonia production. The linkage with energy will invite more investment particularly from the private sector.
- In line with the country's energy transition and proposed achievement of net zero emissions by 2070, a massive program to decarbonize the fertilizer sector, incorporating the carbon capture and storage (CCS) and electrolyser technologies will become necessary.
- Commissioning of plants under construction and debottlenecking of other operating plants with digital capabilities are to be expedited to increase production and improve efficiencies.
- Available low-grade rock phosphate deposits (Rajasthan etc.) may be effectively used through advanced beneficiation etc.
- More scientific application of fertilizers is needed. Promoting low nutrient content fertilizers such as ammonium sulphate and mono ammonium phosphate compared to high nutrient urea and DAP assumes paramount significance in the sense that such products supply only the required quantum of nutrients during the cropping season, the whole of which will be absorbed by the crops leaving little residue. Besides reducing wastage, it will also ward off soil degradation and environmental pollution.
- The Government should institute a countrywide program to promote the use of composts, agricultural wastes, green leaves, and farmland manure as readily available sources of manure for crops.
- For marketing and distribution of fertilizers, emerging technologies – e-commerce platforms, digital marketing, direct benefit transfers etc - must be made use of to improve efficiency and reduce losses and avoid delays.

Modern agriculture is often criticised for being energy and carbon intensive. A paradigm shift is needed to innovate current agricultural practices, with an emphasis on long-term sustainability. The government, together with the scientific community, needs to explore alternatives to traditional fertilizers, such as organic and bio- and nano-based options or precision agriculture techniques. It will also free up the disruption of traditional fertilizer products and raw materials supply chain arising every now and then on account of some reason or another.

The outlook for future market for fertilizers in India, thus, calls for more investment in production, technology access for digitisation and decarbonisation, retrofit and revamp of existing units and above all, farmer empowerment. ■

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Will energy uses drive future methanol demand?

Methanol demand is rising again after a few years of relative stagnation, but with the Chinese MTO boom largely over, it looks to be energy uses which will drive most future demand.

The world market for methanol is around 112 million t/a, about 55% of the size of the ammonia market. Around 40% of this is represented by traditional chemical uses such as formaldehyde and acetic acid, around 30% by olefins production, and around 30% by fuels uses (see Table 1).

Historically, methanol demand was almost exclusively used for downstream chemical production, mainly formaldehyde for resins, acetic acid, methyl methacrylate, methyl chlorides and other solvents. Because it was easily transported, as a bulk liquid at room temperature and pressure, production migrated to 'stranded' gas locations as a use for gas reserves that could not otherwise find a market, in places such as the Middle East, Trinidad, and at the tip of Chile.

The methanol market first began to shift away from this in the 1990s, mainly due to the development by Davy Process Technology (now part of Johnson Matthey) and Lurgi (now owned by Air Liquide) of large scale methanol flowsheets. The move to 5,000 t/d and up plants allowed for economies of scale in methanol production which brought the cost down, and allowed it to compete with oil and gas derivatives both as a fuel and as a feedstock for olefins production. The methanol to olefins (MTO) process was developed by Union Carbide in the 1980s and commercialised by UOP in the 1990s, and Lurgi developed its own parallel methanol to propylene (MTP) process at the same time. This period also coincided with larger scale take up of methanol ether derivatives such as MTBE and TAME as clean burning gasoline additives, initially in the US, but increasingly spreading elsewhere.

But it was the large scale adoption of these technologies by a rapidly industrialising China in the 2000s that made the decisive shift in the methanol market. China sought to use methanol as a bridge from coal – of which it had an abundance – to fuels and olefins, which China otherwise had to import. Methanol derivative dimethyl ether (DME) became a widely used blendstock in liquefied petroleum gas (LPG), used for domestic heating and cooking in China, and methanol was also blended directly into gasoline at up to 10% to eke out gasoline supplies. In the 2000s, this was followed by methanol to olefins plants, either using domestic coal-based methanol, or even buying methanol on the open market.

Table 1: **Methanol demand by sector, 2010-2024, million t/a**

	2010	2015	2020	2024
Chemicals				
Formaldehyde	14.3	21.7	23.8	26.1
Acetic acid	5.1	6.1	7.2	8.2
Methylamine	1.7	1.6	1.6	1.8
MMA	1.0	1.5	1.8	1.8
DMT	0.6	0.5	0.5	0.4
Solvents	2.2	2.6	2.8	3.2
Other	5.2	3.7	3.9	4.0
Total chemical	30.1 (65%)	37.7 (48%)	41.6 (41%)	45.5 (41%)
Olefins				
MTO/MTP	1.1 (2%)	12.9 (17%)	31.2 (31%)	33.7 (30%)
Fuels				
MTBE/TAME	5.6	10.1	10.4	12.7
Dimethyl ether	2.9	3.9	2.9	3.3
Biodiesel	n.a.	1.8	3.0	3.9
Direct fuel use	6.9	11.9	13.1	13.0
Total fuels	15.4 (33%)	27.7 (35%)	29.4 (29%)	32.9 (29%)
Total	46.5	78.3	102.2	112.1

Sources: CMAI, IHS, Argus, MMSA


PHOTO: METHANEX

Waterfront Shipping's Cajun Sun methanol tanker prepares to launch the first net zero methanol voyage from Louisiana to Antwerp in 2023.

As Table 1 shows, the impact of this on the methanol market was profound. Methanol use more than doubled in the decade 2010-2020, with more than half (ca 55%) of this increase coming from Chinese methanol to olefins plants. China also expanded both fuels and chemicals uses for methanol. However, as can also be seen in Table 1, the past few years have seen the rapid expansion of the methanol industry slow back to a more 'normal' level, with the covid-19 pandemic and the Russian invasion of Ukraine both disrupting markets. At the same time, Chinese coal prices have risen, and oil prices have fallen, making coal-based MTO plants less competitive. The Chinese methanol fuel and DME blending markets have reached saturation and China's refiners have managed to slow the adoption of national fuel methanol standards, meaning only certain provinces permit it. There has been a large-scale build of domestic steam crackers to produce ethylene, in competition with olefins from MTO plants, and the slowdown in the Chinese economy has throttled back the need for ever-increasing volumes of plastics and other olefin derivatives, though demand from traditional chemical uses continues to rise.

US shale gas

Methanol production shifted decisively towards China during 2000-2020, mainly based on coal-based production. China now has 60% of all methanol capacity, though it operates at much lower rates than the rest of the world (around 58% compared to around 75% ex-China). But at the same time, the US methanol industry has had a remarkable turn of fortune, thanks to abundant and cheap shale gas. During the 1990s US capacity closed and production shifted to Trinidad and Venezuela where gas was cheap, the methanol being exported back into the US across the Caribbean. The availability of cheap natural gas has turned that around, and in 2024 the US produced 10.9 million t/a of methanol against domestic demand of around 7.5 million t/a. The country has returned to being a net exporter of methanol at the same time that Venezuela's economic and political meltdown and Trinidad's problems with gas supplies have reduced supply from those sources.

Europe and Ukraine

There has been a major impact upon methanol markets due to the war in Ukraine. Europe is a major consumer of methanol – the third highest region after Asia and North America, and also a large importer of methanol, while Russia has been a major exporter. In 2021, Russia exported 2 million t/a of methanol in 2021, and Europe imported most of that. High natural gas prices in Europe caused some shutdowns of European methanol capacity in 2021-22, with imports increasing particularly from the US. Russia had been gearing up for major increases in methanol production, but most of these projects have been put on hold due to the sanctions situation.

Elsewhere

As Table 2 shows, the Middle East has the largest regional share of capacity outside China, and with only modest demand locally it is by far the largest exporting region for methanol, with Saudi Arabia and Iran the largest producers. Outside of Iran, however, new plant building has slowed down as gas supplies become more constrained, while Iran has faced sanctions which have slowed its new capacity additions and ability to sell its product overseas.

India has talked about trying to emulate China's move to domestic fuel and plastics production based on coal-derived methanol. In 2018, government think tank NITI Aayog launched its Methanol Economy initiative with the aim of increasing domestic consumption of methanol from its present 2 million t/a to 30 million t/a. However, in spite of some research and pilot programmes, so far nothing has progressed in terms of actual plant building.

Malaysia has become a methanol producing and exporting hub, with Petronas operating two plants at Labuan with a combined capacity of 2.4 million t/a and Sarawak Methanol another 1.8 million t/a plant which came onstream at Bintulu in December 2024.

Table 2: **World methanol capacity ex-China, million t/a**

Region	Capacity
North America	12.6
South America	12.2
Europe	4.2
Russia/CIS	6.0
Middle East and Africa	33.1
Asia and Oceania	8.5
Total	76.6

Source: MMSA

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Methanol as a bunker fuel

Methanol demand is now increasing at around 2-3% year on year, but there is scope for much larger increases in demand if it achieves widespread adoption as a shipping fuel. Methanex has used methanol as a fuel in its fleet of tankers, operated by subsidiary Waterfront Shipping, for some years, but interest in methanol has been galvanized by plans to decarbonise the maritime industry. The International Maritime Organisation (IMO) has set the target of cutting the sector's carbon emissions by 50% in 2050 compared to 2008 levels. In Europe the change has been given extra impetus by the FuelEU maritime regulation, which came into force in January 2025. By levying heftier non-compliance costs on the use of fuels that emit higher levels of greenhouse gases, more vessel owners will likely be motivated to turn to alternative fuels to avoid higher costs.

Even greater impetus is likely to come from the IMO's 'green levy', agreed in April 2025. The agreement mandates a $100 charge for every tonne of carbon dioxide emitted above an established decarbonisation threshold. Ships with a volume exceeding 5,000 tonnes must progressively reduce their greenhouse gas (GHG) emissions intensity by 30% by 2035 and 65% by 2040, compared to 2008 levels. Vessels that fail to meet the stricter benchmark will face a $100-per-tonne fee, while those that fall short of a less demanding target could be charged up to $380 per tonne. The new system also establishes a carbon credit market, allowing more efficient vessels to sell credits to those with higher emissions. The measures are set to take effect in 2028, though the US has expressed its displeasure with the decision.

There are a number of low carbon fuels under consideration by the shipping industry, including low carbon ammonia, low carbon methanol, hydrogen, biomethane, low carbon synthetic methane and other low carbon hydrocarbons, but there is as yet no firm consensus on which way the industry will go.

Methanol appeared to gain momentum after shipping giant Maersk began to focus upon it in 2022. A number of methanol fuelled vessels have been built or converted in recent years, including the Stena Germanica car ferry operating in the Baltic and several other Stena bulk carriers. Maersk is building 20 large dual fuel container ships that can operate on methanol, with eight delivered by December 2024. HD Hyundai says it has now received orders for 177 methanol-powered engine units for a total of 42 ships. By the end of 2023 138 methanol vessels were on order, putting methanol ahead of LNG as an alternative fuel for ships, and it is estimated that there could be 350 methanol fuelled vessels operational by 2030, requiring several million t/a of fuel.

Some of the shine came off methanol's bunker fuel prospects in 2024 as Maersk appeared to have second thoughts, saying that it planned to order up to 60 vessels capable of running on biomethane. Since then Maersk has clarified that their owned share of the planned fleet renewal is 20 vessels registered as dual fuel methane propulsion systems from 9-17,000 TEU. However, they also confirmed that while technically being registered as dual-fuel liquified gas propulsion vessels, they would also include the option to convert the propulsion system to dual-fuel methanol. Maersk's head of energy transition Morton Christiansen has said that biomethane "is much more available in Europe, where we have difficulty finding cost-competitive green methanol, which should still be the better scalable fuel option."

Methanol bunkering options continue to increase. Singapore's port authority is actively developing plans to incorporate methanol into its bunkering pool and is anchoring two of the largest green corridors globally, including the Rotterdam to Singapore Green Corridor and the Shanghai to Singapore Green Corridor. Maersk is working with the port of Yokohama in Japan to develop methanol bunkering there.

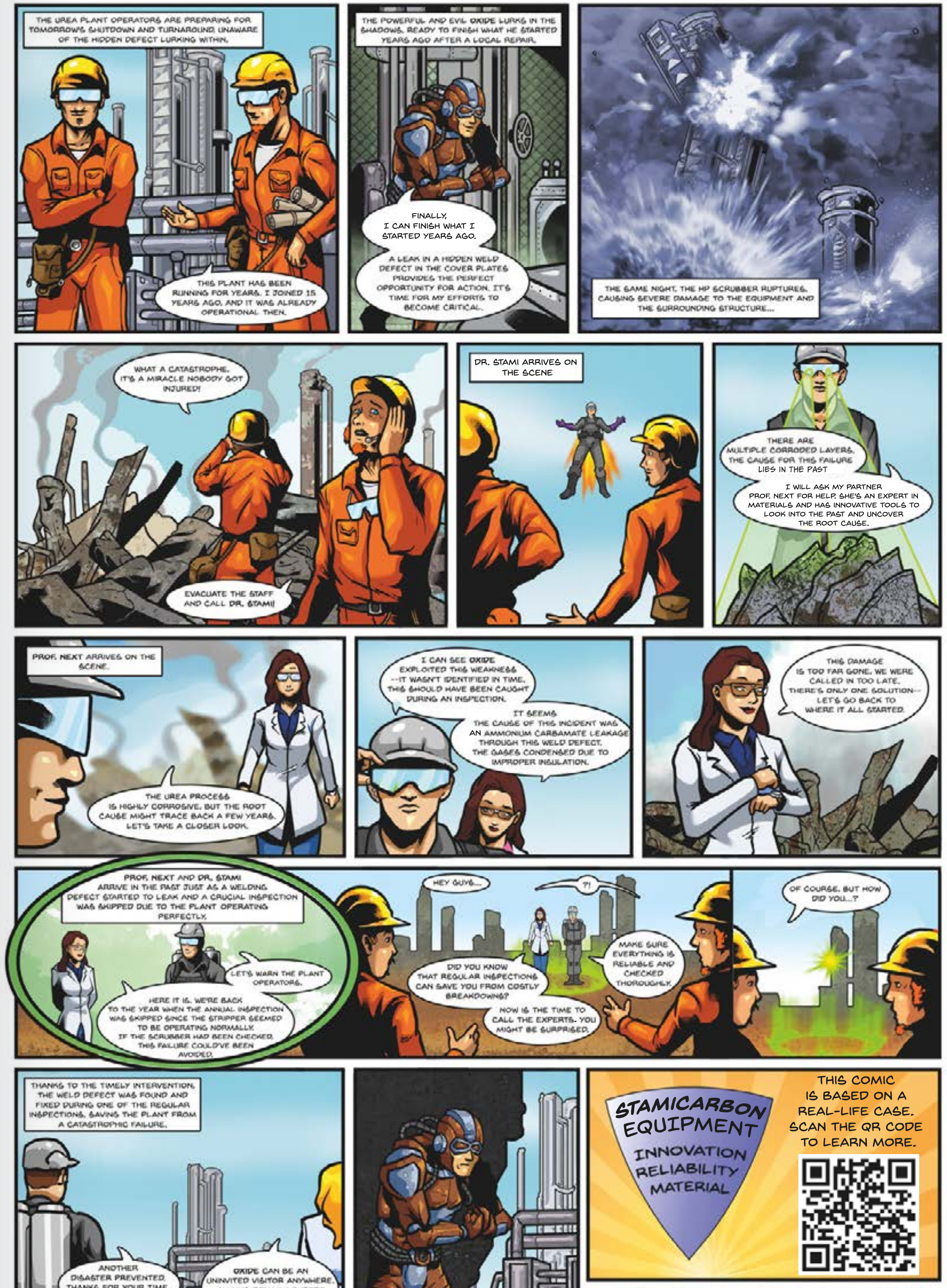
Blue and green methanol

Perhaps the biggest issue for methanol as a shipping fuel is now becoming supply. Much of the impetus behind the move by Stena, Maersk and others to methanol as a shipping fuel is predicated on using low carbon methanol, but the number of existing large scale low carbon methanol plants is relatively small. The methanol shipping tonnage above could require 7 million t/a of low carbon methanol by 2030, but it is far from clear if all of this could be available by then. Europe is on course to be producing 2.2 million t/a of low carbon methanol by then.

As with low carbon ammonia, the number of project announcements has dwarfed those that have made it to a final investment decision. In August 2024 Orsted scrapped development of its 50,000 t/a FlagshipONE green methanol project in Sweden citing slower than expected development of the market for low carbon methanol and lack of an offtake agreement. OCI sold its blue ammonia development to Woodside and its methanol business to Methanex last year, which includes two idled biomethanol plants and a blue methanol project under development. Lake Charles Blue Methanol was due to begin construction this year but is waiting on certainty on Inflation Reduction Act credits, which the Trump administration has tried to cut back on. Mexico's Pacifico Mexinol is still on course to become the largest single ultra-low carbon chemicals facility in the world - producing approximately 350,000 t/a of green methanol and 1.8 million t/a of blue methanol from 2028, but again construction has yet to begin.

While low carbon methanol can be eked out by blending into conventional methanol to lower GHG emissions even if there is insufficient available to completely substitute low carbon methanol, something of a chicken and egg situation is developing where adoption as a maritime fuel waits upon production and vice versa. Global economic uncertainty and a slowdown in the petrochemical sector have not assisted with that process. Higher methanol prices over the past few months due to production outages in Malaysia and Equatorial Guinea, amongst other locations, may also be contributing to the general drift in low carbon methanol projects at present.

However, there are also signs that some companies may be attempting to square this circle. Maersk announced in April 2025 that they would be investing $100 million in C2X to advance the latter's green methanol portfolio, with around 500,000 t/a of green methanol offtake up for grabs. Having put so much store on low carbon methanol as a future maritime fuel, Maersk appears to be prepared to invest to make sure that it happens, and if more shipbuilders and operators do likewise, then the present hurdle will be overcome. As with low carbon ammonia, guaranteed offtake agreements are generally the key to securing financing and final investment decisions. ■



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Ammonia terminals for the energy transition

To cope with higher demand for green and blue ammonia, new ammonia terminals will be required and must be designed with respect to social and environmental challenges, as well as local permitting regulations and safety requirements. Saipem has developed a wide range of solutions to tackle those challenges and requirements by offering large-scale liquid ammonia storage and import/export terminal facilities supported on gravity based structures.

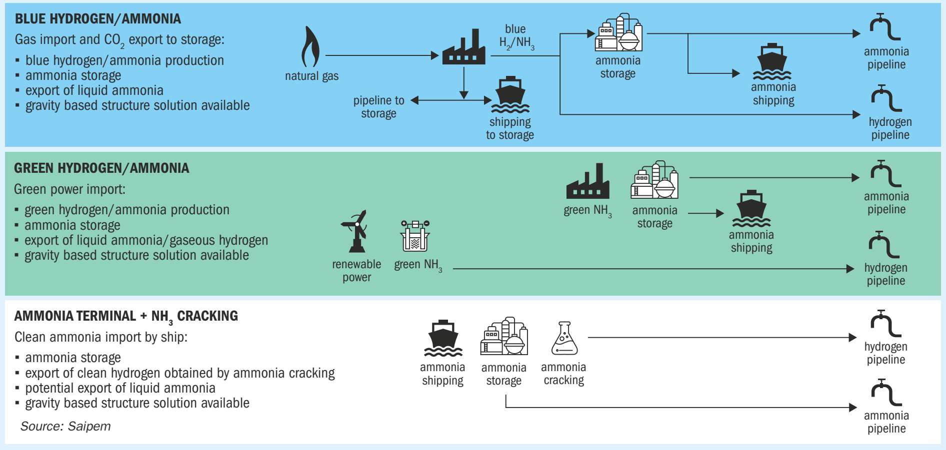
Andrea Zambianco, Ali Natour, Simone Corno (Saipem S.p.A.)

Ammonia is one of the most important carbon-free chemicals, for its use as feedstock in the fertilizer industry and its various applications in the energy sector; it is produced in many countries and traded across the world. In order to satisfy a higher demand for "green" and "blue" ammonia in the fertilizer industry and the energy sector, the supply and distribution of ammonia is significantly increasing and is expected to constantly accelerate in the next decade. In this perspective, new ammonia terminals will be required and must be designed with respect to social and environmental challenges, as well as local permitting regulations and safety requirements.

Various types of ammonia storage systems have been built onshore (e.g. single containment with low bund wall, double containment with outer concrete wall, etc.). However, the necessity of building new large capacity storage tanks and minimising at the same time the risks for ammonia toxic dispersions, has paved the way for the application of ammonia storage inside the GBS hull, an inherently safer solution which is also allowing to obtain large storage capacities in a compact footprint.

The low carbon hydrogen/ammonia value chain is enriched by the possibility to implement GBS solutions either in the production of blue or green ammonia as well as the import terminals of low carbon ammonia, ref. Fig. 1.

Fig. 1: **Low carbon hydrogen/ammonia value chain (Saipem)**



BLUE HYDROGEN/AMMONIA

Gas import and CO_2 export to storage:

- blue hydrogen/ammonia production
- ammonia storage
- export of liquid ammonia
- gravity based structure solution available

GREEN HYDROGEN/AMMONIA

Green power import:

- green hydrogen/ammonia production
- ammonia storage
- export of liquid ammonia/gaseous hydrogen
- gravity based structure solution available

AMMONIA TERMINAL + NH_3 CRACKING

Clean ammonia import by ship:

- ammonia storage
- export of clean hydrogen obtained by ammonia cracking
- potential export of liquid ammonia
- gravity based structure solution available

Source: Saipem

Ammonia storage in a GBS

Historically, Saipem has executed EPC projects with various refrigerated liquified gases stored inside a GBS. In addition, Saipem has designed and built onshore ammonia storage tanks. The adoption of a GBS solution to accommodate the ammonia storage functionality represents a natural evolution combining the above experiences and a way to address mainly safety aspects, social perception of ammonia toxicity and logistic/infrastructures constraints.

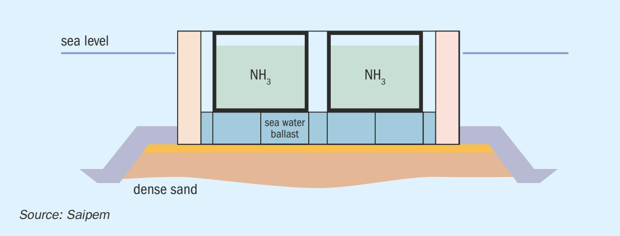
The GBS consists of a concrete hull, laid on the seabed in the near shore. It can contain a portion of the plant inside its hull and the remaining portion on its top slab, including the ammonia production or cracking facilities and relevant utilities, required buildings and the direct berthing and mooring facilities of large vessels (Fig. 2).

Safety related mitigation measures

The toxicity of ammonia has been the major preoccupation for designers and operators of liquid ammonia tanks in the industry, requiring efficient preventive measures to avoid possible causes of ammonia release to the environment. Addressing stress corrosion cracking, advanced types of crack monitoring systems have been developed (e.g. acoustic emission sensors and robotised in-service inspections) for ammonia primary containers thus engaging the operators as well to have special respect for the internal inspection intervals and maintenance scheme of such storage tanks.

Leak risks and toxic dispersions are significantly mitigated in the case of GBS since the ammonia storage tanks are situated inside the GBS hull, fully contained in a stand-alone metallic tank and surrounded by secondary and tertiary barriers of pre-stressed concrete walls in the horizontal direction as well by the GBS bottom and top slabs in the vertical direction. The second barrier is liquid-tight, and it can be designed to become vapour-tight by installing an adequate vapour barrier on the inner face of the concrete components. The third barrier is liquid-tight ensured by the pre-stressed concrete walls.

Fig. 2: **Ammonia storage inside the GBS**



Source: Saipem

These multiple layers of protection drastically reduce the risk of accidental ammonia release into the environment.

Reasons for implementing the GBS concept

GBS solutions have been successfully deployed in the offshore oil and gas industry for more than 30 years.

GBS is a robust, flexible, adaptable and proven asset to overcome onshore constraints and provide an effective and safe solution for the storage of various refrigerated liquified gas applications such as LNG, LPG and ethane.

In particular, the conventional onshore installation of ammonia storage in the proximity of densely populated areas could represent a major concern in respect to the social perception of ammonia toxicity. GBS could unlock the feasibility of the project with respect to this major constraint.

Being a "3-in-1" solution, the GBS concept allows the entire integration of all topside structures and modules necessary for green/blue ammonia production or ammonia cracking or storage facilities on a single concrete hull that contains the liquid ammonia (LNH_3) storage tanks, each one with direct berthing and mooring facilities of large vessels.

GBS option A (blue ammonia production) will host, in addition to LNH_3 storage tanks, the entire ammonia production unit consisting of synthesis gas generation (based on steam or autothermal reforming) and ammonia synthesis loop and refrigeration. Captured liquid CO_2 storage and shipping facilities or CO_2 pipeline for export will be also installed on the GBS.

In option B (green ammonia production) hydrogen generation facilities via electrolysis of water will be installed on the GBS together with the ammonia synthesis loop and LNH_3 storage tanks; the potentially unlimited water source represented by sea water will be exploited by means of desalination units feeding electrolysers with water at the requested purity specifications.

In option C (ammonia cracking) commercial grade liquid ammonia will be delivered by ships, stored in LNH_3 storage tanks and from here pumped to ammonia cracking facilities producing and exporting high purity hydrogen at the requested pressure level. Process schemes have been developed to crack ammonia with zero CO_2 emissions and minimum use of utilities and no steam generation, import or export.

The advantage of using ammonia cracking on the GBS is also to reduce the length of the connecting pipe to the ammonia storage that is basically built under the ammonia cracking plant thus also allowing, in case of need, to safely and easily drain the ammonia cracking lines in the storage.

In option D, the GBS solution represents an ammonia terminal, GBS containing ammonia tanks, which could be entirely built in dedicated yards.

For all the options, ammonia ship could moor directly on the GBS to load or unload the ammonia.

Available and proven technologies for ammonia production and cracking can be adopted for GBS application without any modification relevant to technology considering that the stability of the GBS allows installations similar to the onshore ones. Depending on the location of the GBS, its distance from the coast, certain specific features may vary to cope with the marine environment.

Another reason for implementing a GBS solution is the possible advantages compared to clean hydrogen export via pipelines. GBS can significantly contribute to the ammonia value chain by supporting ammonia storage and cracking applications for hydrogen production. In view of the current

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lack of a well-developed infrastructure for hydrogen offtake, transport, and storage, it can also be utilised for inland hydrogen distribution systems or for the direct generation of thermal power. In a typical harbour setting, this scheme of large-scale storage can be possibly used for bunkering vessels with LNH_3 or LH_2 as fuels.

This solution provides flexibility because (1) hydrogen or ammonia feedstock can be sourced from various locations, (2) hydrogen demand is currently unstable and GBS can scale in increments while a pipeline must be constructed for future demand, and (3) geopolitical conditions may influence energy sources and demand.

GBS offers flexibility and adaptation to market conditions. GBS also provides a robust solution. The architecture of GBS is designed to provide a strong structure essential for ammonia storage. A standalone solution with zero or minor onshore space requirement, the GBS benefits from high resistance to extreme environmental conditions rendering it suitable for harsh environments. Industrial safety risks are significantly reduced due to the positioning of all equipment, piping, and ammonia process systems nearshore or offshore, sufficiently distant from populated areas. As LNH_3 storage is near atmospheric pressure, the explosion risks are also limited. In the worst-case scenario of a high-speed collision causing significant local damage to the GBS caisson, this would never result in loss of the primary containment due to the wide buffer compartment corridors that entirely enclose the ammonia tanks all along the GBS perimeter and act as lines of protection against external boat impact.

A major advantage of GBS is that most of the construction works can be performed safely and efficiently in controlled environments, whether at the GBS construction yard or at the fabrication yards of topside modules and LNH_3 tanks.

After the completion of GBS civil works and the integration of topside modules, the GBS can be floated out from its construction yard, towed, positioned, and sunk at its installation site with very minimal on-site works (permanent ballasting, hook-up, commissioning, and ready-for-start-up). The GBS design can be reproduced with minimal customisation and relocated at any time during its service life due to its classical ballast system, which requires little maintenance.

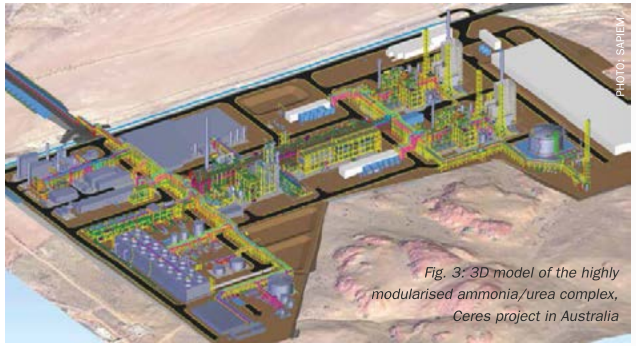


PHOTO: SAIPEM

Fig. 3: 3D model of the highly modularised ammonia/urea complex, Ceres project in Australia

Ammonia facilities modularisation

The modularisation of ammonia facilities has been extensively optimised by Saipem and is currently being implemented in an ongoing EPC large-scale, ATR-based ammonia plant (see Fig. 3).

Modularisation provides benefits in terms of safety and costs for locations where mobilising a large construction workforce is not feasible, or where site access is challenging or restricted for extended periods.

An analysis of module size, considering logistics, cost, time, and yard availability, was performed to optimise the execution strategy.

In a GBS solution, the plant topsides can be modularised to a very large extent, and the entire solution can be mostly developed in pre-selected yards, thus reducing risks and impacts related to safety, quality, severe weather conditions, local workmanship, cost and schedule. The remaining activities to be stick-built on site can be of similar typology to flare assembly and installation, insulation works and commissioning of LNH_3 storage tanks, installation of E&I cables on interconnecting pipe racks, gangway tower installation, standby generators placement, and final hook-up works.

Reference projects

Building large-scale gravity-based structures with Ammonia storage leverages previous projects and extensive experience in GBS and onshore ammonia storage tanks. In the next section, two recent projects are highlighted in order to serve as reliable references for Saipem's proposed configuration.

Reference project: GBS FEED and EPC

Recently, in order to support natural gas pre-treatment and liquefaction needs, three large-scale GBS units (3 x 6.7 t/a LNG trains) were designed for construction, with a total storage capacity of 229,000 m³ of LNG (2 tanks x 114,500 m³) per GBS as well as 1 tank x 75,000 m³ of liquid condensate and 1 x 960 m³ of ethane, to be all contained within the GBS structural hull.

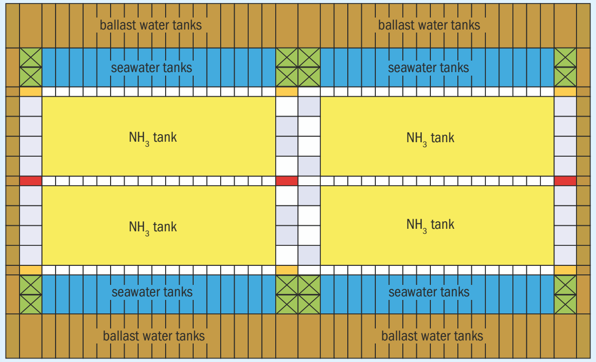
Each LNG train is hosted on a single GBS and consists of several topside modules.

As part of this project, Saipem has carried out extensive FEED activities including engineering and constructability studies. Following the FEED phase, Saipem was responsible during the EPC phase for the detailed engineering and overall completion of civil works for the GBS structural hull as well as for the design and installation of the cryogenic storage systems. Each GBS was constructed in a graving dock with more than 150,000 m³ of concrete per GBS, and then safely towed-out for approximately 1,100 km to its destination.

Reference project: GBS feasibility study

For another project, a techno-economic feasibility study was conducted by Saipem for an ammonia facility comprising two identical ammonia cracking trains, each capable of producing up to 150,000 Nm³/h of pure hydrogen product based on 2,400 t/d of ammonia feedstock. The facility also comprises associated utilities, technical buildings and rooms, auxiliary equipment, living quarters, platforms, and all necessary interconnecting pipe racks to ensure fully independently operable systems. The GBS has the capacity to hold up to 300,000 m³ of LNH_3 within its hull, facilitated by multiple low-temperature storage tanks.

Fig. 4: **GBS plan view at the slab level of LNH_3 storage tanks (Saipem)**



Source: Saipem

The GBS plot plan elaborated at the end of this study was developed based on experience and lessons learnt from Saipem's GBS projects. The monolithic concrete GBS is 328 m long and 152 m wide at the base. Its height is adjusted for floatability, stability, and to meet or exceed the required ammonia storage volume.

Fig. 4 displays the GBS plan view at the ammonia tanks level. Yellow rectangles indicate the ammonia tanks, brown areas are solid ballast tanks, and blue areas represent seawater ballast tanks. The green compartments are designated for utilities storage of other products. The remaining compartments will accommodate access ladders, stairways, ballast pumps, LNH_3 transfer pump rooms, dry compartment corridors, and other necessary infrastructure.

Saipem experience

Saipem is one of the world leaders in the execution of hydrogen/ammonia projects in the last 60+ years. Table 1 shows the recent hydrogen/ammonia projects executed by Saipem.

Saipem can also draw on its vast experience in the design and construction of gravity based structure solution:

- More than 25 years experience in EPC projects with concrete and GBS marine applications.
- More than 350 concrete caissons (<40 m) installed.
- Several large scale (>100 m) concrete structure.

Saipem excels in designing and constructing the whole ammonia complex including ammonia storage facilities. With experience in executing over 130,000 km of pipelines and expertise in gaseous hydrogen and liquid ammonia studies, Saipem is also a major player in offshore and drilling sectors, leveraging its own floaters and ships. This comprehensive capability is crucial for completing the ammonia value chain from production to distribution.

Conclusions

This article has presented some projects which build on Saipem's EPC expertise to design and construct large-scale nearshore GBS with low temperature/cryogenic products storage, such as LNG and LNH_3.

Saipem GBS solutions are flexible and adaptable to project specific needs. Most construction activities can be performed in a well-protected and controlled environment, whether at the GBS construction yard or in the fabrication yards of topside modules, LNH_3 tanks, and other large mechanical outfitting elements.

The GBS concept enables the complete integration of the LNH_3 storage system within a single concrete hull, enclosed in multiple concrete barriers, offering a safer solution than conventional onshore systems.

In case production of clean hydrogen is required, an ammonia cracking plant with zero CO_2 emissions can be installed on the topside of a GBS, acting thus as an import terminal of clean ammonia and export terminal of clean hydrogen. This solution is highly effective, particularly in Europe, considering the expected increase of ammonia import and the high demand for clean hydrogen. ■

Table 1: **Recent hydrogen/ammonia projects executed by Saipem**

Project	Capacity	Scope of work	Client	Country	Completion date
Burrup ammonia-urea (Topsoe ATR and ammonia)	1.2 million t/a ammonia	EPC	Perdaman Chemical and Fertilizer	Australia	ongoing
Haifa ammonia plant	100,000 t/a ammonia	EPC	Haifa	Israel	ongoing
Dangote Fertilizer (Topsoe ammonia)	2 x 800,000 t/a ammonia	EPC	Dangote Fertilizer Ltd	Nigeria	2020
Jazan (4GFU + 2HRU + 4AGR + 4SARU)	4 x 473 MMSCFD treated syngas	EPC	Saudi Aramco	Saudi Arabia	2020
Aegean Refinery	140 MMSCFD hydrogen	EPC	Star Refinery	Turkey	2018
Statoil Refinery	20 MMSCFD hydrogen	EPC	Statoil	Suriname	2015
EGTL Nigeria Project (Topsoe ATR)	2 x 260 MMSCFD hydrogen	EPC	Chevron	Nigeria	2014
QAFCO 5 project (Topsoe ammonia)	2 x 800,000 t/a ammonia	EPC	QAFCO	Qatar	2012

Source: Saipem

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Cracking confidence: Perceived risks for industrial investors

Common risks of ammonia cracking as a new technology and how these risks can be recognised and mitigated by applying an innovative approach of the technology maturation process is described as seen through the eyes of an end user/investor. Addressing those risks is pivotal to enable end users to choose the best technology for their needs. **Albert Lanser** of Duiker Clean Technologies discusses some of these risks and how they have been addressed in its novel technology for producing the lowest levelised cost of hydrogen via its unique ammonia cracking process.

Pressing need in decarbonisation is pushing existing industries to search for innovative technologies. As much as innovations are exciting and inspiring, they always come at a cost and bring risks. Addressing those risks as early as possible and implementing the remedies for de-risking is essential for the successful implementation of new technology. Duiker designed its unique ammonia cracking technology following a structured approach to technology maturation. This process was based not only on Duiker's expertise and engineering experience but also on the perspective of a future client and their view on the risks associated with implementing such innovative technology in their projects.

Ammonia cracking

In certain regions like Northwestern Europe, Japan and South Korea the demand for sustainable energy is expected to rise to large volumes in the near future; however, local wind and solar energy generation is considered insufficient. This creates the need to import sustainable energy. Ammonia plays a key role in this energy transition, especially since ammonia can be used as a carrier for hydrogen and as a fuel. Economically[2, 3] it is cheaper to store and transport hydrogen in the form of ammonia compared to pure hydrogen in gaseous or liquid form. To convert this ammonia back to hydrogen at or near the end-user's location an ammonia cracking process is required.

Bearing in mind the well-known statement of Leonardo da Vinci: "Simplicity is the ultimate sophistication", Duiker developed its design philosophy as shown in Fig. 1.

Applying these considerations, Duiker's ammonia cracking process achieves simplicity by comprising only three main operational units (excluding heat exchangers, pumps and air blowers, see Fig. 2):

- heat generation with ammonia as zero-carbon fuel;
- ammonia cracking;
- purification of cracked gas.

As a result, the cracking process achieves high availability and reliability, and does not emit CO_2 or NH_3, nor does it produce liquid ammonia waste streams. In addition, water or cooling is not required, whilst the hydrogen is delivered at an elevated pressure of 50 bar(g).

Innovation technology maturation process

For an innovation to be successful and commercially viable it needs to bring unique value to the market and client. Therefore, an essential step in the technology maturation process is identifying potential risks, developing solutions to mitigate them, and transforming these solutions into "unique selling points". Sound and structured methods such as Technology Maturation Process[1] help not only to identify and map the potential risks, but also define features and benefits of the innovative technology, frame the opportunity and describe the first potential client early in the development process.

Perspective of industrial investors

There is a common phrase that says: "Every organisation wants to have state of the art technology". However, when it comes to investing a large amount of money for this technology an additional caveat emerges: "… and it should have been proven for more than a decade". This is exactly where the conflict of interest lies; ideally, we want to have the newest technology for a product or process, but the newest will always come along with an uncomfortable feeling about critically evaluating this new technology without existing references. Performing a comprehensive risk analysis is a good approach to focus efforts on the right aspects of the new technology.

Duiker has followed the "TECOPS" principle[1] (technical, economical, commercial, organisational, political and societal risks) and listed the major risks and their remedies with respect to ammonia cracking technology in an overview in Table 1.

Table 1: **Major risks and their remedies**

Identified risk (customer pain points)	**Remedies** (to reduce risk)
Performance	Achieve best-in-class yield for hydrogen conversion. Avoid heat losses & maximise heat integration.
Reliability	High reliability by design, site visits to existing functional references and pilot ammonia cracking technology.
Robustness	Mature and diversified supply chains for critical items. Multi-fuel firing, flexible turn-down, and prepared for next-gen catalyst.
Safety and emissions	Highly automated system requiring fewer operators, inherent safety by simple design, use proven technology in low NOx ammonia firing.
Organisational capacities and capabilities	Rely on expert knowledge and experience of the technology team. Partnerships with reputable world-class EPC(M) companies.
Financial	Insurance on guarantees for first-of-a-kind plant.

Source: Duiker

It is important to note that Table 1 includes only those risks that are under control of the technology developer/innovator. The risks and remedies suggested by Duiker are a result of continuous critical evaluations and are further elaborated below.

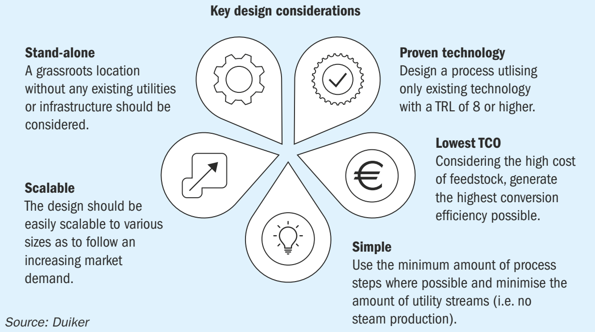
Performance

The importance of well-performing new technology is self-evident and should be optimised to ensure its commercial viability. But what level of performance is required if the technology has not been applied before?

Duiker decided to strive for the highest energy efficiency values by minimising heat loss through implementing a highly heat-integrated system in its ammonia cracking technology. For example, the geometry of the equipment is designed to reduce heat losses compared to alternative designs. Besides that, the select geometry also performs mechanically better and is more predictable when exposed to elevated pressures, which paves the way for operating under higher pressure and results in smaller sized equipment and reduced plot size.

Furthermore, the output pressure of delivered hydrogen makes a post cracking compressor redundant in most projects. Another significant electricity consumer has been eliminated with this approach. Reducing unnecessary energy consumption further enhances the efficiency of the cracking plant. Utilising a liquid ammonia pump to increase system pressure, rather than a compressor for gaseous (vaporised) ammonia, proves highly beneficial. The savings in electrical power consumption from this design choice are undeniable. Heat losses are avoided where possible and together these features lead to a very high energy efficiency. The purity of the hydrogen, considered as another important key performance indicator, complies with ISO 14687:2019 and can simply be achieved by selecting a well-known, proven and scalable purification method: pressure swing adsorption (PSA). The PSA plant will be designed and supplied by reputed companies in this area of expertise.

Fig. 1: **Duiker design philosophy**



Source: Duiker

Reliability

The reliability of a new technology can be considered as one of the key concerns for an investor for obvious reasons; once the business case calculations have been made, an investor wants to have a "certain level of comfort" that the technology will perform and last for the duration of its investment horizon. Reliability has been improved through design features such as extending the lifespan of the tubes in the cracking reactor by eliminating direct combustion.

This approach prevents hot spots on the tubes, which could otherwise cause unexpected tube failures, while also enhancing temperature control within the reactor and reducing plant complexity by limiting the number of equipment items.

Next to design-related solutions, reference visits to commercial scale plants of the new technology can be very insightful as well as piloting the new technology at a relevant scale. In this respect Duiker organised reference visits to commercial scale plants (see Fig. 3) where visitors can directly see and speak with the operators of low NOx ammonia combustion units (SCO). Another milestone in Duiker's endeavour in reducing risks, is to build and operate a pilot for an ammonia cracking plant with commercial scale reactor tubes, that aims to start operation in Q4-2026.

Robustness

Robustness of new technologies in different aspects is always a welcome addition when it comes to reducing investor risks. With respect to robustness in the supply chain, Duiker works with different suppliers for critical components, eliminating the chances of being "locked-in".

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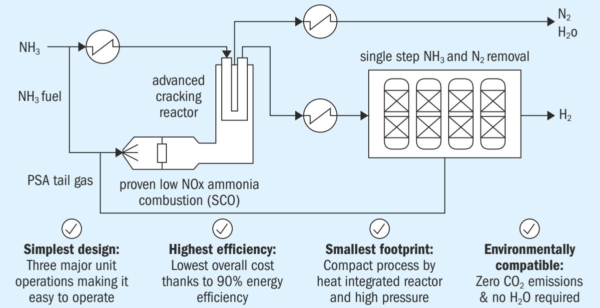
Fig. 2: **Duiker ammonia cracking technology in a nutshell**



✓ **Simplest design:** Three major unit operations making it easy to operate

✓ **Highest efficiency:** Lowest overall cost thanks to 90% energy efficiency

✓ **Smallest footprint:** Compact process by heat integrated reactor and high pressure

✓ **Environmentally compatible:** Zero CO$_2$ emissions & no H$_2$O required

Source: Duiker

Flexibility in fuel selection also offers robustness to the technology. Handling different types of fuels or fluctuating feeds does not have an impact on the performance of the ammonia combustion technology, due to its flexible turndown. Smart choices in design features create flexible scalability for the SCO unit while a “numbering-up” approach for the cracking reactor, allows significant reactor scalability. Together these aspects make most future expansion plans (capacity) or future developments (low temperature catalyst) quite simple and feasible. It can also be integrated with existing capacities, making the technology adaptable for both small and large installations.

Safety and Emissions

“If you think safety is expensive, try an accident” is a statement that perfectly shows why safety is perceived as a big risk of new technologies, especially when they are applied in industry handling hazardous substances, like ammonia. A perfect solution to protect humans is to lower the number of operators required to operate the new technology and reduce the risk of human errors by selecting highly automated process control technologies. Designing the process with fewer steps and fewer equipment means a more inherently safe design because it also simplifies the operation. Supported by decades of experience in ammonia handling within process combustion units, including sulphur recovery (SRU) and stoichiometry controlled oxidation (SCO) for low NOx ammonia firing, Duiker has developed a strong expertise in safely managing ammonia within its ammonia cracking plant.

The emissions hurdles have been addressed by opting for ammonia as a zero-carbon fuel, and applying a proven low NOx ammonia combustion system as the heat generator to keep the NOx and NH$_3$ emissions inherently low. NOx levels can even be further reduced to achieve the most stringent regulatory levels by adding a modest SCR unit. In addition, selecting an advanced PSA removes the nitrogen and ammonia in a single step, eliminating an ammonia waste stream.

Organisational capacities and capabilities

Often neglected or valued as a “low or medium risk”, both the capacities of a team and the capabilities of an organisation are crucial for the success of an innovation. Especially after product launch, in case of unexpected setbacks, the resilience of a team and the organisation, as well as the ability to learn and apply new insights to technology, proves invaluable and helps mitigate risks. Ideally, an organisation builds up its own core knowledge and expertise teams and seeks subject matter experts that can fill temporary knowledge gaps and manage specialised tasks. Duiker also collaborates in long term partnerships with reputable organisations that offer additional capabilities for risk reduction, during engineering, building and operating ammonia cracking plants. To expand capabilities in EPC(M), Duiker is partnering with world-class companies with proven track records.

Fig. 3: **A Duiker SCO unit in operation**

PHOTO: DUIKER

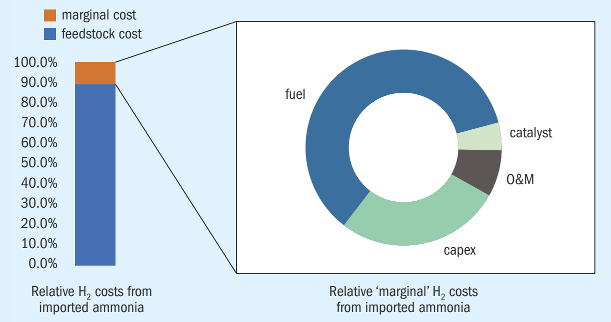
Finance

“Last but not least, it is all about the money” that drives innovation and its commercial success. Clearly, a new technology that provides the lowest levelised cost of hydrogen (LCOH) plays a key role in supporting the feasibility of business cases. Financial risks are reduced hereby, because the new technology is deemed sufficiently bankable to take off and become profitable.

By focusing on the strategies to reduce the cost for cracking, such as:

- avoiding heat loss as it can cause up to 0.5%-point efficiency loss;
- reducing post-cracking compression of hydrogen as it may lower efficiency by 1.5%;
- avoiding the use of H$_2$ or electricity as ‘fuel’;

Fig. 4: **Cost components for ammonia cracking**



Source: Duiker

- catalyst costs are minor component of the overall costs.

Engineering these strategies into smart solutions, the LCOH of cracked hydrogen from Duiker’s technology is among the lowest currently available on the market. For a visual quantification of those costs refer to Fig. 4. The graph is a relevant picture of present day but can fluctuate in time.

Furthermore, Duiker reduces financial risks by offering insurance on guarantees for “first-of-a-kind plant” – a specialised insurance to cover perceived risks exceeding those of a routine technology project.

Conclusion

New technologies, like ammonia cracking, come with risks and it is up to the innovation teams to identify and address these risks by engineering innovative solutions to mitigate and turn them into USPs. It pays to take a structured method for this innovation step. Duiker has greatly succeeded in its innovation process and invites potential customers with interest in ammonia cracking to get in touch about its innovative and reliable ammonia cracking technology that carries one of the lowest cost of ownership in its field. ■

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Low temperature ammonia cracking technology

Mitsubishi Heavy Industries is developing a low temperature ammonia cracking technology (HyMACS™) that leverages exhaust heat from existing sources, such as boilers, steam turbines, engines, and heating furnaces. This innovative approach, which also includes the development of more efficient membrane separation technology using molecular sieves for hydrogen purification, is designed to offer a more sustainable, reliable and cost-effective pathway towards hydrogen production.

Seiji Shinoda, Satoru Teratani, Mikiya Sakurai, Ryota Shimura (Mitsubishi Heavy Industries)

Hydrogen, a promising clean energy source, presents challenges in storage and transportation due to its low energy density and high diffusivity. Considering this, ammonia (NH_3) offers a compelling solution, boasting high hydrogen content, established infrastructure, and safe handling. Its high hydrogen density (17.6% by weight) enables efficient transportation and storage

Ammonia's readily liquefiable nature facilitates safe and efficient handling and transport. In fact, the International Energy Agency (IEA) reported shipping ammonia from Australia to Japan in 2030 is projected to be significantly more economical than directly shipping gaseous hydrogen. In Table 1 various hydrogen carriers are listed and compared as per the report by the Ministry of Economy, Trade and Industry of Japan.

Leveraging current ammonia production, transportation, and storage infrastructure significantly reduces the need for new investments in the establishment of an ammonia-hydrogen supply chain. To fully utilise ammonia as a hydrogen carrier, the development of efficient and cost-effective ammonia cracking technologies is crucial. These technologies aim to decompose ammonia into hydrogen (H_2) and nitrogen (N_2).

Table 1: **Potential hydrogen carriers**

Carrier	**Liquefied H_2**	**Methylcyclohexane**	**Ammonia**	**Methanation**
Volume (relative to normal pressure H_2)	Approx. 1/800	Approx. 1/500	Approx. 1/1,300	Approx. 1/600
Liquid properties and toxicity	-253°C, atmospheric pressure, no toxicity	Normal temperature, atmospheric pressure, toluene toxic	-33°C, atmospheric pressure etc., toxicity, corrosion	162°C, atmospheric pressure, no toxicity
Possibility of direct use	n.a. (no change in chemical properties)	Currently not possible	Possible (coal-fired co-firing, etc.)	Possible (city gas substitution)
Additional facilities for high purity	Not required		Required	
Energy loss of property changes etc.	Present: 25~35% Future: 18%	Present: 35~40% Future: 25%	Ammonia synthesis: 7-18% Ammonia cracking: <20%	Present: ~32%
Utilisation of existing infrastructure	Requires new infrastructure	Yes (chemical tankers etc.)	Yes (chemical tankers etc.)	Yes (LNG tankers, city gas etc.)
Technical issues	Large scale marine transportation technology (large liquefiers, carriers etc.)	Energy loss further reduction	Technology development for direct combustion and ammonia cracking facilities	Competitive green hydrogen supply at production sites and CO_2 supply are essential

Source: Ministry of Economy, Trade and Industry of Japan

MHI's ammonia cracking development

Mitsubishi Heavy Industries (MHI) is actively developing its own innovative ammonia cracking technology, working on its extensive experience in ammonia plant engineering, procurement, and construction (Fig. 1). This approach enables MHI to capitalise on existing expertise, prioritise safety, and offer comprehensive solutions.

MHI can utilise design knowledge garnered from decades of experience in building ammonia synthesis plants, including expertise in handling high-temperature, high-pressure environments, managing corrosion, and working with hydrogen-rich gas streams.

Additionally, MHI draws upon its extensive experience in ammonia plant construction and operation to ensure the utmost safety in ammonia handling practices throughout the entire value chain.

MHI can provide integrated solutions for the entire clean ammonia value chain, encompassing production, ammonia transportation, receiving terminals for ammonia, and ammonia cracking infrastructure.

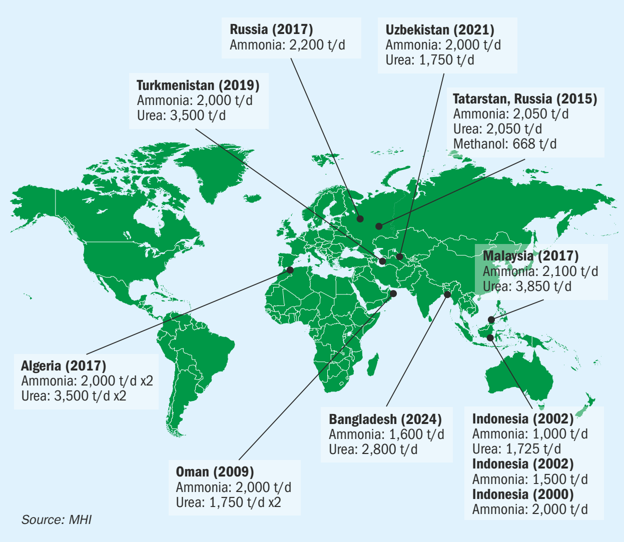
Low temperature ammonia cracking

Typical ammonia cracking process

The cracking of ammonia includes several key steps. First, liquid ammonia is transferred and pressurised for the cracking process. Then, it is vaporised and subsequently cracked by a catalyst. A small amount of unreacted ammonia is absorbed by water and the absorbed ammonia is separated and recovered by distillation. Finally, nitrogen is separated by the membrane separation method and hydrogen is purified. The purified hydrogen can be utilised for various applications, such as fuel cells, industrial processes, or injected into the existing gas grid.

A simplified flow diagram of the ammonia cracking process is shown in Fig. 2.

Fig. 1: **Delivered ammonia plants by MHI**



Source: MHI

Currently, most ammonia cracking systems operate at high temperature (around 700°C). Conventional approaches often rely on high temperature fired heating cracking, akin to steam methane reformers (SMRs). High-temperature cracking faces several critical challenges. High reaction temperature induces significant thermal stresses, potentially leading to equipment fatigue and premature failure. In addition, the high-temperature environment accelerates nitriding, a process where nitrogen from the ammonia reacts with the metal components of the cracking system, causing embrittlement and reducing equipment lifetime. Furthermore, many high-temperature systems utilise the ammonia cracking gas itself as fuel for the cracking furnace, resulting in increased hydrogen consumption and consequently higher operational costs.

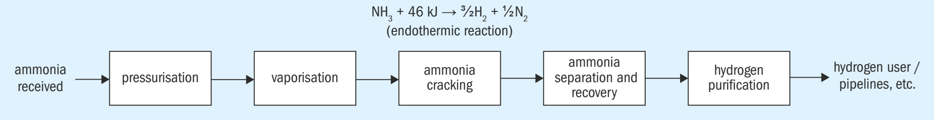
MHI's low-temperature ammonia cracking system

MHI's innovative ammonia cracking system, named HyMACS™, can operate at a significantly lower temperature range (400-500°C), utilising exhaust heat from various combustion sources, such as steam or flue gas from boilers, turbines, and engines.

Fig. 3 compares features of low-temperature and high-temperature cracking.

MHI's approach offers several key advantages. Firstly, developing a non-precious metal-based catalyst will lead the low-temperature ammonia cracking. Accordingly, the lower operating temperature of HyMACS™ minimises the influence of nitriding, a prevalent issue in high-temperature cracking processes that leads to material embrittlement. Mitigating the risk

Fig. 2: **Ammonia cracking process**



Source: MHI

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of nitriding ensures the long-term durability and reliability of the cracking equipment.

The system minimises heat loss by effectively utilising exhaust heat, thus reducing the overall energy consumption and operational expenditure (opex). Additionally, no fired heater is required in MHI's HyMACS™ which leads to a compact system.

Finally, MHI is developing a cutting-edge membrane separation method for hydrogen purification. This technology offers several advantages over traditional pressure swing adsorption (PSA) methods, including higher hydrogen yield and lower operating costs.

These key features demonstrate MHI's commitment to developing a robust and efficient ammonia cracking technology that addresses the challenges of existing systems and offers a competitive advantage in the growing hydrogen economy.

High-activity catalyst in low temperature

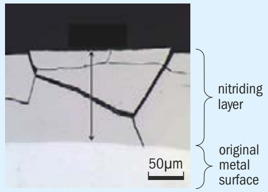
Catalysts for low-temperature cracking typically consist of precious metals such as ruthenium. MHI is actively working on catalysts based on non-precious metals, which are more easily accessible compared to catalysts based on precious metals. These catalysts are designed to be much more active and stable at lower operating temperatures, resulting in high ammonia conversion.

Fig. 4 shows several catalyst types at varying catalyst bed operating temperatures, as well as their respective catalyst activity in terms of ammonia conversion rate. Among the catalysts shown in the figure below, the non-precious metal-based catalyst (highlighted) demonstrated high activity at lower catalyst bed temperatures.

Low nitriding risk

Nitriding, a process where nitrogen reacts with the metal components of the cracking system, is a significant concern in high-temperature ammonia cracking (see Fig.5).

Fig. 5: **Nitriding in metal surface**

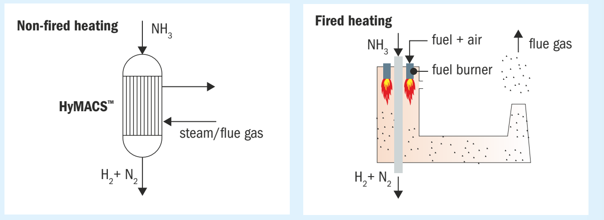


Source: MHI

Fig. 3: **Features of low-temperature and high-temperature cracking**

MHI Technology

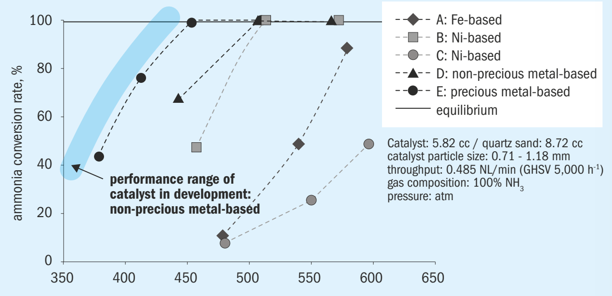
Source: MHI



Low temperature (~500°C)

High temperature (~700°C)

Fig. 4: **Ammonia conversion rate of various catalyst types**



Source: MHI

To mitigate this issue, MHI has optimised the cracking process parameters, such as temperature and ammonia concentration, to minimise the occurrence of nitriding while maintaining high hydrogen yield. MHI's patented technology (JP7389065B2) utilises cracked gas recycling which has lower nitriding potential.

$$\text{Nitriding potential} = (pNH_3 / pH_2^{1.5})$$

where, pNH_3 is the partial pressure of ammonia and pH_2 is the partial pressure of hydrogen.

Compact module

MHI recognises the diverse hydrogen needs of many sectors and applications. To meet this broad demand, MHI's ammonia cracking technology provides a versatile capacity range, from small-scale units producing 10 kg/h of hydrogen to large-scale units capable of producing up to 1,000 kg/h. This scalability enables MHI to deliver tailored solutions for a wide range of applications, including small industrial use, large-scale power generating, and steelmaking.

This adaptable methodology means that MHI's ammonia cracking technology may be smoothly integrated into a variety of current and new hydrogen ecosystems.

Furthermore, MHI's steam heating system outperforms fired-heating systems in terms of opex and capex using the high-activity catalyst with low-temperature cracking technology. The compact container-sized skid module cracks ammonia and produces hydrogen using steam or exhaust gas as a heat source.

Table 2 compares HyMACS™ and fired ammonia cracking

Hydrogen purification with ceramic membranes

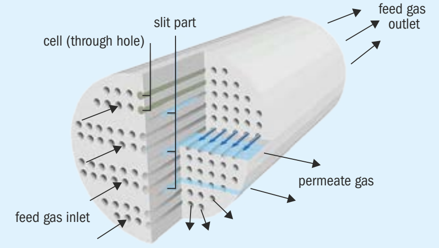
MHI's ammonia cracking technology utilises an innovative hydrogen purification process based on a membrane separation method. This process uses a ceramic membrane as the membrane element, offering significant advantages over conventional purification techniques such as PSA.

Table 2: **Comparison of HyMACS™ and fired ammonia cracking**

	HyMACS™ (non-fired heating)	Fired heating
Cracking temperature, °C	~500	~700
Nitriding	mild	severe
Plot size	compact	large
Equipment scale, kg/h H_2	10~1,000	>1,000
Ammonia consumption	low	base

Source: MHI

Fig. 6: **Ceramic membrane mechanism**



Source: NGK Insulators

In a ceramic membrane purification process, feed gas containing hydrogen and nitrogen enters the membrane material which allows permeate gas, which is hydrogen, to pass through as the main product (Fig. 6). Consequently, outlet gas containing mainly nitrogen with a small amount of hydrogen exits at the outlet of the membrane.

Key advantages of hydrogen purification with ceramic membranes are:

- **Reduced opex**: Compared to the pressure swing adsorption (PSA) method commonly used in the industry, MHI's membrane separation approach offers a substantial reduction in operational expenditure (opex). This is achieved through lower energy consumption and reduced maintenance requirements.
- **High hydrogen recovery rate**: The ceramic membrane will achieve about 10% higher hydrogen recovery rate than PSA (95% vs 85%). This minimises the loss of valuable hydrogen and reduces the consumption of raw material ammonia, as a result contributing to lower operating costs. Hydrogen purity for HyMACS™ membrane separation is >99.0% compared to 99.97% for PSA.
- **Versatility**: Membrane separation technology is compatible with various cracking methods, including steam heating, fired heating, and autothermal systems. This flexibility allows for seamless integration into different ammonia cracking configurations.

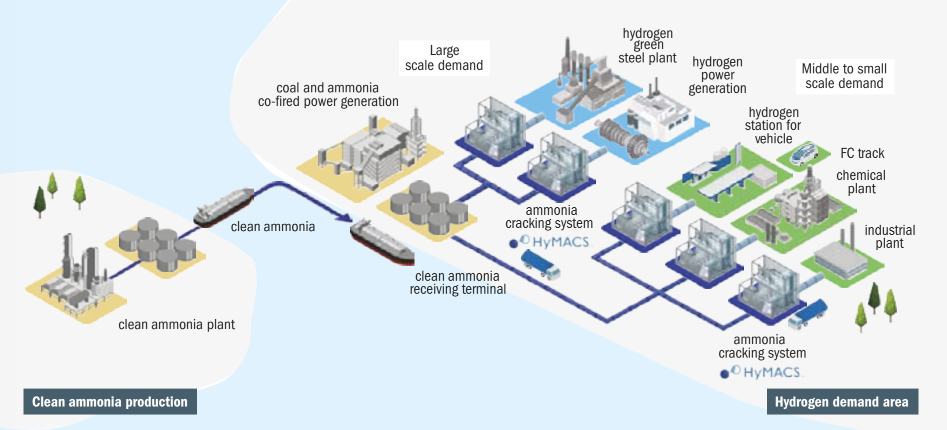
MHI's development of this advanced hydrogen purification process underscores its commitment to innovation and efficiency in ammonia cracking technology. By leveraging the advantages of ceramic membrane separation, MHI offers a cost-effective and environmentally friendly solution for hydrogen production.

Applications of HyMACS™

MHI's HyMACS™ ammonia cracking system is a versatile solution with broad applicability across various sectors, including:

- **Industrial plants**: Integration into existing industrial processes, such as chemical production, steelmaking, and refining, to provide a reliable and cost-effective source of on-site hydrogen.

Fig. 7: **Clean ammonia-hydrogen supply chain**



Source: MHI

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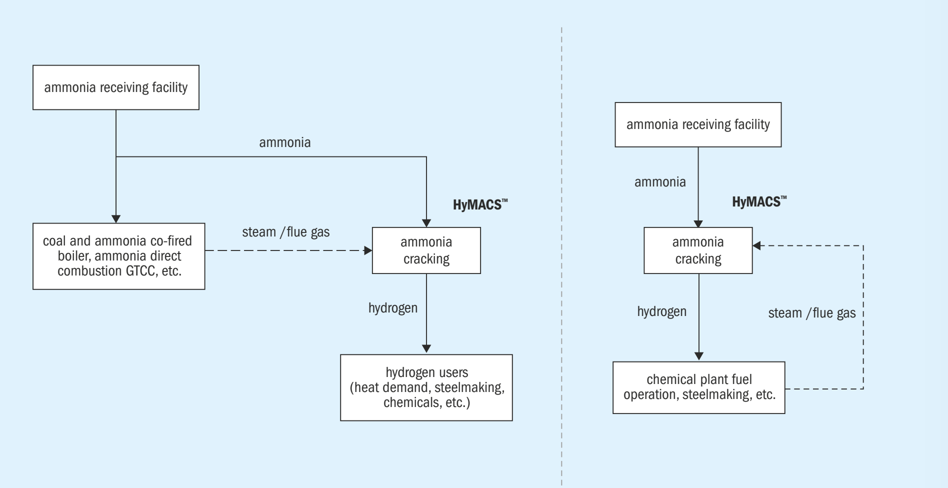
Fig. 8: **Scheme of exhaust heat utilisation**



Source: MHI

- **Hydrogen stations**: Supplying high-purity hydrogen for fuelling fuel cell vehicles, contributing to the development of a sustainable hydrogen infrastructure.
- **Power generation**: Integration with gas turbines offering a clean and efficient alternative to fossil fuels.

Fig. 7 shows the clean ammonia-hydrogen supply chain. With its experience, MHI Group can offer clean ammonia production, ammonia shipping transportation, ammonia cracking, hydrogen power plants, hydrogen green steel plants, as well chemical plants.

In this clean ammonia-hydrogen chain, ammonia is received from the blue or green ammonia plant and delivered to the primary consumer, especially in Japan, the coal and ammonia co-fired power generation facility. From there, ammonia will be delivered to sub-users, such as ammonia cracking devices capable of producing product hydrogen for end customers. The hydrogen supply chain aims to initially meet medium to small-scale hydrogen demands from consumers ranging from chemical plants, small hydrogen boilers or furnaces and hydrogen stations for vehicles before catering to large-scale hydrogen power generation demands.

HyMACS™ utilises exhaust heat from current combustion devices, including steam or flue gas, for the cracking procedure. This greatly lowers energy usage and operational expenses in comparison to systems that depend on combustion heat.

As shown in Fig. 8, steam or flue gas for the cracking process can be sourced from external facilities like coal and ammonia co-fired boilers, ammonia direct combustion gas turbine, among others. Accordingly, product hydrogen can be supplied or exported to meet the demand of external hydrogen users. Meanwhile, product hydrogen can also be utilised within the system or plant and the steam or flue gas generated can be reused as a heat source for ammonia cracking.

Current status of development

Development roadmap for HyMACS™

MHI initiated the development of its ammonia cracking technology in 2017. Laboratory tests for verifying equipment components were successfully completed in 2023. A pilot test is scheduled for completion by the end of FY 2025 at MHI's research laboratory to establish fundamental technologies. After the pilot test, a demonstration test will be conducted to validate the performance and durability on an actual scale, with the first commercial unit expected to be delivered in FY 2028. The development roadmap encompasses scaling up the unit size and comprehensively verifying the performance and durability of the entire system.

Summary

MHI is drawing upon its extensive experience in the design and construction of numerous ammonia plants to develop a low-temperature ammonia cracking system utilising non-precious metal catalysts. The low reaction temperature enables the efficient utilisation of exhaust heat (steam or flue gas) and significantly mitigates the risk of nitriding. Non-fired reactors are particularly well-suited for small to medium hydrogen demand applications and hydrogen purification using ceramic membranes can contribute to substantial savings in ammonia consumption.

MHI is currently preparing to conduct a pilot test, followed by a demonstration test, to validate the technology's performance and readiness for commercial deployment. ■

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Techniques to extend the life of steam methane reformer tubes

Muhammad Faisal Faraz and **Abdullah Al Balushi** of OQBi explain how by implementing a series of technical and process improvements, OQBi has successfully extended the lifespan of its reformer tubes by six years beyond the original design life of 100,000 hours.

The steam methane reformer

The steam methane reformer (SMR) is a critical component for syngas production. The SMR furnace of the OQBi methanol plants is a refractory-lined, down-fired, rectangular-shaped unit with a balanced draft system utilising forced draft (FD) and induced draft (ID) fans, designed by Jacobs (Worley). The furnace contains a radiant section with 768 catalyst-filled tubes (12 rows of 64 tubes) for endothermic reactions. Heat is supplied by 234 burners arranged in 13 rows, each row containing 18 burners. The burners were replaced during a mini- turnaround in July 2021. The mixed fuel comprises natural gas from the battery limit, tail gas from the PSA unit ammonia, purge gas from the synthesis loop, and flash gas from the crude methanol flash drum. Continuous monitoring of the reformer is crucial for maintaining long-term reliability and preventing unexpected plant outages. Key parameters monitored include heat flux, tube outlet temperature, cross-header temperature, reformer outlet temperature (ROT), tube skin temperature (TST), fuel header pressure, combustion air pressure, and reformer draft.

The reformer catalyst tubes have been in service since plant commissioning and have exceeded their useful service life of 100,000 hours (~11.5 years). A life assessment performed in 2023 revealed 26 tubes with indications 2-3 m from the top, with an expected extended life of 5 to 8 years. While the tubes are projected to last until the next turnaround in 2027-2028, ensuring reliable operation within all operating limits is essential to achieve this lifespan.

Asset integrity techniques

Since steam methane reformers are considered significantly complex and critical equipment in such plants, a special focus of inspection and integrity management programs have been developed to assess the health of tubes and implemented appropriate actions to prevent any failure. In OQBi, during any opportunity, reformer catalyst tubes, outlets pigtails and manifolds/hot collectors are inspected and evaluated. The first LEO-SCAN inspection was done as a baseline in 2009 prior to reformer commissioning, followed by a second inspection in the 2014 turnaround.

In the 2018 turnaround, all 768 catalyst tubes were inspected by LEO-SCAN and ID scan. In total, 74 outlet pigtails were inspected for outside diameter (OD) growth. Due to some observed OD growth in the outlet pigtails, the temperature was revised and an integrity operating windows (IOW) program was established for the catalyst tube outlet temperatures, hot collectors/manifolds and outlet cross headers.

During a 2019 pit-stop, selected catalyst tubes were inspected (visually, in-situ metallography, hardness and permeability). In total 89 outlet pigtails were inspected for OD growth during this opportunity.

During a mini turnaround in 2021, since no major indications were observed in 2019, selectively 30% of catalyst tubes were inspected by LEO-SCAN. All outlet pigtails (768) were inspected for OD growth. Any tube which had grown above 6% in OD was replaced immediately. To revise operating parameters and assess tube integrity, a laboratory based residual life assessment (RLA) for catalyst tubes was initiated.

In the 2023 turnaround, all catalyst tubes were inspected by LEO-SCAN and ID scan. Around 30 tubes were observed with small creep expansion (<1%). Another API579-level 1 RLA was conducted based on catalyst tube OD inspection outcomes. It was concluded that, with similar average operating hours, the tubes would maintain full integrity until the next turnaround in 2028. All outlet pigtails (768) were replaced in kind during this opportunity.

The main drivers for conducting the laboratory-based remaining life assessment initiated in 2021 were:

- fuel gas variation – prior to commissioning of the LPG plant, rich gas was supplied directly to the reformer with all hydrocarbons which increased tube temperatures and hot spots;
- observed tube diametric growth;
- to review operating parameters to suit current tube integrity conditions;
- to assess operating over 100,000 hours as recommended by the manufacturer (manufacturer recommended to replace at 100,000 hours if the operating parameters are near to design parameters, whereas actual operating parameters were lower in average).

The RLA considered the following:

- total number of start-ups / shutdowns;
- effective operation hours;
- average operating temperature/pressure;
- historical inspection data;
- design data.

Several techniques were used to enhance the inspection and condition of the reformer tubes and pigtails.

Optical microscopy and metallographic investigation

The metallurgy of the tubes was tested (see Figs 1 and 2) and it was found that there was a significant safety margin as the reformer tubes are operating more than 100°C below the design temperature. Under such conditions no significant creep damage was anticipated.

The microstructures consisted of austenite matrix with a moderate level of the secondary carbide precipitation interspaced by interdimeric primary carbides. The level of thermal aging is moderate. There is no evidence of creep cavitation damage in the microstructure. The OD of the reformer tube contained a recrystallised layer to a depth of 0.25 mm to 0.4 mm. The ID of the reformer tube contained a decarburised layer to the depth of approximately 0.2 mm.

The reformer tubes with diametrical expansion of less than 1%, without any isolated creep cavitation in the microstructure, operate in the early secondary stage of the creep life. The estimated maximum expended life fraction is less than 0.3. The remaining life of the reformer tubes is more than 70% of the original design life. The service life of the reformer tubes is expected to be significantly greater than 100,000 hours if the current average operating temperature is maintained.

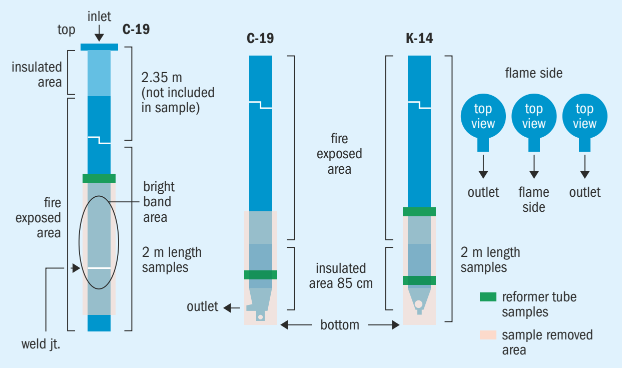
Diameter measurements and strain calculation

Based on measurements of the 'cold section', outside of the radiant fired section, the original OD is likely to be between 148.0 and 149.4 mm. The expected strain percentage for the samples is between 0.0% and 1.2% strain. The reformer tubes are currently operating at very low levels of diametral strain. Long remaining lives are expected, with a maximum of 30% life consumed based on metallurgical assessment.

Stress rupture testing

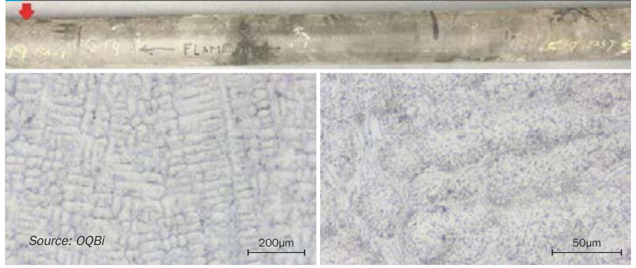
A stress rupture test was performed on three tubes at 500 and 1,000 hours with stress selected to be 30 MPa i.e. double the mid-wall stress of 15 Mpa for the actual operating pressure and temperature, and 938ºC, the average tube skin temperature observed in the frequent TST survey.

Fig. 1: **Tube Samples for RLA study**



Source: OQBi

Fig. 2: **C-19 Top section. No creep cavitation present. Remaining life >70% of design life. (same for all three samples)**



Source: OQBi

It was concluded that:

- The life consumed is approximately 50% (compare to the time to rupture at 938°C). The remaining life for the "cold" section is 100,000 hours compared to 50,000 hours for the "hot" section at 938°C.
- Using the historical average data for either the bottom peephole level or middle peephole as a comparison (928°C or 938°C respectively), the remaining life is more than 100,000 hours.
- The reformer tubes should be capable of delivering another 10 years of service provided the operating temperatures do not exceed the historical averages.

Creep rupture calculation

Historical trends over operation time were reviewed for skin temperatures. The maximum average temperature was found to be 928°C for the lower peephole level. The maximum average found was 938°C which

Table 1: **Example of stress rupture test data**

Tube number	Section	Planned test duration (hours)	Temperature	Stress (MPa)	Actual Test Durations (hours)	Outcome
C-19	Radiant	1,000	938	30	796	Rupture
	Cold	1,000	938	30	+1,500	Discontinued

Source: OQBi

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is a 10°C increase from the bottom. An additional 10°C buffer was added to the averaged historical temperature data to provide insight into the remaining life. All results are for remaining life expectancy across the reformer assuming 100,000 hours from commissioning.

Sensitivity analysis of remaining creep life

Sensitivity analyses were done to display the maximum percentage life consumed at a range of temperatures. Readings are based on the reformer middle peephole data as the temperature readings were higher than bottom peephole measurements. An additional 10% was added to the temperatures in the analysis to overcome the emissivity error while taking the pyrometer measurements.

Finally, the following conclusions were made:

- A low level of creep strain below 1% was measured in the reformer tubes by ECT and laboratory diametral measurements. In total, 230 tubes were tested using ECT in 2021. Only five reformer tubes showed small indications.
- The through wall metallography confirmed no creep damage.
- A maximum of 30% of life consumed (as confirmed by the condition of the microstructure).
- The stress rupture tests showed a significant reduction in the creep life of the radiant section compared to the cold section.
- A maximum of 50% of life was consumed (as confirmed by stress rupture testing).
- The measured skin temperatures are significantly below the design temperature.
- With +10°C uplift, long remaining life was predicted using historical operating data.
- An average of ~3 start-up/shutdown cycles per year have not shown any creep damage on the ID of the reformer tubes.
- No significant reduction in life is expected due to current stop-start cycles.
- The remaining life of the reformer tubes under the current operating conditions is expected to be more than ten years.
- After evaluating the metallurgical properties, creep presence, estimated fractional life, the operating parameters fixed at 865°C as maximum and pressure of 18.2 bar.
- Accordingly, a full-fledged IOW program was established to monitor tube temperature on a daily basis. Since then, any excursion in operating temperature has been tackled and normalised immediately.

Process solutions for reformer tube integrity improvement

Capex and opex projects between 2018 ~ 2024 helped optimise SMR operations. The commissioning of an upstream LPG plant in 2021 stabilised natural gas quality and resolved air/fuel imbalance issues.

Table 2: **Overall comparison of SMR condition before and after applying capex projects**

Process parameters	Before improvement	After improvement
Natural gas quality	No LPG extraction plant upstream of methanol plant thus, frequent NG quality variations (lean/rich).	LPG plant commissioned in 2021 upstream of methanol plant, which stabilised NG quality and recovered additional products (C_3, C_4, condensate) (Fig. 3).
Plant load and energy efficiency	• Methanol plant is limited to 103% load; • Energy intensity ~36.3–37.5 million Btu/tonne.	• After commissioning of new LPG plant upstream and an ammonia plant downstream of the methanol plant, methanol throughput was maximised to 106%. • 1.15% energy reduction; (~$1.15 million/year saved).
Fuel configuration	Purge gas (75–80% H_2); NG (18~19% of total fuel). Flash gas (2~3%).	Purge gas: reduced to <5%. Tail gas: new fuel from PSA~40%. NG fuel: ~35~40% flow increased. Flash gas: 2~3%.
Burner and combustion	Old staged air type burners were used since commissioning, often facing issues of CA balance, hot spots and uneven firing.	Burner upgraded to Ultra Low NOx (dual fuel type) from JZHW, better combustion and flame control (Fig. 4), resulting in additional reformer outlet temperature, conversion and 3% plant load increase (Fig. 5).
TST monitoring	Tube skin temperature (TST) external thermography performed on schedule basis (monthly). Hotspot and flame impingement observed during 2017-2018 turnaround.	TST measuring frequency was revised and included a third party TST survey by a chemical vendor and other vendors to ensure tube integrity are not compromised.
Firing automation	Manual fuel control caused inconsistencies/hotspots/ poor flame pattern leading to reduced plant load and high temperature spread.	Reformer outlet temperature (ROT) controller introduced; automatic fuel adjustments for stability as part of digitial solution, which helped to control temperature and increase plant throughput.
Operating windows	No formal way to monitor/report firing conditions. Limited to field observations only.	New Integrated operating windows (IOW's) are created based on design limits and being automated online. reports are issued daily basis & excursions are being tracked.
Heat flux and S/C control	Manual calculation (theoretical) for heat flux. Operating at higher steam to carbon (S/C) ratio due to hot-spots and uneven firing.	• Automated monitoring of TST. • S/C ratio optimised to 2.85 from average 2.9~2.95 ~$3.5 million/year savings.
Catalyst upgrade	• Desulphuriser consists of a single layer adsorbent from vendor-A. • Vendor-A catalyst has been used since commissioning for SMR.	• Single layer desulphuriser was changed to 3 layers to improve desulfurisation from Vendor-B. • Vendor-B catalyst with improved performance and lower pressure drop observed in SMR.

Source: OQBi

These changes reduced NOx emissions, improved heat distribution, and increased plant load from 103% to 106%. Energy intensity also dropped by approximately 1.15%, saving over $1 million annually. Major process solutions were adopted after the 2018 turnaround, mini turnaround in 2021 and the 2023 turnaround (see Table 1).

Challenges and action plan

Action plans have been put in place to address several remaining challenges.

Small eddy current indications in multiple tubes:

- outlet and cross header temperatures lowered to extend tube life until the 2028 turnaround.
- pre-planned tube inspections conducted at every available opportunity.

Significant temperature deviation might directly affect tube integrity:

- Integrity operating windows (IOW) program has been developed to monitor catalyst tubes, outlet pigtails, and cross headers;
- IOW limits narrowed further to prevent sudden excursions;
- advanced thermal imaging cameras deployed for tube skin temperature (TST) surveys;
- gold-cup tube surveys scheduled twice a year.

Burner tips choking due to throttled firing causing unstable flames:

- online inspection and maintenance procedures developed and implemented;
- daily and weekly visual surveillance initiated for flame pattern and hotspot monitoring.

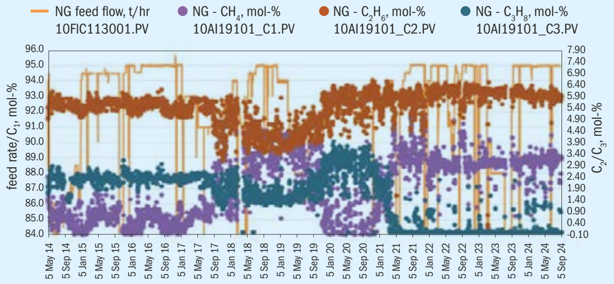
TST survey may contain human and machine error:

- advanced thermal imaging cameras adopted for consistent TST measurement;
- biannual gold cup surveys added as verification;
- alternative peep-door inspection introduced.

Increased CO_2 emissions post fuel configuration change (ammonia commissioning):

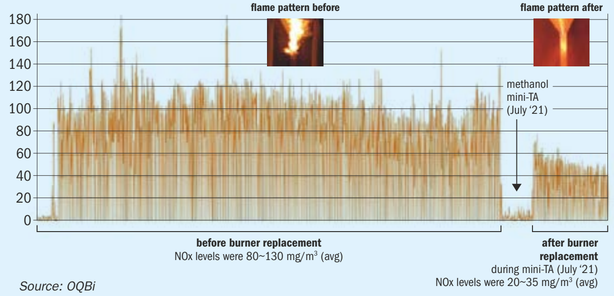
- scope and action plan finalised to achieve
  - ○ 25% reduction in decarbonisation targets
  - ○ 10% reduction in overall energy intensity.

Fig. 3: **Comparison of NG quality variation. Post LPG commissioning (2021), C_3 is extracted as a product and NG stabilised to downstream plant**



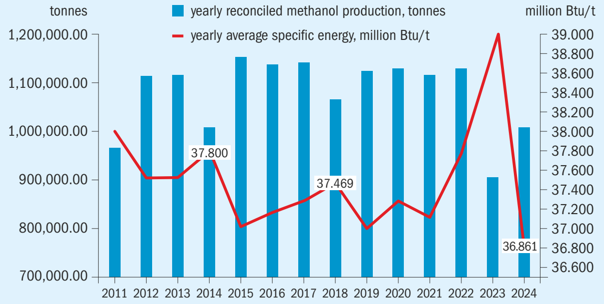
Source: OQBi

Fig. 4: **NOx levels (mg/m³) before and after burner upgrade**



Source: OQBi

Fig. 5: **Overall annual methanol production and plant energy intensity**



Source: OQBi

Conclusion

Through advanced inspection techniques, improved process design, and automated monitoring, OQBi has significantly enhanced the operational reliability and lifespan of its SMR tubes, deferring costly tube replacement, improving plant efficiency and setting a strong benchmark for reformer management.

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KPIs for blue hydrogen technology selection

Key performance indicators at industrial scale, such as feedstock consumption, carbon emissions, and overall costs are compared to evaluate the performance of several low carbon (blue) hydrogen production technologies. A detailed comparison of SCT-CPO, SMR and ATR technologies is reported considering the key driving capital costs and the related operational expenses to achieve net-zero emission requirements.

L. Falbo, F.E.G. Ferrari, G. Albasio, L. Basini (NextChem S.p.A., MAIRE)

Hydrogen is a versatile fuel and chemical compound that can be produced from many energy sources, including coal, oil, natural gas, biomass, renewable energy, and nuclear power. Production can be accomplished through various technological processes, such as reforming, gasification, pyrolysis, electrolysis, and other advanced methods.

Depending on the feedstock and production method, many organisations informally classify hydrogen using a colour-based system[1]. Although this method is commonly employed, it can cause confusion since there is no universally recognised naming convention, despite the general acceptance of three main colours:

- grey hydrogen, created from fossil fuels, mainly natural gas, without capturing the greenhouse gases generated;
- blue hydrogen, produced from fossil fuels, where the carbon dioxide by-product is removed at source using carbon capture and storage (CCS) technologies;
- green hydrogen, generated by using clean electricity from surplus renewable energy sources, where no carbon is produced.

Although there is a wide range of hydrogen production technologies at different stages of commercial maturity, this study focuses on blue hydrogen technologies that use natural gas as a feedstock. While green hydrogen could become highly competitive in the future, considering factors like access to low-cost feedstock and government policies, in the near-to-medium term, blue hydrogen is likely to provide the majority of the world's low-carbon hydrogen. This is due to its more mature production processes and the ability to deploy these facilities at a large scale in industrial clusters with CCS. This also meets industrial demand, which accounts for nearly 100% of current demand.

Steam methane reforming (SMR) with CCS in several configurations has been the subject of most blue hydrogen assessment studies to date, as well the most applied in the existing industrial facilities.

Autothermal reforming (ATR) is another worldwide-used technology to produce low-carbon hydrogen.

The Short Contact Time – Catalytic Partial Oxidation (SCT-CPO) is also applied, constituting an additional solution for improving some limitations of the current technologies.

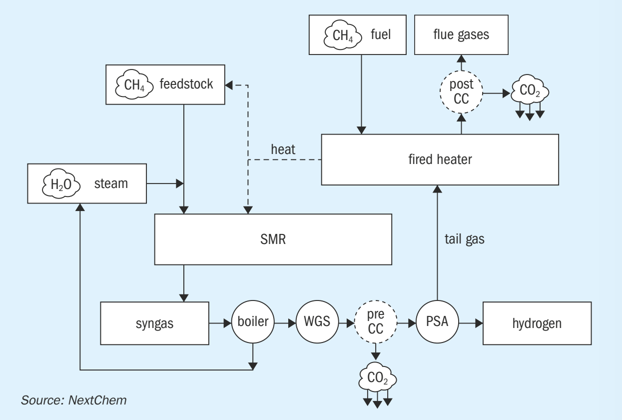
This article provides an overview of three technologies and compares them to identify key performance indicators for selecting the best technology for blue hydrogen production.

Technologies description

Steam methane reforming (SMR)

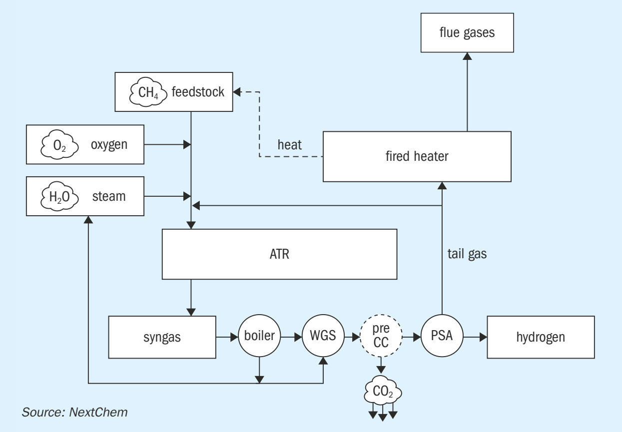
SMR is currently the most utilised technology for syngas and hydrogen production[2]. Fig. 1 shows a typical SMR block flow diagram.

Fig. 1: **Typical SMR block flow diagram**



Source: NextChem

Fig. 2: **Typical ATR block flow diagram**



Source: NextChem

The endothermicity of SMR reactions requires an external heat source, which typically is a dedicated fired heater: reforming reactions take place inside the tubes located in the radiant section, while in the convective section, heat is recovered from the hot product gases for preheating the reactants feeds and for generating superheated steam. The presence of the furnace implies the utilisation of external fuel, with additional carbon dioxide emissions in the flue gases. A variation on this configuration is to use electrically heated reformers (e-SMR), significantly reducing carbon emissions directly produced from the facility.

The reactions are catalysed by Ni-based catalysts, included inside 500-600 tubes for large-scale plants. The inlet temperature is in the range 500-650°C, while gas temperatures at the exit of the tubes are higher than 800°C. The hydrocarbon feedstock is fed into the reforming tubes after sulphur removal, typically through hydrodesulphurisation reactors (HDS), and is mixed with steam at steam/carbon ratios higher than 2.5 v/v, more often higher than 3 v/v. This steam excess is required both for completing the hydrocarbon reforming reactions and for avoiding the occurrence of carbon formation reactions, which lead to pressure drop increase, catalyst deactivation and reaction rates reduction, causing serious heat transfer problems and tube damages.

The syngas produced by the SMR is then upgraded to hydrogen by shifting the CO and H_2O into CO_2 and H_2 through the water gas shift (WGS) reaction. A single high temperature (HTS) or both high and low temperature (LTS) solutions can be foreseen to reduce the CO amount to values below 3 and 0.5 vol-%, respectively.

The WGS effluent is cooled, condensing the produced water, and fed into the carbon capture unit, where CO_2 is removed to a level of 0.1 vol-% or less by adsorption in specific solvents, typically amine-based. The captured CO_2 is then desorbed in a dedicated stripping tower. When the LTS step is used, the heat produced by the exothermic WGS reaction is used to reboil the CO_2 stripper.

When the feedstock does not contain nitrogen, the product hydrogen purity for optimum plant investment is in the range 97-98 vol-%. Higher purities can be achieved at the expense of extra investment and operating costs: pressure swing adsorption (PSA) is used for this purpose. Low-pressure tail gas, containing main impurities, unconverted methane and hydrogen slip is used as fuel for the fired heater to reduce the external fuel request, and associated carbon emissions.

SMR plants are typically sized between 5,000 and 200,000 Nm^3/h and are utilised for nearly the 50% of the world's hydrogen demand. The process is well known and widely applied in the MAIRE group, with the brand NX Reform™. This solution is widely applied at industrial scale to produce hydrogen with very high purity and at lower costs than other technologies. More than 60 hydrogen production units have been executed by KT (Rome) in the last 40 years. Plants have been designed and built for very high plant reliability (>99%) and with a turnaround of up to six years. Furthermore, several optimisations have been executed, from zero export steam solutions to tailored requirements on customer needs with the highest efficiency.

Autothermal reforming (ATR)

The (non-catalytic) partial oxidation of hydrocarbons was the major commercial route for hydrogen production for several decades in the middle of the last century[3]. It uses a controlled amount of oxygen to limit the oxidation reaction to the carbon monoxide production. Being based on oxidation, the involved reactions are strongly exothermic, producing a huge amount of thermal power to be used and recovered in the downstream steps.

The ATR combines non-catalytic partial oxidation and catalytic steam and CO_2 reforming of natural gas in a single reactor. In this process, the hydrocarbon feed and superheated steam are mixed and preheated to about 600°C and then mixed with oxygen. The reagents ignite in a combustion chamber originating a sub-stoichiometric flame. Subsequently, the steam and CO_2 reforming reactions occur inside a Ni-based catalytic bed located below the combustion chamber. By a proper adjustment of oxygen to carbon and steam to carbon ratios the partial combustion in the thermal zone supplies the heat for completing the subsequent endothermic reforming reactions. Fig. 2 shows a typical ATR block flow diagram.

Due to this combination, ATR has a very high energy integration, resulting in a thermal efficiency (calculated as enthalpy ratio between reformed gas and feedstock) of around 89%, instead of a typical 80% for tubular steam reforming. Furthermore, due to the absence of tubes, ATR can be operated at higher temperatures than SMR, leading to the minimisation of methane slip and a lower thermodynamic equilibrium approach also in the presence of sulphur catalyst poisoning.

Sometimes, ATR is also utilised as a "secondary reformer" (for lowering the CH_4 residue) and it is placed after a primary SMR in some applications. In other applications, a gas-heated reformer (GHR) is added to the process to pre-heat and partially reform the natural gas feedstock before entering the primary ATR reformer. The integration of the GHR is typically preferred in the low

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carbon hydrogen compact configuration since the heat transfer within the GHR is convective rather than radiative, the required footprint of the GHR is much smaller than a conventional SMR.

Eventually, in hydrogen production by ATR, the following process stream is similar to SMR, with the WGS reactor before the hydrogen is cleaned by carbon capture and purified in the PSA.

ATR plants are typically sized for large capacity (>150'000 Nm³/h). In the MAIRE group portfolio, the ATR is also present with the brand NX AdWin® Hydrogen Suite. This technology leverages an autothermal reformer operating at high pressure (60+ barg), reducing the size with respect to conventional ATR. A robust proprietary reactor, proven reforming catalyst and a combustion zone properly designed are integrated in a well-established syngas production unit. Furthermore, this is combined with a reduction of external heat requirement from the furnace, which is fed with hydrogen only during normal operation.

Carbon dioxide is captured by a dedicated pre-combustion carbon capture unit, based on a specific cold methanol loop (CML). An overall capture rate higher than 98% is achieved with 40% less solvent circulation compared to a MDEA-based plant.

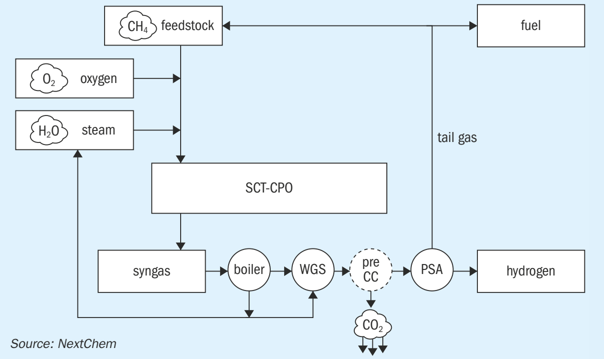
The steam/power production allows the implementation of a self-sufficient system, including the power demand of the air separation unit (ASU) for oxygen production. As a result of these features, hydrogen production cost by using NX AdWin® Hydrogen Suite is reduced by 10% with respect to conventional ATR.

Short contact time – catalytic partial oxidation (SCT-CPO)

The SCT-CPO technology is applied for producing syngas from different gaseous hydrocarbon sources and it constitutes an additional solution for improving some other technology limitations[4,5].

In this technology the oxidation reaction takes place over a catalyst to facilitate the partial oxidation of the hydrocarbon fuel at lower temperatures. The dedicated reactor utilises short contact time – catalytic partial oxidation (SCT-CPO) processes, where reactants and products remain inside the reaction zone for periods between 0.03 - 0.05 s, approximately 1/50 shorter than those of the residence time of the other synthesis gas production reactors. Since 1992 several scientific and technical literature documents and patents have been dedicated to the description of the SCT catalytic partial oxidation phenomena[4]. The SCT-CPO technology is included in the MAIRE portfolio under the NX CPO™ brand.

Fig. 3: **Typical SCT-CPO block flow diagram**



Source: NextChem

The proprietary reactor includes internal refractory layers, allowing it to operate in nearly adiabatic conditions, and it is designed to promote heterogeneous reactions by mixing the gaseous reactants and flowing them on extremely hot catalytic surfaces. Reactant molecules remain confined inside a thin solid–gas interphase zone surrounding the hot catalytic particles for a short contact time at temperatures that can reach 1,200°C. The high-temperature environment and the heterogeneous catalysis favour the formation of partial oxidation reaction products, limiting the contribution of the total oxidation reactions that mainly occur at the beginning of the catalytic bed. Moreover, the very high surface temperatures inhibit catalyst deactivation phenomena related to chemical poison effects.

For these reasons, this chemical process can be carried out in very small reactors, having a very high flexibility towards reactant flow variations. This means that the reactor and the catalyst volumes are reduced by two orders of magnitude with respect to other syngas production technologies, without associating an increase in the technology complexity. This allows the construction of modular pre-built and skid-mounted plant units that can be transported and hooked up to utilisation sites, with a drastic reduction of on-site activities in remote and/or offshore contexts.

Fig. 3 shows a typical SCT-CPO block flow diagram.

Due to the presence of a specific catalyst, the carbon feedstock can be fed to the reactor at temperatures in the range of 300-400°C. These values are considerably lower than the requirements for SMR and ATR, leading to the possibility of preheating the feedstock with a feed-effluent heat exchanger, recovering the power generated by the exothermic reactions. This offers the opportunity to avoid the fired heater, which is a source of additional CO_2 emissions. Therefore, a single source of CO_2 is present in the process scheme, easily removable with pre-combustion carbon capture facilities.

Also for NX CPO™, the treatments for syngas purification to hydrogen are similar to other technologies, removing gradually CO (through WGS), H_2O (through condensation), CO_2 (through CC), and CH_4 and traces of other impurities (through PSA). A specific characteristic of the technology is the possibility to reutilise the tail gas from the PSA directly as reactor feedstock, after a compression step. This further increases the overall process efficiency, reducing the carbon feedstock consumption per hydrogen produced.

The NX CPO™ technology has been intensively studied and applied during the last few years. Since the very early bench-scale experimentation[4,5] and patent publications of the 1990s[6,7], the long effort has led to industrial-scale applications up to capacities of 50-70,000 Nm³/h. Further capacity increases are under development.

Table 1: **Grey hydrogen performance comparison**

Technology	**Methane consumption (MWh/1,000 Nm^3_{H2})**	**Electricity consumption (MWh/1,000 Nm^3_{H2})**	**Production cost***	**Emitted CO_2 (kg_{CO2}/1,000 Nm^3_{H2})**	**Plant surface area**
Conventional SMR	3.9 (0.92 x)	0.04 (2.0 x)	(1.15 x)	780	(1.4 x)
Conventional ATR (purchased oxygen)	3.8 (0.90 x)	0.03 (1.5 x)	(1.30 x)	762	(1.2 x)
NX CPO™ (purchased oxygen) **Base case**	4.2 (1.0 x)	0.02 (1.0 x)	(1.00 x)	805	(1.0 x)

**Production cost of hydrogen calculated as: (capex + 10 years opex)/(10 years H_2 volumes), by using real values 2023 as per Process Economics Program (PEP) Yearbook by S&P (considered Saudi Arabia values) and IEA Net Zero Emissions by 2050 Scenario for other emerging market and developing economies as of the World Energy Outlook 2023. Decarbonised purchased oxygen. Reference hydrogen capacity: 50,000 Nm³/h.*

Source: NextChem

Technology comparison

Two different analyses are carried out: the first without capturing the produced carbon dioxide, with the aim of comparing the technologies when grey hydrogen is produced. In this way, specific advantages related only to the specific technology can be observed.

In a second analysis, blue hydrogen production is evaluated, focusing on the beneficial integration of all the sub-units available in the process. Pre- and post-combustion amine-based carbon capture units have been used to reach the highest degree of decarbonisation for each technology.

In all the analysed cases, the feedstock is natural gas at grid pressure, therefore a dedicated compressor is used to reach the proper pressure. The hydrodesulphurisation step is also present to remove the sulphur amount in the feedstock.

Oxygen required for ATR and CPO cases is considered both as purchased or produced by a dedicated ASU. In this way, the advantage of decarbonised oxygen availability (i.e. presence of an electrolyser for green hydrogen production, specific industrial site cases) can be easily considered in the comparison

High pressure steam is produced and, when available, excess steam can be valorised. Dedicated demi-water supply and cooling medium are considered as utilities available at the site.

Both high and low-temperature WGS reactors are considered, as well as PSA to reach a hydrogen purity of 99.9 mol-%.

The analysed parameters are:

- Methane consumption – calculated sum of carbon feedstock and fired heater fuel gas (when necessary).
- Electricity consumption – used for feedstock compression, tail gas recycling (when present), ASU (when present), and BFW pumping purpose.
- Production cost – calculated considering both capex and opex. Saudi Arabia is considered as a reference country for the price cost estimation.
- Emitted CO_2 – final utilisation of captured carbon dioxide is not considered in the analysis. When oxygen is required, decarbonised oxygen is considered.
- Plant Surface area – considering all the facilities to reach the required hydrogen purity.

Technology comparison for grey hydrogen production

For grey hydrogen production, three cases are analysed:

- conventional SMR;
- conventional ATR, with purchased oxygen;
- NX CPO™, with purchased oxygen. This is used as a base case for comparison purposes.

Table 1 summarises the main results.

The ATR shows the lowest methane consumption among the cases, but there are no huge differences in electricity consumption when oxygen is purchased.

All the cases produce high-pressure steam, which is used as a reactant and as a heating medium when possible. Excess of steam production is observed and valorised.

The production cost of hydrogen results in 15% higher for SMR and 30% higher for ATR with respect to NX CPO™, considering both capex and 10 years of opex.

Fig. 4: **Size comparison between NX CPO™ and conventional SMR**

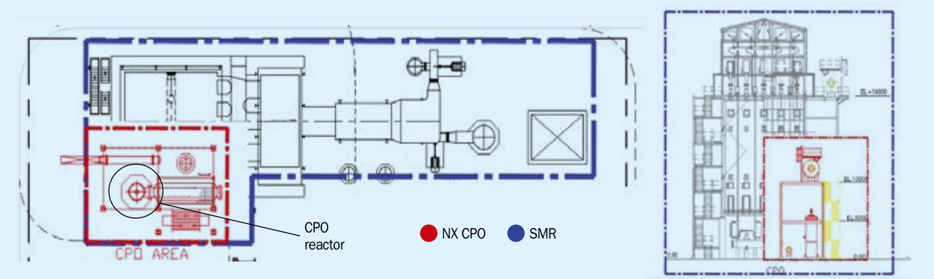


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Table 2: **Blue hydrogen performance comparison**

Technology	Methane consumption (MWh/1,000 Nm$^3_{H2}$)	Electricity consumption (MWh/1,000 Nm$^3_{H2}$)	Production cost*	Emitted CO_2 (kg$_{CO2}$/1,000 Nm$^3_{H2}$)	Plant surface area
Conventional SMR + pre- combustion CC	3.9 (1.08 x)	0.05 (0.8 x)	(1.15 x)	320	(1.4 x)
Conventional SMR + pre- and post-combustion CC	4.1 (1.11 x)	0.07 (1.1 x)	(1.40 x)	27	(2.0 x)
Conventional ATR + pre- combustion CC (purchased oxygen)	3.8 (1.05 x)	0.06 (1.0 x)	(1.30 x)	15	(1.2 x)
NX CPO™ + pre- combustion CC + ASU	3.6 (1.0 x)	0.26 (4.3 x)	(1.0 x)	4	(1.2 x)
NX CPO™ + pre- combustion CC (purchased oxygen) **Base case**	3.6 (1.0 x)	0.06 (1.0 x)	(1.0 x)	4	(1.0 x)

**Production cost of hydrogen calculated as: (capex + 10 years opex)/(10 years H_2 volumes), by using real values 2023 as per Process Economics Program (PEP) Yearbook by S&P (considered Saudi Arabia values) and IEA Net Zero Emissions by 2050 Scenario for other emerging market and developing economies as of the World Energy Outlook 2023. Decarbonised purchased oxygen. Reference hydrogen capacity: 50,000 Nm³/h.*

Source: NextChem

In grey hydrogen, with elevated purity, all the carbon available in the feedstock is transformed into carbon dioxide, therefore, without capturing the produced carbon dioxide, the emissions to the atmosphere are intrinsically related to the feedstock consumption.

As previously reported, NX CPO™ is strongly compact and does not need a fired heater resulting in a lower surface area, as shown also by the size comparison between SMR and NX CPO reactors (Fig. 4).

Technology comparison in blue hydrogen production

For blue hydrogen production, five cases are analysed:

- Conventional SMR with pre-combsution carbon capture: Flue gases from fired heaters are not treated and emitted to the atmosphere.
- Conventional SMR with pre- and post-combustion CC: A dedicated post-combustion carbon capture unit is mandatory for SMR to reach a decarbonisation degree higher than 85%.
- Conventional ATR with purchased oxygen and pre-combsution CC:
- NX CPO™ with oxygen production through a dedicated ASU and pre-combustion CC.
- NX CPO™ with purchased oxygen and pre-combustion CC: This is used as the base case for comparison purposes.

Table 2 summarises the main results.

A reduction of methane consumption, mainly due to the reutilisation of tail gas as feedstock, is observed in blue hydrogen produced by NX CPO™. In this way the overall carbon efficiency of the process increases, leading to extremely low emissions (purge gas to avoid inert gas accumulation).

Differently, an increase in methane consumption is observed in the case of SMR with Pre and Post Combustion CC. The reason is related to the steam balance: post-combustion CC requires a significant amount of low-pressure steam for the solvent regeneration, which can be produced only by increasing the fired heater generated power, and therefore the fuel gas consumption.

The presence of ASU strongly increases electricity consumption (observed for both ATR and CPO). However, ASU installation or oxygen purchase are considered equivalent to the production cost bases used for the study (i.e. electricity and oxygen costs in Saudi Arabia).

As a result of the study, the hydrogen production cost is significantly lower for NX CPO™ than other technologies when integrated with the CC facility. This very competitive price is essentially due to a better energy integration, which leads to low methane consumption, and low capex associated with the technology.

The strong reduction in carbon footprint by using ATR and CPO is conserved also when integrated with carbon capture.

Fig. 5 presents the comparison results regarding the degree of decarbonisation. The NX CPO™ and ATR technologies for blue hydrogen production demonstrate a significant reduction in CO_2 emissions, capturing 98-99% of total CO_2.

In contrast, pre-combustion carbon capture on SMR captures approximately 60% of CO_2 (up to 85% with special configuration). To achieve high levels of CO_2 capture (>85%), SMR would require post-combustion carbon capture, which involves very high operational and capital expenditures.

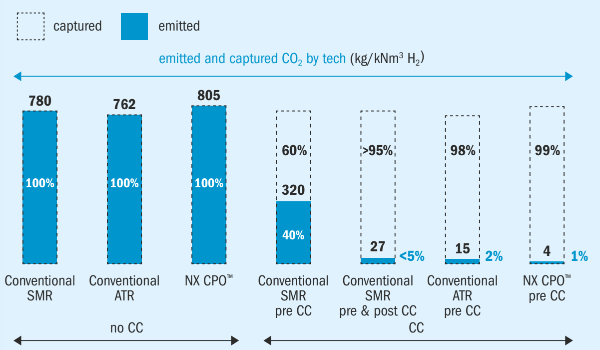
Conclusions

The decarbonising hydrogen production is a complex task and requires a context-specific approach. The different technology solutions involve various degrees of efficiency, carbon capture capabilities, and costs depending on the scale of production and specific operational conditions.

In grey hydrogen production, conventional ATR has the minimum methane consumption, resulting in higher process efficiency and low carbon emission. Therefore, it is generally advised for large-scale hydrogen production. Considering the geographical context used for comparison, NX CPO™ shows the lowest cost for construction and 10 years of production, although its limited application in hydrogen production at comparable scales with SMR and ATR.

Despite the specific analysis performed, SMR is the most widely used technology worldwide in the range of 5 to 200 Nm³/h of hydrogen production, which is the typical requirement in the oil and gas and chemical production sectors.

Fig. 5: **Decarbonisation degree in hydrogen production**



Source: NextChem

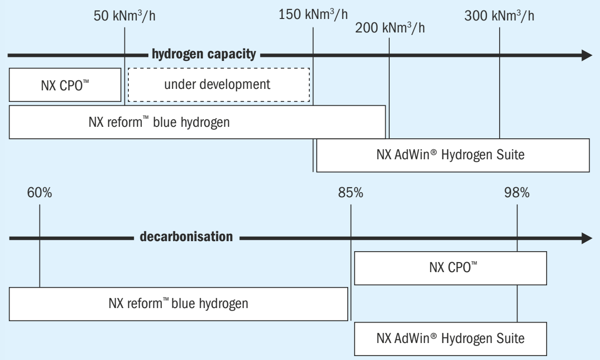
The picture slightly changes when carbon capture is associated to blue hydrogen production. Due to a lower feedstock temperature required for the reaction, NX CPO™ operates without the need for an external furnace, thereby preventing flue gas generation and emission. Furthermore, NX CPO™ can more effectively re-utilise the CO_2-free tail gas produced during the hydrogen upgrading, recycling it as additional reactor feedstock and reducing the overall methane consumption.

In the ATR technology, the external furnace is needed only for feedstock preheating because of the autothermal conditions in the reactor. This lets PSA tail gas be used as fuel without extra external fuel, strongly reducing the CO_2 amount in the flue gas emissions. Thus, decarbonisation levels over 95% can easily be achieved with ATR and NX CPO™. In contrast, SMR requires high consumptions and costs due to the need for carbon capture post-combustion to exceed 85% decarbonisation.

In conclusion, the technology choice for blue hydrogen production must be guided by a comprehensive evaluation of key performance indicators such as the production capacity and the degree of decarbonisation required (see Fig. 6).

NX CPO™ emerges as a highly competitive technology for small to medium capacities (e.g. up to 50,000 Nm³/h) due to its superior energy integration and reduced methane consumption when associated with carbon capture facilities.

Fig. 6: **KPIs for blue hydrogen production technology selection**



Source: NextChem

The compact design allows low capital cost and high flexibility, with the lowest CO_2 emissions.

For medium capacities (e.g. up to 200,000 Nm³/h), NX Reform™ blue hydrogen, based on SMR, is the most applied technology, with a maximum decarbonisation degree of 85%.

While for large-scale production (e.g. higher than 150,000 Nm³/h), the NX AdWin® Hydrogen Suite, based on ATR, offers a robust solution with optimal performance.

There is not a sole technological solution to cover all variables and requirements. As the industry progresses towards net-zero emissions, the findings of this study underline the importance of tailored solutions in achieving sustainable and economically viable blue hydrogen production. ■

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