Gas to Power Journal
Peakload Power and Energy Storage

Focus on Upstream, LNG and Clean Fuels

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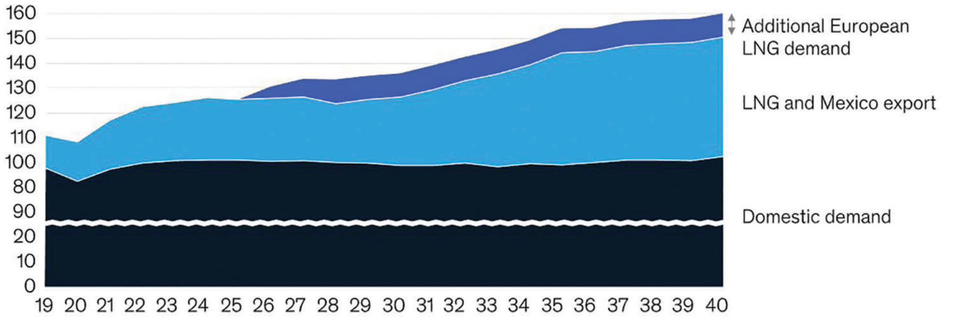
Europe's LNG build-out may pull in additional 80 Bcm of gas

The massive build-out of LNG import terminals in Europe may result in an additional 80 Bcm of gas demand. North America's large gas resources could meet over 30 years of domestic and LNG export demand at a cost of below $3/MMBtu, McKinsey reckons, though this would require investment in new feeder pipelines and buyers commit to 20-year offtake deals.

Increased LNG exports could affect North American gas demand.

North American gas demand under the Current Trajectory scenario[1], bcfd



[1]Dry gas consumption in US and Canada; LNG feed gas. Base case as Current Trajectory scenario from McKinsey Energy Insights Global Energy Perspective.
Source: EIA; NEB; McKinsey Energy Insights Global Energy Perspective 2022

Though US developers need to secure long-term offtake to make investment forthcoming, such long tenures are unattractive for Europe in face of the green energy transition. In fact, European LNG buyers prefer 5-year offtake agreements as much of the continent's gas-fired power stations will be co-fired with hydrogen or gradually replaced by renewable energy sources combined with energy storage.

Gauging future LNG demand is hence difficult, which is why most European buyers abstain from long-term commitment and are prepared to pay high prices for spot deliveries, if needed. Asian buyers, in contrast, are targeting to a greater share of long-term LNG volumes, a McKinsey survey finds. All buyers said they favour Henry Hub and oil indexation in the face of particularly volatile and high Asian and European spot prices.

Abundant, low-cost resources

North America is home to estimated 2,750 trillion cubic feet (Tcf) of natural gas resources, of which around 1,700–2,000 Tcf could

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MOL and NYK to ship ammonia to Hekinan power plant by late 2020s

The Japanese shipping companies MOL and NYK have agreed to transport ammonia as a fuel for JERA's Hekinan thermal power plant from the late 2020s. At unit 4 of the massive 4,100 MW plant, JERA aims to achieve an ammonia co-firing rate of 20% with a view to rolling out the technology across all of its thermal power stations.

To source large volumes of ammonia, JERA had been conducting a competitive bidding process since February of this year which included the option to participate in an ammonia production project. The aim is to create an ammonia supply chain for the Hekinan Unit 4 that reaches from upstream to power generation.

NYK ammonia carrier

To that end, MOL and NKY are working to develop large-volume ammonia carriers which "would be world-firsts," the shipping lines said.

Works at the Hekinan coal-fired power station focus on Unit 4, commissioned in 2001 and equipped with a turbine and generator from Toshiba

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AGENDA

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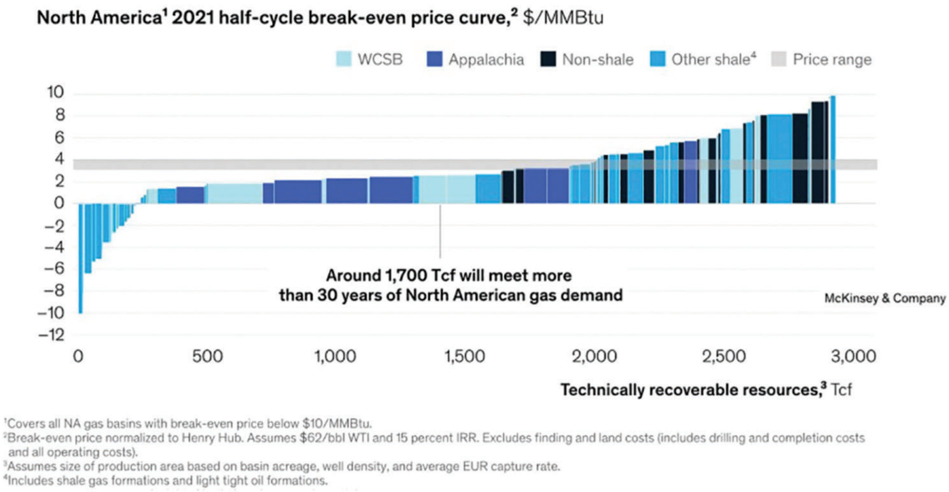

be produced at a cost between $3 and $4/MMBtu.

At stable production prices of around $3/MMBtu, North American LNG exports are globally competitive and can provide reliable and affordable gas to European consumers at a cost below $8/MMBtu — compared with recent prices of $40 to $70/MMBtu.

However, gas prices at demand centres are highly volatile and often rise well above the $3/MMBtu threshold due to pipeline constraints. Yet, if investment in new gas pipeline capacity is not forthcoming, the expansion of export capacity alone could result in a price increase of more than $1/MMBtu for US and European consumers, analysts warn.

"Gas infrastructure development and long-term offtake agreements are fundamental, or there will be higher prices for gas and LNG, which may have spill-over effects for power, fertilizer, and other essential commodities," said Dumitru Dediu, Partner at McKinsey.

On the other hand, if strategic pipelines links get build to connect low-cost gas basins to high-demand areas and export terminals, this could bring gas prices from today's high levels around $6/MMBtu back to about $3/MMBtu at Henry Hub, potentially reducing inflation. ■

ESB stays committed to UK power market despite 45% tax on profits

The Irish utility ESB remains committed to the UK energy market even though the government will levy a 45% tax on any electricity sold for more than £75/MWh ($88/MWh) from the new year to skim of "extraordinary profits" made by power generators. For its Carrington power station, ESB posted a £24.4 million profit last year, double that of 2020.

The new tax will be applicable to electricity from nuclear, renewable and biomass sources, while gas-fired power generators will be exempt despite widening spark spreads and profit margins. The Treasury argued it wanted to avoid setting distorting price signals for flexible assets.

Moreover, electricity generators will still be able to write off their investments against corporation tax by deducting their investment spending from their profit, the Treasury explained. Together with the cooperation tax, the new levy is expected to raise £14.22 billion in the period until the end of March 2028.

Tax impact seen to be "small"

Commenting on the UK's additional tax on profits on some of its power generation assets, the Irish utility said "an initial assessment indicates its impact on the ESB generation portfolio is expected to be small." The company hence stressed it remained committed to its investments in the UK.

At its 881 MW Carrington power station, ESG produced an electricity output of 4,321 MWh last year – more than twice what it generated in 2020. Recently filed accounts show profits from the gas-fired power station more than doubled to nearly £25 million last year which, according to the operator, reflects an increase in run-time hours as a result of energy supply pressure in the UK market.


Carrington Power Station (880MW)

Apart from gas-fired power, ESB owns and operates a number of windfarms in the UK and is developing the massive Neart Na Gaoite offshore windfarm project in Scotland, together with the French utility EDF. The first turbine foundation offshore was installed last month and once completed, the windfall will generate up to 450 MW of electricity. ■

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and a boiler from IHI. In October, JERA shortened the project timeframe and requested its project partner IHI Corp to fast-track delivery and installation of burners, the tank for storing ammonia, pipes, and other equipment necessary for the upgrade.

Once test runs are successful in fiscal 2023, JERA wants to quickly establish a proven technology for ammonia co-firing and subsequently roll out the upgrade at multiple power stations in Japan and abroad. Under its 'Zero CO2 Emissions by 2050' objective, JERA is promoting the adopting of greener fuels and is actively working towards low- or zero-carbon thermal power generation. ■

Europe's short-term dash for gas leaves Africa at risk of stranded assets

Though Europe's need to replace just over 100 Bcm per year of Russian gas by 2030 poses an opportunity to tap Africa's vast reserves, developers could end up with stranded assets. Analysts warn European demand will be short-lived, with offtakers unwilling to sign typical 15-25-year contracts as EU policies limit the role of gas in the energy transition.

To meet its REPowerEU objectives, Europe strives to secure an additional 50 Bcm of LNG imports and more than 10 Bcm of non-Russian pipeline gas supplies. Scrambling to source alternative, non-Russian gas supplies, European gas buyers are turning to Africa which holds 17.55 trillion cubic meters, or 9% of global gas reserves. Large untapped discoveries in Senegal, Mauritania, Mozambique and Tanzania are of particular interest.

But analysts warn that investment in the African upstream sector poses the significant risk of developers ending up with stranded assets since the REPowerEU policy stipulates a 52% reduction in Europe's gas consumption by 2030 by substituting hydrocarbons with clean energy sources. "This timeframe leaves new gas suppliers only eight years to come onstream. [But] projects typically require several years' lead-time before production can begin, and a lifespan of at least 20-25 years to achieve economic viability," Neil Quilliam, Research, Energy Director, Think Research stressed, urging investors and operators to ensure secure offtake agreements to not lose out.

With gas prices soaring, some gas exporting countries in Africa have adjusted their priorities. For example, in 2022, Egypt made plans to divert 15% of gas used for domestic electricity generation to exports to boost revenues and prop up its struggling economy. But in the long-run, Europe may not actually need significant new volumes of African gas, especially if the US delivers on its contractual obligations. "Europe is working with a short-term fix mindset, whereas Africa needs long-term financial and energy sustainability," Quilliam warned, advising African developers invest in clean energy sources instead. ■

US gas-burn forecast to fall in 2023, frees up volumes for LNG exports

Gas consumption in the US electric power sector is expected to decline in 2023 amid continuing growth in LNG exports. Though gas storages in Europe are now largely full, analysts say it will require significant volumes of LNG in the coming months to maintain adequate wintertime supply now that Russia has largely cut off pipeline gas deliveries.

This year, US utilities keep burning more gas to produce electricity despite a stark rise in fuel prices, reaching a peak of 6.37 million Megawatt-hours (MWh) on July 21, 2022, according to the EIA's Hourly Electric Grid Monitor. Analysts relate the soaring gas-burn throughout the summer to above-normal temperatures, reduced coal-fired electricity generation, and recent natural gas-fired capacity additions.

In the first eight months of this year, gas-burn in the electric power sector increased 7% to 33.2 Bcf/d – though gas prices at the benchmark Henry Hub averaged $6.41/MMBtu over that period, compared with pre-year prices at just $3.43/MMBtu. Gas prices were as low as $1.86/MMBtu in 2020 – at the height of the pandemic – but have increased ever since as few new large fields are coming onstream while supply of Russian gas to Western countries has come to a near-halt in retaliation to sanctions due to the Kremlin's war in Ukraine.

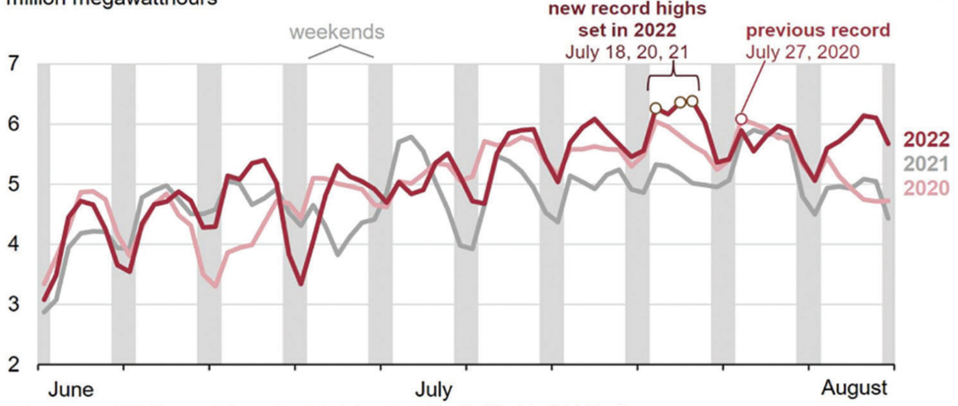
Coal constraints limit fuel switching

Typically, higher natural gas prices reduce natural gas price competitiveness relative to other sources, especially coal. Switching from gas- to coal-fired power generation would hence be the normal reaction of utilities in search of maximising margins.

But this summer, dispatch of coal-fired power plants was substantially lower than in previous summers. Continued retirements of coal-fired generating plants, relatively high coal prices, and lower-than-average coal stocks at power plants have limited coal consumption. In May, coal inventories at power plants averaged 20% lower than the prior-year levels.

Looking ahead, analysts at the US Energy Information Administration (EIA) expect gas-burn in the US power sector to fall in the fourth quarter of this year and during 2023, as more wind and solar power capacity becomes operational. Cold temperature over the winter, especially in January, will increase gas demand for space heating. Gas consumption is forecast to rise this year in the residential sector by 0.9 Bcf/d, in the commercial sector by 0.7 Bcf/d, and in the industrial sector by 0.4 Bcf/d from 2021-levels. ■

Daily U.S. natural gas-fired electricity generation (selected weeks in 2020–2022)
million megawatthours



Data source: U.S. Energy Information Administration, *Hourly Electric Grid Monitor*
Note: We adjusted values for previous years to align weekdays and weekends.

UK windfall tax rise jeopardises £200 billion of energy investments

Oil and gas production in the UK will fall in the coming years as £200 billion of planned investment is in jeopardy after the government increased the windfall tax to 35% from initially 25%. Shell announced it is evaluating plans to spend up to £25 billion in Britain and trade body OEUK warned others may follow suit.

Shell's Nelson platform in UK North Sea

Shell had planned to spend between £20 billion and £25 billion over the next ten years in Britain notably on oil and gas, offshore wind, electric vehicle charging and hydrogen. "But we are going to have to look at each of those projects on a case-by-case basis and re-evaluate them, based on the current fiscal outlook, and that will determine whether or not we invest at the amount we previously discussed," Shell's UK country chair David Bunch told the Confederation of British Industry's annual conference in Birmingham.

"When you tax more you're going to have less disposable income in your pocket, less to invest," he stressed. Last month, Shell posted a third-quarter profit of $9.45 billion (£7.92bn), slightly below the second quarter's record high due to weaker margins on refining and gas trading.

When Shell outlined its investment package five month ago, it underlined the need for a stable fiscal environment, but "since then, we have had three budgets, [and] a couple of prime ministers," Bunch criticised.

Need to rebuild confidence

The trade body OEUK is urging the government to rebuild investor confidence after increasing the Energy Profits Levy that was introduced in March. "This means our headline rate of tax in the UK will be 75%," the OEUK head Deidre Michi said.

"For some companies, the higher levy may mean projects become uneconomic more quickly so decommissioning is happening sooner. Other might reprioritise spend and use their reduced capital for new projects instead," she explained.

But unless there is rapid investment in new infrastructure, British production will fall by 15% a year which would make Britain reliant on other countries for at least 80% of its gas and 70% of oil consumption, Michi warned.

> "...we are going to have to look at each of those projects on a case-by-case basis and re-evaluate them, based on the current fiscal outlook, and that will determine whether or not we invest at the amount we previously discussed"
>
> *– David Bunch, Shell's UK country chair*

German manufacturers reach gas saving limit; Ifo survey finds

Three quarters of German manufacturing companies have managed to save on gas in the past six months without curtailing production, a survey by the Ifo institute finds. But the potential for further savings is running out, with 41% of surveyed industrial companies saying they could only reduce their gas use further by lowering their production and sales.

The Ifo survey was published as the day-ahead German Trading Hub Europe (THE) spot natural gas price increased to the equivalent of $33.95 per million British thermal units, its highest of the winter season so far. The gas price jumped as temperatures across Germany fell to low single figures in most regions.

Researchers specified a total of 59% of the companies surveyed use natural gas in their production processes. Of these, 75% have saved on gas in the past six months without curtailing production. "This large proportion is encouraging, but the differences between industries are significant [and] the potential for further savings seems to be running out," said Karen Pittel, Director of the ifo Center for Energy, Climate, and Resources.

Next six months

Regarding the next six months, only 38.8% of companies say they will be able to further reduce their gas consumption while keeping production at the same level. After all, 41.4% of industrial companies say that the only way for them to save more gas is if they cut back production at the same time. In the glass/ceramics industry, that figure is 69%; in the pharmaceutical industry, 67%; and in the chemical industry, 57%.

And 12.3% of all industrial companies even state that in order to reduce gas consumption further, it will now be necessary to stop production altogether. This is particularly true of food and animal feed manufacturers (27%), printing companies (24%), and metal product manufacturers (also 24%).

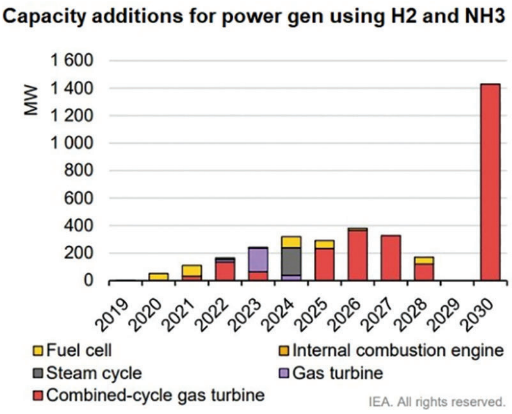
Almost 3.5 GW hydrogen-fuelled power plants due onstream by 2030

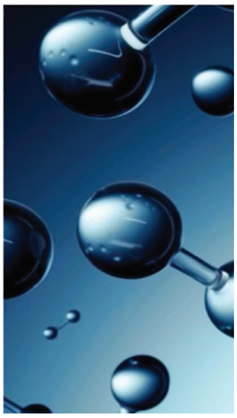
Firm projects to co-fire power stations with hydrogen stack up to almost 3.5 GW capacity by 2030. Hydrogen demand tops 94 million tons, practically all met by plants using fossil fuels with carbon capture, though the International Energy Agency (IEA) expects low-emission hydrogen to reach 16 to 25 million tons per year by 2030.

Of that total, 9 to 14 million tons would be "green hydrogen" produced through electrolysis using renewable energy, while 7 to 10 million tons would still come from fossil fuels with carbon capture, utilisation and storage (CCUS).

Realising all electrolyser projects in the pipeline could lead to an installed capacity of 134-240 GW by 2030, with the lower end of the range similar to total installed renewable capacity in Germany and at the upper end in all of Latin America. But analysts cautioned that just a 4% are under construction or have reached final investment decision (FID).

Manufacturing capacity for electrolysers currently sits at nearly 8 GW/yr, and based on industry announcements it could exceed 60 GW per year by 2030. "This would be enough to meet current government targets for electrolysis deployment, but the build-out depends on government targets being translated into real-world projects beyond the current project pipeline," the IEA commented.





Early support for projects – through subsidies or offtake agreements – is needed to ensure that they reach FID and scale up.

Green H2 competitive with grey one

With today's fossil energy prices, renewable hydrogen could already compete with hydrogen from fossil fuels in many regions, especially those blessed with abundant wind and solar power.

If the planned scale-up in manufacturing capacities takes place, costs for electrolysers could fall by around 70% by 2030 compared to today. Combined with the expected drop in the cost of renewable energy, this can bring the cost of renewable-based hydrogen down to a range to $1.3-4.5 per kilo H2 which is equivalent to $39-135/MWh, according to IEA calculations. The lower end of this range is in regions with good access to renewable energy where renewable hydrogen could already be structurally competitive with unabated fossil fuels. ■

Air Products, Mabanaft to build ammonia import terminal in Hamburg

Air Products and Mabanaft have announced plans to build a green energy import terminal in Hamburg as the Germany government seeks to import green ammonia from Saudi Arabia by 2026. The imported ammonia will be converted to hydrogen via Air Product's facilities in Hamburg before getting distributed to hard-to-abate industries, the transport sector and power producers.

The planned import facility will be situated at Matabaft's existing tank terminal in the port of Hamburg, which helps to quickly realise the project at a lower cost. Subsidiary Oiltanking Deutschland will run the terminal.

Project partners plan to initially invest €500 million, followed by a further €500 million at a later stage, to build a 55,000-ton ammonia storage tank which will be filled by imports from Saudi Arabia. Once filled up, the tank will serve as the basis for Air Products to produce around 100,000 tonnes of hydrogen per year.

As part of its National Hydrogen Strategy, Germany has committed to investing at least €9 billion to scale up the hydrogen economy. But critics doubt it will be able import enough renewable hydrogen to reach the targeted 76-96 TWh by 2030 – hence importing ammonia and cracking it into hydrogen will be part of the solution.

Robert Habeck, the German economy minister, called the investment decision of Air Products and Mabanaft a "strong signal for Germany as an industrial location". It shows that the plans are right "to convert a large nation to climate neutrality in a short time," he said, suggesting: "The dynamics in the topic of hydrogen are much greater than assumed a year ago."

Sourcing additional H2 from Canada and Egypt

Habeck has helped to arrange a memorandum to import LNG and green hydrogen from Egypt just prior to the COP27 Climate Summit. The Canadian provinces of Newfoundland and Labrador also committed to export green hydrogen to Germany, though no clear timeline has been set yet.

Apart from the ammonia import venture in Hamburg, the German utility Uniper plans to set up a hydrogen hub at or near the site of its LNG import terminal in Wilhelmshaven. The terminal will also be

Matabaft's tank terminal in Hamburg

equipped with an ammonia cracker for producing green hydrogen, as well as a 410 MW electrolysis plant, with the output meant to be fed into a planned future hydrogen network.

Rival RWE also plans to build an ammonia terminal at the site of its LNG import facility in Brunsbüttel. Around 300,000 tonnes of green ammonia per year are due to arrive in Germany via the terminal and be distributed to customers from 2026, the company said. The next step would be to build a cracker on a large industrial scale at the terminal to produce green hydrogen on site as well. ■

Bahrain's Alba takes FID for Power Station 5 Block 4

Aluminium Bahrain (Alba), the world's largest aluminium smelter outside China, has reached financial close for Block 4 of its Power Station 5 which will add 680.9 MW and push the plant's nameplate to over 2.4 GW. Mitsubishi and the Chinese contractor SEPCO III will handle EPC works for block 4 which is scheduled to start commercial operations in the fourth quarter of 2024.

The project will see the addition of a fourth combined-cycle power block in 1:1:1 configuration, though the efficiency for this new CCGT unit will be "much higher" than those of Alba's Power Station 3 and 4, the company said without specifying.

Block 4 will be powered by a M701JAC gas turbine, an air-cooled version of J-series gas turbines and a steam turbine. JAC gas turbines can run on up to 30% hydrogen fuel by volume, and Mitsubishi aims to reach 100% hydrogen fuel in the future with minimal infrastructure modification.

"By investing in efficient gas turbine, we will accelerate our energy transition and enable Alba to reduce its greenhouse gas emissions as we embrace Bahrain's objectives to reach Net Zero by 2060," said Alba's chairman Shaikh Daij Bin Salman.

Alba Power Station 5

Project finance consists of a $225 million China Export and Credit Insurance Corporation (SINOSURE) supported debt-facility and a competitive interest rate. The principal amount will be repaid over a 15-year period including a three-year grace period. ■

Chevron, Pertamina tap geothermal energy to produce H2 on Sumatra

US oil major Chevron, together with Singapore-based Keppel Infrastructure, will work with Indonesia's state-owned oil and gas company Pertamina to develop green hydrogen and ammonia projects on the island of Sumatra. The aim is to produce at least 40,000 tonnes of hydrogen per year, powered by 250 MW to 400 MW of geothermal energy in the initial phase.

Volumes of hydrogen produced could later be scaled up to 80,000-160,000 tonnes per annum, depending on the availability of geothermal energy as well as market demands.

Most of the clean-burning fuel will be exported to Asian markets, where several utilities have embarked on test runs to co-fired their hydrogen and ammonia in their fossil power stations. Moreover, ammonia can be used to replace bunker fuels to help decarbonise the shipping sector.

Indonesia is home to about 40% of global geothermal resources which can be used as a stable energy source to produce green ammonia or hydrogen. The mechanism of geothermal energy is simple: ground water is heated by deep underground magma near volcanoes, and the resulting steam turns the turbine of a generator that produces electricity. The International Energy Agency (IEA) believes Indonesia has a viable path to reaching its target of net zero emissions by 2060.

Cindy Lim, CEO of Keppel Infrastructure, said tapping Indonesia's enormous potential for renewables and low carbon energy to produce green hydrogen and ammonia will catalyse investments in green energy supply chain in the region." The Singapore-based company has a track record of developing energy and environmental infrastructure end-to-end, such as the 1,300 MW combined-cycle gas power station and a utility pipe rack that it operates on Jurong Island. ■

EnBW district heating plant gets H2-ready

New equipment in EnBW's Stuttgart-Münster district heating power plant will be H2-ready from the get-go. The retrofit, carried out by Siemens Energy, will see gas will initially replace coal for three years, but the two SGT-800 turbines and all other systems will be apt for hydrogen as EnBW seeks to switch to the green fuel in 10 years' time.

The two new turbines, with 62 MW electrical output each, replace the three coal-fired boilers that have been at the location until now. But both EnBW and Siemens Energy are already planning for a future beyond the gas turbines: "Pipelines, control systems, and boiler technology also have to be converted as quickly and easily as possible when green hydrogen is available," EnBW engineer Diana van den Bergh explained. EnBW is looking at a timeframe of 10 to 12 years.

In the agreements, Siemens Energy provides assurance that the new turbines will be able to process up to a 75% hydrogen admixture from the time they're shipped in 2025, and the overall package is prepared to handle 100% hydrogen.

"We can't yet reliably predict when green hydrogen will be available in sufficient quantity and at affordable prices," EnBW Managing Board Member Georg Stamatelopoulos explained: "But the technology should be in place by that time. We're not going to put the cart before the horse – which, by the way, is the objective in all our fuel switch projects."

Once all approvals have been obtained, construction work on the plant's new combustion system could begin in the first quarter of 2023. ■

Geothermal power plant on Sumatera

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