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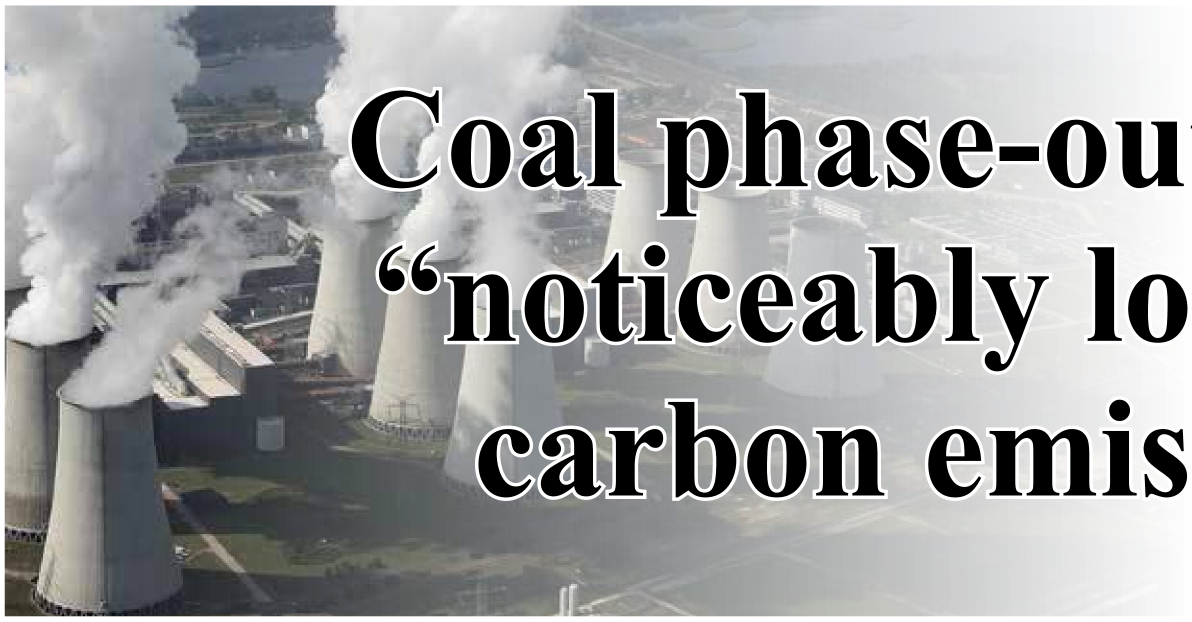

Coal phase-out will "noticeably lower" carbon emissions

Germany has welcomed a proposal to close its coal fired power plants by 2038, as it struggles to keep a lid on greenhouse gas emissions. **Junior Isles**

Germany has taken a significant step in its effort to close the gap on its greenhouse gas emission (GHG) targets, as the government welcomed a proposal to phase out the country's coal fired power plants by 2038. Berlin said it would act quickly to implement the recommendation.

According to management consultancy enervis energy advisors GmbH, the proposal would lead to noticeably lower CO_2 emissions from coal fired power generation. It said that in 2022, about 34 million tonnes less CO_2 will be emitted than in a scenario without forced coal phase-out. By 2030, the reduction is 67 million tonnes.

Germany has been at the forefront of the development of renewable energy in Europe with the government committed to the energy transition (*Energiewende*), a strategy to shift to a low-carbon, environmentally sound, reliable, and affordable energy supply. This has been reflected in the country's 2020 climate protection targets, which are more ambitious than EU targets.

However, Germany has not been able to reduce its emissions fast enough to meet its 2020 national targets because of its significant reliance on coal. Further, the country has committed to reducing carbon dioxide emissions from the energy sector by more than 60 per cent by 2030, using 1990 as the baseline.

In recognition of the challenges it has faced in meeting its own climate protection targets, in June 2018 the government established the Commission for Growth, Structural Change and Employment (Coal Commission). The Coal Commission was asked to produce a plan to close the gap in reaching the 2020 40 per cent GHG emissions reduction target "as much as possible" and then meet the 2030 target.

Germany currently has more than 80 power plants that run on coal and lignite, accounting for about 42 GW of capacity and producing 40 per cent of its electricity.

The Coal Commission's recommendations would mean that about 24 plants would be closed within the first three years of the plan. Just eight coal fired plants would remain by 2030 if the plan is executed as intended. This would see coal fired capacity reduced to 30 GW by the end of 2022 and to 17 GW by the end of 2030.

According to enervis the Commission's recommendation stays close to the exit path that it analysed three years ago for Agora Energiewende, a think-tank supporting the *Energiewende* in Germany.

Julius Ecke of enervis, notes, however that the defined exit path will not

Continued on Page 2

Eskom breakup looms as government moves to stave off crisis

South Africa's state utility Eskom is facing the breakup of its business as the government moves to head-off the collapse of the company.

Last month the government unveiled the largest bailout in the country's history, promising to inject R69 billion ($4.8 billion) over three years to stabilise Eskom's R420 billion debt.

The bailout, however, is conditional on Eskom achieving cost cuts of more than R20 billion per year, and on the imposition of a Treasury-appointed "chief reorganisation officer". It also depends on a plan announced by President Cyril Ramaphosa earlier in February to split up Eskom's power stations, distribution networks and grids into three separate businesses. The businesses would be under Eskom Holdings, while at the same time remaining the property of the state.

Delivering the national budget last month, South Africa's Finance Minister, Tito Mboweni, explained: "Pouring money directly into Eskom in its current form is like pouring water into a sieve."

The crisis is the result of years of mismanagement that has left Eskom unable to finance maintenance of ageing, mostly coal fired, stations. Overruns at unfinished new plants have also put tremendous pressure on its balance sheet. Acting Director General of the Department of Public Enterprises (DPE), Thuto Shomang, added that corruption and bad decision-making were also among a host of other failures.

Phakamani Hadebe, Eskom's chief executive, said a bailout would support two-thirds to three-quarters of its debt servicing costs in the three-year period. "It releases resources to do maintenance and we will be in a better state than we are now," he said.

The Treasury hopes that higher economic growth and increased tariffs paid by Eskom's customers will be able to plug the gap remaining after the state bailout.

In February, government officials told Parliament's DPE committee that Eskom was technically insolvent and would cease to exist in April this year without a bailout from government.

Shamong said the cash generated at the utility was not covering operating and debt servicing costs, the headcount had increased from 32 000 to 48 000 between 2007 and 2018, with the associated costs growing from R9.5 billion to R25.9 billion, while municipal debt was growing at around R1 billion a month.

The risk of a collapse at Eskom, which has led to power plant outages and rolling national blackouts, is a serious threat to South Africa's struggling economy.

In February a senior generation official at the cash-strapped company said about a third of Eskom's 45 000 MW capacity is offline.

Andrew Etzinger told *Reuters* that around 11 000 MW was offline because of plant-related problems, while approximately 5000 MW was out of service because of planned maintenance. A further 2000 MW was unavailable because of a shortage of diesel.

In order to urgently address the operational problems at Eskom, chief amongst which is generation, the DPE, led by Minister Pravin Gordhan and Eskom Chairman Jabu Mabuza, have called on Italian energy supplier Enel to provide the power utility with external technical assistance.

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be easy. He said: "In order to guarantee security of supply and, ultimately, to allow coal power plants to be phased out according to the Commission's recommendation, we need to talk not only about the phase-out of coal, but also about the phase-in of gas fired power stations, CHP and storage facilities. Reasonable incentives and significant investments are needed."

Assuming that the current power market design will continue in the future, in a forced coal phase-out scenario the need for demand flexibility, electricity storage and 'Power-to-X' technologies is much higher, added the company.

Based on its modelling, enervis says the recommendation is therefore only the beginning of an intensive discussion about the future structure of electricity generation and the German electricity market.

Following the accident at the Fukushima nuclear plant in Japan in 2011, Germany took the decision to close all of its nuclear power plants by 2022. In the absence of both coal and nuclear power plants, the country will be looking to renewable energy to cover 65-80 per cent of its power requirements by 2040.

Although green groups welcomed the deal, there was some disappointment that the phase-out would not be completed sooner than 2038. "Better bad climate protection than no climate protection at all," said Kai Niebert, head of the Deutscher Naturschutzring, an umbrella group of environmental organisations.

Many details have yet to be agreed between the affected power generators and the government. The government has yet to transpose the recommendations into law, which will need to receive state-aid clearance from the European Commission.

Altmaier says proposals are good for the economy and the climate

German Economy Minister Peter Altmaier said the Commission's proposals were a "strong signal" that was good for "the economy and the climate". The deal would mean "less CO_2, more new jobs, reliability of supply and affordable [electricity prices]", he tweeted.

An analysis run by Cambridge Econometrics and EU agency Eurofound showed that cutting carbon emissions to zero in line with the Paris climate accord would have larger employment gains in Spain and Germany than in the EU average by 2030. In Germany, the transition toward a low-carbon economy is set to reduce the costs of its large fossil fuel imports, while in Spain lower energy prices are expected to boost consumer spending.

Across the bloc, the construction and manufacturing of renewable and energy efficiency equipment, together with the associated supply chains show the largest projected employment gains. However, employment is also expected to increase in the services sector, partly due to the supply chain, but also as a result of higher consumer spending following lower energy prices.

BP sees rising energy demand, as McKinsey predicts plateau in 2035

While BP's latest Energy Outlook says energy demand will continue to rise, a new report by McKinsey Energy insights predicts economic growth and global energy demand will be decoupled for the first time in 2035. **Junior Isles**

Junior Isles

BP has unveiled several key findings in its latest outlook, 'Energy Outlook 2019'. In its 'Evolving Transition' scenario, which assumes that government policies, technologies and societal preferences evolve in a manner and speed similar to the recent past the Outlook shows global energy demand increasing by around a third by 2040, driven by improvements in living standards, particularly in India, China and across Asia.

At the same time it shows that global carbon emissions continue to rise, signalling the need for a comprehensive set of policy measures to achieve a substantial reduction in carbon emissions.

The report says energy consumed by industry and buildings accounts for around 75 per cent of the increase in overall energy demand, while growth in energy demand from transport slows sharply relative to the past as gains in vehicle efficiency accelerate. The power sector accounts for around 75 per cent of the increase in primary energy.

The new Outlook was launched in London, UK, by Bob Dudley, Group Chief Executive and Spencer Dale, Group Chief economist.

"The Outlook again brings into sharp focus just how fast the world's energy systems are changing, and how the dual challenge of more energy with fewer emissions is framing the future. Meeting this challenge will undoubtedly require many forms of energy to play a role," said Dudley.

Dale added: "The world of energy is changing. Renewables and natural gas together account for the great majority of the growth in primary energy. In our evolving transition scenario, 85 per cent of new energy is lower carbon."

BP's outlook of increasing energy demand through 2040, however, runs counter to the findings in a recent report published by data and analytics specialist McKinsey Energy Insights (MEI).

MEI's '2019 Global Energy Perspective' reveals that global energy demand will plateau by 2035 despite strong GDP and population growth. This is the first time in history that economic growth and global energy demand will be decoupled, it said.

The report shows that OECD countries will see a decline in energy demand due to investment in more green and efficient sources of energy. These high-income countries will demand less energy from fossil fuels, after more than a century of rapid growth, due to the rise of renewables. There will be a reduction of coal use in power generation, especially in China, as renewable generation becomes the cheaper option, accounting for more than 50 per cent of power supply post-2035.

The decrease in energy demand in OECD countries is balanced out by a population peak and growing industrialisation in African and Asian countries. While most OECD countries see a decline, energy demand in Africa and India will roughly double until 2050.

"For the very first time, we are on the cusp of seeing global economic growth decouple from rising energy demand: a truly historic moment. Our scenario is bolder than comparable studies, with energy demand declining faster and sooner, but this reflects what we see in the sector," said Christer Tryggestad, Senior Partner at McKinsey.

The energy perspective also outlines that zero-carbon energy sources, which include renewables complemented by nuclear, will almost double their share in the energy mix from now until 2050. By 2025, new-build renewables will out-compete existing fossil fuel generation on cost in most countries. However, although emissions are projected to decline due to decreasing coal demand, a 2°C pathway by 2050 will still stay out of reach.

Price pressure could impact wind turbine supply chain

Wood Mackenzie Power & Renewables has warned that growing disparity between megawatt growth and units deployed will impact component suppliers as price pressure percolates down the supply chain.

According to its 'Global wind turbine supply chain trends' global turbine supply chain potential is $540 billion over the next 10 years. However, the company's senior analyst, Shashi Barla, stressed: "Global wind annual installations are expected to grow 40 per cent in the next decade – from 53 GW in 2018 to over 75 GW by 2027. Pressure to lower the levelised cost of electricity (LCOE) is accelerating technology developments, which is causing a wider proliferation of next-generation 4.X/5.X/6.XMW turbines. As a result, we expect a 20 per cent decline in the total number of turbines deployed, from over 20 000 turbines in 2018 to just over 16 000 by 2027."

"We expect the global market share among the top five-turbine OEMs to rise to more than 73 per cent by 2027, compared to just 54 per cent in 2016. It is therefore imperative that component suppliers secure strategic relationships with these winning OEMs to solidify their own future success.

The research also highlights the logistical challenges on the horizon for blades and towers as component sizes become longer and taller, respectively. Wood Mackenzie Power & Renewables expects the industry to circumvent these obstacles with new transportation methods and on-site/closer-to-site manufacturing. As such, the increase in project average MW size across global markets will favour this trend due to economies of scale.

It also said turbine OEMs continue to leverage independent suppliers to out-source component manufacturing, while the component design continues to move inwards.

"After exploiting the low-cost footprint advantage in China, Western turbine OEMs are now searching for outsourcing partnerships with Chinese component suppliers as a way to squeeze costs further," said Barla.

"Offshore growth in Asian markets will facilitate expansion opportunities for independent blade suppliers, as Western markets are primarily served by turbine OEMs in-house capacity.

Yet there have been warning signals that some promising offshore wind markets could pose challenges. For example, some argue that recent revisions to offshore wind support in Taiwan are likely to have a lasting impact on international investor confidence.

In November, Taiwan proposed a cut to the price it would pay for electricity from offshore wind farms. Although the proposed 12 per cent cut in the feed-in tariff has been recently softened to a 6 per cent cut, the market is no longer as lucrative before.

Taiwan had looked like becoming one of the world's fastest growing offshore wind markets, projected to bring in $30 billion of investment to the country by 2025.

Danish energy company Ørsted, which was close to approving an investment decision for a $5.4 billion offshore wind farm, on January 31st said it is now in talks with dozens of its suppliers, including turbine giant Siemens Gamesa, to renegotiate contracts to ensure it can still make money under the new pricing structure.

Wind and solar overtake coal

Coal generation was overtaken by wind and solar for the first time in five key European markets last year, according to recent research by Wood Mackenzie Power & Renewables.

Its report, 'European power supply: 2018 in review', showed that in 2018, the combined share of wind and solar in Europe's largest electricity markets – Germany, France, Italy, Iberia (Spain & Portugal) and the UK – increased marginally to 17 per cent, lifting it above coal for the first time.

Commenting on the findings, Matthew Campbell, Wood Mackenzie Power & Renewables Data Associate, said: "Coal fired power supply in Germany fell in 2018, as higher volumes of wind and solar continued to constrain market space for fossil fuel. While production from low-cost, indigenously produced lignite remained almost flat, generation from hard coal dropped to a new low in the market. Coal's overall share of power supply in Germany has fallen from 42 per cent to 35 per cent in the past there years."

The rapid take up of renewables is becoming increasingly evident. At the end of January BloombergNEF (BNEF) reported that corporations bought a record amount of clean energy through power purchase agreements (PPAs) in 2018. Highlights included a wave of smaller corporate energy buyers aggregating their purchases, and the first corporate clean energy power purchase agreements in markets such as Poland.

Its 1H 2019 Corporate Energy Market Outlook showed that 13.4 GW of clean energy contracts were signed by 121 corporations in 21 different countries in 2018. This was up from 6.1 GW in 2017, and positions companies alongside utilities as the biggest buyers of clean energy globally.

Jonas Rooze, Head of Corporate Sustainability for BNEF, said: "Corporations have signed contracts to purchase over 32 GW of clean power since 2008, an amount comparable to the generation capacity of the Netherlands, with 86 per cent of this activity coming since 2015 and more than 40 per cent in 2018 alone."

According to BP's 'Energy Outlook 2019' the pace at which renewable energy penetrates the global energy system is faster than for any fuel in history. Its Evolving Transition scenario sees renewables growing at 7.6 per cent per annum, becoming the largest source of power generation by 2040.

The report also shows, however, that deployment of renewables alone will be insufficient to meet climate change goals.


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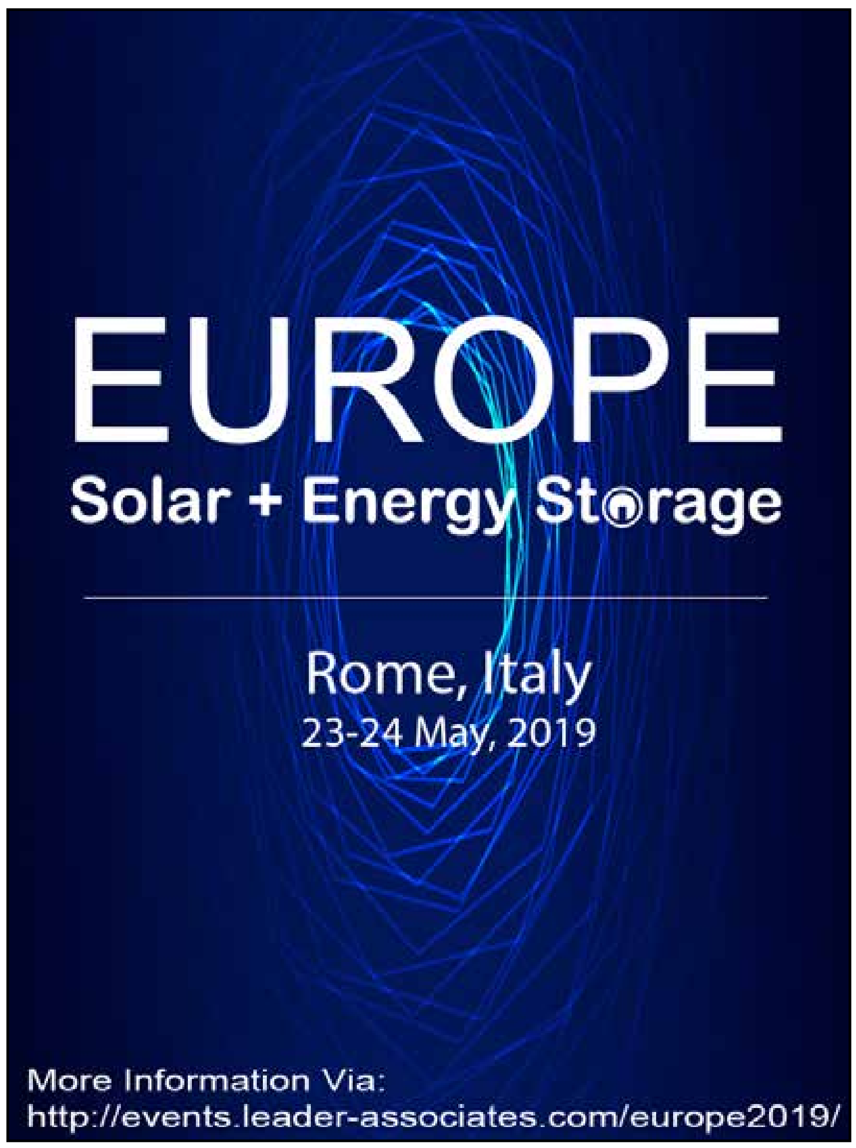
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Developers race for NY offshore contracts

■ 18 bids submitted reaching 1200 MW ■ New Jersey considers offshore bids

Siân Crampsie

Four offshore wind development consortia are vying for contracts to develop at least 800 MW of offshore wind energy capacity off the coast of New York state, USA.

New York State Energy Research and Development Authority (NYSERDA) issued a request for proposals to procure 800 MW or more of offshore wind in late 2018 as part of New York state's plans to build 9000 MW of offshore capacity by 2035.

Four major consortia have responded to that request, submitting 18 bids between them, NYSERDA has confirmed. The solicitation is another step forward in the USA's offshore wind energy industry, which has the potential to deliver large amounts of clean energy to large population centres, the American Wind Energy Association says.

NYSERDA has not revealed the capacities of the projects proposed in the bids, but said that they went up to 1200 MW in size. Atlantic Shores Offshore Wind, a joint venture between EDF Renewables North America and Shell New Energies, submitted eight bids, while Equinor submitted four proposals for its Empire project.

Meanwhile Vineyard Wind, a joint venture between Avangrid Renewables and Copenhagen Infrastructure Partners, put forward three bids for its Liberty wind project, and Bay State Wind, a joint venture between Ørsted and Eversource Energy, proposed three bids for its Sunrise wind project.

The Liberty wind proposals include project size options of 400 MW, 800 MW and 1200 MW. Vineyard Wind said that the 1200 MW projects would be "the most cost-effective option for New York ratepayers".

Vineyard Wind's project is expected to be out of sight from any New York shoreline, placed 85 miles away from the state shore. "Our team's extensive offshore wind experience from around the world and nearby in New England, where we are building the nation's first utility scale offshore wind project, allows us to deliver the best project for New York," said Lars Thaaning Pedersen, CEO of Vineyard Wind.

Bay State Wind's proposal is also expected to be "virtually unnoticeable to Long Island residents and beach goers," placed more than 30 miles east of Montauk Point, according to a press statement.

State policies have been set in Maryland, Massachusetts, New Jersey, New York, Rhode Island and others to drive offshore wind development

Equinor said it has already undertaken "considerable work" for the offshore wind project in New York, including a study of the seabed conditions, grid connection options and wind resources. It recently deployed a floating LiDAR to measure the speed and direction of wind at the site, wave conditions and other factors.

Equinor is also developing an offshore wind project in the Boardwalk Wind lease area near New Jersey, for which it bid in New Jersey's offshore wind solicitation in December 2018. At the end of 2018 it also secured a 128 000 acre site offshore Massachusetts.

The New Jersey Board of Public Utilities (NJBPU) said last month that it expects to announce the winner of the 1100 MW offshore wind solicitation at the end of June.

NJBPU is currently in the process of reviewing applications. Three bidders responded to the solicitation – Ørsted with its Ocean Wind project, Equinor with Boardwalk Wind, and Atlantic Shores Offshore Wind.

Siemens supports Canadian smart grid move

Siemens Canada is planning to support two Canadian provinces in developing and demonstrating smart grid technologies.

New Brunswick Power (NBP) and Nova Scotia Power (NSP) has signed up Siemens to develop the project, which will help the utilities to improve asset management and energy efficiency, and reduce greenhouse gas emissions.

"This partnership will be truly ground-breaking. Together with NB Power and Nova Scotia Power, we will develop and implement a powerful cloud-based Energy System Platform (ESP), allowing everyone to participate in the energy market," said Faisal Kazi, President and CEO of Siemens Canada. "The ESP will enable data analytics, ensure connectivity, and provide tools for developers to create customer-focused applications and services.

"The platform will also optimise the overall electrical grid and reduce the cost of transitioning into a greener future not only in Canada but throughout the globe."

Siemens will research and develop the made-in-Canada ESP software and NBP and NSP will provide the needed assets and customer engagement to demonstrate and test these platforms in real scenarios and real-time.

Siemens and its partners have also committed to increased collaboration with post-secondary institutions, driving greater gender diversity in the workforce, developing intellectual property (IP) produced in Canada, and driving more engagement with local indigenous communities in the clean energy sector.

Clean energy and efficiency help cut US carbon intensity

Increased use of renewable energy and natural gas in power generation has helped the USA's electricity sector to improve its carbon intensity.

According to data from BloombergNEF (BNEF) and the Business Council for Sustainable Energy (BCSE), investments in energy efficiency also helped to drive the improvement in carbon intensity, even in the face of rising economic output and energy demand.

"Continued expansion of sustainable energy is not just beneficial to the environment, it is an engine of American economic growth," BCSE President Lisa Jacobson explained.

"In our seventh year of analysis, we found that energy efficiency, natural gas and renewable energy continue to be key economic drivers. At the same time, they contribute substantially to important efforts to reduce emissions and develop modern and resilient infrastructure."

In their joint publication, '2019 Sustainable Energy in America Factbook', BNEF and BCSE highlight other notable trends in the US energy sector, including greater corporate purchasing of renewables and more state policies and plunging prices for energy storage. Installations of renewables hit 19.5 GW in 2018 and natural gas capacity set new records.

"More coal plants closing and being replaced by cleaner sources of power marked a key trend that continued in 2018," said Ethan Zindler, BNEF's Head of Americas. "However, the overall jump in CO_2 emissions during 2018 is a clear reminder that technological advancements on their own cannot address the climate challenge. Strong, supportive policies are needed at the local, state, as well as federal level."

Puerto Rico divided on privatisation

Puerto Rico's plans to attract investment to its hurricane-hit electricity sector through privatisation have been opposed by lawmakers concerned about proposed price caps.

A bill to award concessions for the country's transmission and distribution system has been amended by the territory's House of Representatives to cap the price of energy at 20 cents per kWh.

Lawmakers in the Senate have turned down the amendment, however, because they are concerned that a price cap may leave energy prices artificially low in a system that is currently highly dependent on imports of oil.

The proposed price cap could also affect a potential deal between Puerto Rico's government and bondholders as the bankrupt Puerto Rico Electric Power Authority (PREPA) tries to restructure its more than $9 billion debt.

In January Puerto Rico's government selected four companies interested in taking on transmission and distribution concessions on offer and asked them to submit formal proposals.

The companies are Duke Energy Corporation, Exelon Corporation, PSE&G Services Corporation and a consortium composed by Atco Ltd., IEM and Quanta Services, Inc.

In February PREPA released a draft of its latest Integrated Resource Plan (IRP), in which it proposed measures to make the electricity system more resilient and secure.

The IRP includes plans to add over 2220 MW of solar and 1080 MW of battery storage to Puerto Rico's electricity system. PREPA would also phase out its use of coal and bunker oil, and build three LNG gas import terminals.

Also included in the IRP are proposals to create segregated 'minigrids' that would enable continued use of distributed resources and essential loads served during and after major storms such as hurricane Maria that hit the island in 2017.

Environmental group Sierra Club welcomed Puerto Rico's plans for the use of solar energy and storage technologies, but is against the privatisation plans for PREPA.

"During Hurricane Maria hundreds of people died simply because they couldn't keep their insulin refrigerated, or their oxygen machines running," said Adriana Gonzales, Environmental Justice Organizer for Sierra Club de Puerto Rico. "We need the solar and storage in this plan so we can protect health and safety through the next hurricane with distributed, reliable energy infrastructure."

Puerto Rico was hit by two major storms in 2017 that wiped out the electrical infrastructure. Full service took one year to resume.

Enel starts Lagoa dos Ventos wind farm build

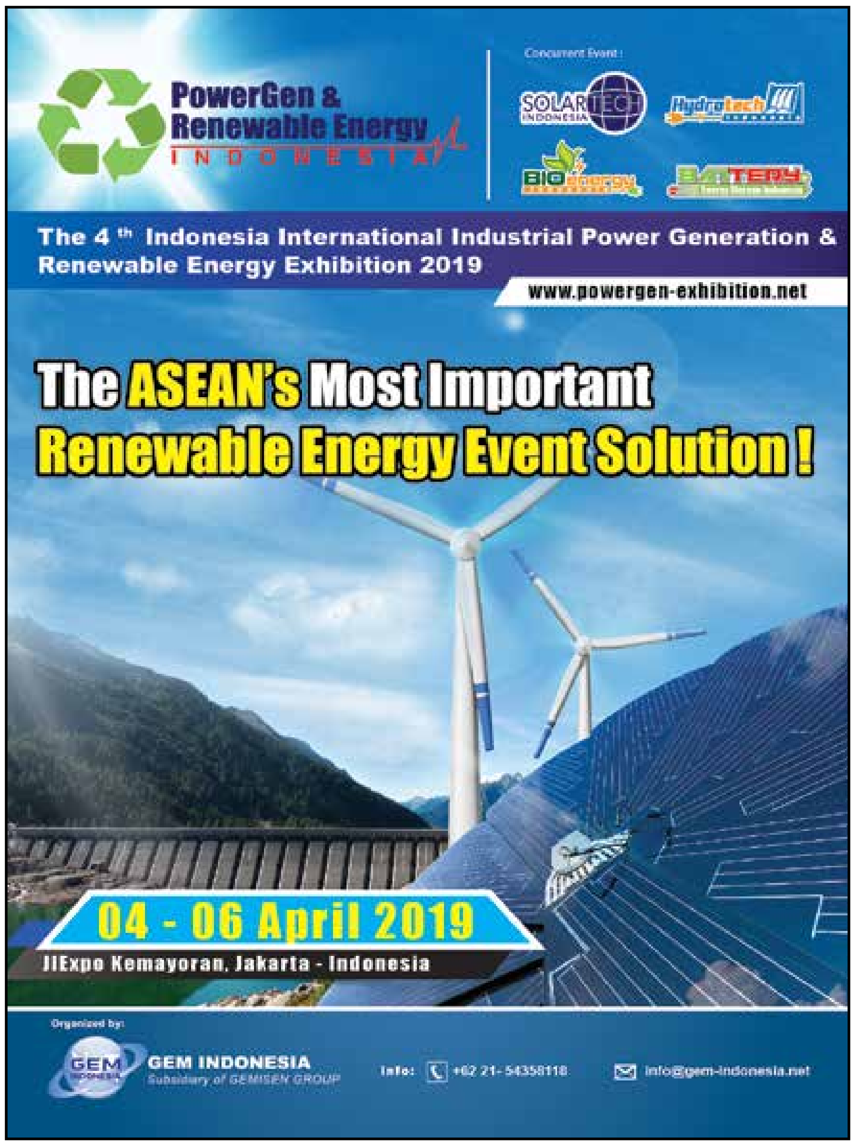
Enel says that it expects South America's largest wind farm to start operating in 2021.

The Italian utility's Brazilian subsidiary, Enel Green Power Brasil Participacoes Ltda., started construction of the 716 MW Lagoa dos Ventos wind farm in Brazil's northeastern state of Piaui last month.

The €700 million wind farm is the largest wind facility currently under construction in South America and Enel Green Power's largest wind farm worldwide.

It will make a major contribution to Brazil's strategy of diversifying its generation portfolio, said Antonio Cammisecra, head of the Enel Group's global renewable energy business line, Enel Green Power.

Last month the Brazilian Minister of Mines and Energy, Bento Albuquerque, announced that the construction licenses for 1572 MW of green projects secured during the August 31, 2018 energy auction had been signed.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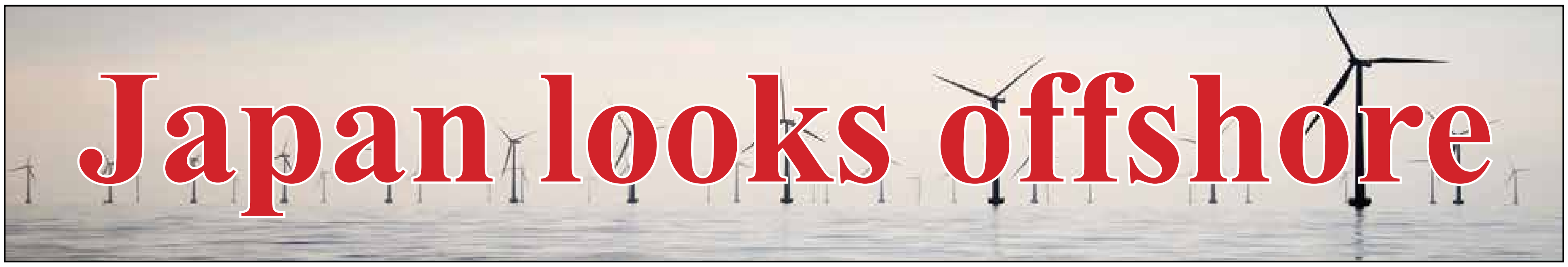
Halt on US Clean Power Plan may have wider implication



Japan looks offshore

■ Offshore wind capacity expected to reach 4 GW ■ Fund buys into UK assets

Japan is looking to offshore wind as it moves to fill the gap left by the closure of its nuclear plants, while meeting its climate change objectives. According to new research by Wood Mackenzie, Japan's offshore wind capacity is expected to reach 4 GW in 2028, a 62-fold increase from 2018.

Wood Mackenzie estimates that Japan will see a power generation shortfall of more than 10 GW by 2030, as it struggles to restart 30 nuclear reactors to meet the national nuclear target, and renewables will play an important role.

"In light of the power shortfall, Japan will need to increase its coal imports, supported by renewable energy capacity," said Senior Analyst Robert Liew. "In terms of renewable energy, scale matters and offshore wind is at an advantage."

According to the consultancy, the participation of Japan's largest utility Tokyo Electric Power Company Holdings (Tepco) in offshore wind shows that the sector is commercially viable, which makes it easier for the government and local companies to accept it.

"The medium- to long-term outlook for offshore wind in Japan looks especially promising with Tepco's involvement in offshore wind, the growing offshore pipeline and new policy measures to support wind development. We expect Japan to emerge as a key offshore wind market in Asia," Liew said.

Japanese companies have also been looking to gain experience in international waters. Last month, Sumitomo Corporation, Sumitomo Mitsui Banking Corporation (SMBC) and Development Bank of Japan established their first fund dedicated to overseas offshore wind projects.

The fund will acquire the assets Sumitomo Corporation holds in the Race Bank and Galloper offshore wind farms in the UK as seed assets.

According to the parties, the fund managed by Spring Infrastructure Capital, will seek to raise up to Yen30 billion ($270 million) from Japanese investors for financing and investing in the projects.

The three companies established Spring Infrastructure Capital in July last year to provide institutional investors with opportunities to invest in renewable energy assets both inside and outside Japan.

Japan's interest in renewables is being driven by a need to keep a lid on CO_2 emissions. At the same time, it is also trying to pull back from coal.

Amid growing pressure, Japan's trading house Marubeni Corp said last year that it would no longer start new coal fired power plant projects and would halve its net coal power generating capacity of about 3 GW by 2030 to help cut greenhouse gas emissions and tackle global climate change.

At the end of January Idemitsu Kosan, Kyushu Electric Power and Tokyo Gas said they had abandoned plans to build a 2 GW coal fired power station in Chiba, near Tokyo, as it would not be economically feasible.

The move follows a similar decision at the end of December by Chugoku Electric Power and JFE Steel, a unit of JFE Holdings, and comes amid growing pressure in parts of the world for companies to divest coal assets due to environmental concerns.

OECD says Australia carbon intensity rising

Australia will fall short of its 2030 emissions target without a major effort to move to a low-carbon model, according to a new OECD report.

The country has made some progress replacing coal with natural gas and renewables in electricity generation yet remains one of the most carbon-intensive OECD countries and one of the few where greenhouse gas emissions (excluding land use and forestry) have risen in the past decade.

The OECD's third 'Environmental Performance Review of Australia' says Australia needs to develop a long-term strategy that integrates energy and climate policies to support progress towards its commitment to reduce greenhouse emissions (including land use and forestry) to 26-28 per cent below 2005 levels by 2030. Australia should consider pricing carbon emission more effectively and doing more to integrate renewables into the electricity sector.

Reliant on coal for two-thirds of its electricity, Australia has one of the highest levels of non-renewable energy use of advanced economies, with fossil fuel consumption still benefitting from government support.

Coal, oil and gas make up 93 per cent of the overall energy mix compared to an OECD average of 80 per cent. The share of renewables in electricity generation has risen to 16 per cent but remains below the OECD average of 25 per cent. Australia's power sector – the country's top emitting sector – is not subject to emission reduction constraints.

The OECD report, however, comes as another research report claims Australians are leading the world in the per capita adoption of renewable energy at a rate which could see 100 per cent green power by 2032.

Australia is installing solar and wind renewable power per capita four to five times faster than the EU, Japan, China and the US, Australian National University Professor Andrew Blakers said.

"The electricity sector is on track to deliver Australia's entire Paris emissions reduction targets five years early, in 2025, without the need for any creative accounting," said Prof Blakers, of the ANU Research School of Electrical, Energy and Materials Engineering. Prof Blakers estimates Australia will generate 50 per cent renewable electricity in 2024 and 100 per cent by 2032.

Last month it was reported that power plants with a combined capacity of 283 MW have secured accreditation under Australia's Renewable Energy Target (RET) in January 2019, bringing the total accredited capacity over the last three years to 4757 MW.

In 2016, CER estimated that reaching the RET of 33 000 GWh renewable power generation by 2020 would require 6000 MW of new capacity. Due to a higher proportion of solar projects in the pipeline, the estimates were later updated to 6400 MW. With the already accredited capacity plus 5499 MW of committed projects, Australia will surpass the targeted capacity.

Indonesia's 35 GW plan on track

State utility PLN's Strategic Procurement Director Supangkat Iwan Santoso says progress of power plant construction is in line with its programme to add 35 000 MW of new capacity. The news came as he announced that Indonesia was aiming to complete 3963 MW this year.

This would bring new installed capacity to 7000 MW or 20 per cent of the programme introduced by President Joko "Jokowi" Widodo four years ago. Supangkat said the programme could be completed in 2022 or 2023.

Supangkat said this year's capacity would come from at least three coal-fired power plants with the total capacity of 2350 MW – PLTU Java 7 and Java 8 with the capacity of 1000 MW each and PLTU Lontar with the capacity of 350 MW.

"There are also a number of small power plants [that would begin operation] this year. But coal fired power plants would provide the largest contribution," Supangkat said.

Thailand power plan to take effect in 2Q

Thailand's new National Energy Policy Council (NEPC) is expected to take effect from the second quarter.

After three years of revising and drawing up a new version of the power development plan (PDP), in late January the NEPC approved the plan for 2018-37, emphasising more participation from private companies in the country's power generation.

The plan can be revised every five years as changes and technological trends occur in the power sector.

The plan reduces the proportion of power generated by the state-run Electricity Generating Authority of Thailand (Egat) from 35 per cent in the previous version to 24 per cent.

The new PDP sees policymakers plan for new power capacity of 56 431 MW, up from 46 090 MW in 2017. Of the planned new capacity, 20 766 MW will be from renewable power projects.

Power plants with a total capacity of 25 310 MW will be retired during 2018-37, so total power capacity by 2037 will stand at 77 211 MW.

Energy Minister Siri Jirapongphan said non-fossil power will represent 35 per cent of total power capacity by 2037, while coal fired power plants will be reduced to 12 per cent.

"We are very keen on renewable energy projects and energy conservation plans, while power imported from neighbouring countries is generated from hydropower," Siri said, adding that Thailand will import 5857 MW by 2037, up from 3528 MW.

"The NEPC has ordered the Energy Ministry to hold talks with Laos and Cambodia regarding capacity and power prices if the two countries want to establish power plants and sell power to Thailand," said Siri.

Siri also noted that the NEPC authorised the ministry and Egat to study grid development in a bid to purchase more renewable power in the future and increase the country's efficiency to become a centre of purchasing power in the region or a grid connection.

Egat and the Provincial Electricity Authority are required to develop a smart grid in the Eastern Economic Corridor in an effort to lower power prices and attract new investment.

The PDP also allows solar panels to be installed on private property and surplus power to be sold to Egat.

"Egat will purchase at least 100 MW of solar power a year in the next 10 years, while the ministry will soon put the purchase plan into action," Siri said.

The NEPC also approved the revision of purchasing power contracts with 25 small power producers (SPP) that are cogeneration plants.

Market turmoil pushes price cap rise

Energy suppliers in the UK have again questioned the viability of the energy price cap scheme after rising wholesale costs force the regulator to raise the cap.

Siân Crampsie

UK energy markets regulator Ofgem has been criticised for raising the level of the energy price cap just six weeks after it was implemented.

The energy price cap is a government initiative designed to keep household energy bills at affordable levels by imposing an upper limit on standard tariffs.

However, a difficult trading environment for energy utilities in Great Britain has forced the regulator to reassess the level of the cap, increasing it by around ten per cent from April 2019.

Joe Malinowski, founder of energy price comparison website TheEnergyShop.com commented: "Anyone who thought that a cap was, well a cap, is in for a nasty shock. Not only have your energy bills gone up under the cap, but they are going to be £40 higher than before the cap came into effect."

Malinowski added: "The energy price cap might have been a nice idea and worked for some, for a few weeks anyway. However, the reality is that government intervention can't hold back the tide of volatile or rising energy bills."

Smart switching service Labrador said that price caps would "never be the way to solve the UK's energy market as they undeniably reduce competition, promote lethargy and consequently, make consumers mistakenly believe that they are getting the best deal when this is not the case".

Ofgem says that the default price cap will increase by 10.3 per cent, or £117, to £1254 per year from 1 April 2019, and will affect around 11 million households. The prepayment price cap will increase by 9.3 per cent to £1242 per annum, affecting some 4 million households.

This new level will run for 6 months. Some £74 (63 per cent) of the increase has been attributed to higher wholesale energy costs, while the balance of £43 (37 per cent) has been attributed to network and policy costs.

Ofgem said in a statement that the increase in the cap reflect "a genuine increase in underlying energy costs rather than supplier profiteering".

Industry trade group Energy UK said that energy suppliers in the UK are facing "drastically rising costs" and notes that 80 per cent of a typical household energy bill is comprised of costs outside energy suppliers' control. "We are seeing a number of suppliers exiting the market due to these rises, which in turn places additional costs on all other suppliers," said Lawrence Slade, Energy UK CEO. "Ofgem need to ensure that the cap allows for these mutualised costs to be appropriately recovered, otherwise it is to the detriment of all customers."

Professor David Elmes, leader of the Warwick Business School Global Energy Research Network, said that the price cap is making it hard to run a viable retail energy business in the UK.

"It is no surprise that Ofgem has been forced to raise the energy price cap," said Elmes. "Last year we saw eight energy companies fail and the merger between SSE and nPower fall apart. The collapse of Economy Energy last month showed 2019 is not going to be any easier for energy companies.

"While it's right to ensure customers get a fair deal and good service, the government and Ofgem are struggling to support a sector that's essential to the UK economy."

Energy UK said that the energy sector is making efforts to keep bills down. "The most efficient way to keep costs down in the long term is through the more efficient use of energy," said Slade. "We therefore continue to call for the government to introduce a national energy efficiency programme."

French wind farms seek EIB funds

- Ørsted, Total and Elicio team up
- France reveals draft 10-year plan

EDF Energies Nouvelles (EDF EN) and Enbridge are hoping to tap the financial resources of the European Investment Bank to fund the Saint-Nazaire and Fécamp offshore wind projects in France.

The two companies have applied for an undisclosed amount of funding from the EIB for the two projects, which will have a combined capacity of almost 1 GW.

EDF EN and Enbridge are partners in the Eolien Maritime France consortium, which is developing Saint-Nazaire, Fécamp and Courseulles-sur-Mer projects off the coast of France.

The funding application is the latest development in France's nascent offshore wind industry. Last month Total, Ørsted and Elicio announced that they had created an industrial consortium to submit a bid for the proposed 600 MW Dunkirk offshore wind farm.

"Total's participation in this offshore wind bid is in line with our strategy to develop a low-carbon electricity business in Europe," said Philippe Sauquet, President Gas, Renewables and Power at Total. "Our recognised offshore oil and gas know-how combined with Ørsted's market-leading expertise across the offshore wind energy value chain, as well as that of Elicio, an experienced developer qualified from the beginning of the bid, provide a solid foundation for success of a safe and competitive project."

France is aiming to make offshore wind a key component of its energy system.

In February the government published a draft 10-year energy plan that would see France's installed renewables capacity more than double to 113 GW by 2028, mainly through the addition of wind and solar power capacity.

Under the draft plan, onshore wind capacity will grow to 24.6 GW by 2023 and up to 35.6 GW by 2028, while offshore wind will rise to 2.4 GW in 2023, reaching between 4.7 GW and 5.2 GW in 2028.

Solar photovoltaic (PV) capacity will range between 35.6 GW and 44.5 GW in 2028, with 20.6 GW installed by 2023. Hydropower capacity is planned to be 26.4 GW-26.7 GW in 2028.

Fourteen nuclear power reactors will be shut down by 2035, including those of the Fessenheim power station, as announced in November 2018.

Ineos calls for seismic shift

Ineos has called on the UK government to relax seismicity limits for fracking operations to help the onshore gas sector exploit the country's shale gas reserves.

The industrial firm says that the current regulatory levels are over 3000 times lower than those typically found in the USA and that the "unworkable" limits will do "irreparable damage" to the UK's industrial sector.

It has also criticised the "archaic, glacially slow" planning policies of the UK and has accused the government of using "slippery back door manoeuvres" to shut down the country's nascent shale gas industry.

Ineos holds licence interests for onshore gas across northern and central England, and wants to exploit shale gas reserves to help fuel its chemicals business.

"The government's position is unworkable and unhelpful," said Sir Jim Ratcliffe, Ineos Chairman. "They are playing politics with the future of the country. We have a non-existent energy strategy and are heading towards an energy crisis that will do long term and irreparable damage to the economy and the government needs to decide whether they are finally going to put the country first and develop a workable UK onshore gas industry."

German permit scheme slows onshore sector

Fundamental issues with the permitting scheme for new wind farms in Germany are slowing down growth in the sector.

The country has now held three under-subscribed auctions for onshore wind, highlighting the need for the government to take "urgent action" to make permitting easier for onshore wind farms, according to industry group WindEurope.

In the latest onshore wind auction, 476 MW of wind farms won capacity against a total of 700 MW on offer. The average price of bids was €61/MWh. This was slightly lower than the previous auction in October 2018 (€63/MWh) but higher than May 2018's €57/MWh.

WindEurope says that it can take over two years for wind farm developers to gain permits for their projects, compared with 10 months just two years ago. Projects are increasingly being challenged in the courts, and at least 750 MW of wind farm projects are currently stuck in legal proceedings.

WindEurope CEO Giles Dickson commented: "This is now the third German onshore wind auction in a row that's been under-subscribed. It's clear the permitting process is not fit for purpose.

"The German government needs to take urgent action to make permitting easier. And the Bundesländer need to identify appropriate new zones for onshore wind. If they don't, auctions will continue to be under-subscribed, and prices will remain higher than they should be. And this will jeopardise Germany's target of 65 per cent renewables in electricity by 2030."

■ Germany's grid-connected offshore wind capacity grew by 969 MW in 2018, reaching a total of 6382 MW. The industry expects that the legally permitted offshore wind expansion of 7.7 GW by 2020 will probably be achieved as planned, but has called for a goal of 20 GW installed capacity by 2030 to be set.

Enel builds out Nxuba

■ Kathu CSP on line ■ Enel grows portfolio in South Africa

Siân Crampsie

Enel is aiming to complete the construction of a 140 MW wind farm in South Africa's Eastern Cape province by September 2020, it has announced.

The company's local subsidiary, Enel Green Power RSA, has started building the Nxuba project, its third wind farm in Eastern Cape.

The €200 million project is the first of five projects awarded to Enel in South Africa's 2015 renewable tender to start construction.

The wind farm will be supported by a 20-year power supply agreement with the South African energy utility Eskom.

Enel RSA will employ innovative tools and practices to build Nxuba such as advanced digital platforms and software solutions to monitor and remotely support site activities and plant commissioning, digital tools to perform quality controls on site and smart tracking of wind turbine components. These processes and tools will enable swifter, more accurate and reliable data collection, improving the quality of construction and facilitating communication between on-site and off-site teams.

Other renewable energy projects are also taking shape in South Africa, including the 100 MW Kathu concentrated solar power (CSP) plant.

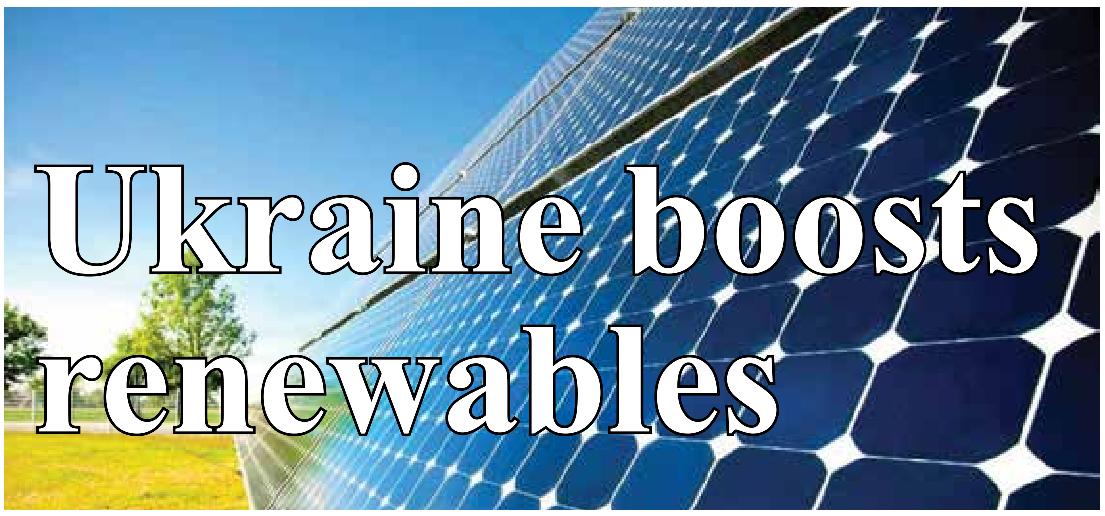
Engie announced in February that the Kathu project achieved commercial operation at the end of January 2019.

Kathu is equipped with parabolic trough technology and a molten salt storage system that allows for 4.5 hours of thermal energy storage to provide reliable electricity in the absence of solar radiation and during peak demand. The Kathu site covers approximately 4.5 km², with 384 000 mirrors.

Kathu is Engie's first CSP development. Engie partnered with a group of South African investors comprising SIOC Community Development Trust, Investec Bank, Lereko Metier Sustainable Capital Fund, and its co-investors – Dutch development bank FMO; DEG, the German investment and development company; and the Public Investment Corporation – to develop the project.

Enel won five projects totalling 700 MW of capacity in South Africa's April 2015 renewable tender capacity.

The other projects awarded to Enel RSA in the renewables tender are the 140 MW Oyster Bay wind farm, also in the Eastern Cape, as well as the 140 MW Garob, the 140 MW Karusa and the 140 MW Soetwater wind plants, all in the Northern Cape province.



Ukraine boosts renewables

■ GE, Trina supply new renewables projects
■ 3 GW of renewables on-line by 2019

Siân Crampsie

Energy firm DTEK is ramping up development of renewable energy capacity in Ukraine.

The company has signed deals with major international suppliers in pursuit of the development of wind energy and solar photovoltaic (PV) capacity.

Last month Trina Solar announced that it had delivered 123 MW of PV modules to DTEK for installation at Ukraine's largest solar power plant. Located near Nikopol, Dnepropetrovsk Oblast in central Ukraine, the project has a planned capacity of 246 MW.

In addition, DTEK has signed a deal with GE Renewable Energy for the procurement, installation and maintenance of 26 wind turbines for stage 1 of the 200 MW Primorskaya wind power plant in the Zaporizhia Region of Ukraine.

GE will provide its 3 MW turbines for the Primorskaya wind farm, construction of which is scheduled to be completed at the end of 2018. The Primorskaya wind farm will be developed in two phases, with a second 100 MW phase due to be operating by 2020.

DTEK has a 1 GW renewable energy project portfolio and said in a statement that it was engaging foreign investors and equipment manufacturers capable of bringing the most innovative and advanced technologies to Ukraine. "The new wind park will strengthen Ukraine's position on its way towards modernisation of its energy sector, energy independence, and diversification of energy sources," said DTEK CEO Maksym Timchenko.

China Machinery Engineering Corporation (CMEC) is the main contractor at the Nikopol solar energy plant, which is expected to be completed in early 2019 and connected to the grid in March.

Last year Ukraine approved a national emissions reduction plan, and also set a target of increasing the share of renewable energy generation in the generating mix to 11 per cent by 2020. Currently the country's energy supplies are heavily reliant on fossil fuels and nuclear energy.

The number of licenses for producing renewable energy delivered in Ukraine grew from 131 in 2015 to 163 and 230 in the following years, according to the Ukrainian Association of Renewable Energy (UARE). State-run power company Ukrenergo expects the country's renewable energy capacity to go from the current 1.5 GW to 3 GW in 2019.

UK funding for Iraq but deals under threat

Over $1 billion of UK export finance is to be used to support critical electricity infrastructure projects in Iraq, although some large deals could be under threat.

UK Export Finance (UKEF), the UK's export credit agency, said it had agreed to support UK firms with $1.02 billion of finance to build two new power stations in Iraq and support the restoration of a number of electricity substations in the country.

Some $620 million of financing will go to support two contracts between GE and Iraq's Ministry of Electricity to build two power stations in Samawa and Dhi Qar, located northwest of Basra, in southern Iraq, UKEF said.

A further $400 million would support a project by GE's Grid Solutions business to develop 14 substations across Iraq. GE will build new substations on a turnkey basis and supply equipment such as transformers and other parts to rehabilitate existing substations, helping to bring power to areas with significant power shortages from the north to the south of the country.

The finance deal follows the agreement between the governments of the UK and Iraq signed in March 2017, which re-affirmed the UK's commitment to Iraq's continued economic development.

The projects will play a key role in bolstering the capacity of the Iraqi electricity grid. The two new power stations, located in the Basra region, will give citizens the access they need to critical infrastructure, UKEF said.

"Power shortages continue to halt Iraq's reconstruction and addressing this scarcity is crucial to the country's future," said Yavuz Akturk, Director at ENKA UK, which is supporting GE as a subcontractor. "As ENKA, we have taken a significant role in rebuilding the country's infrastructure, and with these projects we will help the people in the country which are in urgent need for electricity."

However last month Iraq's electricity minister said that a lack of resources and bureaucracy are threatening large deals with multinational equipment suppliers tasked with refurbishing and expanding the country's energy infrastructure.

Luay al-Khatteeb told the *Financial Times* that although the Iraqi government has signed significant deals with companies such as GE and Siemens, a rapid transformation of the electricity system was unlikely to happen because of "illogical" bureaucracy.

GE and Siemens last year signed separate and non-binding agreements that could add a total of 25 GW of electricity generating capacity to the Iraqi electricity grid, which is struggling due to rising electricity demand and ageing infrastructure.

UAE mulls coal plant plan

The UAE's Federal Electricity and Water Authority (FEWA) is in the initial stages of developing a coal fired power plant, according to local reports.

The proposed 1.8 GW plant would be the second of its kind in the country and developed under an independent power producer (IPP) model. Construction of the country's first coal plant, a 2.4 GW facility at Hassyan, is already under way.

The $3.4 billion Hassyan plant is being developed by a joint venture of ACWA Power Harbin Holding Company and Dubai Electricity & Water Authority (DEWA). It will use ultra-supercritical technology.

Sources quoted by local media indicate that FEWA has already selected three advisers for the proposed second coal fired power plant.

The emirate of Sharjah has also made progress with plans to develop a 1.8 GW combined cycle power plant.

In January GE and Sumitomo signed a 25 year power purchase agreement (PPA) with the Sharjah Electricity and Water Authority (SEWA) to develop, build and operate the 1.8 GW plant located in Hamriyah.

The power plant will consist of three combined cycle blocks, the first of which is expected to come online in May 2021.

Chairman Dr. Rashid Alleem of SEWA said: "We are committed to strengthen Sharjah's electricity infrastructure and provide seamless, affordable power. The proposed plant underlines our focus to promote public-private partnerships to drive a robust power production and management plan that is aligned with local energy needs, as well as the optimal utilisation of natural resources."

GE will supply three HA gas turbines, three steam turbines, six generators, three heat recovery steam generators (HRSG) and turnkey engineering, procurement and construction (EPC) services for the power plant.

GE will also provide parts, repairs and maintenance services for the power generation assets at the site for a period of 25 years.

CFB scrubbers have been installed behind the Soma Kolin CFB boilers in Turkey

CFB scrubbers make a case for India

While wet flue gas desulphurisation (FGD) is the incumbent technology for cleaning up coal fired plants, circulating fluidised bed (CFB) scrubbers are poised to challenge the *status quo*, especially in markets such as India. **Junior Isles**

Pressure on power plant operators to cut emissions has never been greater. It is a global trend that has seen even the likes of China introduce tougher emission standards for sulphur and nitrogen oxides (SO_x and NO_x), particulate matter (PM) and CO_2. Even developing countries such as Indonesia, the Philippines, Thailand and Vietnam are looking at ways to cut emissions from their coal fired fleet. And in India, which has revised its emissions legislation, the pressure is more acute.

Certainly emission-free renewables such as wind and solar are growing at a tremendous rate in many of these countries. India for example has set a goal of adding 175 GW of renewables by 2022. But although renewables are making rapid progress globally, coal plants still have a role to play in providing base load generation and technology therefore needs to be adopted to drastically cut emissions from the coal fired fleet.

Nowhere is this truer than in India, where the country is now assessing technology options to cut SO_x and NO_x from its installed base and any new plants on the horizon.

Robert Giglio is Senior VP Strategic Business Development, Sumitomo SHI FW (SFW), which is currently targeting India as a key market for its circulating fluidised bed (CFB) dry scrubber technology. He commented: "Low emissions has become the new guiding principle for power plants – both old and new, coal and otherwise. Of course renewables are right there touting its benefits of zero emissions and low operating costs, and that's great. But renewables are not able to fill the role of these base load fossil plants. That means we have to deal with the fossil fuel plants already in the ground today and those being put in the ground tomorrow."

"India is the key example in the world right now of a country that has moved from being one of the less conforming countries when it comes to regulatory environmental laws, to one that has actually become very progressive. India is setting the lead for what a big developing country has to do with its coal-based generation fleet."

According to the Ministry of Power, in 2018 coal fired power plants represented just over 56 per cent of the country's installed generating capacity. Many of these plants have no emissions controls, and determining the right technology to control coal plant emissions is a choice that India's plant owners are now facing.

India issued new environmental legislation just over three years ago, setting new standards for NO_x and SO_2 but more recently made some modifications.

Market expert Ravi Krishnan, at Krishnan Associates, explained: "The standards introduced around December 2015 came about all of a sudden because of pressure from the international community at the time to get the country to move to greener energy and also clean up its coal fired power plants.

"But because the regulation came about so quickly, the government underestimated how long it would take to implement the air pollution control projects, and did not really factor in any delays due to custom design considerations for high ash Indian coals and how the costs would be passed on to the customer."

This, he says, led power plant owners to push back on the legislation, forcing the government to extend the guideline for compliance from 2017 to 2022. The new legislation sets different limits for plants installed before 2004, those after 2004 but before December 31, 2016 and those after January 1, 2017.

In short, the legislation means that plants pre-2017 of less than 500 MW have to meet SO_2 standards of less than 600 mg/Nm³, and less than 200 mg/Nm³ for plants larger than 500 MW. For NO_x, the level is 600 mg/Nm³ for all sizes built before 2004. For plants built between 2004 and 2017, the SO_2 limits are the same as pre-2004 plants but the NO_x limit is 300 mg/Nm³. Notably, in some locations units that are smaller than 500 MW but are close to populated areas, also have to comply with the 200 mg/Nm³ SO_2 standard. For plants of any size built from January 2017, both SO_2 and NO_x must not exceed 100 mg/Nm³.

The choice of flue gas desulphurisation (FGD) system, which can either be a dry/semi-dry or wet system, depends on the level of SO_x removal needed and the plant specifics.

Dry/semi-dry FGD technologies include: simple injection of a sorbent into the boiler flue gas (direct sorbent injection or DSI); the more established spray dryer absorber (SDA) system, which sprays a mist of lime slurry into the flue gas; and the relatively new concept of employing (CFB) scrubber technology, with boiler ash and lime circulated through an absorber reactor and typically a fabric filter.

With baseline SO_2 emissions averaging around 1200 mg/Nm³, India's 600 mg/Nm³ limit could be met using a DSI system for many plants but to meet the 200 mg/Nm³ standard would require the use of a wet FGD system, or one of the other dry/semi-dry processes.

For decades, the established technology for cleaning up coal plants has been wet FGD scrubbers, which use limestone as the reagent for capturing SO_x. In India, over the last year or so, around 15 wet FGD systems (representing 10-12 GW) have been ordered for power large plants but going forward, the choice of wet FGD for pollution control might not be so automatic.

"They have gained this dominant position because they were built at scale many decades ago, and proven themselves over a wide range of conditions and fuels and quality of flue gases," said Giglio. "But they have some downsides: they use a lot of water, they're expensive and they take up a lot of room. They don't do a good job on non-water-soluble acid compounds like SO_3 or some of the halogen compounds. And they don't do well with heavy metals. They are really geared to removing SO_2 and there's a lot of maintenance that goes along with the extra equipment involved."

One other potential drawback with wet FGD systems is that they also produce gypsum. Although this can be a valuable byproduct, in some countries such as India where it is projected that there will be an oversupply of gypsum, disposal costs can be a burden.

"The attractiveness of gypsum sale to wallboard manufacturers was initially a big selling point but it turned out there was not really a demand for it. So what was seen as a potential source of revenue offset has not been realised. Furthermore gypsum purity in many cases has not been high enough for commercial sale," said Krishnan. "And with the Indian market being very cost-sensitive, the lower installed cost of the CFB scrubber and its other benefits mean the technology is beginning to emerge as a major alternative."

Dry/semi-dry systems overcome several of the issues facing wet FGD technology. Notably, they have much lower capital cost and use less water than wet FGD technology.

According to Krishnan, in India, the price of wet FGD systems average at about $70-80/kW. According to SFW, this is typically about 40-50 per cent more than a CFB scrubber. This is due to the greater amount of equipment needed by the wet FGD process. A wet FGD system also consumes about 40 per cent more water. And although the limestone used in a wet FGD can be 40 per cent cheaper than the lime used in a CFB scrubber or SDA system, operating costs tend to be higher.

Special Technology Supplement

"In a CFB scrubber, you don't have to maintain lime crushers, mills, slurry pumps, spray nozzles, or drying systems for the byproduct, etc.," noted Giglio.

Despite these advantages, however, in the past they have generally only been selected for projects where the boiler size was not too large and the fuel sulphur level was not too high.

Traditionally, this has been true of both SDA and CFB scrubbers. Since their introduction 10-15 years ago, however, a steady increase in scale is seeing CFB scrubbers become an increasingly attractive alternative to wet FGD systems. During this time, they have also been proven over a much wider range of sulphur levels and coals.

Today, there are single unit designs up to 700 MWe backed by operating references on coal power plants of over 500 MWe and on fuels with sulphur levels above 4 per cent. In June 2011 for example, a CFB scrubber began operating at the 520 MW coal fired plant at Basin Electric's Dry Fork station in Gillette, Wyoming, USA .

According to SFW, CFB scrubbers can operate on a wide range of coals. Low ash, high moisture fuels such as Indonesian sub-bituminous coals might require more reagent but as the fuel's ash level increases less reagent is needed since the ash plays a role in capturing the pollutants in the flue gas.

Giglio noted: "It can take the widest range of fuels – from hardly any ash to an overwhelming amount of ash – and still function well. They can do what a wet FGD system can do in many cases, and they can do it for a lot less cost and a lot less water."

For optimum operation, he says there is "a sweet spot" where ash levels are between 7 per cent up to around 30-40 per cent. This gives the maximum capture with the least amount of reagent injection. This reagent could be anything from hydrated lime, sodium bicarbonate or even activated carbon, depending on the pollutant being targeted.

"The scrubber provides the flexibility to tailor the reagent recipe to most effectively capture the target pollutants," said Giglio. "Whereas a wet system has to be precisely controlled… it's a tight chemical balance – there can't be too much chlorides, metals or ash in the system before adversely impacting the capture efficiency. All these things move it off its optimum operating point. CFB scrubbers use dry absorption chemistry instead of water solubility chemistry to make the reactions work in the scrubber."

He points out, however, that the choice of technology largely depends on the specifics of the project. "Wet FGD uses limestone, which is cheap; whereas the semi-dry processes use a more refined lime that is more expensive. It's all part of a discussion around capital cost, operating cost, what to do with the byproduct, water usage, space requirement. It's never a one size fits all solution."

There are also differences between the dry/semi-dry processes to consider. Compared with SDAs, CFB scrubbers offer lower maintenance cost, compact footprint, and the flexibility to use low quality lime and water.

Another drawback of SDA technology, says Giglio, is that it cannot accept as many solids. SDAs use atomising nozzles, some with motorised rotary heads to enable a very fine mist to be sprayed. Because the nozzles have very fine passages, passing boiler fly ash through them causes blockages and erosion. CFB scrubbers avoid this problem by using large diameter venturis to mix the ash with turbulent flue gas.

Giglio explained: "The CFB scrubber uses the boiler's fly ash to help capture the target pollutants. This benefit can reduce reagent consumption and operating cost, which becomes most significant for fuels containing high levels of calcium in their ash. The technology uses the ash as receptor sites to absorb the vapour phase pollutants (SO_2, SO_3, HCl, etc.) on to the surface of the solid particles.

But the main process advantage of a CFB scrubber is that, unlike SDA or wet FGD technology, the amount of lime injection is not limited by the flue gas temperature, allowing significantly improved acid gas scrubbing performance.

"This a key advantage; none of the other scrubbers do this. SDA and wet FGD technology use a slurry of lime and water to spray into the gas to clean it. But the problem with this is you're now connecting gas temperature and moisture level to sulphur removal. The more slurry that's sprayed into the flue gas, the lower the gas temperature becomes and the more humid it becomes. This means that whatever device is put behind the absorber vessel, you need to ensure that the gas is safely above its water dew point so that it doesn't cause operating problems or corrosion in the downstream device like a baghouse, ESP or stack," said Giglio.

"Both the baghouse and ESP need a gas that's relatively dry – gas that at least has a 20°C approach temperature to the dew point of the flue gas. This limits how much sulphur you can capture.

"This restriction is not there with a CFB scrubber, you can add as much lime as you want to the system because the chemistry is much less dependent on the amount of water injected into the flue gas; water is only used in the CFB scrubber to set the temperature and humidity of the gas. This gives the flexibility and freedom to go to very high levels of capture of all the acid gas and metals."

SFW sees this ability to capture a wide range of pollutants, including SO_x, PM, acid gases and organic compounds, as a big plus in today's market.

Commenting on this flexibility, Giglio said: "You can install one today to get you to where you need to be on SO_2 but it also reduces SO_3, HCl, HF, mercury, beryllium, cadmium – all of these metals that may not be regulated in many countries for a long time but it's coming. So in the future, you don't have to go out and buy another scrubber or add on activated carbon systems as regulations tighten."

In a CFB scrubber, boiler flue gas enters at the bottom of an up-flow absorber vessel. The gas mixes with hydrated lime and water injected into the absorber, as well as recirculated solids from the downstream fabric filter. The turbulator wall surface of the absorber causes high turbulent mixing of the flue gas, solids and water to achieve a high-capture efficiency of the vapour-phase acid gases and metals contained within the flue gas.

The scrubber design incorporates a number of built-in features to maximise reliability. The absorber vessel is a self-cleaning upflow reactor with a cloud of water droplets spreading over a large surface area of solids churning in a 23 m (75 ft) high section within the confines of the vessel walls.

Water injection nozzles, located on the perimeter of the absorber above the introduction points for the re-circulated and sorbent solids, provide an atomised spray cloud of water droplets. These nozzles must be removed periodically for replacement of components subject to wear. However, the entire perimeter of the CFB absorber vessel is used to locate the water nozzles thus additional nozzle locations are typically available to allow installation of a spare nozzle prior to removing an operating nozzle for inspection or maintenance.

One or more multi-compartment fabric filter baghouses are located downstream of the absorber vessel to allow recirculation of particulate solids. The multi-compartment baghouse lends itself to on-line replacement of filter bags with one compartment off-line.

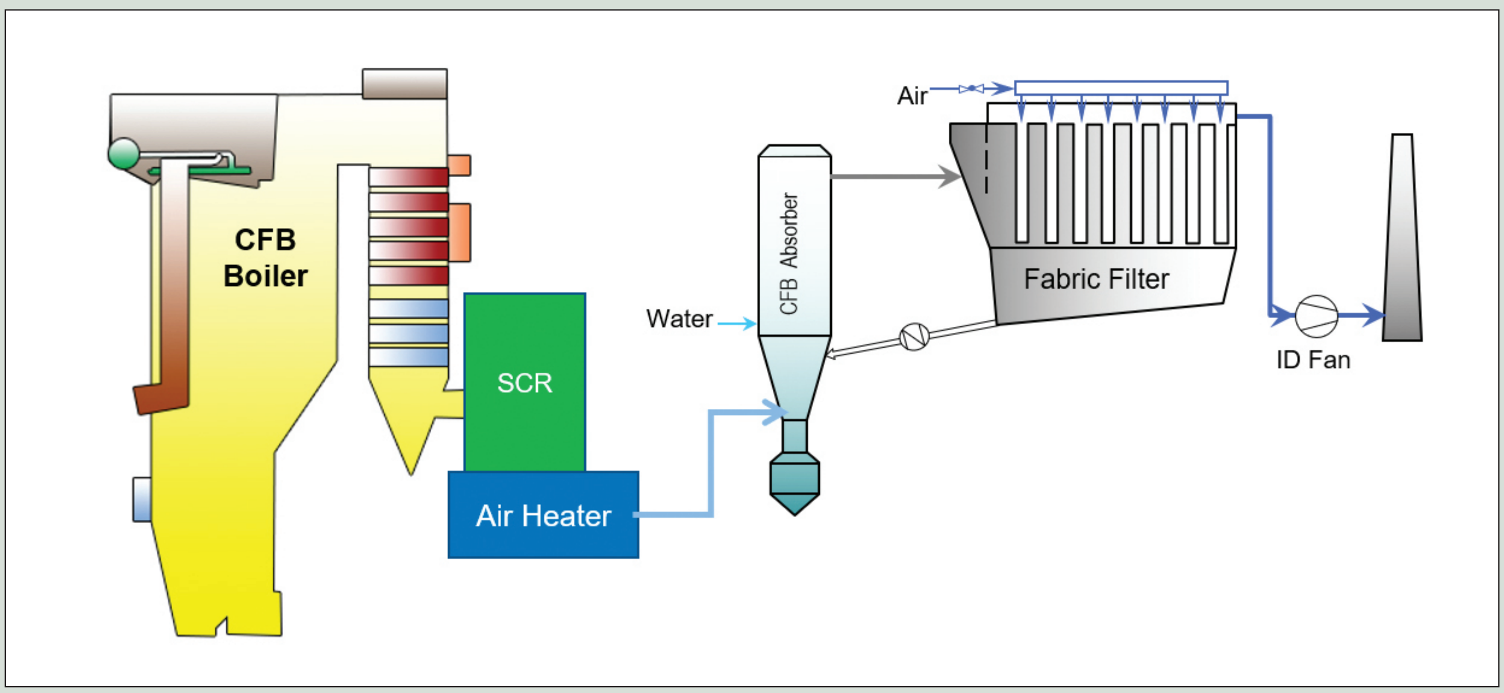
Separate compartments are each lockable on the flue gas side for maintenance purposes thus it is possible to shut down one compartment

SYSTEM CAPABILITIES

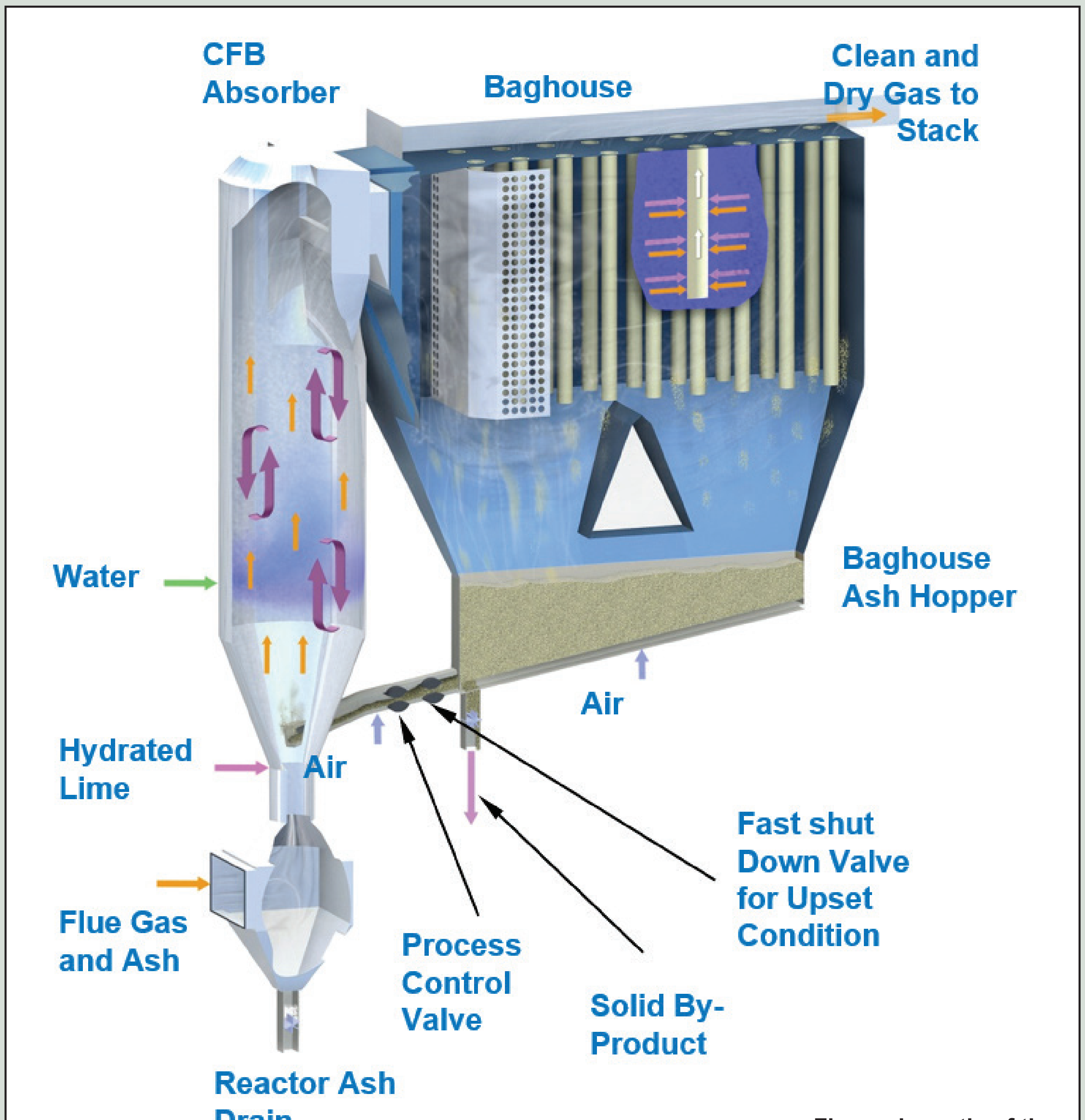
	Wet FGD	SDA FGD	CFB FGD
SO_2 Capture to Meet Low Permit Limits*	Advantage	Disadvantage	Advantage
Low Water Consumption*	Disadvantage	Advantage	Advantage
Fuel Flexibility (Fuel Sulfur Variability)*	Advantage	Disadvantage	Advantage
Fine Particulate Capture*	Disadvantage	Advantage	Advantage
High SO_3 Capture*	Disadvantage	Advantage	Advantage
Compact System Footprint*	Disadvantage	Neutral	Advantage
Minimal Maintenance Requirements*	Disadvantage	Neutral	Advantage
Mercury Capture	Disadvantage	Neutral	Advantage
CO_2 Emissions	Disadvantage	Advantage	Advantage
Waste Water Treatment	Disadvantage	Advantage	Advantage
Use of Low Quality Water	Disadvantage	Disadvantage	Advantage
Use of Limestone Reagent	Advantage	Disadvantage	Neutral
Large Scale Single Unit Size (>350 MWe)	Advantage	Disadvantage	Advantage
Necessary for Retrofit			
• ESP Improvements	Disadvantage	Advantage	Advantage
• Stack Improvements	Disadvantage	Advantage	Advantage
• Flue Gas Reheater	Disadvantage	Advantage	Advantage
OVERALL			Advantage

Advantage Neutral Disadvantage

Wet FGD, SDA, and CFB: comparison of capabilities



Overall flow diagram showing a CFB boiler and cleaning systems



Flow schematic of the CFB scrubber process

for maintenance while running the remaining compartments with 100 per cent boiler flue gas flow. The baghouse hoppers serve as temporary storage bins for the large portion of the material that is fed into the solids recycling system. This is accomplished by means of a control valve via maintenance-free air-slides back into the absorber.

But although the technology is proven and can in many cases be the best choice for pollution control, Giglio says that global deployment is short of where it could be.

There are around 80 SFW CFB scrubbers installed around the world, with half of these being behind waste-to-energy plants, mainly in Europe.

Notable recent references include the Soma Kolin project in Turkey, which has two 255 MW CFB boilers firing low quality lignite. CFB scrubbers have been installed behind the boilers to give future flexibility on what pollutants might need to be captured in the future. The Zabrze plant in Poland is another example, where the CFB scrubbers future-proof the plant against new potential emission legislation for years to come.

Giglio commented: "We have done well in our 'home' markets, i.e. where we supply CFB boilers proving that the scrubber brings additional value to the projects we do. These are mainly in Europe but now we are looking to expand into other key markets such as India, central Asia and southeast Asia."

The opportunity in India is huge. According to Krishnan, the FGD market is roughly 120 GW in terms of size. Almost 100 GW – nearly 50 per cent of the coal fired installed base – is made up of units greater than 500 MW that will need an FGD solution. "The remainder will either have to go for a DSI type system, or retire their plant if it is old. Those [smaller units] that are close to populated areas will also have to put in an FGD system," he said. "This means around 55-60 GW could potentially use CFB scrubbers."

Giglio added: "I would argue it's more about economics than size [of unit]. It also very much depends on geography, supply chains, byproduct options, etc."

With the 2022 deadline fast approaching, power plant operators in India are in the midst of conducting evaluations to avoid stiff penalties for non-compliance. Giglio warned however: "Although the train is moving much faster now, there are still some lingering issues that are allowing the power producers to push back. They need clarification on things such as: will tariff reform allow plant owners to pass the compliance cost on to ratepayers? Will the limestone supply chain develop in time? What are my options for gypsum and byproduct sales or disposal? There are things that might delay the compliance deadline further."

While upcoming elections could heighten uncertainty, the clean up of coal plant is something that is supported by all parties.

In addition to India, SFW sees China and other high coal use countries as the main targets for CFB scrubbers. "China is the biggest market; they've already gone well down the road in adding a lot of systems – both wet and semi-dry CFB scrubber types. They've also done DSI-type systems for plants needing only limited reduction of select pollutants," said Giglio.

"Australia is another key market, which is largely dependent on coal for its power generation with most plants having no control of SO_x or NO_x emissions. While they have been more focused on CO_2, they have ignored the SO_x, NO_x, PM issues. Once they get through the CO_2 debate, which seems to be coming out to a more balanced approach where they will allow upgrade of coal plants in combination with renewables, I think they will start looking at the coal they have and seeing what they can do to make it cleaner.

"Indonesia, Philippines and Vietnam are right now all in the midst of ratcheting down emissions when they look at new coal plants."

He concludes: "The lower costs, lower water consumption, multi-pollutant capability, compact footprint and flexibility to handle a wide range of coals, now combined with the bigger unit sizes, make a compelling case for CFB scrubbers as a coal clean up technology."

A CFB scrubber has been operating at the 520 MW coal fired Basin Electric Dry Fork power station since 2011.
Photograph courtesy: Basin Electric Co-Op and Wyoming Municipal Power Agency

A flexible multipollutant technology

Our Circulating Fluid Bed (CFB) Scrubber efficiently captures all acid gases, metals and particulate matter down to the lowest levels. It is a versatile and flexible technology that can clean up flue gases from boilers and industrial processes using the least amount of water and project capital.

- Uses 30-40% less water than wet FGDs
- 50% lower capital cost than wet FGDs
- Best capture of acid gases and metals
- Excellent capture of oxides of sulfur
- Very low operating cost and need for lime reagent with calcium rich boiler ash (ideal for CFB boilers)
- Low maintenance since it doesn't utilize lime slurry and rotary atomizers

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Shell boosts clean investment

Shell's purchase of battery maker Sonnen will complement its earlier moves into the electric vehicle and home energy market.

Siân Crampsie

Shell is continuing to make investments in the clean energy sector in line with its strategy of diversifying into green technologies.

The Dutch oil giant has sealed a deal to buy German battery manufacturer Sonnen – a move that will put it in direct competition with Tesla in the growing market for smart home energy technologies.

Sonnen is Europe's largest maker of rechargeable battery storage packs and offers smart home energy solutions and digital energy services to consumers. Its acquisition by Shell, for an undisclosed sum, will help drive its growth to "a new level", according to Christophe Ostermann, CEO and co-founder of Sonnen.

Shell first invested in Sonnen in May 2018. The company will help Shell to expand further into the electric vehicle (EV) market as well as into the growing market of smart home energy services. In 2018 it acquired UK power supplier First Utility giving it direct access to retail electricity consumers for the first time, and New Motion, one of Europe's largest electric vehicle charging companies.

"Sonnen is one of the global leaders in smart, distributed energy storage systems and has a track record of customer-focused innovation. Full ownership of Sonnen will allow us to offer more choice to customers seeking reliable, affordable and cleaner energy," said Mark Gainsborough, head of new New Energies at Shell.

Sonnen offers smart energy storage to customers and offers digital energy services via its sonnenCommunity platform. It also provides primary balancing services to TSO TenneT using a network of residential battery storage systems across Germany.

Sonnen and Shell say that they will work together to offer innovative integrated energy services and electric vehicle charging solutions, as well as grid services based on the virtual battery pool.

In February Shell invested an undisclosed sum in Makani Power, developer of an experimental kite-based wind power technology.

Makani says that the investment from Shell will enable it to establish itself as a standalone subsidiary of its parent company, Alphabet, which is in turn owned by Google. It also says that it will be able to establish a partnership with Shell, using the firm's offshore experience in the oil and gas and wind energy sectors.

Makani's protoype is a 600 kW kite generating system tethered to land that floats around 300 m above ground to generate energy.

The company believes that its technology will be ideally suited to the offshore wind energy sector, where wind speeds are greater.

Mitsubishi eyes digital energy move

- Investment boosts Ovo plans
- Ovo launches new tech division

Mitsubishi has bought a 20 per cent stake in UK-based energy supplier Ovo Energy as part of a wider strategy to gain a foothold in the market for digital energy services.

The deal values Ovo at around $1 billion and affirms the company as one of the most successful energy supply start-up companies in the UK.

The investment will help Ovo expand into new markets and underpin the development of a new intelligent energy technology division called Kaluza, Ovo said.

"Ovo and Mitsubishi Corporation share the same vision for the future of energy: secure, distributed and consumer-centric, with affordable clean energy for everyone," said Stephen Fitzpatrick, Founder and CEO of OVO. "We're delighted to be working with an exceptional global partner which is perfectly placed to help us accelerate our international expansion and technology roll-out."

Ovo is currently the seventh largest energy supplier in the UK and focuses on the supply of green energy. Trading conditions in that market are forcing it to look overseas, however. It has already established itself in Germany and is planning to launch in France, Spain and Australia later this year.

Ovo has also invested in technologies such as energy storage and electric vehicle charging. It last year launched a domestic vehicle-to-grid charger that allows EV owners to sell electricity that is stored in their car battery back to the grid.

Mitsubishi is also present across the entire renewable energy value chain, owning and operating renewable energy assets, energy trading, manufacturing lithium-ion batteries and investing in distributed renewable energy projects including energy storage.

"Ovo's business model, long-term vision for the energy sector and culture align well with our own," said Katsuya Nakanishi, Executive Vice President, Group CEO of Mitsubishi's Power Solution Group. "They are precisely the sort of technology-driven and innovative firm we have been looking for in order to strengthen the downstream business in the energy sector.

"Given our global presence and experience in the energy sector, we feel we are uniquely well placed to help Ovo to enhance not only their own business in Europe, but their international expansion plans and broaden their technology offering."

Ovo launched Kaluza last month, a new unit focusing on demand control services that will assist households with energy management.

Vestas extends wind industry lead

Wind turbine manufacturer Vestas has extended its lead in the global wind sector, securing a market share of 22 per cent in 2018, according to data from BloombergNEF (BNEF).

The latest data from BNEF shows that developers commissioned just over 45 GW of onshore wind turbines in 2018, lower than the 47 GW commissioned in 2017, and that just four turbine manufacturers account for 57 per cent of installations.

Vestas installed 10.1 GW of onshore wind capacity last year, extending its market share by six percentage points over the 16 per cent market share it gained in 2017. The Denmark-based company noted last month that 2018 saw it secure its highest-ever wind order intake of 14.2 GW.

"2018 was a year of many highlights. We broke our order record; we entered into new markets; we introduced new technology solutions; expanded our footprint and ramped up manufacturing," Bert Nordberg, chairman of Vestas said.

"To us, the biggest highlight in 2018, which we are very proud of, was that we became the first company to install 100 GW of wind turbines when we completed the 250 MW Arbor Hill project in the US for MidAmerican Energy Company," Nordberg added.

According to BNEF, China's Goldwind rose from third to second place in terms of global market share, lifted by a strong performance in China, where it captured a third of the 19.3 GW market. The company's global footprint, however, remains limited, as only 5 per cent of Goldwind's 6.7 GW were commissioned outside of China.

GE came third with 5 GW, with six out of every ten GE turbines commissioned in the US. Both GE and Vestas commissioned just over 3 GW in the US, with Vestas leading by 44 MW in the neck-to-neck race for US market leadership, BNEF said.

GE restructures renewables

Energy tech giant GE says it will intensify its focus on the renewable energy sector with a new division dedicated to all of its renewable energy and grid businesses.

The USA-based company will consolidate all of its solar, wind, hydropower, storage and grid solutions units together into a single Renewable Energy business.

"One of the broadest portfolios in the industry with wind, hydro, grid, and renewable hybrids is coming together to provide end-to-end solutions for our customers demanding reliable, affordable green power," GE said in a statement.

It added that the decision was driven by the increasing global demand for renewable power generation and the associated grid integration.

According to the International Energy Agency (IEA), renewable capacity additions of 178 GW accounted for more than two-thirds of global net electricity capacity growth in 2017.

The proposed moves are part of a broader effort by GE to position the company to meet the evolving needs of the power market, including the growth of renewable energy.

In addition to consolidating its business units, GE will also streamline its onshore wind business structure by eliminating its headquarters layer and elevating its current regional teams to improve competitiveness, speed, customer focus, and local execution.

GE says that it has the most broad and diverse renewables portfolios in the industry, adding that the restructure would help to drive more local and integrated solutions and improve performance.

"The business will be capable of supporting customers from project development, to equipment and services, to full turnkey solutions," GE said in a statement.

■ GE will have to pay a fine of €50 million for failure to meet an employment target in France following its acquisition of Alstom's energy business in 2015.

Americas

Mainstream bags new Chile order

Senvion and Mainstream Renewable Power Ltd have signed a conditional contract for the supply of wind turbines for the Alena wind farm in Chile.

Senvion will supply 20 of its 4.2M148 wind turbines for the Alena wind farm. The contract is the third signed between the two companies in the space of one month totalling 424 MW of capacity.

The project scope includes the delivery, installation and commissioning of the wind turbines.

Senvion and Mainstream have also signed a long-term full-service contract for the period of 20 years with the option to be extended.

The Alena project is part of the first of three phases for Mainstream's fully-contracted 1.3 GW wind and solar platform awarded to the company in the Chilean energy auction in August 2016. The 4.2M148 turbines have a hub height of 140 m, and the installation is planned for 2020.

Siemens secures HL-class order

Siemens has secured an order in the US for the repowering of Cooperative Energy's R.D. Morrow, Sr. generating station facility in Purvis, Mississippi.

Cooperative Energy will use Siemens' HL gas turbine technology to repower the facility's existing coal-powered steam turbines and create a 550 MW natural gas fired combined cycle gas turbine (CCGT) power plant.

Cooperative Energy will repower one of its existing coal fired generation units with a Siemens SGT6-9000HL gas turbine. The scope of supply also includes an SGen6-3000W generator and the SPPA-T3000 control system. Siemens has also been awarded a long-term service agreement, which will help support the gas turbine and generator's optimal operating efficiency during the life cycle of the project.

Wärtsilä wins Bonaire contract

Wärtsilä has been awarded an integrated 6 MW energy storage project contract for the Caribbean island of Bonaire.

The Finland-based technology group will carry out the engineering, procurement and construction (EPC) for the hybrid energy project, supplying the batteries and inverters as well as an energy management system from its subsidiary, Greensmith Energy.

The energy storage system will enable Bonaire, part of the Netherlands Antilles, to increase its use of renewable energy such as wind and solar.

Asia-Pacific

Aggreko hybrid heads off-grid

Aggreko has signed a contract with mining firm Gold Fields Australia to design, build and operate a hybrid renewable-energy-plus-battery-storage system at the Granny Smith gold mine in Western Australia.

The system, one of the world's largest hybrid off-grid microgrids, will comprise 8 MWp of solar power generation, as well as a 2 MW/1 MWh battery system, integrated with 24.2 MW of existing natural gas generation.

The system will be integrated and managed by Aggreko's control software platform and is expected to reduce fuel consumption at the mine by 10-13 per cent. Construction is expected to begin in May and be completed by year-end.

Goldwind scores in Australia

Goldwind has won a contract for the Kondinin wind farm in the state of Western Australia.

Goldwind will supply up to 46 turbines for the wind project, which will be around 120 MW in size, and manage construction. Developer Lacour Energy says it will start construction of the A$250 million ($179 million) project in late 2019, subject to a final investment decision.

The Kondinin project is scheduled to start operating in late 2021 or early 2022. It is also expected to include a battery storage plant.

JDR to supply Taiwan offshore cables

JDR Cable Systems, a supplier of subsea power cables to the offshore energy industry, has secured a deal from Jan De Nul to supply subsea power cables for the Taiwan Power Company Offshore Wind Farm Phase One.

The project is located off the coast of Fangyuan in Changhua County in central western Taiwan and is being developed by Jan De Nul and Taipower.

Hitachi is the project's main contractor.

Jan De Nul will install twenty-one 5.2 MW offshore wind turbines during the phase one of the project deployment. The project will be completed in 2020.

Australia orders Vestas units

Vestas has signed a 58 MW engineering, procurement and construction (EPC) contract for the Cherry Tree wind farm, located near Seymour in Victoria, Australia.

The Cherry Tree wind farm is owned by the John Laing Group and will comprise 16 Vestas V136-3.45 MW wind turbines delivered in 3.6 MW power optimised mode. Vestas' contract also includes a 30-year Active Output Management 5000 (AOM 5000) service agreement.

Commercial operations at Cherry Tree Wind Farm are scheduled to commence in 1H 2020.

SGRE secures India order

Siemens Gamesa Renewable Energy (SGRE) has secured a new order in India from ReNew Power, India's largest renewable energy Independent Power Producer (IPP).

The scope includes the supply of 270 units of the SG 2.1-122 wind turbines, with a total capacity of 567 MW, to two wind power facilities. Both projects are expected to be commissioned by the first quarter of 2020.

SGRE will supply, install and commission 127 SG 2.1-122 wind turbines for a project in Bhuj, Gujarat, and 143 SG 2.1-122 wind turbines for a project in Davanagree, Karnataka.

GE to digitise Tata fleet

GE has implemented the first Predix Asset Performance Management (APM) solution in India for Tata Power's thermal business.

The work is part of two major deals signed by GE and Tata Power aimed at optimising 8 GW of thermal and renewable energy capacity owned by Tata in India using digital solutions.

GE says it is implementing the Reliability Centered Maintenance (RCM) solutions for Tata Power's thermal assets across nine sites for a period of seven years. The renewable deal is still under execution.

The work will help Tata Power reduce its operating costs, improve maintenance planning and increase the reliability of its power plants.

Toshiba plans 44 MW biomass

Toshiba Energy Systems & Solutions Corp has signed a collaboration agreement with Japan's Omuta City for the construction of a 44 MW biomass plant.

Through its subsidiary Sigma Power Ariake Corp, Toshiba Corp will this autumn start building two 22 MW facilities at Shinkomachi and Nishiminatomachi in the city of Omuta, Fukuoka prefecture.

The units are scheduled to start operating in early 2022.

Europe

CPower seals Ørsted contract

CPower Energy has secured a five-year contract with Denmark's largest energy company, Ørsted, to supply skilled personnel for wind farm projects.

CPower, a wind resources specialist, will supply the full range of personnel required to deliver Ørsted's programme of Dutch wind farms, starting with Borssele 1 and 2. Personnel will have professional wind qualifications and will include project managers, high voltage engineers, client representatives, administrative staff, site technicians and general engineers.

MHI Vestas preferred for Baltic Eagle

MHI Vestas Offshore Wind has been named as preferred supplier of turbines for Iberdrola's 476 MW Baltic Eagle offshore wind farm in Germany.

MHI Vestas will supply up to 52 of its V174-9.5 MW offshore wind turbines to the wind farm, located off the coast of Rügen Island in the Baltic Sea.

Baltic Eagle will be the first commercial offshore wind farm to use MHI Vestas' 9.5 MW wind turbine units. Turbine delivery and installation is scheduled for 2022 and 2023.

Good Energy targets battery market

UK utility Good Energy has teamed up with Belectric and Powerstar to deliver battery energy storage projects to the commercial sector.

The three companies will work together to design, install, operate and maintain commercial battery storage projects. Good Energy said that the partnership would ready its business for future battery storage projects and follows a number of key appointments designed to enable battery storage delivery across its product, strategy, partnerships and business services teams.

ETA bags MeyGen contract from Atlantis

SIMEC Atlantis Energy has awarded a contract to ETA Limited for the manufacture and delivery of the subsea tidal turbine connection system which will underpin the MeyGen extension activities known as Project Stroma.

The subsea hub will allow multiple turbines to be connected to a single power export cable to reduce the costs associated with grid connection.

Project Stroma, located off the north coast of Scotland, will connect two additional Atlantis AR2000 turbines via the new subsea hub to a single power export cable which will then be connected via the MeyGen substation to the National Grid.

SGRE leads in Spain

Siemens Gamesa Renewable Energy (SGRE) says it has affirmed its leading position in Spain's wind energy market through deals with five customers to supply 200 MW.

SGRE has a 55 per cent market share in Spain's onshore wind energy sector, it says. Its latest contracts will result in it supplying 63 wind turbines in 2019 to seven wind farms located in Navarra, Valladolid, Zaragoza, Málaga and Cádiz.

It will also provide operation and maintenance (O&M) services for all of the facilities, SGRE added.

Most of these agreements are for the supply of the SG 3.4-132 model (42 turbines in total), although it will also install sixteen SG 2.6-114 turbines and five SG 2.6-126 machines.

With these contracts, Siemens Gamesa has sold 1.2 GW in Spain since the end of 2017, entailing the production and installation of 265 wind turbines.

International

Nordex secures Ukraine contract

Nordex has secured its first contract in the Ukraine, it has announced.

The German wind turbine manufacturer will install 34 turbines for the first phase of the Syvash wind farm for developer SyvashEnergo-Prom, a joint venture between Total Eren and NBT.

The Nordex machines will have an output of 133 MW and will be installed at the site, located on the north shore of Lake Syvash, by the end of 2019.

A second phase of development at the wind farm will bring its output up to 250 MW.

Voith to modernise Nangbeto

Communtauté Electrique du Bénin (CEB) has placed an order with Voith to modernise the Nangbeto hydropower plant in Togo.

Under the €22 million contract, Voith will carry out extensive rehabilitation and modernisation measures at the plant, which has been in operation for 35 years. The aim of the work is to secure the plant's operation for at least another 30 years and to modernise its auxiliary facilities, Voith said.

The order includes the refurbishment of the generators, the cavitation inspection of the turbines and the replacement of the blades as well as the rehabilitation of the cooling system. In addition, the automation and communication infrastructure will be overhauled.

Marubeni signs PPA for 105 MW Oman PV project

A consortium led by Marubeni Corp has signed a 23-year power purchase agreement (PPA) with Petroleum Development Oman (PDO) for the 105 MW Amin solar photovoltaic (PV) independent power plant (IPP).

The Amin plant will be the first large-scale solar plant in Oman and is expected to start operating in May 2020. Marubeni and its consortium partners, Oman Oil Facilities Development Company (OOFDC), Bahwan Renewable Energy Company, and Modern Channel Services (MCS), won the contract to build Amin in 2018.

For more information, please contact:

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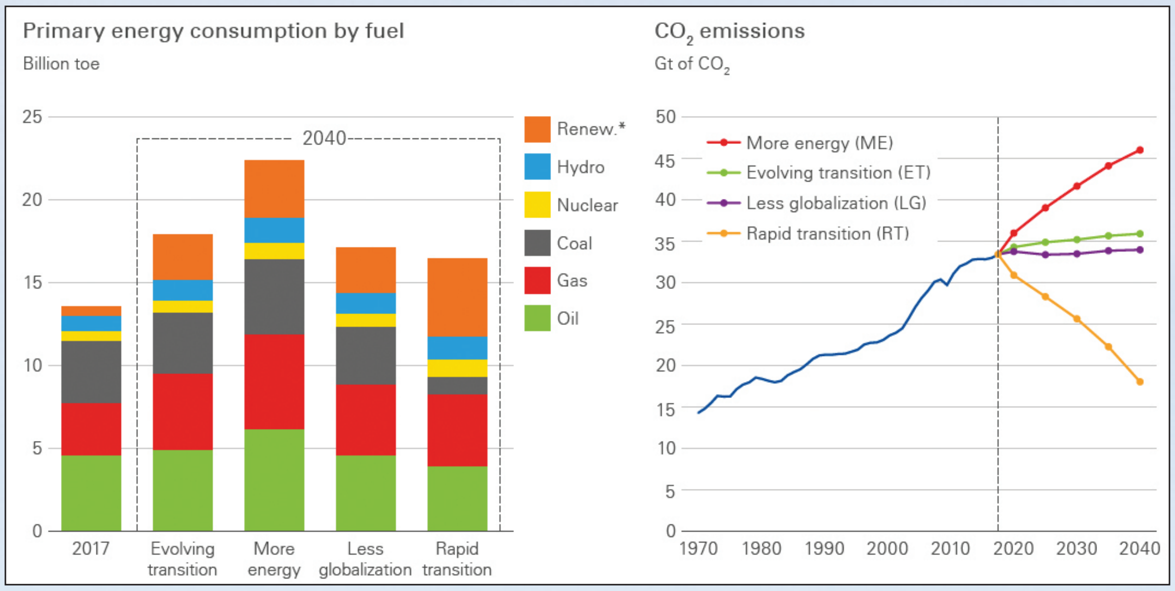
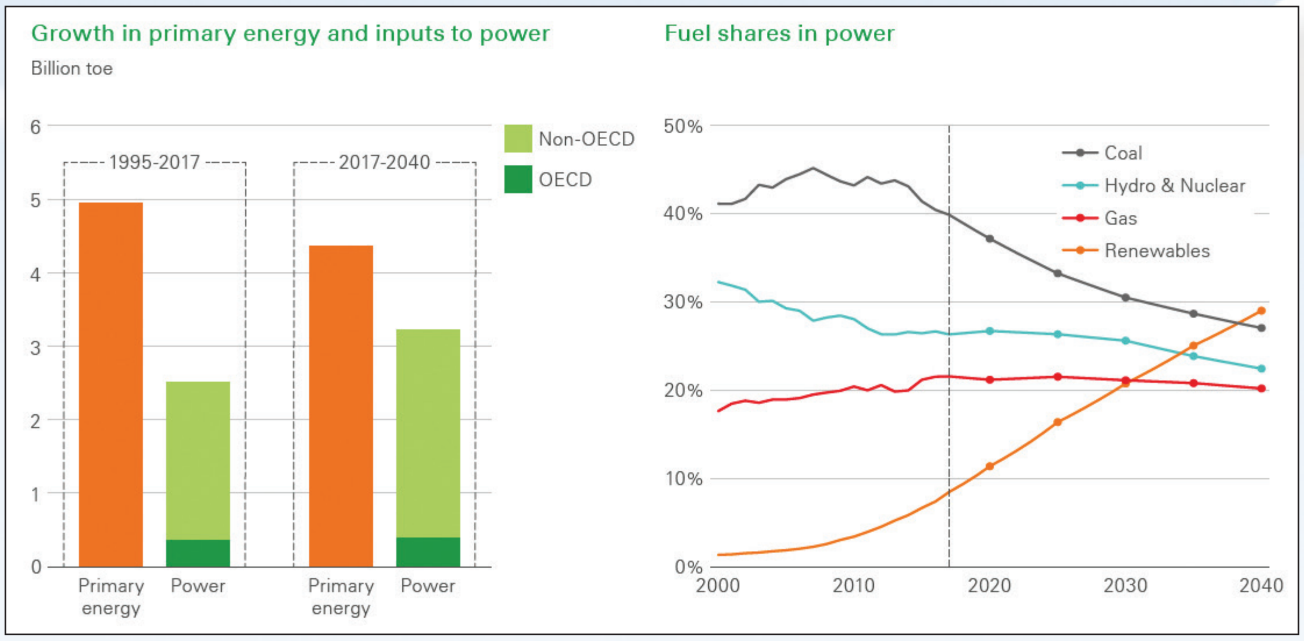
BP's Energy Outlook considers a range of scenarios to explore different aspects of the energy transition



BP Energy Outlook: 2019 edition, page 13, © BP plc 2019

The world continues to electrify, led by developing economies, with renewable energy playing an ever-increasing role



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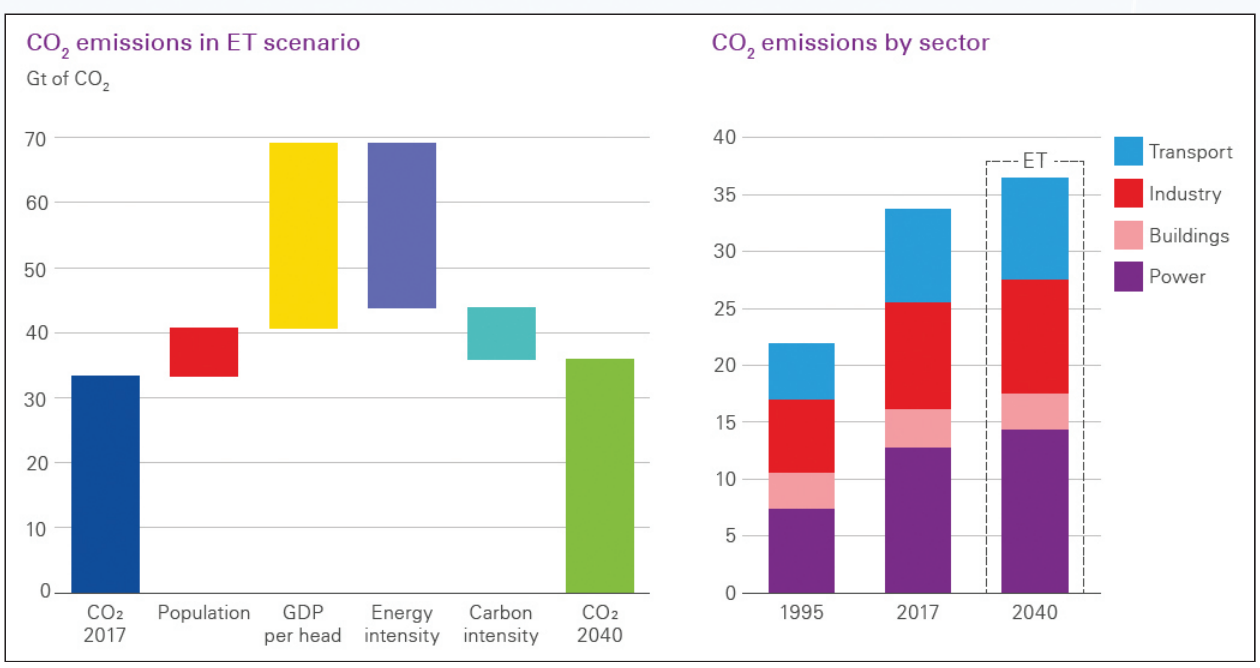
Carbon emissions increase further in the ET scenario with the power sector the main source of emissions



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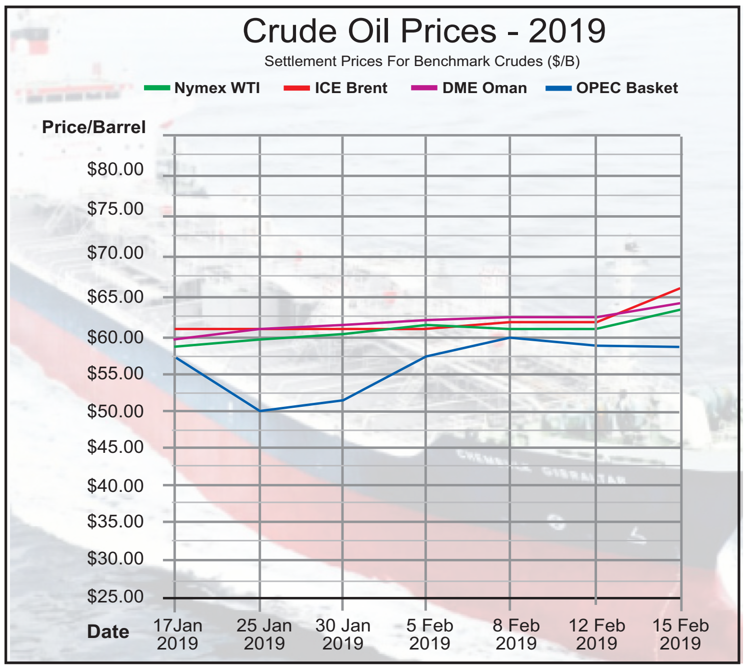
Source: BP Energy Outlook: 2019 edition

Oil



BP sees growth in gas and renewables, but little change elsewhere

- Oil demand to peak in 2035
- Broad-based demand for gas continues

Mark Goetz

The dual challenge for the world is to provide more energy with fewer carbon emissions, the recently released BP Energy Outlook 2019 says, identifying the complicated situation that humans now face on this planet. If improving the lives of humanity depends on increasing energy consumption, how do humans do that without further jeopardising life on Earth, especially when we are so dependent on oil and gas, and coal – and according to the BP report will continue to be so for at least the next 20 years.

The 2019 edition of BP's Outlook examines the "key uncertainties" between now and 2040. "The greatest uncertainties over this period involve the need for more energy to support continued global economic growth and rising prosperity, together with the need for a more rapid transition to a lower carbon future," BP says about the annual report.

BP, as one of the major oil and gas companies in the world, deserves credit for acknowledging the need to reduce carbon emissions in its latest annual Outlook. But with a dire warning last October from the UN Intergovernmental Panel on Climate Change that humans have little more than a decade to get global warming under control, the energy giant doesn't make any big suggestions on how we change the energy system, it only interprets the situation in various ways.

Throughout the Outlook, BP's analysis of future energy trends refers to several scenarios, with primary reference to an Evolving Transition (ET) scenario that assumes that government policies, technology and social preferences continue to evolve in a manner and speed seen over the recent past.

During the next 20 years, global GDP will more than double in all the scenarios devised by BP, and that will be driven by the increasing prosperity in developing countries. Using the ET scenario, BP says improving living standard increases energy demand by around a third by 2040, and two-thirds of this increase will occur in India, China and other Asian countries. However, in 2040 two-thirds of the world's population will still live in countries where average energy consumption is relatively low, "highlighting the need for more energy".

Three-quarters of the growth in energy demand over the next 20 years will be consumed by industries and buildings, but transport demand slows due to improved vehicle efficiency. By 2040, 25 per cent of vehicle kilometres will be powered by electricity, the report says. However, the transport sector will continue to be dominated by oil. In the ET scenario, oil's share in transport declines to around 85 per cent by 2040. Currently it stands at 94 per cent.

Oil will continue to play a major role in the world's energy system beyond 2040, even though BP sees oil demand peaking in 2035 at 108 million b/d and 'plateauing' from there, accounting for some 27 per cent of the world energy mix from its current share of 37 per cent. The increase in the production of hydrocarbon liquids will be led by the US, now the largest producer of oil and gas, due to its shale revolution. However, this will eventually give way to Opec, which will retake its leading position in the oil industry as shale resources in the US decline.

All the demand growth for oil and liquids comes from developing countries, whereas liquid fuel consumption in OECD countries steadily declines. In all the scenarios projected, trillions of dollars of investment will be required meet oil demand in 2040.

The consumption of coal will slip slightly as China and the OECD countries use less, but this will be made up for by India and other Asian countries, according to Outlook projections, which will keep coal consumption basically flat.

Natural gas is seen as having a major impact on energy over the next two decades. There will be broad-based demand for gas as well as an increasing availability, helped by the continuing expansion of LNG, according to the report.

But renewables will be the fastest growing source of energy, contributing to half of the growth in global energy supplies and becoming the largest source of power by 2040. However, renewables will not likely grow fast enough to meet the challenge that climate change is now presenting to the world. In the ET scenario, carbon emissions continue to rise, "signalling the need for a comprehensive set of policy measures to achieve less carbon".

It appears that according to the Outlook, BP and other oil and gas giants will wait for governments to set policy before taking any direct action to address climate change. But that begs a question: when and if those policies are adopted, will big oil willingly comply?

Gas

Needed or not, Russia's Nord Stream II moves forward

A new deal governing import gas pipelines is good news for Nord Stream II.

David Gregory

In early February the EU agreed on new rules governing import gas pipelines, including Nord Stream II, but allowed a loophole in the new agreement that gives regulatory control over the pipeline to Germany.

The government of German Chancellor Angela Merkel supports Nord Stream II and stands at odds with other EU members. Merkel's government argues that the pipeline provides economic benefits, but other EU members, primarily the Baltic, East European and Nordic members fear it is placing too much reliance on Russian gas, a situation that the EU has stated repeatedly that it is trying to avoid. France has also argued against Nord Stream.

Russia's Nord Stream II pipeline is under construction and will be capable of delivering natural gas to Germany by 2020. Like Nord Stream I, which was commissioned in 2012, Nord Stream II will follow a 1200 km offshore route through the Baltic Sea, bypassing other EU member states in East Europe that had for decades relied on Russia for natural gas.

The $11 billion Nord Stream II project, like Nord Stream I, has a capacity to transport some 55 billion cubic metres per year (bcm/year) of Russian gas from Vyborg on Russia's Baltic coast to Lubmin in the northeast of Germany.

When both pipelines are working at full capacity, Russian gas will flow into Germany and Central Europe at a rate of 110 bcm/year. Russia gas flows to Europe during 2017 are reported at 193.9 bcm, an increase over the previous year by 8.1 per cent.

EU imports accounted for 74 per cent of Europe's gas usage in 2017, with Russia supply 42 per cent of that, followed by Norway with 34 per cent and Algeria with 10 per cent. European gas production is declining, with the Netherlands importing gas for the first time in 2017, revealing a decline in output from North Sea fields.

Russian gas monopoly Gazprom owns the pipeline and is carrying out construction that should finish by the end of this year. An overland pipeline will transport Russian gas to the border with Austria, where the Central European Gas Hub is located.

Nord Stream I was a contentious proposal for several reasons but even before work on Nord Stream I began the pipeline project was seen as a political hammer that Moscow would use against Eastern Europe, Ukraine in particular.

Partnered with Nord Stream I was Russia's South Stream gas pipeline project across the Black Sea, which was the Kremlin's answer to the Southern Gas Corridor and the proposed Nabucco pipeline in particular. Both Nord Stream I and South Stream were viewed by the West as a means by which Russian gas supplies would bypass Ukraine and create even more problems for that country.

South Stream was abandoned by Russia in 2013 because it did not comply with EU law and TurkStream was put in its place. TurkStream has completed construction across the Black Sea and is now preparing for extension into Southeastern Europe, but it too may face EU regulations.

Nord Stream II faces the same criticism. It will make Russian pipelines through Ukraine redundant and while Moscow has told Europe that it will continue to use the Ukraine system, someday Kiev will ultimately lose the revenues it earns from transporting Russian gas.

Furthermore, considering that one of the European Commission's stated goals in gas policy is to reduce the body's reliance on Russian gas, there is little reason to think Nord Stream II will accomplish that. While the Nord Stream system will deliver 110 bcm/year of Russia gas to Germany, TurkStream will bring some 15 bcm/year to the Bulgarian border, and the TurkStream plan calls for the pipeline to add another 30 bcm/year capacity. Russian gas also arrives in Europe through Belarus and Poland and through the TransBalkan route via Ukraine.

US President Donald Trump has said the pipeline makes Germany a captive of Russia, and threatened sanctions against the five European companies providing financing for the project: Wintershall, Uniper, Shell, Engie and OMV.

The US has made it clear that it is also unhappy with Nord Stream II, as it serves as a direct competitor to American plans to boost its own LNG exports to European markets. With rising production of shale gas, which has created a booming LNG export business, the US sees itself as an answer for the security of supply and diversity of sources for which the European Union has been earnestly searching.

The future has been written

According to a new EY report, the EU's electricity future has been written – it will be decarbonised, decentralised and electric – and distribution system operators will need to be ready within five years.

Junior Isles

About 12 months ago, EY released its thinking on what it calls "the countdown clock". The research is not only a view of what the future will look like in 2050 but also when it will happen; i.e. what are the key milestones when considering the energy transition and the road to a decarbonised, decentralised and more electric world.

The findings showed there are three tipping points: (1) in 2023 when decentralised generation, i.e. photovoltaic (PV) solar plus batteries becomes cheaper than power from the grid; (2) in 2025, or sooner, when the price of electric vehicles (EV) falls below that of conventional cars; and (3) the point when transmission and distribution costs alone are more expensive than decentralised solutions, forecasted to happen in 2040.

In a move to establish what these imminent tipping points mean to distribution system operators (DSOs), EY has followed up last year's study with a new report entitled: 'Where does change start if the future is already decided?' The report, produced with support from Eurelectric, details what DSOs need in order to be ready for the new reality, which is less than five years away, and what is needed from the regulator in order to make the changes possible.

Lead author of the report, Serge Colle, Global Power & Utilities Advisory Leader, commented: "The implications for the network are enormous and the changes are only one and a half regulatory cycles away. So the DSO community has to move very urgently from what is going on today, for example deployment of smart meters and pilot around all sorts of technologies such as microgrids. We need to have a concrete plan to be ready for that moment in time when we will see mass acceleration, and know what the regulatory implications will look like. Our network will soon be in trouble unless we change something, and that something has to be agreed with the regulators."

The study was carried out with the participation of 15 DSOs through C-Level interviews, and complemented by workshops with technical people and regulators, as well as an online survey involving 117 electricity sector professionals.

According to EY, companies recognise the sense of urgency and the size of the task they face. Although great strides have been made in the journey toward decarbonisation at the utility level and network operators have managed to keep the lights on, despite the huge influx of intermittent renewables, they realise that there remains a tremendous amount to be done.

Massive deployment of variable renewable generation – predominantly solar PV, onshore and offshore wind – is expected over the coming years. The report notes that by 2045, in a scenario where electrification reaches 63 per cent across the EU economy, new load will come from the transport, heating and industrial sectors.

In this scenario onshore wind capacity is expected to triple from its current levels to more than 640 GW, with offshore wind expanding to 470 GW. Solar PV capacity is set to increase seven-fold to 950 GW. Ultimately, renewable generation is expected to meet more than 80 per cent of Europe's future energy needs.

At the same time, more and more consumers are expected to provide demand-side flexibility, with 120-150 GW of flexible load available by 2045. Some of these will be households, commercial or industrial consumers, connected to the distribution grid.

According to Colle, the research revealed that dealing with the technical challenge of the electrification of transport was a major concern of DSOs, even more so than the impact of decentralisation.

In the transport sector, a combination of technology improvements, public policy (e.g., the Clean Vehicles Directive), ambitions set by cities and societies to improve air quality and political mandates, is driving Europe's take-up of electric vehicles (EVs). The penetration of EVs is still low but rising quickly, with adoption expected to accelerate given the increasing economic viability of battery technology and rollout of EV charging points.

The report says EVs accounted for roughly 2 per cent of new vehicle sales in the EU in 2018, but this number is expected to reach 33 per cent by 2030, representing a total of 10 million. EV sales that year alone are expected to be around 6.8 million. Most of this generation capacity and new load will be connected to the existing distribution grid.

Colle observed: "You can see those volumes become very significant very quickly, so there is a sense of urgency. So far, network companies have adopted copper as the solution to deal with renewables – basically business as usual. But putting more copper into the ground will very quickly become economically unsustainable."

EY has therefore been detailing what the alternative approach should be to enabling the energy transition in an affordable way, while still delivering the fundamentals of having a safe, reliable network.

This will require the DSO to evolve into what EY calls "DSO 2.0", Colle noted: "What is the next level of control needed on the network to deal with the increasing level of distributed resources. Some existing capabilities will have to be seriously enhanced but new capabilities will also be needed. We talked about network planning, asset management and systems management, and we already have some of that but it needs serious enhancement. But then we also talked about system operation, flexibility management and commercial operations, which is completely new.

So our point to DSOs is, in five years time, you need to have this. You need to start to understand that you need to have a certain level of visibility of your power flows, loads and connections at the distribution level… at the moment, the visibility of what's happening at the last mile is almost zero. The smart meters that are going in don't give the information about the loads and flows that is required.

"The second thing is flexibility, which we trigger by influencing supply or demand. But right now that technical option does not exist, which brings me to the third part. We don't have a commercial framework to deal with this. For example, if we require DSOs to trigger flexibility options with consumers, there's no framework for it."

This will all require investment and certainly a rebalancing of investment priorities. "We need three things," said Colle. "We need copper; we need to 'sensorise' the network to understand what's going on in the network; and then we need to build the capability to actually trade in flexibility options. The current investment agenda is not aligned with those three objectives. It's overweight on the copper bit; there's no clear strategy on what is required in terms of sensorisation. So the investment needs to change."

Investment, however, cannot come without the right regulation, which at the moment is not there. "There are very big gaps," noted Colle. "Yes, we need to move from a consumption-based tariff to more of a capacity-based system but even this is such a complicated question, which many utilities are discussing with regulators as we speak.

Changing tariffs is very complex... it will need to be continuously revised over time as the configuration of the network and the consumers that operate on top of it change."

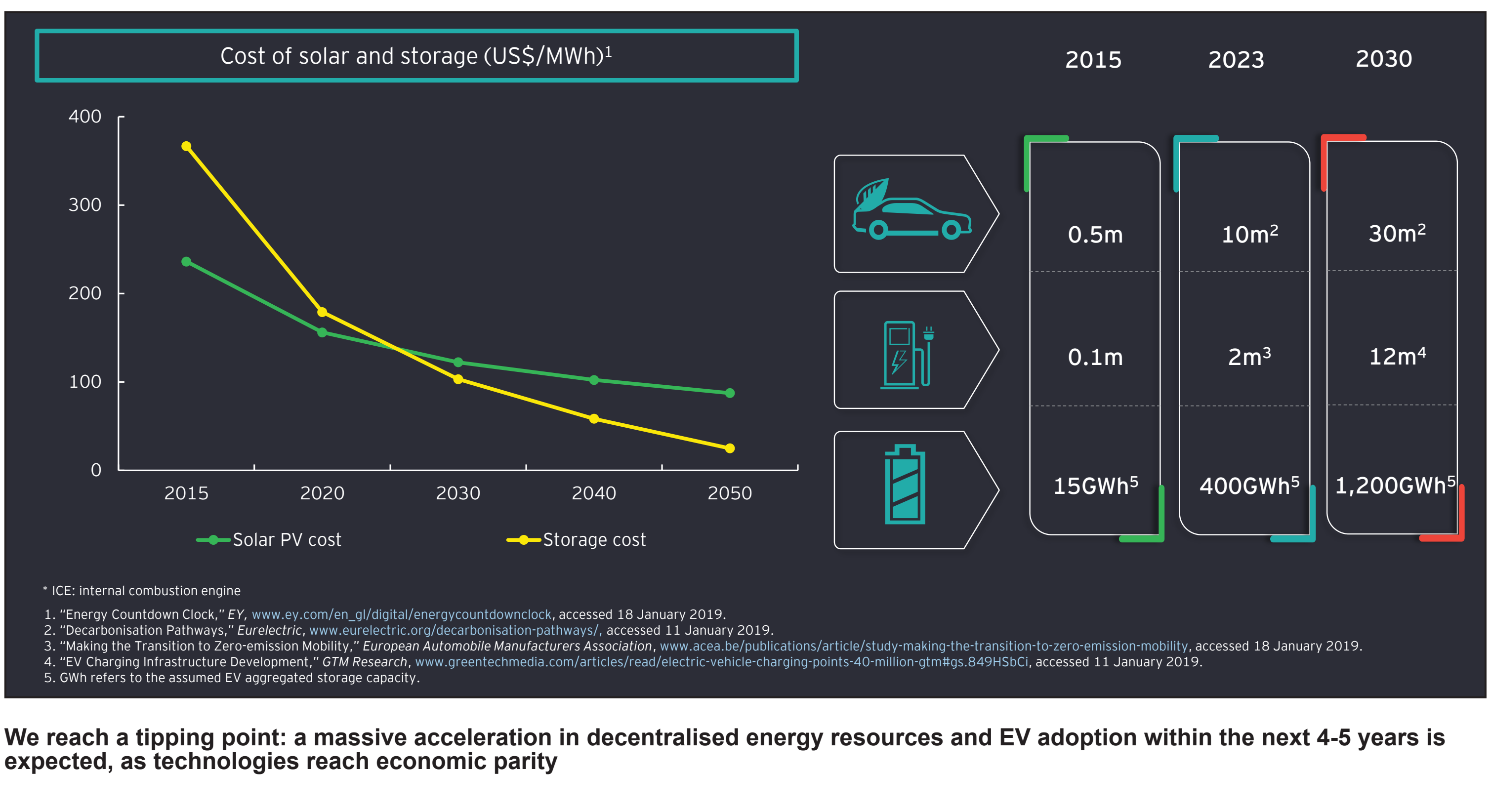
The report notes that regulators and policymakers need to be mindful of the pace of technology change and the degree of customer participation, and reward innovation where it is needed. At the same time, they must facilitate predictable and stable investment returns, so far as national conditions allow, incentivising a higher quality service through meaningful and achievable targets and outputs for DSOs.

EY therefore sets out six priorities for EU policymakers:

1. Recognise the role of DSO 2.0 and new players in the market and define it;
2. Reward innovation with greater incentives. EY notes that there will be different solutions for different networks;
3. Evolve network tariffs to ensure distributed generation pays a price consistent with its contribution;
4. Ensure timely implementation of the Clean Energy for All Europeans package;
5. Allow use of grid-scale storage facilities to secure the technical operation of the grid;
6. Enable implementation of standards and data management models.

Colle believes that whatever happens, DSOs will be at the heart of the transition, noting that even in the most decentralised scenario, utility-scale generation will still represent 70 per cent of the mix.

He concluded: "We know what the future will look like but without DSOs it will not work. Five years from now, we will see mass acceleration so we have to be ready by then, or whatever we try to do to cope with the new reality will be incredibly expensive. This means DSOs need a concrete plan right now. At the same time, they have to talk to regulators about the regulation required to do their three fundamental jobs: enabling the energy transition, keeping the lights on and making it affordable."

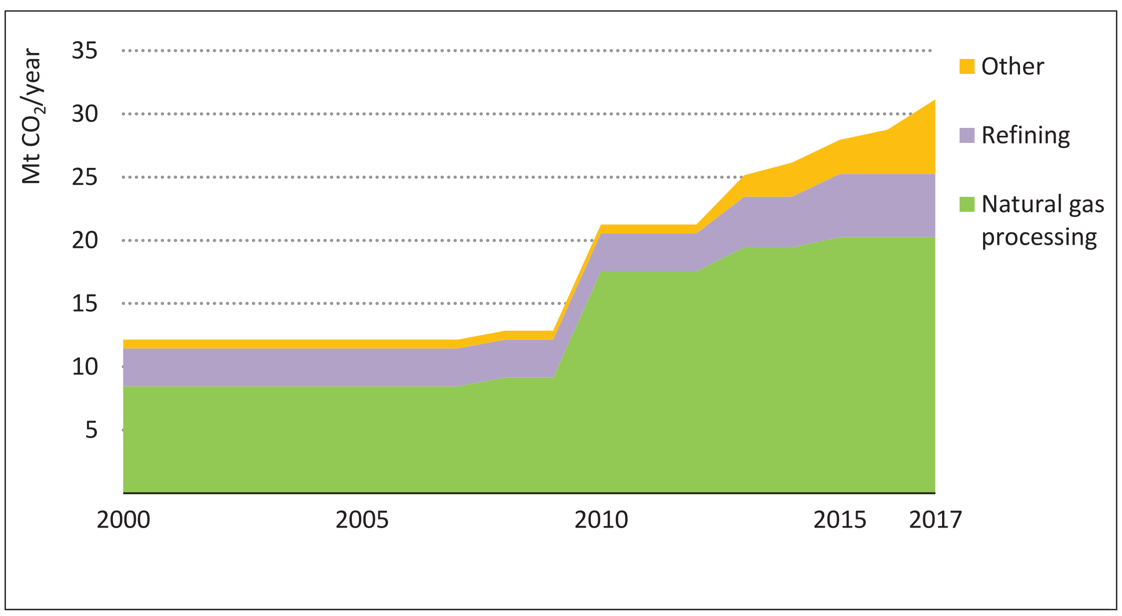


We reach a tipping point: a massive acceleration in decentralised energy resources and EV adoption within the next 4-5 years is expected, as technologies reach economic parity

A new boost for carbon capture

Although challenged by economics, many industry observers maintain that carbon capture utilisation and storage (CCUS) is essential in meeting climate change targets. The Clean Energy Ministerial's CCUS Initiative is hoping to get the technology back on track. ***TEI Times*** **reports.**

Historical volumes of CO_2 captured globally. Nearly 70 per cent of the 30 Mt CO_2 emissions captured today is from oil and gas operations. *© IEA/OECD. Source: World Energy Outlook 2018*



Carbon capture, utilisation and storage (CCUS) has long been recognised by many as one of the suite of technologies needed to combat climate change. Carbon dioxide (CO_2) injection for enhanced oil recovery (EOR) started in the US in the early 1970s, and the world's first dedicated CO_2 storage project, the Sleipner project in Norway, has over 20 years of operational experience.

But despite decades of experience, the technology has struggled to deploy on a large scale. According to the Global CCS Institute, there are a total of only 18 large-scale CCUS projects in operation today. In relatively recent times, progress can at best be described as mixed.

The decision in June 2017 to suspend start-up activities for the Kemper gasification system in the United States, due to the project's economics, is a reminder of the challenges that first-of-a-kind technology faces. It is somewhat ironic that Kemper's problem was not carbon capture technology *per se*, but lignite gasification scale-up.

While there are technical difficulties in operating CCUS plants flexibly, these are deemed to be small in comparison with the economic consequences. High-efficiency CCUS plants are costly to build and it is questionable whether newly built plants would be able to recover costs if required to operate flexibly.

On the positive side, however, the Petra Nova project in the US state of Texas – commissioned in 2017 and delivered on time and to budget – retrofitted post-combustion capture technology on an existing coal fired power station. The project is a vitally important model for the future if operation of today's relatively young global coal fired fleet is to be compatible with a low-emissions future.

Further, lessons from the two large scale commercial retrofit plants in operation – Petra Nova and Boundary Dam in Saskatchewan, Canada – indicate that significant cost reductions are possible. This suggests that CCUS could provide an important strategic hedge for the existing coal fleet in a carbon-constrained world.

Another important step was the world's first large-scale CCS project in the iron and steel industry, which commenced operation in Abu Dhabi at the end of 2016.

Capitalising on the recent surge of attention to CCUS, in May last year the Clean Energy Ministerial (CEM) launched the "CCUS Initiative" aimed at accelerating the deployment of CCUS technologies via the voluntary CEM process. The CCUS Initiative brings together 10 countries spearheaded by Norway, Saudi Arabia, the UK and the US governments (plus Canada, China, Mexico, Japan, South Africa United Arab Emirates) that are key players in CCUS, and for whom CCUS is relevant.

"The CEM CCUS Initiative has attracted critical mass to be a relevant actor, with several of the key countries already involved, but we remain open to further interested governments joining," said Juho Lipponen, ex-IEA CCS team-lead, now working as the initiative coordinator. "We are also keen to partner with industry."

This initiative intends to strengthen the framework for public-private collaboration on CCUS, while complementing the efforts of – and adding co-ordinated value beyond – the activities of existing organisations and initiatives, such as the Carbon Sequestration Leadership Forum (CSLF), the International Energy Agency (IEA), the IEA Greenhouse Gas R&D Programme (IEAGHG), Mission Innovation (MI), and the Global CCS Institute (GCCSI).

At the launch in Denmark, Fatih Birol, Executive Director of the IEA said the initiative represented a "second birth" for CCUS.

The IEA has long held the view that CCUS is essential in meeting climate change targets, pointing out that even with much greater electrification, there will be sectors that will require other energy sources with most of the world's shipping, aviation and certain industrial processes not yet "electric-ready".

In its 'World Energy Outlook 2018' published in November, the IEA noted that finding solutions for these sectors that remain dependent on oil and gas requires a different approach, including further clean technology research and development spending and much more attention to areas such as CCUS.

The oil and gas industry itself is already one of the global leaders in developing and deploying CO_2 capture. According to the IEA, of the 30 Mt CO_2 captured today from industrial activities in large-scale CCUS facilities, nearly 70 per cent is captured from oil and gas operations. Around 4 Mt of the CO_2 captured today is injected into geological storage simply to reduce the emissions intensity of operations.

The oil and gas industry is active in this area because it can often make use of the CO_2 that is captured: either by selling it to industrial facilities or by injecting it into the sub-surface to boost oil recovery. A number of oil and gas processes produce highly concentrated streams of CO_2 that are relatively easy and cost-efficient to capture.

Combining CO_2 capture facilities with enhanced oil recovery projects is not only a way to reduce the emissions intensity of oil; it could also help reduce the costs of future CCUS projects.

Globally, the IEA estimates that just over 700 Mt CO_2 indirect emissions from oil and gas operations could be avoided using CCUS. Further, injecting CO_2 in EOR projects could actually produce "negative emissions" oil if the CO_2 is captured from the atmosphere.

The technology could also have an important role to play in the production of hydrogen in industrial plants, thus serving to facilitate the hydrogen economy.

In *WEO 2018* the IEA stated: "Carbon capture, utilisation and storage needs to play an important role in meeting climate goals". Its findings maintain that to reach Paris climate targets of 2˚C by 2060, 14 per cent of cumulative emission reductions must derive from CCS. But at the same time it observes that "there are very few projects operating or planned".

This can only be addressed through a concerted, coordinated, global effort at the highest level. By bringing a dedicated CCUS work stream under a wider clean energy portfolio, the participating governments of the CCUS Initiative aim to ensure that CCUS has a place in the holistic clean energy debate.

A key objective of the Initiative is to provide a sustained forum for governments to work with both industry and the financial community. By ensuring a channel through which views from industry and particularly the financiers can be directly channelled to decision-makers, the Initiative can accelerate the necessary decisions on policy approaches.

The Initiative will also ensure the sharing of best practice policy and regulatory developments. Carbon Sequestration Leadership Forum "Policy Group" activities will also be transferred to the new Initiative, streamlining the organisational space for CCUS. The Initiative also intends to assist with identifying future investment opportunities, both short- and longer-term.

Perhaps the most pressing activity is, however, to bring the finance sector on board to discuss how to make CCUS projects more investable. Essentially this comes down to defining why CCUS projects are or, as in most cases are not, bankable.

The Initiative will be well-placed to ensure dialogue and information exchange between governments, industry and the finance sector – all key stakeholders to make CCUS projects happen in the future. The initiative intends to ensure that the views of the financial institutions can be taken into account by governments as they plan policy approaches to help CCUS deployment.

"As investment in carbon capture has lagged far behind other clean energy technologies, a particular focus our member governments have is on engaging with the financial sector. Their views on how to make CCUS a bankable proposition are vital for the governments who want to create conducive investment conditions," said Lipponen.

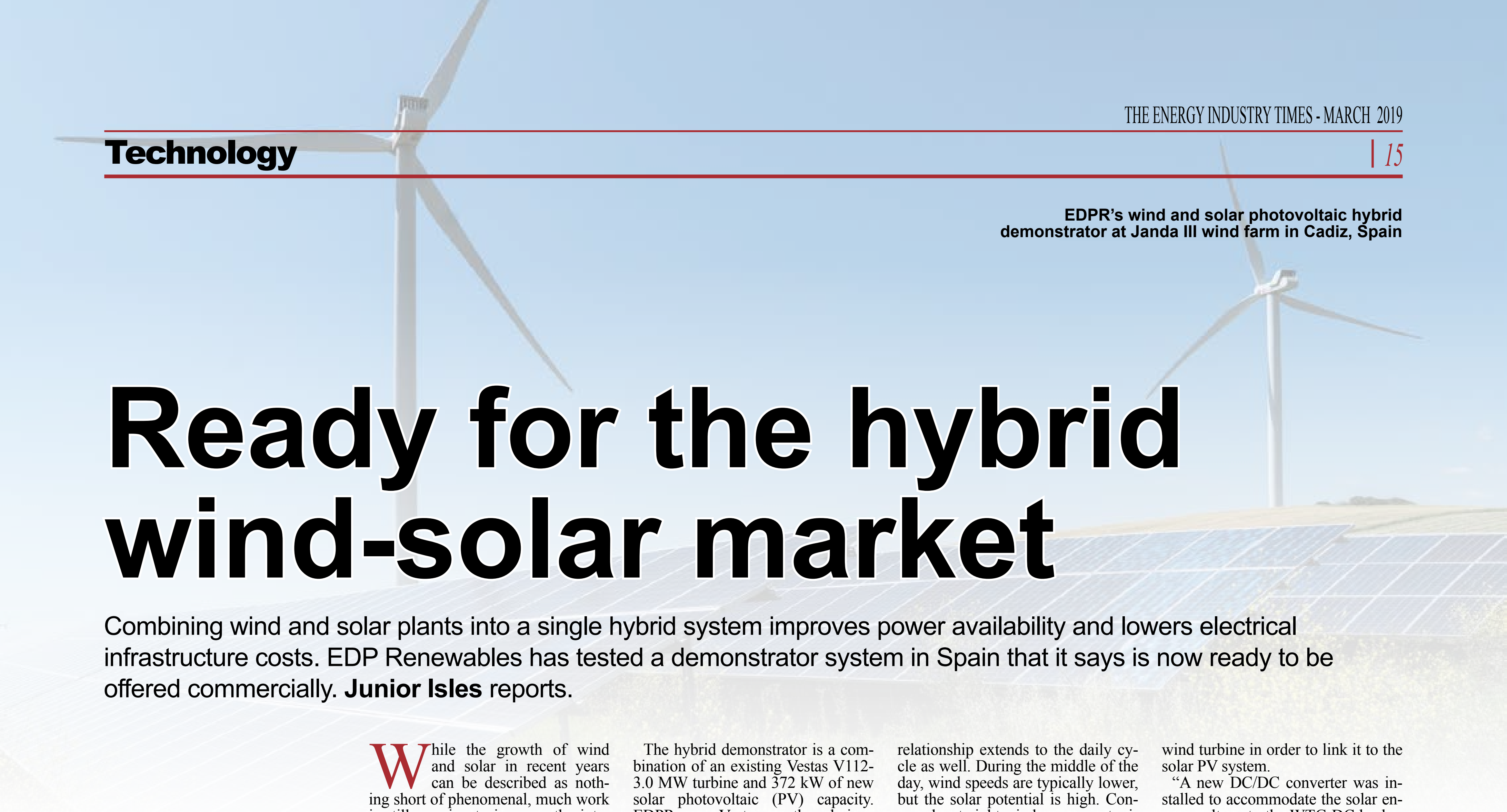
The Clean Energy Ministerial process functions on a voluntary action basis. Rather than signing on to binding objectives, the participating governments come together to showcase clean energy activity and to organise collaboration under various technologies.

While commercial scale CCUS projects in power have been few in number and expensive to date, there are some bright spots. There have been positive developments supporting plans for CCUS and new projects from Norway, Netherlands and the United Kingdom.

The United States passed legislation (the Future Act) that expands tax credits for the capture of CO_2 from power plants or industrial facilities (up to \$50/t CO_2). This means that for a medium-size coal-fired power plant (1-50 MWth), capturing 80 per cent of CO_2 produced could provide upwards of \$70 million per year in additional revenue. The tax credit could also spur investment in CO_2 capture for natural gas processing and refining.

With few projects visible on the horizon, enhanced government support would be necessary to provide opportunities to drive down costs through learning-by-doing. The CEM's CCUS Initiative aims to be a central cog in delivering that much needed global government push.

"We don't have the luxury to wait anymore," Lipponen stressed, "action is needed now and we hope to make a difference with the new Initiative under the Clean Energy Ministerial umbrella."



EDPR's wind and solar photovoltaic hybrid demonstrator at Janda III wind farm in Cadiz, Spain

Ready for the hybrid wind-solar market

Combining wind and solar plants into a single hybrid system improves power availability and lowers electrical infrastructure costs. EDP Renewables has tested a demonstrator system in Spain that it says is now ready to be offered commercially. **Junior Isles** reports.

While the growth of wind and solar in recent years can be described as nothing short of phenomenal, much work is still ongoing to improve the integration of these intermittent renewable energy sources into the grid. Almost a year ago, renewable energy company EDP Renewables (EDPR), one of the world's largest wind energy producers, and wind turbine manufacturer Vestas, launched a project aimed at meeting their customers' increasing need to balance energy supply with grid demand.

In late March last year, the two companies installed a wind and solar photovoltaic hybrid demonstrator at EDPR's Janda III wind farm in Cadiz, Spain. After one year of testing, the technology looks set for commercialisation.

Commenting on the project, José Ángel Diaz, Technology Director of EDP Renewables, said: "We were looking for a hybrid wind plus solar PV generation system that could deliver the maximum synergies possible. The main goal was to show that it is possible to integrate solar and wind energy at the DC level of the wind turbine generator (WTG). This would reduce the amount of electrical infrastructure needed compared to a co-located hybrid plant or an AC connected system."

The hybrid demonstrator is a combination of an existing Vestas V112-3.0 MW turbine and 372 kW of new solar photovoltaic (PV) capacity. EDPR saw Vestas as the obvious partner for the demonstrator.

"The relation between EDPR and Vestas stretches back from long ago; we have partnered on many projects worldwide," said Ángel Diaz. "Vestas is also a technical leader in the WTG OEM market, and when we approached them they were very keen to implement the concept, which we developed, on one of their turbines."

Hybrid systems have several benefits, the main one being the ability to reduce the intermittency of power from wind and solar. In most regions wind speeds are low in the summer when the sun shines brightest and longest. The wind is strong in the winter when less sunlight is available. Because the peak operating times for wind and solar systems generally occur at different times of the day and year, hybrid systems are more likely to produce power when it is needed.

Indeed wind and solar are a natural fit. The two are complementary on a seasonal basis. Winter months with typical reductions in solar irradiance (shorter days) bring an increased power in potential wind energy. This relationship extends to the daily cycle as well. During the middle of the day, wind speeds are typically lower, but the solar potential is high. Conversely, at night winds are more typical, but there is no power available to the PV elements in the system.

Solar PV is operational only during daylight hours, which limits the overall production of a system. Wind has the potential to produce 24 hours a day, given the right conditions, but most importantly throughout evening hours when solar is not available.

A hybrid approach provides a more secure and even supply of energy, and provides an energy floor in the event that a location has seasonal weaknesses in the wind resources available. There are locations that, because of seasonal variations in wind resources, do not support a wind-only solution.

If the production of energy during extended periods is not guaranteed, energy storage requirements to bridge the lean times are expensive, and the return on investment can be excessively long. Where both wind and solar are in abundance, hybrid systems make more sense, especially in space constrained installations.

While having unconnected solar PV and wind turbines on the same site is possible – with power from the PV panels fed to the grid via its own inverter and similarly having the wind turbine connected to the grid via its generator – it is not the most economical way of evacuating electricity from the site.

EDPR says this is where a hybrid system has advantages. Ángel Diaz explained: "Injecting the solar PV energy directly to the DC bus of the turbine, allows a reduction of the electrical infrastructure needed to evacuate the energy. Using the same grid converter and transformer (as well as the entire electrical infrastructure of the wind farm up to the connection point), provides a cost reduction and maximisation of the use of the existing infrastructure."

EDPR notes that this can be interesting where there are space constraints and the physical conditions make it possible to only place a small number of PV panels near the wind turbine generators. It adds that a hybrid system also provides: smoother power output; use of the wind farm's O&M services and operational infrastructures; and more complete utilisation of a location's renewable resources.

According to the company, very few changes had to be made to the wind turbine in order to link it to the solar PV system.

"A new DC/DC converter was installed to accommodate the solar energy voltage to the WTG DC busbar at the converter, and some additional cabling and protection had to be introduced," said Ángel Diaz. "Additionally, the control algorithm was refurbished and new communication signals were added."

The key challenges in developing the demonstrator, he said, were related to the control system, i.e. how to achieve the integration of solar energy whilst keeping all the WTG performance and regulation features unaltered. He added: "We also had to be able to select between wind priority mode and solar priority mode when reaching the maximum interconnection capacity."

EDPR says the development and running of this demonstrator was an "interesting opportunity" to test some of its "hypotheses on the hybrid power plants of the future". In addition to showing that the two systems could be integrated at the DC level of the WTG, another key hypothesis it set out to test was that it could be done without affecting the overall behaviour of the generation system in terms of grid code compliance (active and reactive power capabilities and regulation, low voltage ride through (LVRT), harmonics emission, flicker, etc.).

Commenting on the tests, which have now been fully completed, Ángel Diaz said: "The key findings were that the initial hypotheses were successfully proven. There was no electro-technical issue with the connection of both systems, the control refurbishment was carried out with no difficulty, and finally a 'new generator' was created that maximised power output, with greater predictability and a smoother power output curve."

Now the next step is to have a commercial offering. Ángel Diaz said: "On one hand, the WTG OEMs will be developing new products based on this technology, as long as there is a market for them. And on the other hand, we, as a project developer and operator, are actively analysing future power plants where this solution can be the most interesting – both for retrofitting current plants and engineering new ones."

EDPR has not specified a timeline on when it expects that the first systems will be deployed but said: "We believe that this type of technology will be part of the renewables landscape in the coming future."

Ángel Diaz: EDPR was looking for a hybrid system that "could deliver maximum synergies"

|Junior Isles

ET is green… with a bit of brown

With the introduction last year of its 'Evolving Transition' (ET) as the reference scenario in its annual 'Energy Outlook', to all intents and purposes BP, the oil and gas major, officially acknowledged that the energy transition is here to stay. The ET scenario assumes that government policies, technology and social preferences continue to evolve "in a manner and speed seen over the recent past".

This year BP continued in a similar vein, highlighting the changing energy landscape while stressing that meeting growing energy demand and at the same time reducing carbon emissions presented "one of the biggest challenges of our time".

Launching the Outlook, Bob Dudley, BP's Chief Executive, said: "The Outlook again brings into sharp focus just how fast the world's energy systems are changing, and how the dual challenge of more energy with fewer emissions is framing the future. Meeting this challenge will undoubtedly require many forms of energy to play a role."

"The world of energy is changing," agreed Spencer Dale, BP Group Chief Economist. "Renewables and natural gas together account for the great majority of the growth in primary energy. In our evolving transition scenario, 85 per cent of new energy is lower carbon."

According to the Energy Outlook, renewables are set to penetrate the global energy system more quickly than any fuel previously in history. "Historically, it has taken many decades for new fuels to penetrate the energy system," it stated. "For example, it took almost 45 years for the share of oil to increase from 1 per cent of world energy to 10 per cent in late 1800s/early 1900s. For natural gas, it took over 50 years from the beginning of the 20th century."

In the ET scenario, the share of renewables in world energy increases from 1 per cent to 10 per cent in only 25 years.

BP points out that during the outlook period, the mix of fuels in global power generation shifts materially, with renewables gaining share at the expense of coal, nuclear and hydro. The share of natural gas is broadly flat at around 20 per cent.

As the fastest growing energy source (7.6 per cent p.a.), renewables account for around two-thirds of the increase in global power generation during the period, and become the single largest source of global power generation by 2040.

Both wind and solar power grow rapidly – increasing by a factor of 5 and 10 respectively – accounting for broadly similar increments to global power. This rapid growth is aided by continuing pronounced falls in the costs of wind and solar power as they move down their learning curves.

In terms of regional deployment, the EU continues to lead the way in terms of the penetration of renewables, with the share of renewables in the EU power market increasing to over 50 per cent by 2040.

The growth in renewable energy is dominated by the developing world, with China, India and 'Other Asia' accounting for almost half of the growth in global renewable power generation.

The airtime given to clean energy in the Outlook is a far cry from 2015 when the focus was largely on oil and gas, with little mention of renewables. Since 2016, however, with the public spotlight on climate change, BP has been slowly acknowledging the importance of low carbon energy sources such as wind and solar.

BP says the 'Energy Outlook' is "produced to aid its analysis and decision-making, and is published as a contribution to the wider debate". Some, however, appear to believe it is perhaps designed to colour the debate. Certainly it is debatable whether BP's apparent shifting in stance is due to a true recognition of, and subsequent alignment with, where the sector is heading, or whether it is down to pressure from external voices.

The company recently announced it is supporting the aim of the Paris Agreement, with its call to rapidly reduce greenhouse gas emissions in the context of sustainable development and eradicating poverty, since it was agreed in 2015.

At the start of February BP said that it would support a call from a group of institutional investors for the company to broaden its corporate reporting to describe how its strategy is consistent with the goals of the Paris Agreement.

Investor participants of the Climate Action 100+ initiative have proposed a resolution to be put to shareholders at the company's annual general meeting in May 2019 – a resolution that the BP Board says it will support.

In line with the proposed resolution BP will describe how its strategy is consistent with the Paris goals, as well as set out a range of additional related reporting.

But not all are convinced of BP's true commitment to a clean energy future. In response to the group's claim that its business plan is aligned with the Paris climate targets, Charlie Kronick, Oil Campaigner for Greenpeace UK, said: "Whether deluded or disingenuous, BP's management clearly isn't up to the task of navigating the transition to a low carbon economy. BP claiming its business plan is in line with the Paris targets, while still planning to drill for new oil the world can't afford to burn in an area of huge ecological significance like the Mouth of the Amazon, is simply ridiculous. If climate change wasn't actually a matter of life and death, this claim would be comical."

In its Outlook BP maintains that "significant levels of investment" are required for there to be sufficient supplies of oil to meet demand in 2040.

Climate change is certainly no joke but when considering the tone of the Outlook and the company's statements, such accusations by environmental campaigners seem somewhat harsh at first glance.

BP may or may not be wholeheartedly invested in the dream of a carbon-free energy future, if indeed such a thing is even possible. As it points out, its challenge is to "understand, adapt and ultimately thrive in this changing energy landscape".

Interestingly, however, in every Outlook BP foresees continued growth in energy demand and therefore is always able to justify ever greater demand for fossil fuels.

Highlighting the power sector, which accounts for the lion's share of energy demand, it states: "The strong growth of power demand in developing economies means there is greater scope for renewables to increase. But in the ET scenario, renewables do not grow sufficiently quickly to meet all of the additional power demand, and as a result coal consumption also increases."

It also says natural gas grows strongly, supported by broad-based demand, plentiful low-cost supplies, and the increasing availability of gas globally, aided by the growing supplies of liquefied natural gas (LNG).

In the ET scenario, natural gas grows at an average rate of 1.7 per cent p.a. – increasing nearly 50 per cent by 2040 – led by industry and the power sector. The additional gas absorbed by the power sector is driven by the overall growth in power demand, with the share of natural gas in the sector remaining relatively stable at around 20 per cent.

But how sound is BP's assumption of ever-increasing demand? A recent report by McKinsey Energy Insights predicts energy demand will plateau by 2035, despite strong GDP and population growth.

It will be interesting to see if BP's Outlook next year, or any subsequent year, ever shows a decoupling of economic growth and energy demand. If not, I suspect the Outlooks might continue to gradually become greener but will always retain a browner hue than some might be happy with.

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