Renewables drive transformation of power system

Damon Evans, SINGAPORE: Integrating large amounts of variable renewable energy into the energy mix is really about transforming the world's power systems, the International Energy Agency (IEA) has said.

"Integration is not simply about adding wind and solar on top of business as usual. We need to transform the system as a whole to do this cost-effectively," the agency's executive director Maria Van der Hoeven said at the launch of the IEA's latest report.

In *The Power of Transformation – Wind, Sun and the Economics of Flexible Power Systems*, the agency says that integrating high shares – more than 30% of yearly electricity production – of wind and solar photovoltaics (PV) in power systems can come at little additional cost in the long term.

But costs depend on the flexibility of systems and what strategies are taken to develop system flexibility in the long run. Managing this transition will be more difficult for some countries or power systems than others, the study says. Today, wind and solar PV make up just 3% of world electricity generation, but some countries already feature very high shares. In Italy, Germany, Ireland, Spain, Portugal and Denmark, these renewable energies made up from around 10% to more than 30% of electricity generation in 2012.

Integrating the first 5-10% of variable renewable energy generation poses no technical or economic problems at all within existing systems set up to cope with variable demand. However, going beyond this to a share greater than 30% necessitates transforming the system, says the IEA. Such a transformation has three main requirements; deploying variable renewables in a system-friendly way using state-of-the art technology, improving day-to-day operations of power systems and markets, as well as investing in additional flexible resources.

In stable systems, such as those in Europe, the existing asset base will help provide sufficient flexibility to increase variable renewable energy further. But, in the absence of demand growth, expanding variable renewable energy in stable systems inevitably comes at the detriment of incumbent generators and puts the system as a whole under economic stress. The transformation challenge in stable systems is twofold; scaling up the new flexible system, while scaling down the inflexible part of the old. Clearly governments with stable systems face tough policy questions about how to handle the distributional effects, in particular if other power plants need to be retired before the end of their lifetimes and, if so, who will pay for stranded assets.Nevertheless, "these surmountable challenges should not let us lose sight of the benefits renewables can bring for energy security and fighting dangerous climate change.

If OECD countries want to maintain their position as front runners in this industry, they will need to tackle these questions head-on," Van der Hoeven said.

By contrast in dynamic power systems – where significant short-term investments are needed to meet expanding power demand or replace old assets – such as India, China, Brazil and other emerging economies, wind and solar PV can be cost-effective solutions to meet incremental demand.

Variable renewable energy grid integration can – and must – be a priority from the onset, Van der Hoeven added.

"Emerging economies really have an opportunity here. They can leap-frog to a 21st-century power system – and they should reap the benefits." ●

KazTransGas to tap Kazakhstan CBM

Helen Robertson, LONDON: Kazakhstan's state-run gas pipeline monopoly KazTransGas has reached a deal with local government to explore the country's coal-bed methane (CBM) reserves.

KazTransGas has signed a memorandum of understanding with the municipal government of Karaganda city to jointly explore for CBM in the Karaganda coal basin, according to local media. Karaganda is the capital of Karagandy Province, which lies in the centre of the country. Oilfield services company Schlumberger says Kazakhstan's CBM reserves could total 650 million cubic metres (cm), while other estimates peg reserves at between 1.2 trillion cm to 1.7 trillion cm. The government is hoping CBM production from the basin could eventually reach 4 billion cm a year. Kazakhstan has sizeable conventional reserves of oil, gas and coal which have enabled it to become a major energy exporter.

According to Cedigaz, Kazakhstan has around 56 million tonnes of oil equivalent of coal reserves, 1.4 billion barrels of oil and 1.3 trillion cm of gas. However rising domestic demand means it is seeking new sources of energy.

The Central Asian country is heavily reliant on coal for domestic energy use, with around 85% of its power generation being derived from the carbon-intensive fossil fuel, according to the US Energy Information Administration.

Kazakhstan also wants to explore its shale gas production potential although its reserves are unknown. ●

Tanzania edges along the LNG road

Martin Quinlan, LONDON: A successful production test has raised prospects for Tanzania's planned liquefied natural gas (LNG) complex, the location of which is due to be announced shortly. Latest reserves estimates for offshore areas operated by Statoil and BG are approaching 1,000 billion cubic metres (cm) – enough to support a complex of four or more of the largest LNG trains.

Statoil, operator for Block 2, said the first drill-stem test in the block, carried out on the Zafarani-2 well, gave an equipment-limited flow of 1.87 million cm/d, and confirmed the quality and connectivity of the reservoir.

The test reduces the uncertainties of the development and confirms that production wells will have high flow-rates.

The Zafarani field, 80 km offshore the southern coast and lying under 2,400 metres of water, is seen as the cornerstone for the LNG development. Appraisal will be completed with the Zafarani-3 well, to be drilled next.

Statoil has five large gas discoveries in Block 2 – Zafarani, Mronge, Tangawizi and, with two separate reservoirs, Lavani. It estimates that gas-in-place amounts to 481 billion-566 billion cm. The company holds the block in a 65:35 venture with ExxonMobil.

BG is the operator for the neighbouring blocks 1, 3 and 4, where it has nine gas discoveries – Mzia, Jodari North, Jodari, Chaza and Mkizi in Block 1, Papa in Block 3 and Chewa, Ngisi and Pweza in Block 4. With much appraisal work completed and drill-stem tests carried out, the company's estimate for reserves across the three blocks is 425 billion cm. BG holds 60% of the three blocks, joined by Ophir with 20% and Pavilion, owned by Singapore's state investment company Temasek, with 20%.

The two operators have been in discussions about a coordinated LNG development and – according to reports quoting the country's energy minister – are about to announce their choice of location for the complex. A site in the southern Lindi region is being tipped – although there is local pressure for the complex to go further south, to the poorly-developed Mtwara region.

Statoil and BG have been asked by the government to set out their plans and schedule at a meeting in April. With much infrastructure to be constructed before work on the complex can begin, it is indicated that production will not be starting until 2021-22. ●

$1.2bn boost for Freeport LNG

Helen Robertson, LONDON: The Freeport Liquefied Natural Gas (LNG) project has received a $1.2 billion funding boost from Japanese utility companies Osaka Gas and Chubu Electric. Freeport LNG said the new investment would fund the first of three proposed liquefaction trains for the project on Quintana Island near Freeport, Texas.

The company secured funding for the second train and an LNG loading facility in December when fund manager IFM Investors pledged $1.3 billion.

The project is being developed by Freeport LNG Development, which owns and operates an existing LNG regasification terminal located near Freeport.

Freeport LNG Development is owned by Freeport LNG Investments, ZHA FLNG Purchaser (a subsidiary of Zachry American Infrastructure), Texas LNG Holdings, (a subsidiary of The Dow Chemical Company) and Turbo LNG, (a subsidiary of Osaka Gas). The deal is expected to close in the second half of 2014, subject to regulatory approvals.

The initial three-train facility will have a liquefaction capacity of around 13.2 million tonnes per year (t/y). Freeport LNG hopes to bring the first two trains online in 2018, with the third becoming operational in 2019. Freeport LNG has sales agreements in place under use-or-pay liquefaction tolling agreements with Osaka Gas, Chubu Electric, BP, Toshiba and SK E&S LNG. In 2012 Osaka Gas and Chubu Electric signed sales agreements for the whole capacity of the first liquefaction train, around 4.4 million t/y of LNG, according to Freeport LNG.

In May 2013 the US Department of Energy (DOE) granted Freeport LNG conditional permission to export 1.4 billion cubic feet per day (cf/d) of natural gas to non-free trade countries from the Quintana Island terminal on the Gulf Coast, starting in 2017. The application to build the Freeport LNG project is subject to receiving permission from the US Federal Energy Regulatory Commission (FERC) and a final investment decision being taken by Freeport LNG. The company said it expects to receive FERC approval by mid-2014 and to start building the first two liquefaction trains in the second half of 2014. Construction of the third train is expected to start in the first half of 2015 and first gas is expected from train one in 2018. Start up of the second and third trains will be staggered at six and 12 month intervals after the first train becomes operational.

Meanwhile, the DOE has approved Delfin LNG's application to export 1.8 billion cf/d of gas over a 20-year period to countries which have a free trade agreement with the US.

Delfin applied for the licence in October 2013 and on 20 February the DOE announced it had been approved. Gas will be exported from the proposed floating LNG (FLNG) project, which would be located in the West Cameron Block 167, in the Gulf of Mexico. The FLNG project will involve building a floating liquefaction facility and using floating storage vessels, which will be moored around 48 kms offshore Cameron Parish in Louisiana, near an existing platform.

The liquefied gas will be transferred onto LNG carriers using a ship- to-ship transfer process.

Delfin said the platform is connected to an existing Enbridge offshore gas pipeline system which can transport the gas to the shore via a 48-km pipeline.

The company is still awaiting permission to build the floating liquefaction facility from the US Department of Transportation's Marine Administration (MARAD) because it qualifies as a deep-water port.

The DOE has also approved ConocoPhillips' Alaska Natural Gas Corporation's (CPANGC) application to export up to 40 billion cf of LNG, from its existing facility, on a cumulative basis over a two-year period to nations which have a free trade agreement with the US.CPANGC is the operator of natural gas liquefaction and marine terminal facilities near Kenai, Alaska. The company produces LNG from gas fields in the Cook Inlet region of southern-central Alaska and exports to Japan. ConocoPhillips applied to the DOE to for a new export licence in December after its previous export licence for the Kenai LNG Plant expired in March last year. ●

Canacol touts Colombia shale results

Justin Jacobs, BEIJING: Colombia's efforts to drum up interest in its unconventional oil and gas sector received a boost after US supermajor ExxonMobil and its partner Canacol Energy announced the country's most successful shale well to date in March. Canacol said results from the Mono Arana-1 well in the La Luna shale in central Colombia compared favourably with shale wells drilled in the US and Argentina's Vaca Muerta.

The vertical well was not hydraulically fractured (fracked), but produced around 590 barrels a day (b/d) of oil, compared to less than 300 b/d for a typical well in the US Bakken or Eagle Ford shale plays, Canacol said in a statement. "We are very pleased with the flow test results from the La Luna naturally fractured reservoir at the vertical Mono Arana-1 well," Charle Gamba, Canacol's chief executive said.

Canacol said they expect better results with future wells. However, Mono Arana-1 was cased and cemented improperly, the company said, which damaged the formation where testing is taking place. As a result, only the upper half the La Luna shale formation is being tested.

Canacol said they were also encouraged by high pressure in the La Luna formation, which is crucial for pushing hydrocarbons through the dense shale. Canacol has bet big on the early stages of Colombia shale exploration, snapping up low-cost acreage in the hopes that drilling success inflates the value. The company has bought seven blocks with shale oil potential and signed deals to jointly explore the acreage with ExxonMobil, Shell and ConocoPhillips.

Although still in the very early stages of exploration, Canacol has estimated its acreage could hold 2.3 billion barrels of recoverable oil, though much work still has to be done to confirm the figure.

The Colombian government is keen to see success in its shale patch. Over the past decade, strong government support for the industry, attractive fiscal terms and an improved security situation have drawn billions of dollars of investment into the oil sector. As a result, production has risen sharply, from around 520,000 b/d in 2004 to just over 1 million b/d in 2013. But production growth is starting to decline and the government has said there is an urgent need to prove up new reserves. Colombia's reserves to production ratio is just 6 years.

The US Energy Information Administration estimated Colombia had 15.5 trillion cubic feet of shale gas and 6.8 billion barrels of shale oil resources, making it potentially one of the most attractive shale plays in the region.

To try to boost investment Colombia is pitching unconventional acreage in the 2014 licensing round in July. The round will include 19 shale blocks in an area stretching across central Colombia near where Canacol, ExxonMobil, Shell, ConocoPhillips and state-run Ecopetrol have been exploring for the past couple years. The government will be hoping for more interest this year after the first attempt to license unconventional acreage in the 2012 licensing round failed to attract significant interest. In that round, the government offered financial incentives and restructured its contracts to account for the longer exploration time required in frontier shale operations. But with limited geological data available and uncertainty around environmental and other regulations for shale development, most saw the risks as too high. ●