Exxon over a barrel with Gorgon LNG deal

Sally Bogle in Perth

FRESH from renegotiating a long-term LNG contract with Qatar’s RasGas, India’s Petronet is reportedly lobbying ExxonMobil to revise the price of its 20-year supply contract with Gorgon before the project’s scheduled startup later this quarter.

If successful, it could open the floodgates for a host of renegotiation requests from Gorgon’s other buyers, which have seen the Western Australian venture face delays and cost blowouts since lead developer Chevron took an FID in September 2009.

A senior LNG analyst, who asked to remain anonymous, told Interfax the move shows the robustness of long-term take-or-pay contracts is “now being tested”.

“Contract details, such as averaging designed to damp out volatility in a market that has gone through a sudden change in the oil price regime, are now inappropriate. This may be exacerbated by the supply surplus and the emergence of a significant, competitive spot market,” the analyst added.

According to Indian media sources, Petronet has requested a lower price for the 1.5 mtpa of LNG it is committed to buy from Exxon’s portion of Gorgon’s output given continuing low prices for oil-indexed gas. Petronet signed a sales and purchase agreement (SPA) for the LNG in 2009 and is due to start importing it into the Kochi LNG terminal in the state of Kerala later this year.

When contacted by Interfax, a spokeswoman for Exxon would only say that “ExxonMobil has a commercial agreement with Petronet LNG Ltd. to supply liquefied natural gas from the Gorgon project in Australia. The terms of the agreement are confidential.” Petronet could not be reached for comment.

Petronet was due to start receiving gas last year. However, ongoing delays and the halving of oil prices since mid-2004 – with little expectation they will recover to levels seen before the crash – will provide extra leverage for contract renegotiation, analysts say.

Facts Global Energy believes the “sanctity” of price formulas in long-term LNG contracts could begin to unravel as buyers, sellers and financiers question their value.

LNG is crucial to the economic prosperity of India, which is considered the next-largest growth market for the fuel after China. Ratings agency Moody’s says India’s LNG imports will increase from 10.4 mt in 2014 to 24 mtpa by 2020 as industrial demand rises and domestic gas production falls.
Petronet announced on 31 December that it had revised the price of its 25-year SPA with Qatar’s RasGas, under which India has been contracted to import 7.5 mtpa of LNG since 2004. Petronet had been paying $12-13/MMBtu for Qatari LNG, but has cut this to $6-7/MMBtu. Qatar has also waived Petronet’s $1.5 billion take-or-pay penalty for taking less gas than contracted.

**Exxon under pressure**

With Australia’s traditional LNG buyers, such as China, requiring fewer cargoes than originally expected, coupled with the fact India is set to become a major growth market for Aussie LNG in the future, Exxon is under pressure to agree to Petronet’s request.

India’s largest LNG importer, Petronet was established by the Indian government as a joint venture between four of the country’s state-owned energy companies: Oil and Natural Gas Corp., Indian Oil Corp., Bharat Petroleum and Gail.

Gorgon is a joint venture of the Australian subsidiaries of Chevron (operator, 47.3%), Exxon (25%), Shell (25%), Osaka Gas (1.25%), Tokyo Gas (1%) and Chubu Electric (0.417%). Chevron, Exxon and Shell have sold most of their shares of the output to buyers such as JX Nippon, Kyushu Electric, GS Caltex and SK LNG Trading.

Chevron recently signed a non-binding heads of agreement for LNG with China Huadian Green Energy for up to 1 mtpa of LNG over 10 years from 2020.

**Final Destination: Mapping the Future of LNG Trade Flows** is the latest Interfax special report, featuring 16 pages of maps, forecasts and analysis of global LNG trade flows.

The report includes detailed maps of each region, comparing 2014 flows with forecasts for 2020. Also included is a look at trends in the industry to 2020 and beyond by Global Gas Analytics’ lead analyst Peter Stewart and price forecasts by the GGA team.

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**Europe**

Construction has started on **Scotland’s largest solar farm**, which will include 55,000 solar panels on 28 hectares of land near Perth. The farm is expected to be operational by early March and provide power to more than 3,500 homes via the National Grid, Ontario-based Canadian Solar said in a release on Wednesday. Although Bristol-based Elgin Energy designed the site, Canadian Solar constructed the facility and will operate it. “Solar technology has a far greater role to play in Scotland’s energy mix than many people might realise – due to reducing installation costs and a climate of support from the Scottish government, we are continuing to see an appetite from developers to take forward new development sites, even with reducing subsidy support from the Westminster government,” said Thomas MacMillan, energy director for property services firm Savills Smith Gore, which secured the site.

The **UK’s union for energy industry workers**, the GMB, has asked Secretary of State for Energy and Climate Change Amber Rudd to ensure there are no delays in decommissioning offshore installations to save future jobs and investment. “Nearly 300 platforms need to be decommissioned and 4,000 wells plugged and abandoned, and there is no logical case for delaying decisions,” the GMB said in a release. “GMB has written to the government warning that offshore decommissioning decisions should not be delayed. By all means extend the working lives of oil and gas platforms where possible but don’t just kick the decommissioning can down the road,” said Brian Strutton, GMB national secretary for energy.

**FSU**

**Kazakhstan’s Prime Minister Karim Massimov** has signed a decree approving a privatisation plan for state companies between 2016 and 2020, as well as target benchmarks for implementing the plan. The document was published on Wednesday on the website of the Ministry of National Economy and includes a list of entities to be spun off, which include oil and gas company Kazmunaiinas; nuclear firm Kazatomprom; the national railway, Kazakhstan Temir Zholy; and mining companies Samruk-Energy, Tau-Ken Samruk, and Kazzinc. The decree came into effect on 1 January.

**Ukraine’s** gas imports fell by 3.1 billion cubic metres in 2015, a 15.9% drop year on year, to 16.4 bcm, Uktransgaz has reported. Gas imports from Europe reached 10.3 bcm in 2015, up from 5.1 bcm in 2014. Imports from Slovakia came to 9.7 bcm, Hungary shipped 500 million cubic metres (MMcm) and Poland sent 100 MMcm. Ukraine imported 6.1 bcm of gas from Russia in 2015, 58.3% less than in 2014, when it imported 14.5 bcm. Imports from Europe reached 10.3 bcm in 2015, a 15.9% drop year on year, as well as target benchmarks for implementing the plan. The document was published on Wednesday on the website of the Ministry of National Economy and includes a list of entities to be spun off, which include oil and gas company Kazmunaiinas; nuclear firm Kazatomprom; the national railway, Kazakhstan Temir Zholy; and mining companies Samruk-Energy, Tau-Ken Samruk, and Kazzinc. The decree came into effect on 1 January.

**Energy futures**

<table>
<thead>
<tr>
<th>Front-month futures</th>
<th>Unit</th>
<th>Closing date</th>
<th>Close</th>
<th>High</th>
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<th>% change</th>
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<tr>
<td>Brent Crude</td>
<td>$/bbl</td>
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<td>34.57</td>
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<tr>
<td>WTI Crude</td>
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<td>36.39</td>
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<tr>
<td>Henry Hub</td>
<td>$/MMBtu</td>
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<td>2.24</td>
<td>-2.49</td>
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<td>34.90</td>
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**Source:** GlobalView

GlobalView provides benchmark pricing, news and analytics for the commodities and energy sector. For more information please contact sales.london@marketview.com

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**Breaking around the world**

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including 5.02 bcm, worth $1.76 billion, from suppliers in Europe.

Middle East & East Mediterranean
Oman Power and Water Management (OPWP) has awarded a $2.3 billion contract to a Mitsui-led consortium to build two gas-fired combined-cycle power plants in the country. The 1.45 GW Ibi and 1.70 GW Sohar 3 plants will be located in northern Oman and will meet 30% of electricity demand in the Omani capital of Muscat. Mitsui has a 50.1% share in the consortium and will operate both plants – with the power generated sold to OPWP under a 15-year contract. The plants are due to start up in early 2019. Mitsui’s partners are ACWA Power and Dhofar International Development and Investment.

Petro Sharouk, a subsidiary of Egypt’s Petrobel, will start the first development phase of Egypt’s huge Zohr gas discovery in the Mediterranean Sea before the end of 2017, Daily News Egypt has reported. The Zohr field, discovered by Italian energy company Eni in August, is estimated to hold 850 billion cubic metres of gas. Drilling vessel Saipem 10000 has arrived at the site of the Zohr 2 well to start drilling. Petrobel’s current daily production amounts to 112,000 barrels of crude and condensate and 25 million cubic metres (MMcm) of gas, according to the news report. Gas production is expected to increase to 76 MMcm/d by 2019, Egyptian General Petroleum Corp. (EGPC) Chief Executive Mohamed al-Masry said. EGPC negotiated a price for Zohr gas with Eni of between $4/MMBtu and $5.88/MMBtu. Masry said EGPC and Eni agreed to review the price formula two years after the start of production, which is slated for 2017. All production from the field is designated for the local market and will not be exported unless volumes exceed local demand. Egypt’s Ministry of Petroleum informed Eni in an official letter.

Asia Pacific
Indonesia’s state utility PT Pertamina Gas (Pertagas) plans to increase its capital expenditure by 44% in 2016. Pertagas plans to complete 500 km of pipeline projects, improving the country’s domestic infrastructure and increasing residential and industrial use of gas, The Malaysian Insider reported. Pertagas plans to increase spending by $325 million in 2016, up from $225 million in 2015. “We will develop more gas pipelines, as much as we can,” Hendra Jaya, Pertagas president and director, told Reuters on Tuesday. “If they are not built, gas won’t be delivered to consumers and our gas business won’t develop.” Pertagas plans to build four new pipelines in 2016, adding to its existing 2,300 km domestic network on the islands of Java and Sumatra.

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Crude oil prices continue to fall, with Brent hitting an 11-year low on Thursday to trade at $33 per barrel. In the United States, West Texas Intermediate futures fell by 3% from the day before to trade at $32.77/bbl. China suspended trading on its stock exchange for the second time this month, and ample crude supplies put further pressure on prices. Crude oil prices have dropped nearly 70% since 2014 as a result of high production levels from OPEC members and weak end-user demand.

California Governor Jerry Brown declared a state of emergency this week in the Los Angeles suburb of Port Ranch after Southern California Gas Co. failed to contain a gas leak at a storage facility. Brown ordered state agencies to ensure the utility fixed the leak, which was reported on 23 October and has released “major amounts of methane” into the area. It is reported to have caused minor illnesses, and 2,000 families have been temporarily moved out of their homes. “All necessary and viable actions will be taken to ensure Southern California Gas Co. maximizes daily withdrawals of gas from the Aliso Canyon Storage Facility for use or storage elsewhere; captures leaking gas and odorants while relief wells are being completed; and identifies how it will stop the gas leak if relief wells fail to seal the leaking well, or if the existing leak worsens,” the order said.
Carbon capture and storage could be a lifeline for the coal sector, but only if governments support the technology. EU Policy and Regulation Editor Andreas Walstad reports from Brussels.

LARGE-SCALE use of carbon capture and storage (CCS) technology is a prerequisite to avoid a virtual phase-out of coal-fired power generation in the longer term, according to the International Energy Agency (IEA).

The COP21 climate summit in Paris – where nearly 200 nations agreed to limit global warming to below 2°C – was another blow to the coal industry, which has faced strong headwinds in recent years.

Many experts have predicted coal will be all-but phased out after 2050 because power generation using the fuel is the largest source of man-made carbon dioxide emissions. However, CCS could offer coal a lifeline if it receives government support, the IEA said in a report released in December.

“CCS is the only technology capable of delivering significant emissions reductions from the use of coal and other fossil fuels,” the report said. “With increasing carbon prices, decreasing costs of renewable power generation, and the more ambitious climate policies that are coming, the business case for unabated coal use diminishes.”

The IEA noted that several commercial-scale projects had started or were under construction in North America and Australia. There are now 15 large-scale CCS facilities in operation around the world, a number expected to rise to 22 by 2018. However, the agency said supportive policies are needed to accelerate development.

“Efforts by governments and industry to support the development and deployment of CCS have fallen well behind that of other low-emission technologies,” the IEA said. “CCS will require targeted, transitional support mechanisms to drive early deployment, in much the same way that targeted mechanisms have supported the deployment of renewable energy and driven technology cost reductions for wind and solar.”

However, government support for CCS has been lacking in several countries for a number of reasons – including public opposition, high development costs and technological uncertainties.

The UK’s £1 billion ($1.46 billion) CCS competition was cancelled in November last year, meaning the White Rose project – which planned to use CCS at a new-build coal-fired unit at Drax power station in North Yorkshire – is unlikely to go ahead. White Rose had also secured £300 million ($326 million) in funding from the European Commission’s NER300 scheme.

It is the only CCS project to receive cash from NER300, which uses revenue from the EU’s Emissions Trading System to help fund clean technology projects. The scheme, which raised €2.1 billion between 2011 and 2013, has been upgraded and renamed NER400. It hopes to raise €9 billion for clean technology.

Leigh Hackett, chief executive of White Rose developer Capture Power, said he was “surprised and very disappointed” that the British government had cancelled the CCS competition.

“It is too early to make any definitive decisions about the future of the White Rose CCS project. However, it is difficult to imagine its continuation in the absence of crucial government support,” he said.

The UK is also considering shutting down all its coal-fired power plants by 2025, the government announced in November.

**Progress elsewhere**

Although the outlook for CCS in Europe looks bleak, progress is being made in other parts of the world. The Boundary Dam CCS project in Saskatchewan, Canada has been operational for over 12 months – marking the first time CCS has been used at an existing coal-fired power plant. Meanwhile, two coal power projects are expected to be commissioned in the United States in 2016: the Kemper County project in Mississippi and the Petra Nova project in Texas.

The IEA also highlighted that China – which accounts for around half of the world’s coal consumption – has the potential to develop CCS on a large scale.

“The retrofit of existing plants with CCS could be particularly important in countries like China, which has a large (830 GW) and modern fleet of coal-fired power plants. The IEA has assessed that more than 300 GW of China’s coal power capacity could be candidates for CCS retrofit, including having access to suitable storage,” the report said.

It pointed out that CCS could also be used for other fossil fuels, including oil and gas, as well as for industrial processes such as steel and cement production, where there are limited or no low-emission alternatives.

However, the relatively low price of oil and coal threatens CCS and other new technologies, Fatih Birol, executive director of the IEA, told a press conference in Paris in December.

“Governments and industry must increase their focus on this technology if they are serious about long-term climate goals,” Birol said following the launch of the IEA’s report.

“CCS is not just a coal technology. It is not a technology just for power generation. It is an emissions reduction technology that will need to be widely deployed to achieve our low-carbon future,” he added.

Contact the editor at: andreas.walstad@interfax.co.uk
Corrib still plagued by statutory challenges

Ireland’s Corrib field saw in the new year with a potential breach of its pollution licence, but other legal challenges are likely to prove bigger problems. Western Europe Contributor Astrid Madsen reports from Dublin.

IT took little more than a day for Shell’s Corrib gas project to attract yet more controversy after the field, located off the northwest coast of Ireland, drew first gas at the turn of the year.

Minister for Energy Alex White granted the government’s consent to operate the Corrib upstream gas pipeline on 29 December, representing the last regulatory hurdle for a project that has been beset by delays.

Subsidiary Shell E&P promptly issued a statement the next day stating production had started. But a stronger-than-expected flare sparked concern among local residents, prompting Ireland’s Environmental Protection Agency (EPA) to launch an investigation into the incident.

The EPA has said it is in “regular contact” with Shell, and is “examining all evidence in relation to the flaring operation”.

“Having completed this examination the EPA will decide on the appropriate enforcement action, if any, to take in relation to the flaring,” the agency said.

The EPA is investigating a breach of Condition 3.9 of Corrib’s pollution licence, which states flaring shall only be used “for safety reasons or for non-routine operational conditions”.

The outcome is likely to be no more than a slap on the wrist for Shell – the policy of the EPA’s Office of Environmental Enforcement (OEE) provides alternatives to prosecution that include warning letters, statutory notices and court orders.

The policy also states the OEE’s actions should be “proportionate to the risks posed to the environment”. With prosecution, the maximum penalty for an environmental breach is a fine of €15 million ($16.3 million) and/or 10 years’ imprisonment.

Happy new flare
According to The Irish Times, a YouTube video posted on 31 December showed John Egan, communications director at Shell, stating at 8pm that the startup operations and associated flaring were an “extraordinary sight” and a “fantastic way to spend New Year’s Eve”.

The video was taken down the next day. Shell spokesperson Philip Robinson told Interfax on Wednesday that Egan was no longer working for the company, effective from 31 December, but that his departure had been planned.

Robinson added: “We had said there would be a possibility of some flaring […] however, this particular incident of flaring was more intense than originally planned or anticipated.”

“It was part of the startup process – for example the offshore pipeline would have had back-feed gas as part of the testing, so we had to dispose of that.”

He said future flaring would be less intense. “We do expect flaring to be intermittent over the next couple of days and we will take all measures to minimise the impact locally.”

Legal challenges
Meanwhile, proceedings are under way in Ireland’s High Court. Four local residents are suing the EPA, contesting the validity of the industrial emissions licence (P0738-03) granted to Shell.

The judicial review was granted on 14 December and the agency was served papers on 23 December, a spokesperson for the EPA told Interfax.

The judicial review could deem the licence to be invalid on the grounds that the proper procedures – in this case the thoroughness of the environmental impact assessments and associated environmental reports – were not followed.

According to the EPA press office, a judicial review was granted for the previous iteration of the industrial emissions licence (P0738-02) and, in that instance, the court “did not find in [the plaintiff’s] favour in the substantive case”.

The consent given by the minister could also be subject to another judicial review, but an application must be made within three months of the 29 December decision.

White has said the project is in line with the government’s roadmap to turn Ireland into a low-carbon economy by 2050.

“This transition will take time, and fossil fuels will remain part of our energy mix for some years to come, as we first eliminate the most polluting fossil fuels such as coal,” he said in a press release.

Ministerial consent for Corrib was granted with 20 conditions, many of which require Shell to provide inspection plans and status reports to the government.

One condition relates to providing the public with a means of registering and resolving grievances.

Located 83 km off the Irish coast in water depths of 350 metres, Corrib is expected to produce 7.4 million cubic metres per day at peak production, meeting around 42% of Ireland’s gas demand over its first two years of operation.

Shell’s project partners are Statoil (36.5%) and Vermilion Energy (18.5%).
The UK’s second capacity auction took place in December, but it has left power generators with lower revenues than last year’s.

Power generators and importers offered to make capacity available for the period between October 2019 and September 2020 in exchange for a fixed price guaranteed by the government.

The clearing price settled at £18 per kW ($26.3/kW), which was around 9% lower than last year’s auction for the 2018/2019 period, meaning generators will receive lower revenues than last year.

“The auction result suggests that the electricity market remains comfortably supplied, despite capacity closures in the past year and media concern that Britain has insufficient spare capacity, reducing the prospect for a near-term recovery in generation spreads,” said ratings agency Moody’s in a note to investors.

The agency said the participation of interconnectors in the auction had put downward pressure on the price. Interconnecters were not allowed to participate in last year’s auction.

“The inclusion in this year’s auction of 2.4 GW of interconnectors, of which 1.9 GW were awarded a contract, put significant downward pressure on the price,” said Moody’s. “If the treatment of interconnectors had not been changed, we estimate that the clearing price would have been closer to £25/kW.”

Moody’s cautioned that the capacity market may not be achieving its goal of encouraging investment in new generation capacity. It noted that 95% of the contracts in the auction were awarded to existing power plants and interconnectors.

“We expect that the UK government will review the design of the market for the 2016 auction in order to encourage construction of gas-fired generation on larger scale,” it said.

Andreas Walstad in Brussels
EnergyHub profile: Malaysia

Petronas aims to deliver the world’s first FLNG project this year, helping it to develop remote gas fields and meet growing domestic demand for the fuel. Research Analyst Andrew Walker reports from London.

MALAYSIA is one of the world’s largest LNG exporters and boasts an eight-train export facility at Bintulu in Sarawak. The plant started up in 1983, making Malaysia the third country in Southeast Asia to export LNG after Brunei and Indonesia.

LNG exports have grown steadily over the past three decades as new trains have been added. Exports were just 200,000 tons below the facility’s 25.7 mtpa capacity in 2014, according to trade data. The country is seeking to develop new fields to maintain and expand production.

State-owned Petronas is adding a ninth train to Malaysia LNG, which will expand its liquefaction capacity to 29 mtpa. This train is expected to come online in 2016, the start date having been pushed back from late 2015.

Malaysia’s export capacity will also be expanded by 1.2 mtpa when its floating LNG project becomes operational, which is scheduled for mid-2016. Petronas FLNG 1 will be moored offshore Sarawak and produce LNG from the Kanowit field. It will be the first FLNG project to come online and there is considerable interest in its progress. If the project can delivered quickly, economically and safely it would help satisfy investors’ concerns about the technology and help other FLNG projects around the world.

Petronas has already commissioned a second FLNG vessel, which is under construction at the Samsung Heavy Industries shipyard in Korea and will liquefy gas from the Rotan field. It is expected to start exporting LNG in 2018.

Demand for gas in peninsular Malaysia is outpacing production, requiring the region to import gas and LNG. Malaysia imports gas from Indonesia via pipeline and inaugurated its first LNG terminal in mid-2013. A second terminal is under construction at the Pengerang Integrated Petroleum Complex in Johor. The terminals allow Malaysia to deliver LNG internally to meet demand.

Petronas has also entered into a supply agreement for 2 mtpa from Gladstone LNG in Australia, as well as agreements with Statoil for around 700,000 tpa and GDF Suez for 2.5 mtpa, providing diversity of supply. Petronas holds stakes in import projects around the world and is expected to expand its role as a portfolio player, delivering LNG cargoes in response to market signals.

Contact the author at: andrew.walker@interfax.co.uk

Export plants – under construction
MLNG Train 9

| Start date | 2016 |
| Capacity   | 3.2 mtpa |
| Stakeholders | Petronas |
| Notes      | Work also includes expansion of existing facilities at Bintulu plant |

PFNLG 1

| Start date | Mid-2016 |
| Capacity   | 1.2 mtpa |
| EPCIC      | Daewoo Shipbuilding & Marine Engineering; and Technip |

PFNLG 2

| Start date | 2018 |
| Capacity   | 1.5 mtpa |
| EPCIC      | Samsung Heavy Industries; and JGC Corp. |

Import terminals – under construction
Pengerang LNG

| Start date | 2019 |
| Capacity   | 3.5 mtpa |
| Stakeholders | Dialog; Vopak; and Johor State Secretary Inc. |
| EPC        | Samsung C&T |
| Notes      | Will form part of the Pengerang Integrated Petroleum Complex, being built in Johor |

LNG imports, exports and project intelligence

EnergyHub offers a wealth of information on the world’s LNG import and export infrastructure. But it is more than just an LNG database, it aims to give the user an understanding of the sector and how these projects fit into the global market.

Explore our database at interfaxenergy.com/energyhub
Colombia puts brave face on El Niño woes

Delays to Venezuelan imports will leave energy-hungry Colombia exposed to the elements in the first quarter of this year. Latin America Editor Chris Noon reports from Buenos Aires.

COLOMBIAN authorities have played down the significance of delayed Venezuelan gas imports, claiming the country is seeking to make up the shortfall with increased production.

However, there will be jitters in Bogota. Colombia depends on gas for power generation during the drier conditions created by the El Niño weather phenomenon. The country is also facing an imminent supply crunch because of declining reserves.

“The volume of gas involved – 39 million cubic feet per day [1.1 million cubic metres per day: MMcm/d] – is only 3% of Colombia’s total gas supply,” a Bogota-based spokesman for Ecopetrol told Interfax on Tuesday. “At the moment, we are assessing the issue from a technical point of view to make up the shortfall,” he added.

The spokesman said Ecopetrol supplied Colombia’s gas-to-power sector with around 2.4 MMcm/d of gas between September and December 2015 to help the country cope with the effects of El Niño.

He added that Venezuelan state-run company PDVSA had not confirmed a new startup date for gas exports to Colombia. At the time of publication, a Caracas-based spokesman for PDVSA had not returned calls seeking comment.

PDVSA informed Colombian authorities on 30 December that exports would not begin on 1 January 2016 as planned because of the impact of “climatic variability” on Venezuelan power generation.

The delay is a setback for Caracas’s gas export ambitions. Ecopetrol confirmed to Interfax in November 2015 it would import Venezuelan gas, a deal that marked a reversal in flows between energy-hungry Colombia and its gas-rich neighbour.

Venezuela imported up to 4.25 MMcm/d of Colombian gas through the Antonio Ricaurte pipeline, which links Colombia’s Caribbean coast to the Venezuelan city of Maracaibo, between 2007 and mid-2015.

However, PDVSA said in June it would not renew its contract to import gas from Ecopetrol and Chevron, and would instead meet demand with domestic production. European giants Eni and Repsol began gas production from the Cardon IV block in the offshore La Perla field in July.

Under the weather
There will be concerns in Bogota about the wisdom of an energy policy that relies on Venezuelan imports during adverse weather conditions. Colombian meteorologists have predicted Q1 2016 could be one of the driest periods in the country’s history as a result of El Niño.

The weather phenomenon is caused by warm waters off the Pacific coast of South America. It occurs at irregular intervals every two to seven years, but can disrupt weather patterns across the Americas for up to two years afterwards.

Colombia and Venezuela usually experience drier and hotter weather as a result of El Niño. This affects hydroelectric production in both countries, which rely on hydro for around 70% of their power.

Venezuela was previously the bigger victim of dry weather conditions. Bogota cut gas exports to Venezuela in mid-2014 and ramped up electricity production from gas-fired power plants to conserve water for hydropower generation later in the year.

Colombia’s plight could be exacerbated by a looming supply crunch. The country’s Petroleum Association warned in 2015 that Colombia would have a gas deficit by Q1 2017 unless it took urgent steps to remedy the situation. Colombia’s proven reserves are forecast to fall by 5% per year until 2028, resulting in an undersupply to the Atlantic Coast from 2017 and a countrywide deficit from 2018.

The gas deficit will be around 5.4 MMcm/d in 2018 and 9.8 MMcm/d in 2021. The Colombian energy ministry has forecast the country’s gas demand could be as high as 47 MMcm/d by 2018. Colombia is expected to have produced a small surplus in 2015 – the country’s output was 34 MMcm/d while domestic demand was 29.7 MMcm/d – although statistics are not yet available.

Colombia’s Atlantic coast will be particularly vulnerable if Caracas cuts exports. There is no pipeline between Colombia’s gas production heartlands in the Cusiana-Cupiagua fields in the eastern lowlands and the country’s energy-hungry Caribbean coast.

Associated production from Cusiana-Cupiagua is expected to increase from 37.5% of Colombia’s output at present to nearly 60% by 2022. Non-associated production from the Guajira fields on the Caribbean coast will decline from 46.4% of output to 18.5% during the same period.

An LNG terminal being built in Cartagena to supply local power plants will bring relief for Colombia, but the facility is not scheduled to come online until 2017. The $500 million project will include a port, pier and connecting pipelines, as well as an FSRU with 170,000 cubic metres of storage and 11.3 MMcm/d of regasification capacity.

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