Opec: supply adequate; IEA lacks transparency

By Derek Brower

OPEC went on the offensive yesterday, dismissing the IEA’s claim that prices have been driven by an “oil shock” and saying the agency’s figures lacked sufficient transparency to encourage producers to bring more oil on stream in the long term.

And Abdulla El-Badri, Opec’s secretary-general, told WPC News in Madrid that in a market now “disconnected” from fundamentals, “it is anyone’s guess” how high prices will rise. “People say $100 [a barrel] and it goes to $100. People say $150 and it goes to $150. Now people are saying $170 or $200 – but I hope it will not happen, because there is no reason whatsoever to reach that.”

With OECD stocks at 53.3 days, he said world supply remained adequate, blaming speculators for “leading this hijacking of the market”. El-Badri also said geopolitics is pushing prices higher – and suggested that an attack on Iran could trigger that country’s use of the “oil weapon”.

“If something happened in Iran, it is difficult to replace 4.1m or 4.2m barrels a day (b/d) [of Iranian production],” he said. “The price, of course, will go up.”

Relations between the US and Iran remain tense amid Western suspicions about Iran’s nuclear programme. On Saturday, the head of Iran’s Revolutionary Guard said Iran would close the straits of Hormuz if attacked by Israel. About 25m barrels of oil – 40% of Mideast production – pass through the straits every day.

“When you are in war, you are in war – you can use anything,” El-Badri said.

And the Opec boss used figures from the IEA’s own most recent market report, released here on Tuesday, to reject the agency’s claims that a tight supply/demand balance is driving up oil prices.

According to the report, the “call on Opec” for crude so far this year is still beneath the group’s production of 32.2m b/d, he said. “We see excess capacity.”

In addition, the group’s spare capacity will continue to grow, with Opec set to invest $160bn to increase capacity by 5m b/d by 2012.

El-Badri also hit out at IEA statistics on Opec’s production capacity. In its most recent report, the IEA subtracts 1m b/d from Opec’s own estimate of its spare capacity, claiming “historically effective Opec spare capacity averages 1m b/d below national spare capacity”.

El-Badri suggested the adjustment was arbitrary. “There is nothing called ‘effective’ capacity,” he said. And he said a lack of accurate data from consumers about future demand could undermine long-term upstream investment. “The last [IEA] report gives no transparency whatsoever.

Opec could spend $300bn up until 2020 investing in new capacity to reach 38m b/d, he said. But without adequate assurances over demand the group fears the money could be wasted.

“Suppose we invest to satisfy the market and the market doesn’t absorb that quantity. That [$300bn] could be used on housing, education, health – lots of areas where we can improve the standard of life of our people.

“All we want is a clear picture of demand.”

El-Badri admitted that Opec is “annoyed” by claims that it could do more to ease prices. “We are annoyed because we are investing, we are producing more than the market needs. We are annoyed because the price we see at this time shows a disconnect between price and fundamentals.”

He added: “We want to see a price that reflects fundamentals not a price that reflects speculation and other factors.”

In New York yesterday, front-month crude was trading at around $141/b as WPC News went to press.
Access to reserves critical as gas demand surges, says Shell

By Alex Forbes

ACCESS to reserves remains the greatest challenge the natural gas industry faces in ramping up production, according to project growth in demand over coming decades, Linda Cook, Shell’s executive director for gas and power, claimed yesterday.

“Largest known racing ahead with unparalleled growth in demand for energy – in particular natural gas – and an industry challenged to keep pace,” she told delegates at the 19th WPC in Madrid. “We need access to gas.”

And she called on the US to open up acreage that is presently off-limits to explorers – “all of the Atlantic and Pacific coasts, and the eastern GOM.”

Linda Cook called on the US to open up acreage that is presently off-limits to explorers – “all of the Atlantic and Pacific coasts, and the eastern GOM.”

She added the little exploration that has been carried out in those areas took place 30 years ago and has not been tested with the latest exploration technology.

Cook also said that even when permits are granted, operations can be delayed by 10-15 years, he said, high oil prices are a signal of the urgent need to step up investment in oil and gas projects.

“It’s time we all made a recognition of what I think is the market is trying to signal – at what price people are ready to prepare to invest serious amounts of money, he said. As well as the talent shortage, barriers to investment include limited access for private-sector oil companies to prospective acreage and unhelpful changes in taxation in developed and developing countries.”

“Every time you change a tax regime, you’re introducing an additional level of uncertainty and risk into the investment equation,” he said.

Andrew Gould – “everyone’s trying to hire the same population”

Other senior industry executives, including Total’s chairman, Thierry Desmares, have also suggested that services contracts may become a more common contract model for IOCs. But, said Gould, “they’ll still use us to do the work. It’s just a different holder of the contract.”

Meanwhile, with the cost of offshore rig now around $0.6m a day – and support vessels and associated services typically pushing the cost to around $1.2m a day – technologies, such as seismic, capable of increasing the accuracy of well placement and limiting downtime will be at a premium, he said. The oil companies “don’t want us to stop work”, he said.

In addition, technologies that improve operators’ ability to identify bypassed oil have not kept pace with developments in drilling technology, but will also prove vital, given the need to increase recovery factors at existing oilfields, said Gould. “We can drill a squash court from 10 miles away. But you have to find the squash court.”

Angola needs $100bn to keep output steady

By NJ Watson

ANGOLA’s production will soon plateau at 2m barrels a day (b/d), but the country will need another $100bn of investment to keep it at that level in the medium term, according to Soaonghi, which the state-owned oil firm can “guarantee” 2m b/d for four to five years, according to vice-president Syanga Abiolo. But with fields ageing, more $100bn will need to be invested to keep it at that level beyond 2012 or 2013, he said. That will involve the drilling of over 100 new exploration wells and the construction of more than 10 floating storage, loading and offloading vessels over next five to seven years.

Supply to meet part of that effort will be the resumption of the licensing round for new blocks that was supposed to have resulted in bids being submitted in March. But the process will not restart until 2009 at the earliest.

Schlumberger sees talent war intensifying

By Tom Nicholls

WAGE inflation will accelerate in the next few years as a wave of new offshore rigs come into service, according to Andrew Gould, chairman and chief executive of Schlumberger.

“There is going to be another war of trying to hire each other’s people to staff these jobs,” he told WPC News in Madrid, identifying the shortage of engineer-was the biggest problem. “Anyone with over 10-15 years experience in a technical domain – everyone’s trying to hire the same population.”

Gould said Schlumberger has experienced roughly a 50% surge in the wages of technical staff over the last four years. And he said that while salaries have reached a plateau, they will accelerate as the 160 or so rigs that are under construction worldwide come into service.

Meanwhile, with the cost of offshore
Aconcagua, 22,841 feet.
So you’ll have an idea how deep we go in the pursuit of energy.

**Dutch minister in town for gas talks with Iran, Angola**

By NJ Watson

The Netherlands plans to line up new gas suppliers in an effort to turn the country into a gas hub for markets in western Europe, according to the Dutch energy and economic affairs minister, Maria van der Hoeven.

Speaking exclusively to **WPC News** two days after giving the green light for construction of the country’s first LNG-import terminal, van der Hoeven said she was attending the WPC to have discussions with potential suppliers, including Iran and Angola.

“We want to grow into a gas hub to provide west European markets and this LNG terminal is of utmost importance to bring this idea to realisation,” she said.

“The LNG terminal already has a number of customers, so it’s very important to organise supply to the Netherlands and that’s why I’m very interested in having discussions with my colleagues from, for instance, Iran and Angola.”

This week, Linda Cook, Shell’s executive director for gas and power, said buyers in Asia and Europe are quickly “mopping up”, under long-term contracts, volumes that had previously been considered flexible. And she warned that countries or customers who are unwilling to secure supplies under long-term contract run the risk that the natural gas won’t be there when they need it.

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By Alex Forbes

CONSTRUCTION contracts for Algeria’s Gassi Touil LNG project will be awarded “very soon”, enabling the long-delayed project to come on stream as early as 2011, says the head of Sonatrach.

Mohamed Meziane also confirmed that Sonatrach is proceeding with the project on its own, having last year rescinded contracts with former Spanish partners Repsol YPF and Gas Natural, because of delays and cost overruns. He declined to say what the LNG terminal is of utmost importance. 

Gassi Touil LNG: building to start “very soon”

By Derek Brower

**Canada will employ the “best and lat-**

est technology and engineering available” to solve environmental problems arising from its development of the oil sands, and is to launch an aggressive programme to reduce emissions and air pollution.

“There won’t be any developments [of the oil sands] that has taken place or that will take place that is not sustainable,” said Alberta energy minister Mel Knight. In an interview with **WPC News** yesterday in Madrid, he also attacked “misinformation” about oil-sands development.

Some US states are considering legislation to prevent development of the oil sands from outside the country. But their development has been criticised as costly both in environmental and financial terms.

Knight said such complaints lack perspective. “Globalia Canada accounts for 4% of emissions – and the oil sands less than one-tenth of 1%,” he said. Meanwhile, Alberta’s baseload coal generation produces 48% of the province’s GHG emissions – more than double the amount produced from the oil sands.

Air-quality monitors around the oil sands developments, in central and northern Alberta, rate it as “good or best”, and better than that found in any North American city, he claimed.

And Alberta and the federal government would “in the very short term” make a “very aggressive stand” on CO2 emissions from the oil sands, Knight said. Carbon capture and sequestration (CCS) would be the “main building block” to move forward with some “absolute reduction in CO2 emissions”. CCS will cut emissions from the oil sands to be around 40m tonnes a year (tt/year) by 2015, Knight said.

Greenpeace estimates emissions from the oil sands to be around 40m tonnes a year and says emissions will double by 2011.

Knight refused to be drawn on how the province would develop its CCS programme, but pointed to examples of “very promising potential” in neighbouring Saskatchewan as evidence of CCS potential.

He also rejected claims that the oil sands use too much natural gas and water for extraction. “Most operators recycle 90% of the water they use,” he said. Companies like Suncor, one of the same biggest operators, have reduced the amount of natural gas use by 45% in the past decade, he said.

And he expects new mining and extraction technology to “be developed even more efficiently.”
Operators venture into deeper Chinese waters

By Ian Lewis

THE COUNTRY’S refiners are starting to feel the pinch, as government restrictions over how much they can charge for products in the domestic market prevent them from passing on the rising cost of oil imports to consumers.

In April, Sinopec, Asia’s biggest refiner, announced a slump in net profit for its refining operations, which it attributed to lower oil prices and a 0.7m t/y aromatics complex. By mid-2008, it will have a 0.8m tonnes a year (t/y) ethylbenzene steam cracker, a 0.8m t/y polyethylene plant and a 0.2m t/y propylene facility. Both are part of an expanding portfolio of plants, as onshore pipeline infrastructure development has improved. PetroChina is also due for completion, preparations are under way to drill a 4,000 metre exploratory test well. PetroChina has 17 offshore blocks for foreign participation, but these covered over 45,000 square km of shallow-water areas in the South China Sea and no deep-water blocks. Last year, CNOOC offered 22 blocks, including one in deep water. "The foreign companies are most excited about the deep-water blocks - they are higher risk, but higher potential," says Mark McCafferty, an analyst at Wood Mackenzie, a consultancy.

Whatever deep-water opportunities are offered in coming months, the supernumery may remain reticent. With only the Husky discovery made so far, and yet to be fully appraised, they will be waiting for further discoveries to be made before embarking on potentially complex and costly deep-water ventures.

It also remains to be seen whether oil or gas predominates in the blocks around the Husky find. With gas production set to play a greater role in Chinese companies’ portfolios, as onshore pipeline infrastructure develops and plans to increase gas usage solidify, this is not the stumbling block it once was.

Without foreign partners, Chinese firms are determined to maximise the potential of domestic reserves and have made some significant discoveries. PetroChina’s 2007 discovery in Bohai Bay, off the east coast, was the largest for a decade with estimated reserves of up to 2.2bn barrels.

‘They have done a good job of maintaining production and enhancing production of older fields, but no-one is expecting a massive turnaround,’ says McCafferty. These efforts have enabled China to become the world’s fifth-largest oil producer, but they are unlikely to stave off a medium-term fall-off in output, assuming a string of deep-water mega-discoveries are not forthcoming.

In first-quarter 2008, China managed a 2.2% year-on-year increase in crude production to 344m barrels, according to government figures. PetroChina, which produces around 60% of the country’s crude, has been struggling to raise production from the northwestern and north of the country that have traditionally been among China’s production mainstays. Sinopec produced around 20% of the total, while CNOOC and its PSC partners produced the rest.

This is a country now firmly in thrall to imports. China produced 3.73bn b/d of crude in 2007, compared with estimated consumption of around 7.5bn b/d, according to US Energy Information Administration data. Gas production in 2006 was 1.96 trillion cf, roughly matching consumption.

Price caps put a squeeze on China’s refiners

By Ian Lewis

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WHEN ExxonMobil and Qatar Petroleum decided in July 2002 to build a two-train liquefied natural gas (LNG) project to supply 15.6m tonnes a year (t/y) to the UK, a new era dawned for what was previously seen as a specialist industry.

Each of the 7.8m t/y “mega-trains” would be 50% larger than any before, in a very small country, and they symbolise LNG’s move into the mainstream of natural gas.

Over the ensuing three-and-a-half years, Qatar and its various international oil company partners – ExxonMobil, ConocoPhillips, Shell and Total – reached final investment decision on six mega-trains, a total additional production capacity of 46.8m t/y, at a cost of tens of billions of dollars.

When all these projects are completed, Qatargas will be the world’s largest LNG-producing company, with capacity of 41.2m t/y. Its sister company, RasGas, will be a close second, with 36.3m t/y. Each will be a bigger producer than the next biggest LNG-producing country – Indonesia (around 21m t/y) – making Qataris, per capita, the planet’s richest people.

All four mega-trains, two at Qatargas 2 and one each at the other two projects, have been under construction for some time. So have another two mega-trains at RasGas. The first of these trains is several months behind schedule and as our tour begins, you can see why. Time and again we are forced to double back and take a different route, because a track that was clear yesterday is blocked today. “Imagine,” says a project engineer, “what it’s like just trying to get a crane from one part of the site to the other.”

Each train is 1 km long, there are four of them, and there are 35,000 people working on their construction.

As we wend our way around we pass a seemingly endless succession of huge steel structures, vast pressure vessels, storage tanks, complex interweavings of piping, tanks, turnarounds, and by-pipe cranes. “This,” says the engineer, “is a world-scale three-dimensional jigsaw puzzle.”

When all these projects are completed, Qatargas will be the world’s largest LNG-project construction market, creating shortages of labour, skilled people and materials. The engineering, procurement and construction contracts for the mega-trains were awarded mostly before the overheating began. But the Qatargas expansion project has struggled. By comparison, the first RasGas expansion project brought trains 3, 4 and 5 on stream within budget and ahead of schedule – and well before the overheating got under way.

Sibling rivalry

While Qatargas and RasGas co-operate efficiently in many ways, sibling rivalry between the two groups is strong. There has been talk of merging them – to create an overarching Qatar LNG – but the existing structure is working well. To simplify day-to-day management of all the various joint ventures, two operating companies were created, one for the Qatargas projects and the other for the RasGas group.

Housing, feeding and transporting the 35,000 people working on the projects isn’t easy, either. Some 40% of workers come from 54 countries and speaking more than 20 languages, just communicating safety messages is a challenge.

Co-ordination between the three project companies is another issue, because the foreign partners are different in each one, as are their time-lines. It seems inevitable that at times there must be competition between them for available resources. The official line now is that the first of the mega-trains will reach mechanical completion in June/July and that first LNG will be produced “in the third quarter”.

A postcard from Ras Laffan

From Alex Forbes

CONSTRUCTION is ramping up on the Qatar Petroleum and Shell-sponsored Pearl GTL venture in Qatar, one of the largest energy projects by value in the Middle East. Many will be surprised at how much money the project will make – if the technology works. The project’s managing director, Andy Brown, gives insights into the technology works. The project’s managing director, Andy Brown, gives insights into the technology works.

Interview by Alex Forbes

Earlier, Qatari energy minister, Abdulrah bin Hamad Al Attiyah, told Petroleum Economist that he was “not concerned” about project delays and still considered 2010 a realistic target for meeting the target of 77m t/y of production. “If there is a delay of a few months, we will cope with it. We are putting a lot of pressure on our contractors to meet their commitments. We are pushing them hard for recovery planning to tackle this few months’ delay.”

The most obvious source of the delays is overheating in the energy-project construction market, creating shortages of labour, skilled people and materials. The engineering, procurement and construction contracts for the mega-trains were awarded mostly before the overheating began. But the Qatargas expansion project has struggled. By comparison, the first RasGas expansion project brought trains 3, 4 and 5 on stream within budget and ahead of schedule – and well before the overheating got under way.

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Pearl GTL – a gem of a project, so long as it works

Interview by Alex Forbes

Early this year, we visited the Qatar rival project, brought onstream within months of the Pearl GTL project. Later, we visited RasGas to see the project in the middle of mechanical completion. The contrast couldn’t be greater.

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Qatar GTL – a gem of a project, so long as it works

Interview by Alex Forbes

CONSTRUCTION is ramping up on the Qatar Petroleum and Shell-sponsored Pearl GTL venture in Qatar, one of the largest energy projects by value in the Middle East. Many will be surprised at how much money the project will make – if the technology works. The project’s managing director, Andy Brown, gives insights into the project’s economics and progress.

Q: Since Shell took the final investment decision (FID) to proceed with Pearl GTL in 2006, there has been much speculation on the project’s economics. At the time of FID, people calculated from figures Shell had published that the required investment would be $12bn-18bn, compared to $4bn-5bn when the project was proposed. You said at the beginning of 2007 that $10bn had been committed in contracts that had been awarded. What can you say now about costs?

A: Our guidance hasn’t changed. We will produce around 3bn barrels of oil equivalent (boe) of wellhead gas over the period of our development and production-sharing agreement (PSA). Development costs of the project are between $4 and $6 a barrel. That equates to between $12bn and $18bn.

Q: What can you say about the ecosystem? By the end of 2007 we’ve seen very large increases in recent years in the costs of energy projects. On the other hand, we’ve seen oil prices move upwards. Are the economics more or less robust than they were when you took FID?

A: Insomuch as our cost guidance hasn’t changed and insomuch as there’s a view that oil prices have firms upwards in the last 18 months, the project is looking attractive. We have development costs of $4-6/b and we sell GTL products at crude values plus product-price margins, plus the GTL premium on top. We will produce 140,000 barrels a day (b/d) of GTL and 120,000 boe/d of condensate, liquefied petroleum gas and ethane. Multiply that by the number of days we’ll be producing and the relevant prices, and you can quite quickly calculate what kind of payback period this project might have. We’re comfortable with the economics of the project.

Q: How does the DPSA you’ve signed with the Qataris work?

A: We, the contractor, invest 100% of the capital from our balance sheet. We’re under some government constraints, but essentially we are operating the project during the construction and we will operate the plant when it starts up. When revenues start to come in, a portion is allocated for cost recovery, to pay for recovery of capital costs and continuing operating costs. The remainder is profit and that’s shared between the Qatar government and Shell.

Q: To contain costs, Shell adopted a complex contracting strategy: to increase competition by dividing up work among lots of contractors; and to employ a project-management company (PMc) to pull everything together. How well is that working?

A: Andy Brown: “We’re comfortable with the economics of the project ... and with the returns it gives to Qatar”
Biofuels argument intensifies

By Ian Lewis

A UN Food summit in Rome last month largely avoided the controversy about the inflationary effect some parts of the biofuels industry may be having on food prices. But with an EU-US spat over US biofuels producers’ splash-and-dash tactics still simmering, this is a problem that will not go away.

The UN Food and Agriculture Organisation’s (FAO) High Level Conference on World Food Security was marked by a bad-tempered disagreement between Jacques Diouf, the FAO’s director-general, and US agriculture secretary Ed Schafer over the extent to which demand for biofuels, especially in the US, is driving up food prices.

“Nobody understands how $11bn-12bn in subsidies in 2006 and protective tariff policies have had the effect of diverting 100m tonnes of cereals away from human consumption, mostly to satisfy a thirst for fuel for vehicles,” Diouf told the conference in remarks aimed, in part, at the growing US market.

Sustainable development

FAO data circulated at the conference suggested increased biofuels production accounted for nearly 60% of the global rise in the use of coarse grains and wheat between 2005 and 2007, and for 56% of the increase in use of vegetable oils. Separately, the IMF estimates biofuels production has been responsible for up to 30% of recent global food-price rises.

But Schafer contested this, saying that biofuels production was responsible for less than 3% of price increases.

The conference’s final declaration was carefully worded to avoid offending either side: “It is essential to address the challenges and opportunities posed by biofuels, in view of the world’s food security, energy and sustainable development needs.” It eschewed any direct warnings over possible negative effects, instead referring to the need for “in-depth studies” to ensure biofuels are developed sustainably.

Fudged declarations are unlikely to quell debate over this or other aspects of the biofuels industry. Next up could be an escalation of the EU-US row over alleged US dumping on the European market.

European biodiesel producers filed an official complaint to the European Commission on 25 April about federal subsidies to the US biodiesel industry – the so-called splash-and-dash regime under which US producers can add just a drop of mineral diesel fuel to biodiesel for export to become eligible for tax credits worth up to $300 a tonne. These US exports can then be treated as pure biofuels on reaching Europe, making them eligible for further subsidies under EU regulations. The European Biodiesel Board (EBB) argues that, in many cases, US biofuel can be sold on European markets at less than the cost price of locally produced biodiesel.

The EBB’s US equivalent, the National Biodiesel Board, says the European industry’s troubles are the result of a reliance on expensive feedstock and the failure of governments in some countries to support them adequately. But this defence is expected to cut little ice and the Commission is likely to launch an investigation into the dumping allegation, which could result in punitive duties being imposed on US biodiesel imports. However, one source close to the EU side of the dispute says the Commission is hopeful a resolution will be found without going that route.

The US’ National Biodiesel Board says the EU industry’s troubles are the result of a reliance on expensive feedstock.
Saudia Arabia is planning significant increases in upstream activity that should, it hopes, end accusations that it is not doing enough to develop its oil resources. Under a revised five-year plan, the company will boost drilling activity by a third and upstream investment by 40%, to $14bn.

Yet while it may be keen to prove its commitment to upstream development – and to establishing a more balanced oil market, characterised by lower prices – the government has also expended considerable effort in recent weeks on dampening market expectations about how much more oil it will supply.

In April, King Abdullah bin Abdulaziz said there would be a moratorium on drilling for the new, more cautious thrust to Saudi energy policy. He told Petroleum Argus that there was no longer any reason to step up the kingdom’s oil production capacity beyond the 12.5m barrels a day (b/d) level that the Saudis are due to reach in 2009. “It behaves us to pause, instead of extending unnecessary funds on expanding capacity that will probably not be needed,” al-Naimi was quoted as saying.

But there is no contradiction, at least in Saudi eyes: to maintain crude produc- tion at existing fields, the company says it needs to drill more wells – as many as 248 in the 2009-13 period, a substantial increase from the previous 178 that it had previously announced plans in April to raise fuel economy, a consultancy, and a former consultant to Aramco.

Saudi policymakers have, generally, adjusted swiftly to changes in the US mar- ket and recent events suggest that remains the case. Since President George Bush an- nounced plans in April to raise fuel econ- omy standards for cars and trucks to 13.4 km a litre (31.6 miles a gallon) by 2015, US officials have repeatedly said that this – and other efforts to minimise fuel usage and promote carbon-efficient sources of energy – may undermine the country’s security of demand by causing a general decline in oil consumption.

**Demand misinformation**

In his interview with Aramco’s al-Naimi, the Saudi oil minister during the 1970s, has criticised Opec for failing to achieve its predictions for new capacity now implies an outlay of $5,000-8,000 a barrel, compared with about $2,000 b on the Gharaw field – the source of much of the Saudi crude on the market.

Aramco is also increasing offshore spending – at its main offshore fields, Safaniyah, Marjan, Berri and Zuluf – under its five-year plan: the company will invest $2.58bn in offshore maintenance, and as more efficient transportation sys- tems are developed, consumption growth may level out. “You might not need to go further than 12.5 m b/d,” he says.

The concern about demand for Saudi oil has resulted in an integrated approach to oil developments, with Aramco expand- ing its downstream footprint to ensure that sufficient capacity exists to process the heavy, sour grades that form the bulk of its spare capacity. A shortage of refining ca- pacity – particularly for heavy, sour crudes – is the main cause of tightness in oil mar- kets and the greatest threat to country’s security of demand by causing a general decline in oil consumption.
Repso YPF: turning the corner

By NJ Watson

WHEN Repsol YPF revealed in February that 2007 profits were down by 16% on the year, despite record oil prices, but then described how business was about to improve, the collective groan from the analyst community was almost audible: Repsol YPF has made upbeat strategy presentations before – and all too often failed to deliver.

One of the most important changes is a decision to reduce its exposure to Latin America, the source of many of its problems, operations in the continent have been adversely affected by production declines at ageing fields, contract changes by governments seeking higher rents for the state and the heightened regulatory uncertainty that characterises resource nationalism. The company now wants 55% of its assets to be located in OECD countries by 2012, 31% in Latin America, and 14% in Trinidad & Tobago.

But on 13 May, the Spanish energy group announced a confusing, yet surprisingly healthy, set of first-quarter figures – confusing because the firm provided several pro forma profit figures to reflect changes in its business and healthy because the figure that most analysts identified as the important one showed net profit of €9.81bn ($12.75bn). While virtually flat from the year-earlier period, it was above the consensus forecast.

The headline figure the company gave was even better, showing a rise in net profit of 36.5% from the year-earlier period, to €1.2bn. That figure included €236mn in non-recurring items, particularly accounting and tax gains linked to the sale of a 15% stake in its Argentine subsidiary, YPF, and a €165m revaluation of its inventory.

So what has changed in Repsol YPF’s business and will the improvement continue?

The company has made particular headway in reducing its exposure to Argentina, divesting a 14.9% stake in YPF, raising 70% for the company to invest in acreage outside the region. On 15 May, chief executive Antonio Brufau said the firm would press on with its plan to float another 20% of the subsidiary on the Buenos Aires stock exchange in the second half of the year. That might raise another €3bn. The company has turned a corner in its efforts to diversify away from troublesome Argentina, says David Stedman, an analyst at DAW Institute of Research.

Excluding Argentina from its upstream division, Repsol YPF’s overall production was about 4% lower in underlying terms in the first quarter, which is an improvement from the 8% overall decline recorded over the whole of 2007. However, it still compares unfavourably with the performance of other oil majors.

To address this problem, at its February strategy presentation for 2008-12, Brufau outlined plans to invest €32.8bn – €11.7bn more than the budget set in its previous strategic plan, from 2005. The Spanish firm will focus on 10 projects that will be responsible for 75% of the group’s projected growth over the next few years. These include five large upstream projects: Brazil’s Carioca oilfield; the Shenzi and Genghis Khan fields in the Gulf of Mexico; the Libya UR field; Algeria’s Reggane gasfield; and Block 39 in Peru. The list also includes three large downstream projects in the Iberian Peninsula. With 70% of investment to be focused on three core exploration areas and elsewhere. That compares with 54%, 38% and 9%, respectively, in 2007.

The firm has made particular headway in reducing its exposure to Argentina, divesting a 14.9% stake in YPF, the former NOC.

Source: Repsol YPF; Petroleum Economist

Photo courtesy Repsol YPF

North Africa, northern Latin America and deep-water areas in the Gulf of Mexico and Brazil – Repsol YPF aims to add 400mn barrels of oil equivalent (boe) by 2012 at the same time as reducing the “geological risk profile of its exploration portfolio”.

The Carioca oilfield, in which Repsol YPF holds 25%, is a notable recent success. In April, Haroldo Lima, head of ANP, Brazil’s upstream regulator, blurted out that the field’s reserves might amount to 33bn boe, which would make Carioca the world’s third-largest field. Operator Petrobras, which holds 45% (the UK’s BG Group holds the remaining 50%), swiftly qualified that statement by saying it would take until July at least to drill deep enough to make an accurate estimate. But even if just 10% of Lima’s reserves figure is proved, then Repsol YPF would be adding 0.825bn boe. That would increase the company’s reserves by a third.

“With this find, Repsol YPF solves a large part of its reserves-replacement problem for the next few years and could increase the life of its reserves to nine years and approach the level of other integrated oil companies, which have a life of 10-12 years,” says Alvaro Navarro, an analyst at the Spanish investment bank Ahorro Corporacion Financiera.

Repsol YPF’s first-quarter figures also show an improving trend in the refining and marketing segment. Operating profit from the refining division was up by 2% as a strong performance in petrochemicals offset a contraction in the company’s Spanish refining margins, which fell by 19% compared with first-quarter 2007.

Set for a strong Q2

Higher prices for products sold in Argentina since August were the main reason behind the strong performance of YPF in the period and prices there are set to continue rising. In addition, with the group expected to benefit from higher prices downstream in Brazil from June, Repsol YPF looks set for a strong second quarter, says Stedman: “The long period of dull operational and financial performance may finally be coming to an end.”

Eureka!
By Robert Caulliean

Petrobras on top in Latin America

Petrobras has the largest proved oil reserves outside the Middle East and achieved $90bn last year. But the Venezuelan national oil company (NOC) is in trouble: production is falling and, with a substantial margin of its profits being spent on social projects, oil investment is insufficient.

PdV’s decline coincides with an impressive upsurge in the fortunes of Brazil’s NOC, Petrobras. When Venezuelan President Hugo Chávez was elected in 1998, PdV dwarfed Petrobras, producing 3.5m barrels a day (b/d) of oil, compared with Brazil’s 1.3m b/d. But Petrobras, which has recently boosted oil exports to the US, says it expects to be bigger than PdV investing in new gas liquefaction and petrochemical projects.

Petrobras has already overtaken PdV in crude output and reserves, and is gaining on its rival. Since 1998, Venezuela’s production has fallen; PdV claims that it is producing around 3.3m b/d, but other organisations, such as the International Energy Agency, estimate output at 2.3m-2.4m b/d. In the last 10 years, Petrobras has raised its output in Brazil by around 70% to nearly 1.9m b/d. Petrobras plans to reach 2.1m b/d of oil production by December. With around 340,000 barrels a day of non-Petrobras ethanol production, Brazil may already outdo Venezuela this year in production of petroleum and equivalent liquid fuels.

Local fuel subsidies are one reason why PdV is much less profitable than Petrobras: retail gasoline costs around $0.05 a litre in Venezuela, while consumers pay $1.50/l for gasoline in Brazil.

Petrobras is already ahead of PdV in sales, with $112bn last year, compared with $90bn for PdV. Petrobras achieved a profit of $13.1bn in 2007. Depending on whom you ask, PdV’s net income amounted either to $1.50bn, according to the Central Bank, or $6.3bn, according to PdV.

Venezuela and PdV vs Brazil and Petrobras, in numbers

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PdV aspires to pump 6.2m b/d in Venezuela by 2020, but spending is insufficient to reach this total. Last year, PdV’s corporate spending was $11bn, or marked down from the $14bn of social projects – PdV now runs subsidised grocery stores and cafeterias.

Petrobras, whose $20bn in spending last year was mostly used on Brazilian oil and gas development, sees its domestic output rising to 3m b/d by 2016. That forecast could include oil from Petrobras’ new sub-salt oilfields, such as the 5m-8bn barrel Tupi discovery, which Petrobras says may produce an additional 0.5m-1m b/d by the end of next decade.

Until recently, PdV’s vast reserves made Petrobras look like a poor cousin. Now the Brazilian firm is quantifying significant new reserves discovered under a layer of subsea salt, prompting chief executive Jose Gabrieleli to predict Brazil, which held 12bn barrels of oil equivalent in proved reserves last year, could soon be “somewhere between Nigeria and Venezuela” – which held proved reserves of 30bn and 60bn b/d respectively.

Not to be outdone, Chávez has predicted Venezuela will be able to book more than 20bn barrels of new proved reserves in the Orinoco region. But those reserves are bituminous, extra-heavy crude. The tar-like sludge must pass through multi-billion dollar upgrading facilities to convert it into synthetic crude that can then be processed by normal refineries.

Petrobras is also challenging Chávez’s pre-eminent position as oil supplier to the US, making investments in US refineries – as PdV did long ago through Citgo, its US subsidiary – to handle its increasing exports of heavy crude, which exceeded 0.5m b/d last year. But it is in South America that the rivalry between Petrobras and PDV has been most evident.

When Bolivia nationalised its gas industry in 2006 (with guidance provided by some of Chávez’ energy-policy advisors), Petrobras, the largest foreign investor in Bolivia, was the biggest loser. It agreed to pay sharply higher taxes and royalties, while ceding control of gas at the wellhead to the state. But when Petrobras froze investments in Bolivia because of the nationalisation, PdV said it would fill gaps left by the Brazilians.

Ecuador’s government (a close ally of Chávez) is sorting Petrobras from the country, potentially forcing it out of two Amazon-region oil blocks in royalties and taxes (including a tax that is likely to “illegally” transferred part of its Ecuadorian concessions to Japan’s Teikoku Oil. Without first seeking government approval, Petrobras denies those charges: it accepts it invited Teikoku into its concessions as a partner, but says it complied with government regulations.

PdV’s, the Marathon basin. will be angling to enter Ecuador to develop around 1bn barrels of oil in the Amazon-region’s Ishpingo-Tambocho-Tiputini block – an area Petrobras had hoped to exploit.

Thanks to the size of its reserves, Venezuela continues to draw interest from foreign investors seeking to offset changes in the country’s oil regulations since the late 1990s and sharp increases in tax on windfall oil profits, passed in April, designed to contribute an additional $9bn a year to state finances). Petrobras produces around 14,000 b/d in Venezuela, but has seen its share of field output – and profit – fall because of changes in operating terms. It has shown little interest recently in new oil ventures in the country.

Another attraction of Venezuela’s upstream is low production costs. Oil minister Rafael Ramirez has claimed production and upgrading costs at future developments in the Orinoco heavy-oil belt may be as low as $5.50 a barrel.

PdV has already pumped 0.625m b/d from the Orinoco region. By contrast, costs at Brazil’s new sub-salt fields will be very high. Petrobras’ new first sub-salt well at the Tupi field cost $240m.

By Tom Nicholiss

Peru considers more LNG as bid round launches

Companies must submit a letter of intent and qualification documents by 11 August and, Saba said, licence awards will be made in October. At present, 84 areas are licensed for upstream work, comprising 65 exploration contracts and 19 exploitation contracts. Saba said there is a high level of interest in the licences: interest included national oil companies from China, South Korea and Vietnam. If all of the 17 blocks are awarded, said Saba, virtually all of the country’s acreage will be under licence.

Recent finds are encouraging. Earlier this year, Repsol YPF made a gas discovery in block 27. The field may hold up to 2 trillion cf. Meanwhile, progress continues with the development of the 16 circular cf Camisea fields: Peru LNG’s export terminal should start to receive 0.62bn cf of gas from 2010. The country’s modest internal needs will also be catered for by Camisea: gas consumption, mainly by industry and the power-generating sector, amounts to just 4 trillion cf every 20 years, leaving considerable scope for exports.

Saba is also optimistic that Peru will be able to boost oil production and reserves around 2bn barrels at present. Peru is surrounded by prolific hydrocarbons producers – Venezuela, Colombia, Brazil and Bolivia – he pointed out, but added that because of years of unattactive contract terms the country has failed to realise its potential. "We are sure there is a lot of oil and gas in the jungle and offshore," said Saba – identifying the deep-water Telerca region as particularly prospective. "Peru will be producing at least 0.5m barrels a day (b/d) within 10 years," he claimed.

PdV’s upstream opportunities are therefore certainly improving. At present, Peru is a net oil importer: it produces around 120,000 b/d of oil and condensates, and consumes around 150,000 b/d. But by 2011, said Saba, production should have reached 300,000 b/d, making the country a net exporter, by a comfortable margin.

Most of the increase will come from two prospects. Perenco’s 100%-owned block 67, in the Matucana basin, will produce up to 100,000 b/d, with production scheduled to start in January 2011. The block contains the Canchis oil fields, which together hold estimated proved and probable reserves of over 300m barrels, according to Perenco, which will drill over 100 wells from 10 platforms, construct three processing facilities and local pipelines for delivery of crude oil into the export-pipeline system. Production will flow to the country’s main pipeline, the pacific coast, 1,000 km from the block.

The other large prospect is nearby block 39, operated by Repsol YPF. Saba said the field should contribute around 50,000 b/d to the country’s output. Repsol YPF, which ranks the project as one of its 10 most interesting, expects production to start up in late 2011.
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Fuel subsidies are distorting the oil market. With oil prices so high, something has to give

By Derek Brower

EVEN AT $135 a barrel, consumers are in pain. Whether the price is not sufficiently expensive to deter consumption to a significant degree, or the market is not working as it should. That is where fuel subsidies come in – and they make for severe distortions. Drivers in Turkey, home of the world’s most expensive fuel, complain, to no effect, that their cars are being subsidised gasoline, say Morgan Stanley, an investment bank. And the proportion of subsidised gasoline to total consumption has risen significantly as oil prices have doubled. When oil was at $60 a barrel at the end of 2006, only 10% of gasoline was subsidised. But with oil costing around $135 per barrel, gasoline subsidies in the US, with its fastest-growing market, China: more than $1/01/litre compared with about $0.64/litre. In Saudi Arabia, gasoline costs $0.12/litre, yet “net taxes” have declined as subsidised gasoline of total consumption and most-expensive (over $2.50/litre). In Spain, gasoline costs $0.64/litre, yet “net taxes” have declined as subsidised gasoline of total consumption and most-expensive (over $2.50/litre). In Indonesia, petrol costs $0.05/litre. Or compared with about $0.64/litre. In Saudi Arabia, gasoline costs $0.12/litre, yet “net taxes” have declined as subsidised gasoline of total consumption and most-expensive (over $2.50/litre).

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In economic terms, these subsidies help to explain why the laws of supply and demand keep bending, with sustained high prices so high, something has to give. When it comes, demand will be massive. The IMF says a better option is to reduce fuel subsidies. The IMF also makes this argument and says that, in reality, fuel subsidies in poor countries end up helping the better-off – the ones who drive gas-guzzling cars and enjoy heated or air-conditioned apartments – more than the poor.

Fuel subsidies are distorting the oil market. With oil prices so high, something has to give.
Time for an image make-over

By Leor Rotchild

Attracting the best and brightest young talent to the petroleum industry will require an image make-over, but young people are too savvy and mistrustful to fall for an empty public-relations exercise. This make-over will have to be grounded in substance, consistent with their desire for a better world.

Over the past century of oil and gas development, the petroleum industry has overcome many challenges ranging from financial to technological. But now, a new and different problem is emerging, at a time when demand for oil is rapidly rising.

The problem lies with the most vital and common element required in the production of oil and gas: people. Over the past few decades, there has been a dwindling number of young employees joining the industry. The average oil and gas employee is 50 years old and while this translates to an experienced workforce, there are not enough skilled people to take over.

The skills gap, which is estimated to include a 38% shortage of engineers and geoscientists in the next two years, could cause more safety and environmental incidents, project delays, supply shortages and result in even higher prices.

There are three main reasons for the low number of youth entering the oil and gas business. One is simple demographics: the number of young people entering the workforce is half what it was in the 1980s and 1990s. In the US, half a million people were laid off during those two decades, resulting in an 85% drop in the number of young people reaching employment age is smaller than the number of employees retiring. As a result, companies around the world have already begun competing to hire them.

The second is that oil and gas is viewed as a sunset industry. This is reinforced by projections of peak oil and the widespread industry lay-offs that took place during the 1980s and 1990s. In the US, half a million people were laid off during those two decades, resulting in an 85% drop in petroleum-related undergraduate enrollment between 1982 and 2003.

The third reason is that the petroleum industry has developed a negative reputation by being connected, in some instances, with human-rights abuses, corruption scandals, explosions and oil spills. Climate change is rapidly becoming one of the defining challenges of this generation and much of the public’s fear and frustration around this issue is directed at the oil and gas sector. As a result, many young people are choosing careers in industries with less tarnished reputations.

How to do it

How can the petroleum industry improve its reputation and make oil and gas careers more attractive? Could technology help?

New technologies are being employed to meet this new demand.

Companies to recognise this and take steps to attract the best and brightest young talent to the petroleum industry.

Petroleum Council Youth Committee

Leor Rotchild is secretary of the World Petroleum Council Youth Committee and a senior analyst for social responsibility at Nexen.
Successful development of the deep-water Atlantis field has required continual innovation

By Anne Feltus

BP COMMISSIONED and began exporting oil and gas from the Atlantis field in 2003, bringing to the Gulf of Mexico (GOM) in December. One of the most technically demanding projects the company has ever undertaken in the region, Atlantis has resulted in several record-breaking accomplishments and industry firsts. And, until BP’s 1.5bn barrel Thunder Horse field comes on stream at the end of this year, it will be the GOM’s biggest hydrocarbons producer.

BP discovered Atlantis a decade ago, in the southern Green Canyon area, about 125 miles off the Louisiana coast. At the time, the field was believed to hold about 300m barrels of oil equivalent (boe). After additional appraisal drilling, four years later, BP and minority partner BHP Billiton had increased that figure to 0.575bn boe and it was increased again, to 0.635bn boe, in 2003, making Atlantis the third-largest field discovered in the GOM.

The water depth and reservoir structure have called for continual innovation: Atlantis lies in waters ranging from 4,400 to 7,100 feet deep on the edge of the Nogoe Escarpment, an area of the GOM that has strong subsea currents and some of the most complex topography in this offshore basin. Much of the field is covered with a thick sheet of salt, which makes it difficult to see using conventional seismic survey techniques.

To obtain higher-quality 3-D images, BP employed two remotely operated vehicles (ROVs) to situate more than 900 nodes, or seismic recording units, in a 2.40 square-km grid pattern on the seafloor, where they continuously recorded signals sent from sources near the ocean surface. This was the first large-scale commercial use of ocean-bottom nodes in a deep-water seismic acquisition survey and BP boldly went from concept to application in ultra-deep water without first testing the system in shallow water. Completed in March 2006, the survey also represented the largest ROV-based subsurface deployment and recovery of equipment, based on the number of units used and area covered.

BP signed a three-year charter for the GlobalSantaFe Development Driller II, a custom-built semi-submersible equipped for drilling, completion and well intervention. This will enable the operator to re-enter wells and have more flexibility in selecting well sites.

Bigger than most semi-submersibles, the GlobalSantaFe Development Driller II measures more than 324 feet long and 259 feet wide and has a 60,000 tonne deadweight and usable deck space, can handle more than 7,700 tonnes of variable deck load and has 46,000 tonnes of operating displacement. BP postponed the start-up of the Atlantis field once because of a shortage of skilled workers for offshore services and, on another occasion, possible problems with its subsea manifold, which sends oil and gas from individual wells towards the production platform on the surface.

In the second case, the causes of the delay also provided opportunities for innovation. In early 2006, after a leakage, apparently caused by a bad weld, in the subsea manifold, an area of the GOM that is vulnerable to wear and tear, the need to monitor the equipment less dangerous to the people who use and service it.

The ABB product is smaller than most wireless vibration-monitoring systems exist, the ABB product is smaller than those produced by competitors, say the industry’s leading and circuit board are all housed in a cylinder-shaped container less than 4 inches tall and less than 1½ inches in diameter.

Although a production start-up date for the wireless vibration sensor has not been determined, it is likely to have a ready market when it does become available. As the industry’s leading while other producers change, the demand for new devices grows, machine fail can continue to age and become more susceptible to wear and tear, the need to monitor the condition of the sensor will increase. And as oil and gas companies venture into deeper waters, farther from shore, the need for wireless systems that enable the quick collection and analysis of data will increase. The Atlantis field will still be in operation well into the future, and its ability to provide continual and less than 1½ inches in diameter.

In 2007, the platform finally set sail from the fabrication yard in Ingleside, Texas, where integration of its hull and three topside modules took place. Production began in October: as the Caesar oil pipeline system and gas will travel through the Cleopatra pipeline – both part of the Mardi Gras Transportation System, the world’s highest-capacity deep-water pipeline system.

Sensing bad vibes

By Anne Feltus

VIBRATIONS on a motor almost always mean trouble: a bad bearing, a worn gear or an electrical fault that could cause the motor to malfunction or fail. And when that motor is a critical component of an oil or gas platform located perhaps hundreds of miles from shore, its failure could have serious – and costly – consequences.

Offshore platforms operate in a corrosive environment: battered by high winds, waves, currents and other physical forces that could damage the equipment on-board. Consequently oil and gas companies send personnel out to these structures to check their condition, either periodically or continually.

That can be expensive, says Egil Birkenmoe, sales manager, enhanced operations and production, for Norwegian-based technology company ABB. For the last two years, ABB, Swedish roller-bearings manufacturer and support company SKF and Sintef, the largest independent research organisation in Scandinavia, have been collaborating to develop a cheaper solution: a wireless sensor allowing vibrations emanating from equipment on offshore platforms to be monitored remotely. The system would indicate that vibrations were occurring – and provide more quantifiable data.

“If the balls in a ball bearing are faulty, they generate a high-frequency ringing noise, while machines produce a low-frequency thumping sound with other types of wear,” says Maake Tako, of Sintef’s micro- and nanotechnology laboratory. “The new sensor is capable of measuring both types of sound simultaneously.”

Mounted directly on machinery near a bearing, the system would have an accelerometer for registering abnormal vibrations, as well as a sensor that measures the temperature of the motor. The data from these sensors would be transmitted to an onshore computer for analysis.

The system would allow companies to schedule maintenance based on need rather than calendar. The ability to correct problems with its subsea manifold, which sends oil and gas from individual wells towards the production platform on the surface.

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An unconventional approach

By Tom Nicholls

Interview with Glenda Wylie, director of technical marketing, Halliburton

What is the potential of unconventional gas and how can it be realised?

A

The potential is huge. According to an article in Oil and Gas Journal last year, 43% of the US’ natural gas production comes from unconventional resources. That percentage will continue to grow.

In my paper, I predict that unconventional gas resources will become a source of supply for developing countries and for countries that have to import their energy. Additionally, I believe we will undergo a change in philosophy: even conventional wells will be examined for their potential to supply unconventional gas. A well will be seen as a portfolio of energy supplies.

What attracted you to the energy industry?

A

I try to live by two important principles: make life better for others and give society your best. Nothing has a broader effect on humans’ quality of life than hydrocarbons, and the energy industry faces daily challenges in finding oil and gas, accessing and delivering the energy to the marketplace. Helping the energy industry meet the challenges gives me a way to fulfil my guiding principles.

What is the most challenging part of your job?

A

Addressing the customer challenges that arise daily – dealing with every type of resource, environmental condition, economic barrier, local community and location (ultra-deep to remote onshore) involved in projects from across the globe.

Have you ever felt that gender is an issue in the energy industry?

A

I look at the gender issue as an opportunity. I continually challenge myself to gain more education and experience and to deliver a service that exceeds expectations.

Is enough being done in general in the US to encourage more women to enter the energy business?

A

Yes. Today, around 50% of petroleum engineering students are female. Companies are making it easier for women with families to work in the energy industry by furnishing child care, flexible work hours, family leave time and other programmes.

What is Halliburton doing (not just in the US) to encourage greater involvement of women in the energy industry?

A

I am seeing an increased emphasis on giving women greater opportunities than ever before. Additionally, women are being placed in very high positions with decision-making authority. This will help in both recruitment and retention of women employees.

Halliburton has made great strides in moving employees in Latin America and the eastern hemisphere into higher-level managerial positions. Expansion into regions where Halliburton had no presence 10 years ago has resulted in more jobs available globally in research and development (R&D), manufacturing, sales and operations. Opportunities are also expanding for women and men of all cultures.

Are you seeing an increase in the number of women taking jobs with the company or applying for positions? If so, why?

A

More women are applying for and accepting jobs in the company, particularly in Latin America and the eastern hemisphere. Many of these women have received excellent educations from which Halliburton will benefit in R&D, technology application, economics, marketing, human resources and business development.

Halliburton is recruiting not just in the US but globally. The women hired through these efforts will be able to use their education and skills in their home countries, where knowing the regional culture, people and language is an enormous advantage to working in that country. Many countries require knowledge in more than one language, making it easy for individuals to work in many countries and not be limited to just one country.

Additionally, Halliburton’s real-time technology makes it easy for people to live in one country and work on resources in another country (or countries) without leaving home. Today’s workers have a global perspective, unlike previous generations who lived in one country and for whom communications were more restricted. The energy industry is a global business and employees must be able to transcend boundaries and perform work on diverse assets. Advancements in satellite, video and communication technologies have afforded this benefit to companies and to individual employees.

*Glenda Wylie, global technology manager, Halliburton, is presenting a paper at the WPC on the economic recovery of thin-layered gas deposits.

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