



## Tanker sector pain slams top Nordic firms

### Frontline, Maersk Tankers expect hard times ahead

London—The grim results posted February 22 by two of the world's leading players indicated starkly that the global tanker industry continues to hemorrhage almost as fast as corporate physicians move to stem the flow of red ink—and both firms pointed to more pain ahead.

Nordic groups Frontline, the world's biggest independent tanker group, and Maersk Tankers both posted deep fourth-quarter losses and said that tanker rates are not picking up fast enough.

The figures and commentaries by both Norway's Frontline and Denmark's Maersk, analysts say, indicate that conditions are so bad for the industry that—if they are not terminal—then there will almost certainly be more corporate casualties on the way, adding to the list of those companies already fallen by the wayside.

Frontline reported that the average daily Time Charter Equivalents earned in the spot and period market in the year ended December 31, 2012 by the company's VLCCs, Suezmax tankers and Suezmax OBO carri-

ers were \$22,200, \$15,200, and \$33,600, respectively.

That compared with \$22,800, \$14,100 and \$36,700, respectively, in the year ended December 31, 2011.

Compounding the bad news, Frontline added that it estimated average cash cost breakeven rates for 2013 on a TCE basis for its VLCCs and Suezmax tankers of approximately \$24,200 and \$18,800, respectively.

"We are not particularly optimistic in the near future in the tanker segment," AP Moller-Maersk group CEO Nils Smedegaard Andersen told an analyst conference.

The management of Frontline has been more blunt, with CEO Jens Martin Jensen having said repeatedly that more companies need to fold so that tonnage will be withdrawn from the glutted tanker market.

"I agree with Jens Martin Jensen," Baltic and International Maritime Council (BIMCO) analyst Peter Sand told Platts by telephone. "We need close to 40 to 50 VLCCs to be

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## BP set to tangle with US over Macondo oil spill

Washington—When the civil trial against BP begins on February 25 in New Orleans the US Justice Department will be attempting, for only the second time, to hold a company liable for "gross negligence and willful misconduct" in connection with an oil spill.

The only other time the US aimed for the maximum penalty under the Clean Water Act a judge drastically reduced the penalty the government sought.

The US is trying to hold BP responsible under the CWA for the maximum civil damages for the 2010 oil spill from the company's Macondo well in the Gulf of Mexico. Under the CWA, as amended by the Oil Pollution Act of 1990, a company can be fined either by the day or by the barrel.

The fines range from \$37,500 per day of the discharge or up to \$1,100 per barrel spilled. If a court finds that the company acted with "gross negligence or willful misconduct," the per barrel penalty is increased to a maximum of \$4,300.

But, the law gives the court wide discretion both in finding that a company acted with gross negligence and in setting a fine. The law

requires the court to consider eight factors in reaching that determination and allows for a much lower penalty—including no penalty at all.

Attorneys who specialize in litigation under the CWA and OPA 90 say they will be watching this trial closely because it is only the second time that the issue of gross negligence—and how a court weighs the eight factors—has ever reached the trial stage.

"The term 'gross negligence' appears in a number of environmental statutes, but it's rarely litigated in part because environmental matters are usually resolved by settlements," said William Hassler, a partner at Steptoe & Johnson in Washington.

The only other case that went to trial resulted in a judge slashing the amount of fines sought by the Justice Department.

The US sued Citgo in 2008 in connection with a spill of slop oil from storage tanks at its Lake Charles, Louisiana refinery in 2006. Both the amount of oil spilled and Citgo's conduct were disputed, as is the case in the BP trial.

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## Santos posts 34% rise in underlying profit

### Emerging Australian LNG producer eyes higher output ahead of major projects

Sydney—Australian exploration and production company Santos posted a 34% increase in underlying profit for 2012, and forecast higher production of between 53 million and 57 million barrels of oil equivalent for 2013.

Santos' production for the full year, which was announced last month, was a record 52.1 million boe, up 10% from 2011.

Crude oil production was 33% higher at 9.5 million barrels following the commissioning of the Chim Sao project in Vietnam in late 2011 and due to increased output in Australia's Cooper Basin. Natural gas production rose 8% to 223 petajoules, driven by record Western Australian output, partly offset by a

## Pertamina and partners to spend big on Cepu gas

Jakarta—Indonesia's state-owned oil and gas company Pertamina and its partners will spend \$3.3 billion developing the Cepu field, with first gas production expected by 2017 and condensate by 2019, an official at the country's upstream regulator SKK Migas said February 22.

"SKK Migas has approved the development plan last week," SKK Migas spokesman Elan Biantoro told Platts. "Under the plan, they will spend \$3.3 billion, including \$1.9 billion for operational expenditure and another \$1.4 [billion] for capital expenditure. But the figure could be changed depending on [the] final investment decision."

The FID is expected to be taken over the 2015-2016 period, while engineering, procurement and construction works are forecast to start at the end of this year, he added.

Production at Cepu is expected to start up at 185,000 Mcf/d of gas and 3,000 b/d of condensate.

Pertamina and ExxonMobil Oil Indonesia signed a heads of agreement in August 2011 to develop Jambaran and Tiung Biru fields at the Cepu project. The HOA covered developing the fields together because they are in the same structure, with Pertamina acting as operator.

The Jambaran field is part of the Cepu block where Pertamina and operator ExxonMobil own 45% each, with local governments holding the remaining 10%. Tiung Biru is outside the Cepu block and is 100% owned by Pertamina EP.

The fields contain 1.2 Tcf of recoverable gas reserves and 18.6 million barrels of condensate reserves, Biantoro said. The block's production lifespan is 2017-2035.

The Cepu block, straddling the border between Central Java and East Java, is estimated to contain about 600 million barrels of oil. Banyu Urip, the block's major oil discovery, is estimated to hold more than 250 million barrels of oil. Jambaran is the block's gas field.— *Anita Nugraha*

lower net entitlement to Maleo gas in Indonesia following a favorable price review.

"Santos achieved its highest oil production in four years, strong operating cash flow, a material gas discovery at Crown and Australia's first production of gas from a shale well," CEO David Knox said. "Production increased by 10% in 2012, driven by new assets in Western Australia and Vietnam, and strong Cooper oil production. We expect a further lift in production in 2013."

Santos' major growth assets, its 13.5%-held 6.9 million mt/year Papua New Guinea LNG and 30% owned 7.8 million mt/year Gladstone LNG projects, remain on schedule for startup in 2014 and 2015 respectively, Knox added. Capital cost estimates for both projects are also unchanged at \$19 billion for PNG LNG and \$18.5 billion for GLNG.

## PTTEP's Australian offshore field to start in March

Singapore—Thailand-based PTT Exploration and Production's Montara field offshore Australia is scheduled to start production at between 25,000 and 30,000 b/d by the end of March, a spokeswoman for the company said February 22.

The development of Montara was suspended in 2009 following a major oil spill. Since then the startup of production has been repeatedly delayed. State-controlled PTTEP said in October last year that production was anticipated by the first quarter of this year.

"There has been a slight delay due to weather conditions but we now expect it to start production by the end of March," the spokeswoman said, adding that the field's full production capacity was 35,000 b/d.

PTTEP subsidiary PTTEP Australasia acquired the Montara project as part of its purchase of Coogee Resources in December 2008, and had planned to start producing about 40,000 b/d of crude from the field in late 2009. The project became the source of Australia's worst-ever oil spill in August 2009, when a well being drilled by PTTEP began leaking. The spill continued unchecked for 10 weeks, eventually causing the drilling rig to catch fire, before the well was "killed" in early November.

In Thailand, PTTEP will keep output at its onshore Sirikit 1 field at 30,000 b/d this year, up from an average 28,000 b/d last year, the spokeswoman said. The mature field has been producing for over 30 years, but PTTEP has managed to boost output through enhanced recovery techniques.

The Sirikit 1 field reached record-high output of 37,000 b/d on February 22, the spokeswoman added. All of the crude from the field is used in the domestic market.— *Song Yen Ling*

Meanwhile, the company continues to make "good progress" on offshore oil projects, with construction at its 44% held 15,000 b/d Fletcher Finucane field off Western Australia ahead of schedule with the project expected to start up by the middle of the year. First oil from the 31.875% held Dua project in Vietnam, designed to produce 8,000-10,000 b/d, is expected as planned in the first half of 2014, Knox added.

Separately, Santos said its proved and probable hydrocarbon reserves had increased to 1.406 billion boe at the end of 2012. The figure represents a 2P reserves replacement ratio of 180% and provides a reserves life of 27 years based on 2012 production.

Santos' net profit for the 12 months to December 31, 2012 was A\$519 million (\$536 million), down 31% from A\$753 million in 2011, the company said February 22. The result included A\$77 million of after-tax impairments, whereas the previous year included net gains on asset sales of A\$408 million.

Underlying net profit was A\$606 million, up from the previous \$453 million. The improvement was driven by higher liquids volumes and gas prices, partly offset by higher costs, mainly due to new assets coming online, Santos said.— *Christine Forster*

## CNOOC hikes stake in China coalbed methane

Singapore—China National Offshore Oil Corporation has raised its stake in state coalbed methane company China United Coal Bed Methane from 50% to 70%, the company said February 21.

CNOOC will acquire the stake from China National Coal Group, leaving the state coal producer with the remaining 30%. No financial details were disclosed.

In August, CNOOC said it would jointly work with CUCBM to develop coalbed methane resources in China, particularly in Shanxi, Shaanxi and Jiangxi provinces. The move was widely seen as a major boost to the CBM sector in China and instrumental in helping it achieve its official target to produce 16 billion cubic meters/year of CBM and 14 Bcm/year of surface coalmine methane by the end of 2015.

CUCBM was established by the Chinese government in 1996 as a joint venture between PetroChina and China National Coal Group to develop domestic CBM resources, but progress has been slow as the company lacked technical expertise and funding. In 2009 the company was restructured and the government divided CUCBM's assets between both shareholders. CNOOC then took a 50% stake in China National Coal Group's assets in 2011.

CNOOC said that since its involvement, CUCBM's total capital investment has reached Yuan 4.79 billion (\$768 million), while 95.9 BCM of additional proved CBM reserves have been discovered.— *Song Yen Ling*



## Denmark's Maersk sees 7% output decline

### Still hopeful to reach production of 400,000 boe/d by 2020

London—Denmark's Maersk Oil expects its oil and gas production in 2013 to fall by up to 7%—on the back of a 23% output fall last year—as the group wrestles with long-term declining trends.

But the company said it was pushing ahead with the development of a brace of new major projects and it was on track to deliver production of 400,000 b/d of oil equivalent, nearly doubling current levels, by 2020.

The company, which is part of the diversified AP Moller-Maersk group, said its global production would “stabilize” in 2014 and output would thereafter return to growth, but it did not give a precise timeline for when the turn in fortunes would kick in.

AP Moller-Maersk group CEO Nils Smedegaard Andersen told an analyst conference, held after the 2012 financial results were published, that production this year would fall to 240,000-250,000 boe/d.

Maersk posted 2012 average production of 257,000 boe/d in line with its previously announced forecast of 258,000 boe/d, but down a hefty 23% year on year compared with 2011 output of 333,000 boe/d.

“We have been investing significantly in recent years but it takes time before you can get the assets into production,” a Maersk

spokesman told Platts.

“We aim to stabilize production in 2014 and return to growth,” he said. “We do not have an estimate for 2014 production or when [precisely] we will return to growth.”

The company said the fall in output was mainly due to lower output from its North Sea projects and a drop in its share of production from its Qatar field.

Maersk's share of production last year from the Al Shaheen field in Qatar was 103,000 boe/d, down 34% from 157,000 boe/d in 2011. It is receiving a lower share under its production sharing deal to recover its investments and costs. Gross production from the field continued unchanged at 300,000 boe/d.

Its output from the North Sea offshore Denmark was 91,000 boe/d, down 19% from 2011, as the long-term trend of mature field depletion due to inadequate fresh discoveries remains unchanged.

Offshore UK, however, it reported stable production at 28,000 boe/d. In 2011, this stood at 27,000 boe/d.

Maersk says the Gryphon North Sea FPSO, damaged during a storm in February 2011, is back on location but has yet to restart production. Maersk has an interest in 14 producing fields, operating seven of those.

The FPSO vessel is stationed above the Gryphon, Maclure and Tullich oil and gas fields. A complex piping system runs from wells on the seabed to the FPSO.

Production at Gryphon was expected to resume in the first quarter of 2013, Maersk said.

Its share of production from Algeria was 27,000 boe/d in 2012, slightly higher than 25,000 boe/d in 2011, following the settlement of a tax dispute with the national oil company.

Maersk posted revenue of \$10.2 billion for 2012, down from \$12.6 billion in 2011. But its net operating profit rose to \$2.4 billion from \$2.1 billion in 2011, boosted by the Algerian tax gains and profits from a divestment in Brazil.

### Norwegian field startup

Maersk said that, with five major projects under progress, output would almost double by 2020. This includes the massive Johan Sverdrup oil field, one of the biggest discoveries ever made offshore Norway. It is due to start production around 2018.

Its recoverable reserves are estimated at 1.7 billion-3.3 billion barrels. Maersk has a 20% stake in one of the two licenses that straddle the field.

“Maersk's aspiration is to grow the business by almost 50% to reach a share of production of 400,000 boe/d by 2020, which implies significant capital expenditure in the coming years,” the company said.

Maersk said there would be \$1 billion in capital expenditure in 2013, about the same as last year, but thereafter it would accelerate to \$3-\$5 billion per year developing discoveries towards production.

“The current production profile reflects that Maersk is in a catch-up phase with respect to replacing reserves,” Maersk said.

“Exploration activities have been scaled up and a number of high impact discoveries have been made over the last couple of years.”

Smedegaard Andersen said that Maersk Oil was one of the core areas of the Copenhagen-listed earmarked for targeting rapid growth.

“We continued our push towards building our four strategic core businesses with a high level of oil exploration in Maersk Oil, securing long-term contracts for five of our seven new drilling rigs,” he said in the report.

Maersk said that in Algeria, development of the El Merk field continued with first oil expected in the first quarter of 2013.

In Angola, the group added that work was continuing on the development plan for the Chisonga discovery in Block 16 and drilling of the 4th appraisal well was completed late 2012.

The development will likely comprise a stand-alone FPSO with first oil expected in 2017-18.

At the end of 2011, Maersk had entitlement reserves and resources of 1.38 billion boe including proved reserves (1P) of 443 million boe. The company said that estimate would be updated with the first quarter results due out in May.— *Patrick McLoughlin*

## China's plan for new Nigeria refineries hits snags

Abuja—Bureaucratic delays and a lack of funding have delayed the construction by a Chinese firm of three private refineries in Nigeria despite the urgent need for the country to improve its refining capacity to meet growing fuel demand.

Nigeria's state-owned NNPC sealed an agreement with the China State Construction Engineering Corp. in May 2010 to build the refineries and a petrochemical plant at a cost of \$23 billion.

The projects, which would add 750,000 b/d of extra refining capacity in Nigeria, were to be built in Lagos, Bayelsa and Kogi states.

“The ministry of finance is yet to approve release of funds to progress work on the green-field refineries,” a spokesman for NNPC said at an industry event in Abuja February 22. “We are waiting on the ministry to move forward.”

The refineries were to be funded by a consortium of Chinese banks and China's Export and Credit Insurance Corporation. NNPC was to fund the feasibility studies for the projects, a key requirement under the agreement signed by the two parties.

However, the project has also been delayed by a lack of progress in Nigeria's oil reform legislation.

The passage of the Petroleum Industry Bill (PIB) aims to make way for deregulation of the downstream sector but the bill has to yet to be passed into law.

“The [agreement] between NNPC and the Chinese investors was signed on the assurance that the PIB would be in place by end of 2011,” an industry source said February 22.

“While the federal government is reluctant to throw money into new refineries, the Chinese have also simply put on hold their investment,” the source added.

Nigeria has four refineries with an installed capacity of 445,000 b/d but is forced to import some 85% of its fuel because of low runs at the refineries due to mismanagement and disrepair.

Fuel subsidies in Nigeria cost the country billions of dollars a year and the government has said they would be abolished as part of the deregulation of the downstream industry.

Previous efforts to build new refineries have been cancelled. India's ONGC held talks to build a \$4 billion, 180,000 b/d refinery in 2005 but the project has failed to get off the ground.

In November 2012, the Nigeria National Refineries Special Task Force recommended that majority shareholding, a minimum of 51% in the refineries should be divested to the private sector.

The Task Force stated that private investors must include companies with background and experience in managing and operating refineries, good technical and financial capability.— *Staff reports*



## Ukraine leader slams EU energy community

### President Yanukovich bemoans lack of support over Russia

Kiev—Ukraine may quit the European Energy Community (EEC) because of a lack of support for the country in its ongoing natural gas disputes with Russia, President Viktor Yanukovich said, adding he was unhappy that the community had given a green light to Russia to build gas pipelines to Europe that bypass Ukraine.

“The interests of Ukraine have been violated,” Yanukovich said February 22 in remarks aired by state television. “So, the question is ‘Why do we need to be in the community?’”

“I will say this: we have considerably sharpened our position on this matter today,” Yanukovich said. “We, as a member of the community, are extremely dissatisfied with the way the community treats Ukraine.”

Yanukovich’s comments come ahead of a summit in Brussels set for February 25 between Ukraine and the EU.

Ukraine became a member of the EEC in January 2011 in the hope it would help increase investments in the country’s energy infrastructure, in particular its gas pipeline network.

Russia is not a member of the community and has repeatedly suggested Ukraine quit

the group as part of a deal to allow Gazprom to take control of Ukraine’s gas pipelines, according to a Ukrainian government official.

Yanukovich stressed that Ukraine would not allow the sale of its pipeline network, but did say Kiev could be willing to lease it out. “We will not sell the pipeline [system]—not to anybody. Perhaps it will be leased out under our conditions,” he said.

Ukraine may make a decision in the first half of the year on whether to lease out the network.

Moscow previously made a proposal to Kiev to form a trilateral consortium with European companies to manage Ukraine’s gas pipeline network, but talks on the subject have come to nothing.

Russia’s Gazprom has made joint management of Ukraine’s pipeline a key condition for reconsidering an existing 10-year contract that runs until 2019, which Kiev has tried to renegotiate in order to reduce the price it pays for Russian gas. However, Ukraine has proved reluctant to cede any type of control over its pipeline network.

Yanukovich is also unhappy that the

EEC did not block the construction of North Stream, a Russian gas pipeline across the Baltic Sea to Germany, which led to a reduction in Russian gas supplies via the Ukrainian gas pipeline system in 2012.

Yanukovich also criticized the community for giving the go-ahead, despite Ukrainian concerns, for the South Stream pipeline which will link Russia and Bulgaria across the Black Sea.

South Stream threatens to dramatically reduce gas supplies via the Ukrainian gas pipeline system, which until recently pumped up to 80% of Russian Europe-bound gas supplies.

Yanukovich was also angry that the community did not publicly support Ukraine after Gazprom imposed a \$7 billion fine on Kiev for failing to import the contracted volumes of gas in 2012.

Ukraine has refused to pay the penalty and is currently involved in talks with Russia over the matter, Yanukovich said.

Gazprom hit Ukraine with the penalty last month in response to a steep decline in its gas purchases in 2012. Naftogaz Ukrayiny, the national energy company, bought 24.4 billion cubic meters of gas last year, down from 40 Bcm in 2011, citing high gas prices.

But Gazprom says a take-or-pay clause in a 2009 gas supply agreement obliges Naftogaz to buy contracted gas volumes regardless of price.

The agreement, negotiated by then prime minister Yulia Tymoshenko and then Russian prime minister Vladimir Putin in January 2009, calls for Ukraine to import 52 Bcm of gas annually through 2019.

The agreement allows Ukraine to cut gas imports to 41.6 Bcm/year without penalty and to 33.3 Bcm/year with Gazprom’s written consent.— *Alexander Bor*

## PKN steps up Polish shale gas exploration campaign

Warsaw—Poland’s largest refiner PKN Orlen is stepping up an exploration campaign at one of its most prospective shale gas blocks in the country, while a different agreement for a number of state companies to form a venture to explore for Polish shale gas seems to have stalled.

PKN said February 22 it has now spudded its third gas exploration well at the Wierzbica block, its sixth in Poland.

“The Wierzbica license area is one of the most prospective locations, which is why we are committed to stepping up our efforts in the area,” Wieslaw Prugar, CEO of Orlen Upstream, said in a statement.

“The results of our preliminary geological surveys proved very promising and so we decided to start a new exploratory well there,” Prugar said. Wierzbica is located in the Lublin basin in southeast Poland.

The latest well—the vertical Streczyn-OU1 well—is to be drilled to a total depth of 3,400 meters and will collect 300 meters of core samples. The work is expected to last 45 days.

Orlen Upstream said it is preparing two new vertical exploration wells and will perform hydraulic fracturing of two horizontal wells in Wierzbica and the Lubartow license area in the first half of 2013.

Orlen Upstream has stakes in 10 shale gas exploration license areas in the Lublin and Podlasie basins in south eastern and eastern Poland.

So far it has completed drilling three vertical and two horizontal wells.

Separately, Poland’s PGNiG, three state-

controlled power utilities and the country’s largest copper miner, have extended for the second time a deadline for fixing the details of an agreement to cooperate on shale gas exploration.

The companies said February 22 they needed more time to work out the details of their planned cooperation and gave themselves a new deadline of May 4 for reaching agreement. In November the companies extended the first deadline until February 4.

Poland’s three largest vertically-integrated power companies—Polska Grupa Energetyczna, Tauron Polska Energia, and Enea—and copper miner KGHM in July signed a framework agreement with PGNiG to partly fund exploration activities at its Wejherowo concession in northern Poland in return for an unspecified share of profits from future gas sales.

The companies said if the details are not finalized by May 4 any of the parties can terminate the agreement. If the required anti-monopoly clearances for future cooperation are not acquired by the end of 2013, the agreement will expire, the statement said.

Wejherowo is thought to be the most promising of PGNiG’s 15 shale gas exploration licenses. But the company cannot afford to fund the drilling program required to exploit the gas on its own. Shale gas drilling costs are up to three times higher in Poland than in the US.

PGNiG said in the framework agreement it estimates expenditure of Zloty 1.72 billion (\$544 million) to build three wellpads with multiple wells at Kochanowo, Czestkowo and Tepecz.— *Adam Easton*

## Sonatrach commissioning of El Merk begins

Algiers—Sonatrach and its foreign partners have begun commissioning the large El Merk oil and gas complex in Algeria and the state-owned company expects first production in the next few days.

El Merk, being developed by a consortium of Sonatrach, the US’ Anadarko Petroleum, Italy’s Eni, Denmark’s Maersk Oil, Canada’s Talisman and the US’ ConocoPhillips, is expected to produce 130,000 b/d of crude oil and condensate and 30,000 b/d of LPG at peak.

A Sonatrach source said production at El Merk would be ramped up “in the coming months.”

El Merk will have two 65,000 b/d oil trains and 600,000 Mcf/d of natural gas processing capacity.

Algeria’s oil and gas production capacity has remained fairly static for a number of years and new project startups are rare.— *Lies Sahar*



## BP set to tangle with US over Macondo oil spill

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While the US requested fines of as much as \$247 million, a judge rejected the argument that Citgo acted with gross negligence and cut the number of spilled barrels. After considering the eight factors, the judge ordered a fine of \$111/b, or about \$6 million.

The case is under appeal by both sides. Attorneys say that since no appeals court has ruled on the CWA provisions, the judge in the BP case has almost no judicial guidance on how to apply the law.

"It gives both sides the possibility of an appeal if they can't resolve it (before trial)," Hassler said.

The eight factors are:

- The seriousness of the violation
- The economic benefit to the violator, if any, resulting from the violation
- The degree of culpability involved
- Any other penalty for the same incident
- Any previous history of violations
- The nature, extent and degree of success of any efforts of the violator to minimize or mitigate the effects of the discharge
- The economic impact on the violator of the penalty
- Any other matters as justice may require

The civil penalty trial will take place in two phases. The first, set to begin February 25, will focus on the issue of negligence and in apportioning blame for the disaster among BP, driller Transocean and cement contractor Halliburton. The second phase, set for September, will focus on the issue of how much oil spilled from the well for the purposes of determining per barrel fines.

BP and the government have already agreed to lower the total amount spilled from 4.9 billion barrels to no more than 3.1 million barrels. The lower figure results from subtracting the 810,000 barrels that were captured from the gushing well and never made contact with the environment.

### Ready to rumble

The government and BP have already signaled their intent to tangle over one of the eight factors—the one that considers efforts the company made to mitigate the effects of the spill.

In a court filing the day after BP pleaded guilty to criminal charges and agreed to pay a \$4 billion penalty, the government sought to waive BP's attorney-client privilege in regards to early calculations of the flow rate from the Macondo well.

The government has argued that BP conspired with its attorneys to mislead Congress, oil spill responders, shareholders and the public by "presenting flow rate numbers that the company knew were too low."

In pleading guilty to criminal charges and one civil charge from the Securities and Exchange Commission, BP admitted it insisted in the early days of the spill that the oil

from Macondo was flowing at a rate of about 5,000 b/d when it knew the rate was much higher—as high as 100,000 b/d.

The deception caused the government to approve several attempts to cap the well that were doomed to fail because of higher flow rates, the government claims.

"The United States needed truthful and accurate information regarding quantification of the oil spill and the flow rate of the hydrocarbons," the government's motion states.

The effort to force BP to produce its communication with attorneys over the flow rate issue is aimed at undermining any defense that BP might wage by citing its efforts to mitigate the Macondo spill.

BP has to file its answer to the US motion by February 28.

The company addressed the issue of its mitigation efforts in a February 19 press release detailing its intent to fight the govern-

ment's civil penalty action.

"We believe that consideration of all eight legal factors together weighs in favor of a penalty that is lower than the statutory maximum," Rupert Bondy, BP's group general counsel said in a statement.

"In determining the penalty, we believe the court should consider, among other things, the fact that BP immediately stepped up and acknowledged our role in the accident. We waived the statutory cap on liability, and to date, we've spent more than \$23 billion in response, clean-up, and payments on claims by individuals, businesses, and governments.

"No company has done more, faster, to meet its commitment to economic and environmental restoration efforts in the wake of an industrial accident, and although the court will ultimately decide, we believe that both the statute and public policy more generally contemplate consideration of our efforts to do the right thing in determining an appropriate penalty," Bondy said.— Gary Gentile

## Canadian crude displaces Venezuelan oil in US

Washington—While US data expected out this week will likely show that crude oil imports from Venezuela increased slightly in 2012, the longer-term trend of declining US imports from Venezuela remains firmly in place, according to analysts.

"US imports from Canada and US production from the Gulf of Mexico will be a challenge for the three largest exporters to the US Gulf Coast, which include Mexico, Saudi Arabia and Venezuela," said economist Ed Morse, global head of commodities research at Citigroup.

Venezuelan oil shipments to the US climbed every year between 1988 and 1997, from 439,000 b/d to 1.394 million b/d, according to Energy Information Administration data. Then they hovered between 1.15 million b/d and 1.297 million b/d for the next decade before taking a plunge.

The US imported 1.039 million b/d in 2008; 951,000 b/d in 2009; 912,000 b/d in 2010; and 868,000 b/d in 2011.

Venezuelan oil imports dropped to 683,000 b/d in January 2012—a low not reached since February 1992, when the country sent 655,000 b/d to the US.

EIA's monthly import data for last year shows Venezuelan oil imports to the US averaging 896,000 b/d through November, an increase of 3% from 2011 levels.

The agency is set to issue its data on December imports on February 27.

Venezuelan imports have long played a role in the US debate on whether the White House should approve TransCanada's controversial Keystone XL pipeline. Supporters of the project often promise that the Canadian supplies it will carry would diminish reliance on less-friendly oil producers.

"Really, it's displacing oil from Venezuela," Gary Doer, Canada's ambassador to

the US, said February 19 during a Maclean's event in Washington. "That is the fundamental issue of the national interest in the United States. Two years ago, when the State Department looked at this, they evaluated that Canadian oil was 2% higher in [greenhouse gas emissions] than Venezuelan crude. The latest reports from Daniel Yergin have it at or below Venezuelan oil."

Growing volumes of Canadian oil flowing across the US border have already pushed out some Venezuelan imports.

Canadian net crude imports to the US climbed 36% to 2.178 million b/d between 2005 and 2001, according to EIA data. During the same period, Venezuelan imports fell 30% to 868,000 b/d.

EIA's year-end stats for 2012 will likely show another jump in Canadian imports. Monthly import data through November averaged 2.339 million b/d, or 7% higher than 2011 imports.

David Pumphrey at the Center for Strategic and International Studies said it's safe to assume, as Keystone XL supporters do, that Venezuelan imports would drop further with the addition of pipeline capacity from Cushing, Oklahoma, to Gulf Coast refineries. But so could heavy crude imports from Mexico or the Middle East.

"While it's useful to point out Venezuela, you really don't know in the end how the balance will go and what the company decisions will be," said Pumphrey, co-director of the think tank's energy and national security program. "It's all going to be a pricing choice."

Venezuelan imports have certainly fallen as a result of more Canadian oil reaching the US Gulf Coast, Pumphrey said.

— Meghan Gordon



## CenterPoint marries utility with upstream

### Power company's Bakken play could lead sector into oil business

Houston—US-regulated natural gas and power utility CenterPoint Energy plans to enter the crude business with a Bakken Shale gathering system, possibly leading the way for other utilities to follow into the lucrative production playground.

International Gas Consulting analyst Ken Beckman, said on February 22: "If this happens to start an industry-wide phenomenon, then these guys are on the cutting edge of it."

CenterPoint Energy Bakken Crude Services is planning to build a 19,500 b/d pipeline that will be part of the new crude oil gathering system in North Dakota, spokeswoman Alicia Dixon said February 20.

The first phase of the new crude gathering system is expected to become operational in the fourth quarter of 2013. An open season for the project closes on March 29.

"Would the older utility types...like Duke Energy...charge into this ground? I think this

is unique and going to be on a company-by-company basis," Beckman said.

"We are hearing a lot of chatter about non-traditional players looking to get into the [crude] midstream sector, particularly in the Bakken," Bentek senior energy analyst Christopher Micsak said.

Micsak noted a recent deal where natural gas and NGL-focused midstream Targa Resources Partners acquired Saddle Butte Pipeline's ownership of its Williston Basin crude oil pipeline and terminal system. Bentek is a division of Platts.

There are "big arbitrage opportunities" that are presenting themselves and "lots of money to be made in relieving infrastructure constraints" in the Bakken, Micsak said, adding that new crude pipeline infrastructure in the US has not been necessary for 60 years.

"This means that domestically, there are

only a handful of companies with significant expertise in crude midstream, leaving lots of opportunity for new entrants," he said.

The Bakken will produce over 2 million b/d of crude by 2022, and "there was little to no existing infrastructure up there as recently as a few years ago," Micsak said.

CenterPoint's entry into crude gathering is an extension of the company's natural gas gathering services, Andy Lipow of Lipow Oil Associates said. CenterPoint has a significant presence in natural gas pipeline infrastructure in Oklahoma, Arkansas and Louisiana, he said.

Natural gas and crude gathering systems are similar in scope and operation, Gregory Harper, CenterPoint's senior vice president and group president of energy pipelines and fields services said during the company's second quarter 2012 earnings call.

"As far as crude versus natural gas liquids versus natural gas gathering, a few of the specs are a little bit different based on codes," he said, according to a transcript. "But other than that, it's welding pipe and operating a system. It's some pumps versus compression. We have the technical capabilities in-house."

During the call, officials said that the company had a letter of intent with a major Bakken producer and had started preliminary survey and right-of-way work for a potential crude gathering system costing \$100 to \$200 million.

The gathering system announced this week is in connection with the company's Bakken plan discussed on the call, Dixon said February 22, but would not name the Bakken producer involved in the deal.

"We have been pursuing a number of growth opportunities outside our geographical footprint in liquids-rich areas," Dixon said February 20. The new system will allow the company to "diversify our product gathering capability and pursue significant growth opportunities in this liquids-rich basin," she said.

The new gathering system would receive Bakken crudes from Dunn and McKenzie counties in North Dakota and ship them to Great Northern Gathering and Marketing's Watford terminal located in McKenzie County.

Wells Fargo Securities analysts said in a recent note that they view CenterPoint's move into crude gathering favorably. However: "It is unclear at this point whether the open season will generate enough interest to justify the investment."

The analysts pointed to previous CenterPoint open seasons that did not come to fruition, including a proposed gas gathering system in the Mississippian Lime area of north central Oklahoma and south central Kansas.

"If you take [the Bakken gathering project] from the point of view [that this] is what is hot in our business, and that [CenterPoint] are following the trend, then yes, [the project] makes perfect sense to me," Beckman said.

If one considers the fact that the crude project is unfamiliar territory for a utility "then it is very creative," he said.—*Bridget Hunsucker*

## Imperial executive change raises Kearl questions

Calgary—Imperial Oil's announcement of a new president and CEO has raised eyebrows in industry circles, with some observers linking it to a C\$2 billion (\$2.1 billion) cost escalation of the company's Kearl oil sands project in Alberta, now at the final stages of startup.

Late on February 21, Canada's Imperial, which is 70% owned by ExxonMobil, said Rick Kruger would take over as the company's new chief from March 1, replacing incumbent Bruce March. Kruger is currently president of ExxonMobil Production Co. in the US.

Imperial, in its announcement, did not give any reasons for the change in its top guard, although a company spokesman on February 22 termed March's appointment as part of Imperial and ExxonMobil's "executive succession" planning, explaining it had been planned for some time.

March has been appointed senior vice-president of global operations with ExxonMobil Chemical in the US.

But some analysts questioned the timing of the Imperial moves.

"March was appointed in January 2008 and we wonder whether his departure in related to cost overruns at Kearl," said Michael Dunn, vice-president of institutional research with First Energy Capital, said in a phone interview.

Another Calgary-based analyst, who did not wish to be identified, said the Kearl project has faced several challenges, including court cases and litigation in Idaho and Montana over the transportation of oversized modules.

"There has not only been a delay in starting up the facility, but the company also revised total project cost to C\$12.9 billion up from C\$10.9 billion that was announced earlier," Dunn said. "Surely, ExxonMobil feels there are better ways in which the project

could have been managed."

Imperial spokesman Pius Rolheiser said the timing of the appointment was "opportune to take advantage of Kruger's extensive production operating experience, as Kearl moves into the production phase in the coming weeks."

He said that Imperial also has in the near term the start-up of the Nabiye expansion at Cold Lake in 2014 and the Kearl expansion phase in 2015, all of which will benefit from Kruger's global production operations experience.

### Kearl start-up

Imperial is making "good progress" on the first phase of construction at Kearl and continues to anticipate producing first oil later this quarter.

"Exactly when that will be, will depend on our progress in the coming weeks. Kearl has been in the works for years and will operate for decades, so our care and attention to executing critical start-up processes safely and flawlessly is more important than which calendar day we see first oil production," he said.

The Kearl open-pit bitumen mining facility is 45 miles north of Fort McMurray and is being developed in stages. The initial development will have a capacity of 110,000 b/d and will eventually be increased to 345,000 b/d through an expansion and debottlenecking. The project will be Imperial's first 100% oil sands facility in Alberta.

The company is also moving ahead with three other oil sands facilities in Alberta.

The first is Nabiye in the Cold Lake area, for which Imperial approved C\$2 billion last February. Imperial also is evaluating a potential oil sands development in Fort McMurray called Aspen, about 22 miles south of Kearl.—*Ashok Dutta*



# Japan gets chance to press US for LNG

## As Prime Minister Abe meets Obama at White House

Washington—Japanese Prime Minister Shinzo Abe went to the White House on February 22 to discuss energy and other issues with President Barack Obama, giving Abe a golden opportunity to press Obama for assurances that the US will export much-needed LNG to his energy-starved country.

The closed-door meeting at the White House came amidst Japan's most significant shift in energy policy in decades, as the country needs LNG and other commodities to make up for the nuclear power that it took offline after the tsunami-triggered nuclear disaster it suffered two years ago.

Neither Abe nor Obama mentioned the issue of LNG exports during a post-meeting

session with reporters, although Abe has previously urged the US to approve exports of LNG to his country.

Japan, which has limited domestic oil and gas resources and a long-standing dispute over territorial claims to oil and gas deposits in the East China Sea with China, was largely dependent on energy imports even before the 2011 partial meltdown at the Fukushima Dai-ichi nuclear power plant.

According to the US Energy Information Administration, Japan in 2011 was the third-largest net importer of oil in the world, at 4.3 million barrels per day, behind only the US and China. Nearly 90% of Japan's oil imports come from the Middle East, with 1.1 million

b/d coming from Saudi Arabia.

Japan is also the second largest importer of coal in the world, and the largest importer of LNG. The accident at Fukushima, and the effective shutdown of the country's previously prosperous nuclear industry, forced the country to boost LNG imports 11% in 2011 to 3.8 Tcf. From April 2011 through February 2012, LNG imports jumped by 18%, according to IHS, a Colorado-based energy consulting firm.

While most of the country's LNG imports come from regional suppliers in Southeast Asia, the country has attempted to diversify the mix of suppliers. In 2011, Malaysia (19%), Australia (18%) and Qatar (15%) made up Japan's biggest LNG suppliers.

But faced with near-record energy prices, Japan is looking to diversify this import mix further, including talks with Russia for a proposed pipeline or additional LNG shipments and, long range, imports from Canada and the US.

Following a trip to Japan last month, Alaska Senator Lisa Murkowski, the top Republican on the Energy and Natural Resources Committee, said Japanese officials repeatedly pressed her for assurances that the US would soon begin exporting LNG to Japan.

"It's one thing to come calling and offering up a resource; it's another to be able to deliver it," Murkowski said of a specific request for assurance from Japan's deputy prime minister, Taro Aso. "We're not able to make that commitment now."

Under current law, the Energy Department is required to quickly approve applications to export LNG to countries that have free-trade agreements with the US. But the DOE can prevent or restrict proposed exports to non-FTA nations, such as Japan, if they are deemed to not be in the US' interest.

Murkowski, who toured the damage from Fukushima while in Japan and planned to meet with Abe during his Washington visit, said Japanese lawmakers are "scrambling" to find enough energy to meet the nation's needs, not just from LNG, but from coal and fuel oil as well.

Murkowski's visit followed a mid-December electoral victory for the Liberal Democratic Party, which shifted power in Japan's influential Lower House back to the party which had helped build up Japan's nuclear industry over the past 50 years.

The immediate result of that election and Abe's return to the prime minister office he held from September 2006 to September 2007 is a move away from the energy policy proposal by previous Prime Minister Yoshihiko Noda and the formerly ruling Democratic Party of Japan to phase out all nuclear power over the next 20 years.

That energy plan called to increase the share of renewable energy in electricity supply to 20% by 2020, likely spurred by a massive government investment in solar and wind projects.— *Brian Scheid*

## Judge sends RINs fraudster to jail for 12 years

Washington—The Maryland man who tried to pass off an empty warehouse as a biodiesel plant and sold oil companies \$9.1 million in bogus renewable fuel credits will spend more than 12 years in jail for the fraud, a US judge ruled February 22.

Rodney Hailey, 34, sold more than 35 million renewable identification numbers (RINs) through the company Clean Green Fuel between March 2009 and December 2010 without making any of the 23 million gallons of biodiesel the credits represented, according to evidence presented by the Department of Justice at his trial in June.

A jury convicted him on eight counts of wire fraud, 32 counts of money laundering and two counts of violating the Clean Air Act.

US District Judge William Quarles Jr. in Baltimore sentenced Hailey to 151 months in prison followed by three years of supervised release. He ordered him to pay \$42.2 million in restitution to more than 20 companies and forfeit all of the cars, jewelry and houses he bought with the \$9.1 million proceeds.

"Any government program that is based on trust is vulnerable to a fraudster like Rodney Hailey," US Attorney Rod Rosenstein, top prosecutor for the US District Court for the District of Maryland, said in a statement. "The only thing Rodney Hailey's 'Clean Green Fuel' business produced was the dirty money he used to fund his lavish lifestyle."

The 42 criminal counts carried a maximum jail sentence of 484 years under federal sentencing guidelines.

Hailey, who relied on a public defender during the trial, does not likely have the ability to pay the restitution.

The investigation was the first of three fraud cases to roil US markets for biodiesel and RINs. The fallout crippled many legitimate biodiesel producers last year, as oil companies that buy RINs—to prove compliance with the federal renewable fuel mandate—largely stopped deal-

ing with all but the biggest fuel producers.

National Biodiesel Board spokesman Ben Evans said the hefty sentence sends a message.

"Mr. Hailey's fraud cost honest biodiesel producers and refiners millions of dollars and threatened the livelihood of dozens of small biodiesel companies across the country," Evans said.

In late January, EPA proposed a regulatory fix aimed at getting the RINs market moving again. It would create two new categories of credits that shield refiners from liability from faulty RINs if they participate in third-party auditing programs.

David McLeod, special agency in charge of EPA's criminal enforcement program in Maryland, said Hailey's prison term "demonstrates that those who blatantly thumb their nose at the law in order to make money illegally will be prosecuted."

Thomas Kelly, an Internal Revenue Service special agent, said it also shows the government will follow the money trail to root out fraud.

Hailey collected \$6.5 million from broker OceanConnect, which filed for bankruptcy protection this month; \$1.7 million from ConocoPhillips; \$688,000 from biofuel maker Green Diesel; \$159,000 from broker International Exchange Services; and \$35,000 from broker Mudskipper Investments, according to prosecutors.

He used the RINs profits to buy houses, private jet flights to Disney World with his family and employees, jewelry and dozens of luxury cars, according to the Department of Justice.

The Environmental Protection Agency last year declared invalid another 48 million RINs sold by Absolute Fuels of Lubbock, Texas, and 60 million RINs sold by Green Diesel of Houston.

Absolute Fuels owner Jeffrey Gunselman pleaded guilty in December to a \$42 million scheme. No charges have been filed against Green Diesel or CEO Phil Rivkin.— *Meghan Gordon*



## Canada pipeline firm eyes bitumen, diluents move

Calgary—Canada's Inter Pipeline Fund is positioning itself to transport 3.1 million b/d of diluents and diluted bitumen in Alberta to keep pace with the fast-growing oil sands output in the province.

"We see lots of producer activity over the next few years and remain on track to invest C\$1.4 billion [\$1.41 billion] in 2013 to expand throughput of our existing pipelines," CFO Bill Van Yzerloo said during a Q4 results call.

In fourth-quarter 2012, the oil sands sector generated revenues of C\$84.1 million, or 26% of the total C\$318.4 million for the company, he said.

IPF is the operator of three oil sands pipeline systems in Alberta: Polaris, Cold Lake and Corridor. Those lines moved 838,200 b/d of oil sands in Q4 2012, compared with 769,400 b/d in the same period last year, he said.

Last month, the company said work was underway to increase capacity of Polaris by 120,000 b/d to 820,000 b/d and of the Cold Lake pipeline by 115,000 b/d to 650,000 b/d. The expansion includes the construction of 840 km (538 miles) of pipelines, seven mainline pump stations and installing two quarter-point stations along with existing station upgrades.

### New facilities

The Cold Lake facility is due to be completed by mid-2013, while Polaris is due to be commissioned in stages starting from mid-2014 and ending in 2017, Van Yzerloo said.

IPF may further increase the capacity of Polaris and Cold Lake to 1.2 million b/d and 1.9 million b/d, respectively, he said, adding that the capital cost of the planned expansion is yet to be worked out.

"We are not talking of billions, rather they would be millions of dollars. But before that we would need to sign definitive transportation agreement with more oil sands producers," he noted.

IPF, which already has major producers like Imperial Oil, Husky Energy, Shell Canada, Cenovus Energy and ConocoPhillips as its customers, announced last December a five-year deal with Suncor Energy to transport 10,000 b/d of diluents.

The company is now aiming to sign another deal with a joint venture of ConocoPhillips and Cenovus for increased oil sands production from their Foster Creek and Christina Lake facilities.

"We were due to sign this deal by end-2012 and it has taken us a longer time. But there are multi-decade arrangements and the talks can be complex," Van Yzerloo said, adding IPF hopes to sign the deal by late March.— *Ashok Dutta*

## Petrodollars

China's heightened pollution problems this year have put state refiners in the spotlight and again highlighted the need for energy pricing reforms.

Following serious problems in January, when both national and other privately-tracked data showed air pollution at record levels in much of the northeast, the government faced severe public criticism and is now pushing for cleaner fuels to be adopted with renewed urgency.

The State Council, or Cabinet, said early this month it wanted to speed up the implementation of cleaner fuel specifications for transport diesel and gasoline, setting a transition deadline for National Phase V fuels for 2017.

This would cap sulfur levels to 10 parts per million, tightening from Phase IV standards of 50 ppm currently being introduced. The deadline for transition to Phase IV gasoline is early next year, while that for Phase IV diesel is the end of 2014.

China had previously set deadlines for the introduction of Phase IV specifications by 2011, and then 2012, but these were not mandatory and were delayed due to various problems, including fears of insufficient supply of low-sulfur fuel and protests by refiners about additional costs.

"The government has not brought forward the Phase IV deadlines but wants the refiners to stick to the existing timetable," said Kang Wu, an expert on China's energy sector at FACTS Global Energy.

With the latest pollution problems, the pressure now is on everyone to improve the situation—state refiners and various government divisions, including the environment ministry and the National Development and Reform Commission responsible for energy pricing reforms, Kang said.

Analysts say Sinopec and PetroChina had already been upgrading their refineries in the last few years to cope with the new demands, and the additional investment is not likely to be significant compared with their overall capital budgets. JP Morgan expects 770,000 b/d of new crude distillation capacity this year, 6.5% more incremental capacity added compared with last year.

But the new cleaner fuel requirements raise further concerns about refining profitability and the country's existing system of cost controls on retail oil product prices, which has caused refiners billions in lost refining margins.

"The main issue here would be the cost. Who will bear the additional cost of [the cleaner] fuels?" said Liu Gu, analyst at Guotai Junan Securities in Shenzhen.

Price controls at the pump would prevent Sinopec from passing on the costs fully to end-users, Moody's said, and suggested that the government could subsidize some of the cost.

"Sinopec's financial burden reflects its social responsibility role, which is one of the most important considerations supporting its strategic importance to the Chinese government. As air pollution becomes a severe social problem for the government, it may receive fiscal support from the state."

But while Beijing has not explicitly stated if the consumer or producer will shoulder the financial burden, Premier Wen Jiabao said in a recent work report that some environmental costs have to be borne by society.

"This suggests that the government's thinking is to increase prices and make energy sources valuable and more expensive for consumers," said Liu.

Plans have been afoot to reform the current pricing mechanism but were stymied by inflation concerns in 2011 and the ongoing leadership transition last year.

Reforms are widely believed to be announced this year but more details will only likely be revealed following the annual meeting of the National People's Congress next month, when wide-ranging policy issues are debated by the legislature.

"While previously the concern was with [the impact of higher fuel prices on] economic growth and stability, the pollution situation will likely spur the NDRC to accelerate pricing reforms," said Kang.

He added that refiners likely want to see price differentials being set for various fuel standards to reflect the production costs.

The immediate concern for refiners is to remain profitable. The last retail price adjustment—a roughly 3.5% cut—to gasoline and gasoil prices was in November last year and since then global crude prices have risen by more than 4%, which is the threshold that would technically trigger a price review by the National Development and Reform Commission.

Under the current mechanism, the NDRC can adjust prices of gasoline, gasoil and kerosene if the 22-day rolling average of a basket of Cinto, Dubai and Brent benchmark crude prices rise or fall by more than 4% from the previous price adjustment.

More timely price changes, along with less volatile crude prices last year, improved both PetroChina and Sinopec's refining bottom lines.— *Yen Ling Song in Singapore*



## Tanker sector pain slams top Nordic firms

...from page 1

scrapped to bring the market back into balance. That's a lot out of a total fleet of 600 VLCCs," he said.

"And we are expecting 35 more newbuild VLCCs coming onstream in 2013, so it is not building a picture for recovery."

### Supply overhang

Frontline has indicated before that existing players have not shown enough commitment to reducing the global tanker supply overhang, which is depressing tanker rates.

"If the market does not recover it is highly likely that we will see more companies facing financial difficulties. It could be a struggle for survival. They have been through this poor tanker cycle for four to five years," said BIMCO's Sand.

An analyst who did not want to be named says the biggest players are unlikely to sink beneath the waves.

"It is unlikely those two companies will close [Frontline and Maersk]. But unless companies are backed by bigger groups, then the standalone companies could have difficulties surviving," he said.

In the meantime, even those who have major backers behind them are still feeling the heat.

Maersk Tankers posted a loss for 2012 of \$312 million, which was more than double the loss of \$153 million for the previous year on stable revenue of \$1.256 billion against \$1.299 billion previously.

Oslo-listed Frontline posted a net loss for 2012 of \$82.8 million compared with a net loss the previous year of \$529.6 million. The Q4 net loss was \$16.6 million against the previous year's loss of \$343.7 million, as the group continued to post impairment charges connected with the termination of long term charter contracts.

Reflecting on the numbers, Maersk Tankers said the current global overcapacity of tankers, which was depressing tanker rates to loss-making levels, would extend throughout the current year.

"Significant VLCC tonnage will be added to the market in 2013 with demand growth expected to be unchanged," Maersk Tankers said.

"General overcapacity and weak demand growth affected the product tanker segments negatively in 2012. Expectations for 2013 remain unchanged with a relatively flat demand/supply development."

Maersk Tankers said that vessel oversupply of the global fleet and slower demand growth continue to drive the unfavorable market balances in most segments.

During the year, the sagging market conditions led Maersk Tankers to adjust the medium-term outlook, resulting in \$268 million impairment loss on VLCCs, product handy-tank-

ers and the small product tanker segment.

"Significant uncertainty regarding valuation of vessels remains," the company said.

"In the gas segment, earnings are expected to come under pressure from increasing vessel supply in 2013."

Maersk Tankers said it had entered into an agreement to divest the Handygas segment and the transaction would take place some time in 2013.

### Continued pain

Maersk said that in addition to the other cost saving initiatives it had introduced, including significantly reducing its time charter fleet by 25 vessels, it had also decided to lay up two VLCC vessels.

But BIMCO's Peter Sands says companies folding or selling tankers may not tip the balance for the industry into recovery.

"Just the outright closure of companies is not enough. We need those vessels broken up," he said.

Meanwhile, Frontline for its part predicted extended pain ahead during the current year for the oversupplied global tanker industry.

"The tanker market has shown a strong negative development in the last four years. Currently crude tankers are going through one of the worst winters ever with VLCC rates close to zero, limited number of fixtures and very high availability of VLCC tonnage," Frontline said.

The company said that several tanker companies were already experiencing severe problems and if the weak market continued it was likely to lead to "significant financial problems" for the whole tanker industry.

"Consensus is that the tanker market will not experience sustained recovery until overcapacity is removed," Frontline added.

The group, which is part of the wider financial empire of the Norwegian shipping billionaire John Fredriksen who previously restructured the company because of financial difficulties, said Friday that it faced further stormy conditions of its own.

"If the tanker market does not recover before 2015 and no additional equity can be raised or assets sold there is a risk that Frontline will not have sufficient cash to repay the existing \$225 million convertible bond loan at maturity in April 2015," the company said.

"Such a situation might force a restructuring of the company, including modifications of charter lease obligations and debt agreements," it added.

Nordic owners were not the only sufferers; Bermuda-based Teekay Tankers reported a net loss in the fourth quarter of \$356.6 million, including a vessel sale impairment charge, compared with a loss of \$6.9 million in the same quarter of 2011. The company cited the continuing weak tanker market, delays to the expected tanker market recovery and a further decline in vessel market values during the course of the year.— Patrick McLoughlin

## South Korea's January Iranian crude imports fall 16%

Singapore—South Korea imported 5.896 million barrels or an average 190,190 b/d of Iranian crude in January, a 16.1% decrease year on year, according to data released by state-run Korean National Oil Corp.

January volumes were however up 3% from December 2012, the data showed February 22.

The Ministry of Knowledge Economy, which is responsible for energy, industry and com-

merce, said the country plans to keep crude import volumes from Iran low in 2013 to get continued exemption from US sanctions.

South Korea won a 180 day exemption from US financial sanctions in June last year after it pledged to reduce oil imports from Iran. In December, the US extended the waiver for another six months.

South Korea did not import Iranian crude for almost three months to September due to a European Union ban on the provision of EU-linked insurance cover for any vessels carrying oil from Iran. The sole buyers of Iranian crude, refiners SK Innovation and Hyundai Oilbank, were able to resume imports from Iran from October as the National Iranian Oil Company had offered to deliver oil on Iranian tankers and provide insurance cover for the shipments.

South Korea's total crude imports in January were 81.71 million barrels (2.64 million b/d), up 2.8% year on year. Saudi Arabian volumes were largely flat at 25.09 million barrels, versus 25.14 million barrels a year ago, although Kuwaiti volumes fell 6.8% year on year to 10.32 million barrels.— Song Yen Ling

### South Korea's top crude suppliers

('000 b/d)	Jan-13	Jan-12	% chg
Saudi Arabia	809	811	-0.2
Kuwait	333	357	-6.7
UAE	249	364	-31.6
Qatar	216	275	-21.5
Iran	190	227	-16.3
Indonesia	71	27	163.0
Brunei	37	9	311.1
Oman	13	12	8.3
Others	718	481	49.3
Total	2,636	2,563	2.8

Source: Korea National Oil Corp.



## Oil markets stabilize following mid-week selloff

London—NYMEX April crude settled 29 cents higher at \$93.13/barrel February 22 after a largely rangebound trading session, bouncing back slightly after a two-day selloff.

“We’re pretty unchanged with the market attempting to stabilize after the past couple days of blood-letting,” Tradition Energy commodities analyst Gene McGillian said, referring to the selloff that saw April NYMEX shed more than 4% of its value at midweek.

Data released February 22 by the US

Commodity Futures Trading Commission showed money managers decreased their net length in NYMEX crude futures by 28,029 lots to 181,536 contracts for the reporting period ended February 12.

Crude futures dove nearly \$4/b in the subsequent trading sessions following the reduction in length on a mix of poor economic readings in both the US and Europe, profit-taking, and waning sentiment that the US Federal Reserve will maintain its open-ended asset purchasing purchasing, or quantitative easing, indefinitely.

ICE Brent also settled stronger, boosted during overnight trading by favorable consumer and business confidence data out of Germany, analysts said, even as data from German statistics agency Destatis confirmed Q4’s surprise 0.6% contraction in GDP.

ICE April Brent settled 57 cents higher at \$114.10/b.

“With the equity markets focused more on German business confidence than downward revisions to euro zone economic forecasts, the petroleum markets are seeing at least a limited bounce after the Wednesday-Thursday drop,” Citi Futures Perspective analyst Tim Evans said in a note.

Equities markets turned broadly positive overnight with European markets posting the heaviest gains after sharp declines posted earlier in the week. US equities also gained February 22.

The NYMEX RBOB contract continued to find support following an unexpectedly large draw in US gasoline inventories, analysts said, with markets growing increasingly conscious of supply constraints heading in to the peak-demand summer season.

NYMEX March RBOB settled 4.31 cents higher at \$3.0796/gal, while the April contract settled up 3.18 cents at \$3.2658/gal.

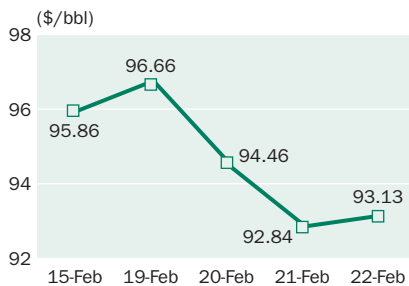
“RBOB prices over the past two months have climbed nearly 50 cents on concerns that high levels of refinery maintenance will curtail supplies,” McGillian said. “On top of that, with the closure of Hess’ [70,000 b/d Port Reading, New Jersey] refinery, supplies could be limited as demand picks up.”

McGillian added that demand for the road fuel has yet to show evidence of increasing significantly.

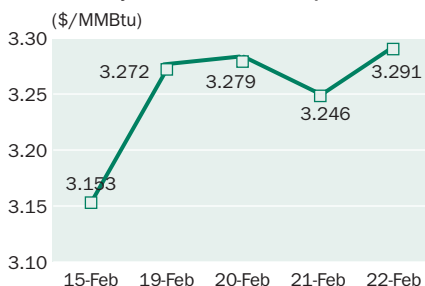
Gains in distillates were less pronounced February 22. NYMEX March heating oil settled up 85 points at \$3.1042/gal, while ICE March gasoil was unchanged at \$981.50/mt— Paula VanLaningham, with James Bambino in New York

### What crude & natural gas markets are doing...

NYMEX crude settle, first month  
February 22 settle: \$93.13 up \$0.29



NYMEX natural gas settle, first month  
February 22 settle: \$3.291 up \$0.045



## US rig count falls by 1

Houston—The US rig count was 1,761 for the week ended February 22, down by 1 from the prior week, according to Baker Hughes.

The latest count includes 1,708 land and 53 offshore, with 428 assigned to gas, 1,329 to oil and 4 to miscellaneous drilling. The rigs were drilling 424 vertical, 197 directional and 1,140 horizontal wells.

Here are Baker Hughes’ latest figures for the total number of active rigs in the US (with selected states) and Canada, plus comparable figures for a week ago and a year ago:

	2/22/13	2/15/13	2/24/12
US	1,761	1,762	1,981
Alaska	9	8	9
California	34	34	43
Colorado	57	56	69
Kansas	26	25	36
Louisiana	109	110	139
New Mexico	75	76	81
North Dakota	173	177	187
Oklahoma	185	194	198
Texas	843	838	920
Wyoming	45	47	45
Canada	662	651	701

# platts Oilgram News

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