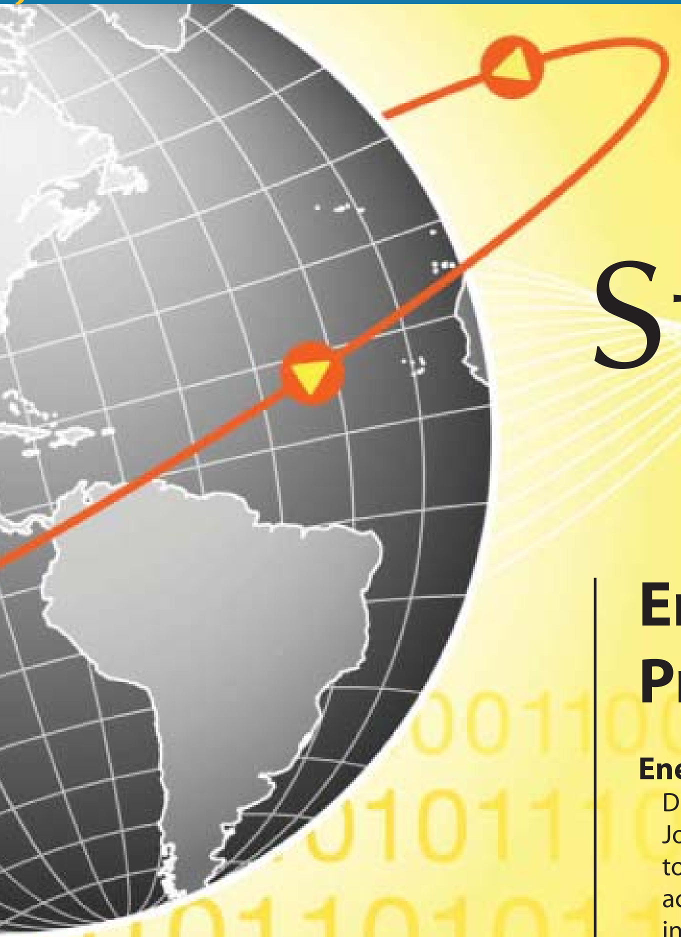

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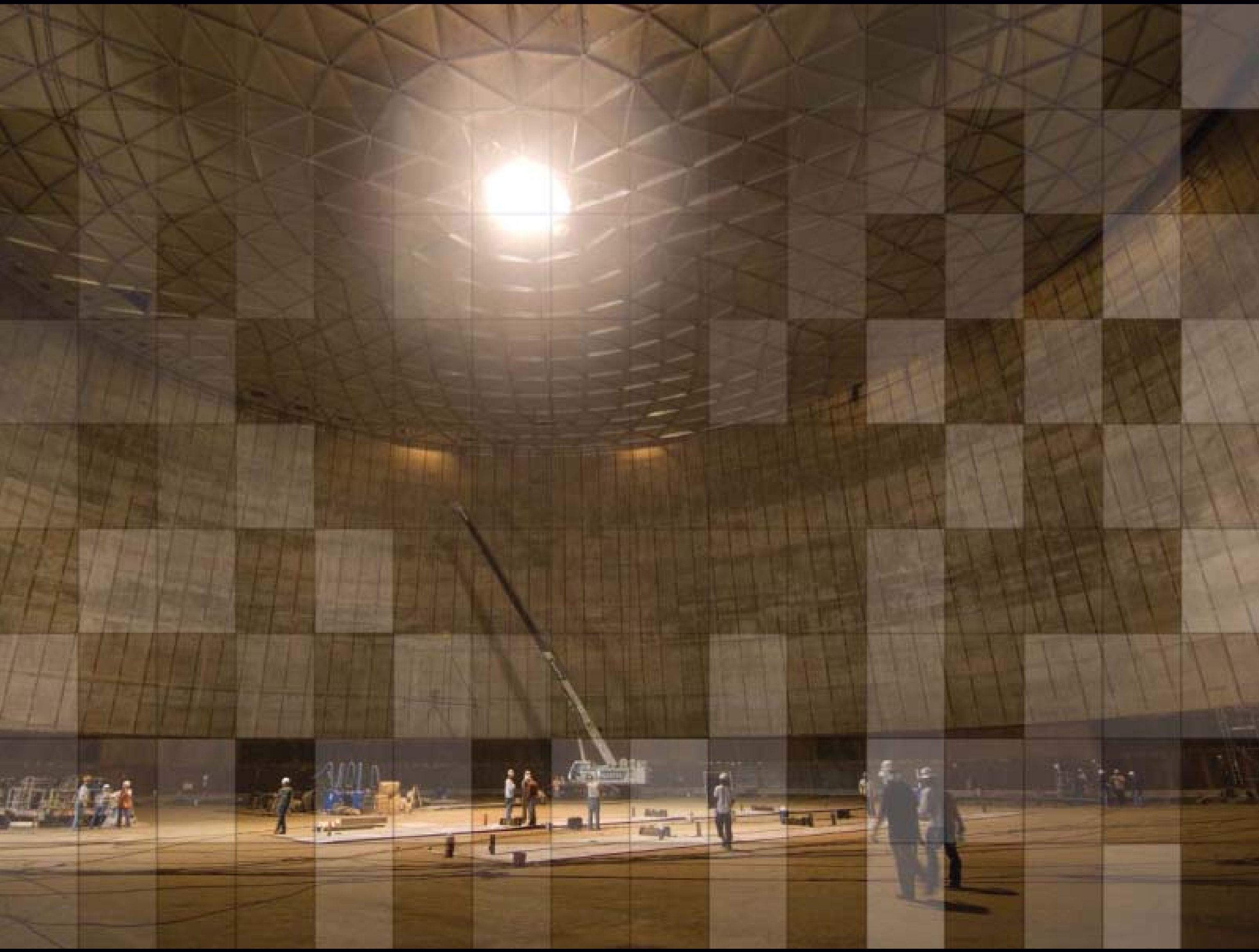

LNG Update

Mexico's oil decline rate to steepen through 2010
North Amethyst, first White Rose satellite to be developed
Pure rolling of bit cones doubles performance

Process Notes

Oil Sands Crude – Profits and Problems?

Canadian bitumen production currently runs about 1 MMbpd, with some being sold as Synbit and Dilbit. Over the next 10-12 years output is expected to increase to 3.5 MMbpd and more refiners will begin investing to process it and come to depend on the Synbit and Dilbit for a significant part of their supply. Few today, however, have ever processed these feeds at high blend ratios, and are unaware that conventional process and equipment designs are not up to the job. Canadian oil sands feedstocks are extremely hard to desalt, difficult to vaporize, thermally unstable, corrosive, and produce high di-olefin product from the coker. If you intend to lock into a long-term supply, therefore, it is imperative that you consider reliability and run length from a particular design.

Too low tube velocity in the vacuum heater tubes will lead to precipitation of asphaltenes. Too fast a flow rate will erode the tube bends. If coil layout, burner configuration and steam rate are not correct, run length will be measured in months, not years. Diluent recovery unit designs must take into account possible upsets from water slugs and other unpredictable situations that have damaged internals, resulting in diluent losses and high vacuum unit overhead condensable oil. Diluent is neither cheap nor plentiful, and high vacuum column operating pressure will reduce overall liquid volume yields. And if the design of the delayed coker fractionator is based on today's experience with conventional heavy feedstocks you will be lucky to run six months.

What all this means is that special process and equipment designs are needed to satisfy the special demands of processing oil sands crudes. Such processes are not generated by computer based designers who have little or no experience and never leave the office. They are developed only by engineers with know-how who have real experience wearing Nomex® suits and measuring true unit performance in Northern Alberta. Shouldn't this be kept in mind by those considering long term supply agreements?

For a discussion of factors involved in designing refinery units to process difficult oil sands feedstocks, ask for Technical Papers #234 and 238.

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OIL&GAS JOURNAL

Feb. 25, 2008
Volume 106.8

LNG Update

Regular Features

Cover

Work progresses in late 2006 inside one of two 160,000-cu-meter full containment LNG tanks for Freeport LNG near Freeport, Tex., on the US Gulf Coast. This view shows the steel vapor barrier lining the interior of the concrete outer tank before installation of the 9% nickel inner tank. The terminal, able at peak capacity to send out 1.75 bcfd of natural gas, is one of four likely to start up in 2008 on the Gulf of Mexico. This annual special report on LNG begins (p. 20) with a look at recent trends in funding for LNG projects A second article (p. 49) sets out a near-term outlook for the global industry. The final article (p. 57) looks at future Asian LNG markets. Photograph from Freeport LNG; photo by John Smallwood, Houston.

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General Interest — Quick Takes

WoodMac: Operators still vexed by high costs

High oil prices have not resulted in high returns on projects because of an increase in exploration costs and the taxes earned by host governments, according to energy consultancy Wood Mackenzie Ltd., Edinburgh.

Operators now need to assume an oil price of $70/bbl to earn close to 15% on exploration, delegates at International Petroleum Week in London were told. Alan Murray, WoodMac exploration service manager, said, "Cost increases mean that pretax margins on new fields have not increased with oil prices."

Many host governments such as the UK, Algeria, and Bolivia changed their fiscal regime as oil prices soared, leaving fiscal certainty a major issue for companies. This is having the greatest impact on exploration economics, Murray said. Other governments such as India, Malaysia, and Angola have tried to capture the upside in their progressive production-sharing contracts, which allow them to benefit if oil prices increased.

Companies are using different methods to build on their assets—either through exploration programs, mergers and acquisitions, or participating in developing major resource opportunities such as Russia's Shtokman gas field in the Barents Sea.

But dry holes remain a major risk with exploration, and high development costs are key problems in a volatile market. Pursuing M&A deals also is costly, with the risk high of overpaying for assets in a high-priced environment.

"Exploration is the better option as a resource capture strategy because this has better returns and allows more flexibility compared with other strategies," Murray said.

IP Week: Technology to aid in skills shortage

Technology will aid in improving the productivity of skilled labor as the petroleum industry struggles to attract and retain new recruits, IP Week delegates were told in London.

Antoine Rosand, a senior executive with Schlumberger Business Consulting, said remote, real-time drilling centers with features such as model-based surveillance and integrated well planning would enable companies to boost production and handle risk better.

Encouraging new entrants to pursue petroleum careers would be tougher in the West, compared with Africa and Asia, where the energy industry has a more acceptable public image and people compete for jobs in the industry. India and China in particular are producing thousands of graduates for the petroleum sector. "Most universities are still based in the West, but they need people who attend them to become technical leaders and innovators to bring in students from local areas," Rosand added.

Although the exploration and production industry has sharply increased its recruitment of geologists, geophysicists, and petroleum engineers, global graduate supply is barely meeting the industry's needs, Rosand said. For 2006-10, the net supply of geologists and geophysicists entering the E&P industry is expected to be 60% and for petroleum engineers, 80%.

UK subsea sector rises to £4.3 billion in value

The UK subsea oil and gas sector has grown by almost 30% in value to £4.3 billion in 2007, according to industry association Subsea UK.

"The year-on-year growth rate...exceeds market expectations, with further increases expected for 2007-08," Subsea UK said.

Exports, an important element for companies involved in the subsea sector, constitute 50% of revenues and are expected to grow dramatically compared with the domestic market. Exports have risen by 26%, increasing at a rate similar to market growth.

But the UK risks losing its global leadership position because companies are finding it challenging to find qualified engineers and rapidly deliver new technology to the market, Subsea UK said.

Industry collaboration with the support of government and academia is vital to developing skilled people and an effective technology program, Subsea UK noted.

CERA: Collaboration key for energy industry

Company collaboration will be essential to address the energy industry's changing dynamics as competition increases for resources and as fiscal terms become more stringent, said StatoilHydro AS Chief Executive Helge Lund.

Speaking at CERA Week in Houston Feb. 13, Lund stressed that exploration has become more difficult because of harsher environments, heavier oils, and tougher projects. "Politically, resource nationalism is an emerging reality," Lund said.

The merger of Statoil and Hydro has given the company the clout to face the challenges with confidence. Although companies have prospered from high commodity prices, there is now limited access to exploration and production opportunities, which has intensified competition for them.

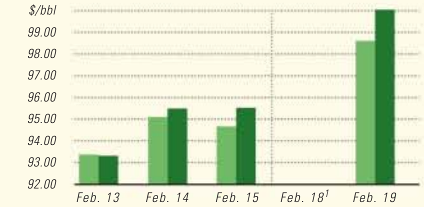
"I think we are all now faced with a new game: How to accommodate interests and expectations in a world that has prospered even [with oil at] $50-100/bbl," Lund said.

He argued that the industry is now in a phase of realignment and rebalancing of business models where companies must align interests to create genuine successful partnerships.

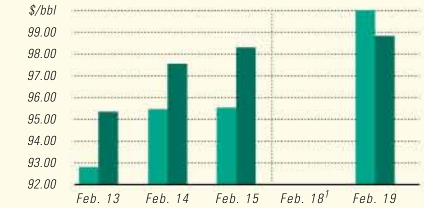
But any downturn in the US economy is likely to affect economies in other countries and their demand for oil. "The uncertainty is bigger than it has been in the past," Lund said. ✦

Industry Scoreboard

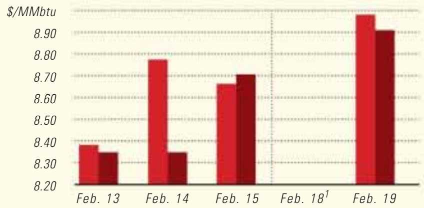
IPE BRENT / NYMEX LIGHT SWEET CRUDE



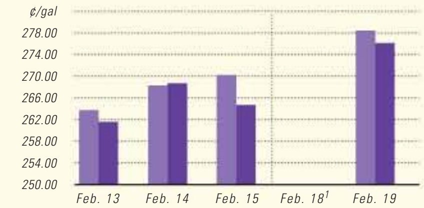
WTI CUSHING / BRENT SPOT



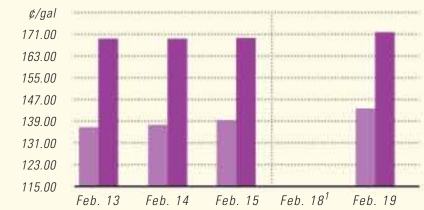
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



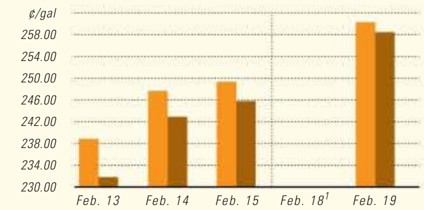
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE (RBOB)[2] / NY SPOT GASOLINE[3]



[1]Not available. [2]Reformulated gasoline blendstock for oxygen blending. [3]Nonoxygenated regular unleaded.

US INDUSTRY SCOREBOARD — 2/25

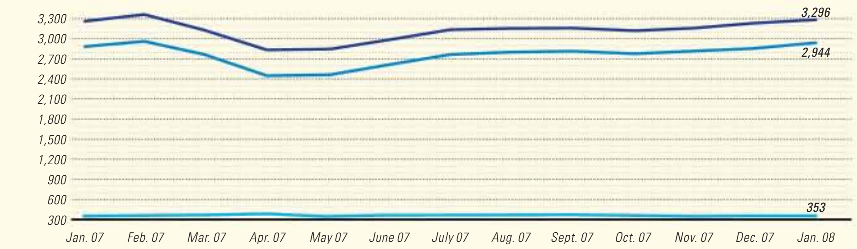
Latest week 2/8	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	8,960	8,925	0.4	9,043	8,958	1.0
Distillate	4,230	4,351	–2.8	4,226	4,434	–4.7
Jet fuel	1,538	1,621	–5.1	1,546	1,626	–4.9
Residual	720	801	–10.1	732	848	–13.7
Other products	5,088	5,039	1.0	5,103	5,049	1.1
TOTAL DEMAND	20,536	20,737	–1.0	20,650	20,915	–1.3
Supply, 1,000 b/d						
Crude production	5,024	5,184	–3.1	5,027	5,172	–2.8
NGL production[2]	2,561	2,242	14.2	2,432	2,235	8.8
Crude imports	10,116	9,906	2.1	10,110	9,650	4.8
Product imports	3,628	3,353	8.2	3,460	3,283	5.4
Other supply[3]	922	987	–6.6	1,059	1,046	1.2
TOTAL SUPPLY	22,251	21,672	2.7	22,087	21,386	3.3
Refining, 1,000 b/d						
Crude runs to stills	14,896	13,848	7.6	14,896	14,712	1.3
Input to crude stills	15,091	15,058	0.2	15,091	15,087	—
% utilization	86.5	86.3	—	86.5	86.4	—

Latest week 2/8	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	301,070	300,004	1,066	323,889	–22,819	–7.0
Motor gasoline	229,236	227,487	1,749	225,156	4,080	1.8
Distillate	126,973	127,139	–166	133,327	–6,354	–4.8
Jet fuel-kerosine	41,093	41,166	–73	39,295	1,798	4.6
Residual	36,893	36,459	434	41,279	–4,386	–10.6
Stock cover (days)[4]			Change, %		Change, %	
Crude	20.6	20.3	1.5	21.8	–5.5	
Motor gasoline	25.6	25.3	1.2	24.8	3.2	
Distillate	30.0	30.0	—	29.6	1.4	
Propane	21.7	22.0	–1.4	22.1	–1.8	
Futures prices[5] **2/15**			Change		Change	%
Light sweet crude, $/bbl	94.12	89.09	5.03	59.05	35.07	59.4
Natural gas, $/MMbtu	8.56	8.04	0.52	7.73	0.83	10.7

[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average of daily closing futures prices.

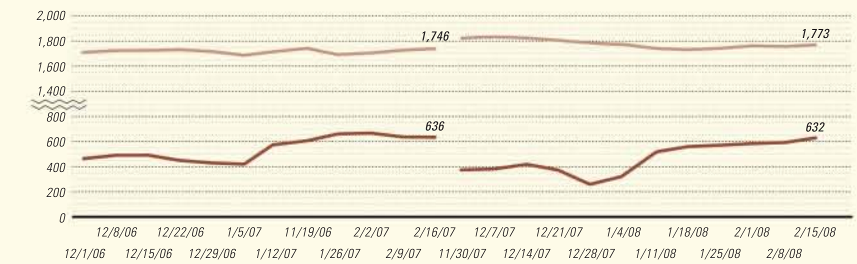
Sources: Energy Information Administration, Wall Street Journal

BAKER HUGHES INTERNATIONAL RIG COUNT: TOTAL WORLD / TOTAL ONSHORE / TOTAL OFFSHORE



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

Exploration & Development — *Quick Takes*

BP sets 2010 target for Libya exploration well

BP PLC plans to drill its first onshore well in Libya's Ghadame basin in 2010, assuming it can secure the necessary rigs, said BP Exploration Pres. Libya Peter Manoogian at International Petroleum Week in London.

BP will invest more than $2 billion in its work program, which will include the drilling of 17 exploratory wells.

Manoogian said he remains "very optimistic" about onshore development, as the company knows the basin well. "We are targeting gas accumulations, and if we find any, then production could start in 2018."

Seismic acquisition will begin in the third quarter. Although the company's strategy in North Africa is gas, if it found oil, that would not be "a bad thing," it said, adding, "We will monetize the oil if it's found, and that is covered in our contract with [Libya's National Oil Co.]"

Last year BP and partner Libya Investment Corp. signed an agreement with NOC to explore 54,000 sq km of the Ghadames and offshore frontier Sirt basins (OGJ Online, June 1, 2007).

If hydrocarbons are found, offshore production could start in 2020, Manoogian added. Sirte is challenging, however, because it is in deep water with seismic imaging issues, and it is 300 km from the nearest well.

With the Ghadames basin holding tight gas, there are complex reservoirs, and BP will utilize advanced drilling and completion technology during its exploration program.

NOC, through an aggressive offshore and frontier exploration program, wants to boost Libya's oil reserves to 20 billion boe under a plan covering 2005-15.

NOC expects to increase production to 3.5 million b/d by 2020 by encouraging the drilling of at least 50 wildcats/year and acquiring at least 4,000 sq km/year of 3D seismic data and 10,000 km/year of 2D seismic data.

Manoogian said: "We think that partnerships between international oil companies and national oil companies are desirable. The transparency in regulation and its proximity to Europe makes Libya an attractive investment."

But fierce competition between IOCs in accessing new hydrocarbon resources led them to reduce their share of benefits in bidding for acreage under Libya's recent gas licensing round, Manoogian said. "We can't say that was imposed by the NOC. IOCs have to take bigger risks because of the competition for resources."

ONGC, Shell ink NELP-VII bids, joint projects

India's Oil & Natural Gas Corp. (ONGC) and Royal Dutch Shell PLC recently revised their joint participation memorandum of understanding for projects to be auctioned in the forthcoming seventh round of India's New Exploration Licensing Policy VII.

The original MOU was aimed at cooperation in field optimization using Shell's proprietary enhanced recovery technology and in other areas such as LNG importation, development of coalbed methane, underground and surface coal gasification projects, refinery upgrades, and trading and development of supply chains.

The exploration and production giants have agreed to evaluate jointly setting up surface coal gasification facilities to create synthesis gas for power generation or other uses.

They also plan to jointly explore opportunities for technology induction in field optimization and integrated brownfield development in mutually agreed assets.

Shell will provide technical knowledge, including operational experience.

Depending on the outcome of a planned prefeasibility study, Shell may commission a detailed feasibility study to evaluate the possibility of taking equity in such projects under a separate licensing agreement.

The energy majors also agreed to study the feasibility of gasifying petcoke produced by ONGC subsidiary Mangalore Refinery & Petrochemicals Ltd. ✦

Drilling & Production — *Quick Takes*

BPZ Energy working to restart oil output off Peru

BPZ Energy Inc. expects to restart production of its 21XD and 14D wells within 3 weeks. The wells in Corvina field off northwestern Peru were shut in following an accident involving a BPZ-chartered tanker.

A Peruvian Navy tanker, the Supe, caught fire and sank on Jan 30, resulting in the death of one sailor and serious injuries to four other sailors (OGJ, Feb. 11, 2008, Newsletter).

The tanker, being used for oil storage, was moored near BPZ's CX-11 platform in Block Z-1. Consequently, platform operations were halted. The 21XD and 14D wells produced 4,200 b/d of oil when they were shut in. The platform and wells had no fire damage.

BPZ hired Clean Caribbean and Americas (CCA) to conduct an environmental damage assessment. CCA concluded most of the 1,300 bbl of oil in the tanker was burned.

Divers inspected the sunken tanker, resting in 200 ft of water. No crude oil or fuel was detected in any tanks. Tests to seawater indicated no contamination to water and marine life.

BPZ of Houston is an exploration and production company having exclusive license contracts for 2.4 million acres in four properties in northwest Peru. It also owns a minority working interest in a producing property in southwest Ecuador.

StatoilHydro leases deepwater drillship

StatoilHydro AS will use the GSF Explorer ultradeepwater drillship to drill three exploration wells on Indonesia's Karama Block off West Sulawesi in late 2009. The company has a 51% stake, and Pertamina holds a 49% share in the block.

StatoilHydro is a member of the Makassar Strait Explorers Consortium, which signed the 2-year contract to lease the rig; together the group will drill 12 exploration wells. Marathon International

Petroleum Indonesia Ltd. is the lead operator for the consortium, and each company is responsible for its own committed wells. However the group is now planning products procurement and services programs.

The first of the three wells in the Karama license is scheduled for second half 2010, StatoilHydro said. Karama is in deep water in Indonesia's Makassar Strait.

The MSEC members are Anadarko Popodi Ltd., ConocoPhilips (Kuma) Ltd., Eni Bukat Ltd., and Talisman (Sageri) Ltd.

Petrobras lets contract for P-57 FPSO unit

Petroleo Brasileiro SA (Petrobras) reported signing a $1.195 billion turnkey contract for the construction of the P-57 floating production, storage, and offloading unit with Single Buoy Moorings Inc. (SBM). The P-57 FPSO will be ready in 3 years and will help Brazil reach its production goal of 3.45 million boe/d by 2015. Current production is about 1.85 million boe/d.

Separately, SBM Offshore NL said the P-57 FPSO would likely be converted in Singapore using one of SBM's very large crude carriers in inventory, the Accord. Topsides will be integrated in Brazil, "in accordance with new local content requirements."

Petrobras said 65% national content is required and the topsides work would be completed at Brasfels, in Angra dos Reis, Rio de Janeiro state.

The P-57 will have the capacity to process 180,000 b/d and compress 2 million cu m/day of gas. It is destined for the Jubarte field off Espirito Santo state, where it will be installed in 4,100 ft of water. The field produces 17° gravity oil, according to Petrobras.

Petrobras also awarded SBM a $63.55 million, 3-year operating contract.

In January 2007 Petrobras canceled orders for the construction of the P-55 platform, which would have had the capacity to produce 180,000 b/d of oil from Roncador field off Rio de Janeiro state, as well as construction of the P-57 FPSO because of excessive cost.

StatoilHydro starts Volve oil and gas production

StatoilHydro has begun oil and gas production from Volve field in the Norwegian North Sea from the large Maersk Inspirer jack up rig, while Navion Saga will be used as a storage vessel for further transport.

Gas will be exported from the Sleipner A platform. The company drilled eight wells to develop reserves of 78.6 million bbl of oil and 1.5 billion cu m of gas. An additional five wells are planned.

Volve production, which will continue for 4-5 years, is expected to plateau at 50,000 b/d by the end of first quarter 2009.

Volve is 200 km west of Stavanger in the southern section of the Norwegian continental shelf. StatoilHydro has a 59.6% interest in the field and has partnered with ExxonMobil Corp. 30.4% and PA Resources 10%. ✦

Processing — *Quick Takes*

Alon USA updates Big Spring refinery after fire

Independent Dallas refiner and marketer Alon USA Energy Inc. reported last week that all but one of the four workers injured in the early morning Feb. 18 explosion and fire at its 70,000 b/d Big Spring, Tex., refinery have been released from the hospital.

"The cause of the explosion, which occurred in the area around the propylene splitter unit, has not yet been determined," Alon USA said. "However, the fire has been extinguished, allowing the investigation to begin as soon as reasonably possible."

The extent of the damage is still being evaluated, but an initial assessment showed that the propylene recovery unit was destroyed and equipment in the alkylation and gas concentration units were damaged in the fire, the company said.

The one remaining injured employee was treated for burns and at presstime last week was in stable condition, Alon USA said.

Alon USA's Big Spring refinery lies 290 miles west of Dallas in west-central Texas. The facility employs about 170 workers and is one of four refineries owned by Alon USA, which was formed when Alon Israel Oil Co. Ltd. acquired certain US assets from Total SA.

Alon Pres. and Chief Executive Officer Jeff D. Morris said, "We are developing contingency supply plans for our customers and expect to have those in place in the next few days. We are also in the process of developing an operating plan for repairing the facility and bringing the refinery back into operation as soon as possible."

Based on preliminary assessments, Alon said it plans to resume partial operations in about 2 months.

Trinidad and Tobago to build second refinery

Trinidad and Tobago's Minister of Energy and Energy Industries Conrad Enill has announced that the twin-island nation will construct a $3-4 billion refinery next to its existing 168,000 b/d refinery at Pointe-a-Pierre.

The Minister said, although the final figure is not yet in, he expects the refinery's capacity to be in the order of 200,000 b/d.

Enill told a BG Trinidad & Tobago-sponsored luncheon the new refinery would be export oriented. "As a producer of approximately 150,000 b/d of oil, the country would benefit from being able to refine its own crude and convert it into salable products for the fuels retail market," Enill said.

The energy minister said bottom-of-the-barrel products from state-owned Petrotrin can be utilized as feedstock for the new facility.

The government is close to hiring a contractor, Enill said, but the final figures are not in so the final cost has not yet been determined.

Dinaz to start refinery construction in 2010

Latvia's Dinaz plans to start construction of the country's first refinery in 2010 so it can reduce product imports.

Dinaz Pres. Nikolay Yermolayev said the €2 billion, 6 million tonne/year refinery would be built near Daugavpils just north of the Belarus-Lithuania border. The greenfield site is 4 km from Druzhba pipeline, which transports Russian oil to Europe.

Yermolayev said the company is conducting a feasibility study for the refinery and will start the environmental process in 2009. Dinaz also is seeking partners in developing the refinery.

Separately, Dinaz also plans to construct a 10 million tonne/year oil terminal in Riga that would increase its trade links and improve domestic fuel trading, Yermolayev said.

Preem seeks permits for coker at refinery

Swedish refiner Preem Petroleum AB is seeking envrionmental permits to build a new 4 million tonnes/year coker unit near its 220,000 b/d Lysekil reinery on Sweden's west coast.

The expansion will propel the company's move from fuel oil into transportation fuels, according to Michael Low, Preem president and chief executive, who spoke at International Petroleum Week in London. Preem hopes to make a final investment decision on the project by yearend, although if the project proves uneconomical, the company will examine other options. Low declined to comment on what these other options would be, however.

The coker would have high feedstock flexibility and utilize spare hydotreating capacity. Low said it was unclear how much it would cost, but high costs, exacerbated by a shortage of contractors and materials, are impacting timely delivery of projects and whether refiners should progress with upgrades.

"Supply bottlenecks faced by the refining sector will not go away until at least 2009-10," Low said.

However, tightening environmental standards are also increasing costs and workloads for companies in the petroleum sector to ensure they produce cleaner fuels. Utilizing a coker unit would produce more carbon emissions, and Preem is investigating methods of carbon capture and sequestration with research institutions.

Europe's surplus of gasoline in the near future will be a major challenge as it has lost an export market to the US where the preference is to use diesel-run cars instead. Attractive incentives have also encouraged a boost in diesel production. "The car industry needs to come up with ways to make efficient gasoline cars; it's not a problem that we can solve by ourselves," Low said.

Low was also doubtful that the European Union will reach its target of having 5.75% of its transportation fuels coming from renewable sources by 2010 as EU members are at different levels in boosting their share of alternative fuels in the energy mix. "In Germany the government stopped subsidizing grapeseed oil, and that has left many companies bankrupt," Low said. ✦

Transportation — *Quick Takes*

Russia, Ukraine settle gas debt dispute

Russia and Ukraine have resolved their disagreement over the supply, pricing, and transit of Central Asian natural gas following a meeting between the leaders of the two countries.

"We regret that problems of the kind are still popping up," said Russian President Vladimir Putin, who said, "Our partners told us that they would soon start repaying the debts."

Ukrainian President Viktor Yushchenko explained that the debt would be repaid at last year's price of $130/1,000 cu m, rather than this year's price of $179.5/1,000 cu m. "We agreed that Ukraine would [on Feb. 14] start repaying the debt of last November-December," he said.

Ukraine's debt for gas supplied by Russia since Jan. 1 reportedly is nearing $500 million, while the country's overall gas debt exceeds $1.5 billion. Ukraine is said to have received 1.7 billion cu m of Russian gas for which it has not yet paid.

Meanwhile, OAO Gazprom Chief Executive Officer Alexei Miller said Neftegaz Ukrainy, which plans to settle the gas problem by the end of February, will join with his firm to establish two new companies involved in supplying gas to Ukraine.

"We are forming a new structure of Ukrainian gas imports, which includes the establishment of a new gas importing company on 50-50 terms. Fifty percent will belong to Gazprom, and another 50% to Neftegaz Ukrainy," he said.

In addition, Miller said, "We will form a company to sell gas on the Ukrainian domestic market, again on a 50-50 basis."

While Gazprom and Neftegaz Ukrainy will soon start working on a new formula of gas supplies, the disputed RosUkrEnergo will remain the only supplier of Central Asian and Russian gas to Ukraine.

Russia recently threatened to cut off all supplies of its natural gas to its neighbor after incoming Ukrainian Prime Minister Yulia Timoshenko suggested increasing the tariffs for Russian gas transiting her country and dispensing with RosUkrEnergo (OGJ Online, Feb. 8, 2008).

Suez JV obtains approval for Chile LNG terminal

GNL Mejillones (GNLM), a 50-50 joint venture of Suez Energy International and copper company Codelco, has obtained the environmental permit for its planned LNG regasification terminal in Mejillones in northern Chile.

The terminal will have a planned annual send-out capacity of 5.5 million cu m of gas, sufficient to produce 1,100 Mw of electricity.

GNLM plans to start preparatory field work immediately and will begin construction of the jetty and onshore terminal within the next few months, Suez said.

Gas is expected to start being delivered at yearend 2009 or early 2010.

For LNG storage, GNLM will use a conventional LNG carrier that will remain permanently moored to the jetty. Suez Global LNG will provide the floating storage unit (FSU). Onshore facilities will include pumps, compressors, vaporizers, and pipelines.

Mining companies BHPB-Escondida, Collahuasi, El Abra, and Codelco Norte have all signed gas purchase contracts with GNLM to cover electricity generation needs for 3 years, beginning in 2010. GNLM also signed an LNG supply agreement with Suez for identical volumes and duration.

The company expects to reach a decision by yearend on Phase 2, the construction of an onshore storage tank to replace the FSU. ✦

Letters

Peak-oil context

The letter by Al-Husseini and Al-Husseini about the Cambridge Energy Research Associates decline-rate study, as well as comments by other peak oil theorists on the subject, demonstrates their habit of ignoring historical context (OGJ, Feb. 4, 2008, p. 12). The point is that the decline rate, and the effect of depletion on capacity, is not a new element; rather, the industry has been replacing about 4 million b/d of lost capacity a year for some time now. With growth of approximately 1.5 million b/d of capacity every year, the gross additions must be on the order of 5.5-6 million b/d, or more than a Saudi Arabia every 2 years. Analysts like Matt Simmons and ASPO-USA always describe this without context. Thomas Petrie, for example, was quoted as saying, "When was the last time we discovered another Iran?"

Yet the industry has not only raised capacity by about 15 million b/d over the last 10 years, it has replaced something like 35 million b/d of capacity lost to depletion. This is equal to 10 Irans, without actually finding a new, major petroleum basin.

The only point of interest is whether or not the decline rate in existing fields has grown with new technologies, as some have claimed. CERA states that it did not find this to be the case. Why peak-oil pundits ignore this is hard to explain. Indeed, ASPO-USA's comment that "betting on depletion is like betting on rust" nicely demonstrates the shortcoming of their thinking: The oil industry, and many others, deals with rust all the time, without thinking it will cause them to peak and decline.

Depletion, like rust, has always been with us and can be dealt with, given proper investment.

It is hard to produce oil, and always has been. But the industry has managed not only to run faster to stay in place, but to continually pull ahead. The resource that is lacking is logical thinking on the part of the peak-oil community.

Michael Lynch, President
Strategic Energy & Economic Research Inc.
Winchester, Mass.

Calendar

✦ Denotes new listing or a change in previously published information.

OIL&GAS JOURNAL online

Additional information on upcoming seminars and conferences is available through OGJ Online, Oil & Gas Journal's Internet-based electronic information source at http://www.ogjonline.com.

2008

FEBRUARY

AAPG Southwest Section Meeting, Abilene, Tex., (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 24-27.

Laurance Reid Gas Conditioning Conference, Norman, Okla., (405) 325-3136, (405) 325-7329 (fax), e-mail: bettyk@ou.edu, website: www.lrgcc.org. 24-27.

Middle East Refining Conference & Annual Meeting, Abu Dhabi, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 25-26.

CERI Natural Gas Conference, Calgary, Alta., (403) 220-2380, (403) 284-4181 (fax), e-mail: jstaple@ceri.ca, website: www.ceri.ca. 25-26.

SPE Intelligent Energy Conference & Exhibition, Amsterdam, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 25-27.

IADC Drilling HSE Asia Pacific Conference & Exhibition, Kuala Lumpur, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 26-27.

Middle East Fuels Symposium, Abu Dhabi, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 27-28.

MARCH

GPA Annual Convention, Grapevine, Tex., (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 2-5.

GEO Middle East Geosciences Conference & Exhibition, Bahrain, +44 20 7840 2139, +44 20 7840 2119 (fax), (fax), e-mail: geo@oesallworld.com, website: www.allworldexhibitions.com. 3-5.

Subsea Tieback Forum & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.subseatiebackforum.com. 3-5.

NPRA Security Conference, The Woodlands, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 4-5.

ARTC Annual Meeting, Bangkok, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 4-6.

Global Petrochemicals Annual Meeting, Dusseldorf, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 4-6.

IADC/SPE Drilling Conference & Exhibition, Orlando, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 4-6.

SPE Indian Oil & Gas Technical Conference & Exhibition, Mumbai, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-6.

Annual Middle East Gas Summit, Doha, +971 4 336 2992, +971 4 336 0116 (fax), e-mail: sarita.singh@ibc-gulf.com, website: www.ibcgulfconferences.com. 5-6.

NPRA Annual Meeting, San Diego, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 9-11.

World Heavy Oil Congress, Edmonton, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 10-12.

New Zealand Petroleum Conference, Auckland, +64 3 962 6179, +64 4 471 0187 (fax), e-mail: crown.minerals@med.govt.nz, website: www.crownminerals.govt.nz. 10-12.

Gastech International Conference & Exhibition, Bangkok, +44 (0) 1737 855005, +44 (0) 1737 855482 (fax), e-mail: tonystephenson@dmgworldmedia.com, website: www.gastech.co.uk. 10-13.

API Spring Petroleum Measurement Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 10-14.

European Fuels Conference & Annual Meeting, Paris, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 11-12.

IADC International Deepwater Drilling Conference & Exhibition, Rio de Janeiro, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 11-12.

SPE North Africa Technical Conference & Exhibition, Marrakech, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 12-14.

NACE International Conference & Expo, New Orleans, (281) 228-6200, (281) 228-6300 (fax), website: www.nace.org. 16-20.

Offshore Asia Conference & Exhibition, Kuala Lumpur, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshoreasiaevent.com. 17-19.

Sub-Saharan Oil, Gas & Petrochemical Exhibition & Conference, Cape Town, +27 21 713 3360, +27 21 713 3366 (fax), e-mail: expo@fairconsultants.com, website: www.fairconsultants.com. 17-19.

Turoge and Black Sea Oil & Gas Exhibition & Conference, Ankara, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 18-20.

AAPG Prospect & Property Expo (APPEX), London, (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 24-26.

AAPG Pacific Section Meeting, Bakersfield, Calif., (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. Mar. 29-Apr. 2.

NPRA International Petrochemical Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. Mar. 30-Apr. 1.

SPE Middle East Petroleum Engineering Colloquium, Dubai, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Mar. 30-Apr. 2.

Calendar

PIRA Understanding Global Oil Markets Conference, Tokyo, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. Mar. 31-Apr. 1.

ERTC Sustainable Refining Conference, Brussels, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. Mar. 31–Apr. 2.

APRIL

SPE/ICoTA Coiled Tubing & Well Intervention Conference & Exhibition, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 1-2.

ERTC Biofuels+ Conference, Brussels, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 2-4.

GIOGIE Georgian International Oil & Gas Conference & Showcase, Tbilisi, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 3-4.

Middle East Petroleum & Gas Conference, Doha, +65 6222 0230, +65 6222 0121 (fax), e-mail: mpgc@cconnection.org, website: www.cconnection.org. 6-8.

✦Australian Petroleum Production & Exploration Association (APPEA) Conference & Exhibition, Perth, +61 2 9553 1260, +61 2 9553 4830 (fax), e-mail: appea2008@saneevent.com.au, website: www.appea2008.com.au. 6-9

ACS National Meeting & Exposition, New Orleans, 1 (800) 227-5558, e-mail: natlmtgs@acs.org, website: www.acs.org. 6-10.

American Institute of Chemical Engineers (AIChE) Spring National Meeting, New Orleans, (212) 591-8100, (212) 591-8888 (fax), website: www.aiche.org. 6-10.

CIOGE China International Oil & Gas Conference, Beijing, + (44) 020 7596 5000, + (44) 020 7596 5111 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 7-8.

API Pipeline Conference & Cybernetics Symposium, Orlando, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 7-10.

EAGE Saint Petersburg International Conference & Exhibition, Saint Petersburg, +7 495 9308452, +7 495 9308452 (fax), e-mail: eage@eage.ru, website: www.eage.nl. 7-10.

IADC Well Control Europe Conference & Exhibition, Amsterdam, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 9-10.

ENTELEC Annual Conference & Expo, Houston, (888) 503-8700, website: www.entelec.org. 9-11.

North Caspian Regional Atyrau Oil & Gas Exhibition & Petroleum Technology Conference, Atyrau, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 9-11.

API Spring Refining & Equipment Standards Meeting, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 14-16.

API/NPRA Spring Operating Practices Symposium, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 15.

SPE Gas Technology Symposium, Calgary, Alta., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 15-17.

SPE International Health, Safety & Environment Conference, Nice, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 15-17.

GPA Midcontinent Annual Meeting, Okla. City, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 17.

AAPG Annual Convention & Exhibition, San Antonio, 1 (888) 945 2274, ext. 617, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org/santantonio. 20-23.

SPE Improved Oil Recovery Symposium, Tulsa, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-23.

ERTC Coking & Gasification Conference, Rome, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 21-23.

WestAsia Oil, Gas, Refining, & Petrochemicals Exhibition & Conference, Oman, +968 24790333, +968 24706276 (fax), e-mail: clemento@omanexpo.com, website: www.ogwaexpo.com. 21-23.

International Pump Users Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), website: http://turbolab.tamu.edu. 21-24.

SPE Progressing Cavity Pumps Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 27-29.

MAY

IOGCC Midyear Meeting, Calgary, Alta., (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 4-6.

PIRA Canadian Energy Conference, Calgary, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 5.

API International Oil Spill Conference, Savannah, Ga., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 5-8.

Offshore Technology Conference (OTC), Houston, (972) 952-9494, (972) 952-9435 (fax), e-mail: service@otcnet.org, website: www.otcnet.org. 5-8.

GPA Permian Basin Annual Meeting, Odessa, Tex., , (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 6.

PIRA Understanding Global Oil Markets Conference Calgary, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 6-7.

ERTC Asset Maximization Conference, Lisbon, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 12-14.

International School of Hydrocarbon Measurement, Oklahoma City, (405) 325-1217, (405) 325-1388 (fax), e-mail: lcrowley@ou.edu, website: www.ishm.info. 13-15.

Uzbekistan International Oil & Gas Exhibition & Conference, Tashkent, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 13-15.

NPRA National Safety Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 14-15.

IADC Drilling Onshore America Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 15.

SPE Digital Energy Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: service@spe.org, website: www.spe.org. 20-21.

Mediterranean Offshore Conference & Exhibition (MOC), Alexandria, Egypt, + 39 0761 527976, + 39 0761 527945 (fax), e-mail: st@ies.co.it, website: www.moc2008.com. 20-22.

NPRA Reliability & Maintenance Conference & Exhibition, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 20-23.

Society of Professional Well Log Analysts (SPWLA) Annual Symposium, Edinburgh, (713) 947-8727, (713) 947-7181 (fax), website: www.spwla.org. 25-28.

Middle East Refining and Petrochemicals Conference & Exhibition, Bahrain, +973 1755 0033. +973 1755 3288 (fax), e-mail: mep@oesallworld.com, website: www.allworldexhibitions.com. 26-28.

SPE International Oilfield Corrosion Conference, Aberdeen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 27.

SPE International Oilfield Scale Conference, Aberdeen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 28-29.

JUNE

ERTC Management Forum, Copenhagen, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 2-4.

Caspian Oil & Gas Exhibition & Conference, Baku, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 3-6.

Oklahoma Independent Petroleum Association (OIPA) Annual Meeting, Dallas, (405) 942-2334, (405) 942-4636 (fax), website: www.oipa.com. 6-10.

SPEE Society of Petroleum Evaluation Engineers Annual Meeting, Hot Springs, Va.,

(713) 651-1639, (713) 951-9659 (fax), e-mail: bkspee@aol.com, website: www.spee.org. 7-10

PIRA Scenario Planning Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 9.

Asian Geosciences Conference & Exhibition, Kuala Lumpur, +44 (0) 20 7862 2136. +44 (0) 20 7862 2119, e-mail: geoasia@oesallworld.com, website: www.geo-asia.com. 9-11.

Independent Liquid Terminals Association (ILTA) Annual Operating Conference & Trade Show, Houston, (202) 842-9200, (202) 326-8660 (fax), e-mail: info@ilta.org, website: www.ilta.org. 9-11.

SPE Tight Gas Completions Conference, San Antonio, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 9-11.

EAGE/SPE EUROPEC Conference & Exhibition, Rome, +31 30 6354055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.nl. 9-12.

ASME Turbo Expo, Berlin, (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 9-13.

PIRA London Energy Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 10.

Asian Oil, Gas & Petrochemical Engineering Exhibition, Kuala Lumpur, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: oga@oesallworld.com, website: www.allworldexhibitions.com. 10-12.

Global Petroleum Show, Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 10-12.

IADC World Drilling Conference & Exhibition, Berlin, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 11-12.

PIRA Understanding Global Oil Markets Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 11-12.

Asia's Subsea Conference & Exhibition, Kuala Lumpur, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: subsea@oesallworld.com, website: www.subseaasia.org. 11-13.

CIPC/SPE GTS Joint Conference, Calgary, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 16-19.

American Association of Professional Landmen (AAPL) Annual Meeting, Chicago, (817) 847-7700, (817) 847-7704(fax), e-mail: aapl@landman.org, website: www.landman.org. 18-21.

LNG North America Summit, Houston, (416) 214-3400, (416) 214-3403 (fax), website: www.lngevent.com. 19-20.

IPAA Midyear Meeting, Colorado Springs, Colo., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 19-21.

PIRA Scenario Planning Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 23.

API Tanker Conference, San Diego, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 23-24.

API Exploration & Production Standards on Oilfield Equipment & Materials Conference, Calgary, Alta., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 23-27.

PIRA Understanding Global Oil Markets Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 24-25.

Winter woes

Warren R. True
Chief Technology Editor-LNG/ Gas Processing

Extreme weather tests even the richest, most well-managed economies. So, when winter 2007-08 brought cold and suffering to two countries whose hydrocarbon wealth should have softened the blows, the world took note. Something else must be going on.

China possesses the world's third largest coal reserves, behind the US and Russia. Yet extraordinary winter snows there in January and February overwhelmed its energy-delivery infrastructure and caused near riots in major southern cities.

Similarly, Iran holds the world's second largest natural gas reserves behind Russia: at least 974 tcf proved and probable. Contract squabbles with Turkmenistan reduced natural gas for reinjection into major Iranian oil fields, forced power plants to switch to more polluting fuel oil, and cut the country's ability to honor export contracts, especially with Turkey.

And Iran's people shivered and many died in winter storms across its north.

Reserves; disasters

China's 2005 coal reserves, according to the US Energy Information Administration, were nearly 114.5 billion tonnes, comprising 12.6% of world coal reserves. Most are in the country's west; most recent and rapid demand growth is along the coastal east.

The world's largest consumer of coal, China produces around 78% of its electricity from it. The country's infrastructure to move coal to power plants and produced electricity to markets has not kept pace with economic development, according to the Wall Street Journal. China has even had to import coal, especially for markets along its coasts and in large southern cities.

These weaknesses were on display when mid-January storms exposed the thin supply margin for its power-generation industries and the precarious conditions of its straining infrastructure.

The Associated Press reported snow and ice in some areas snapped power lines, cutting power from the 500-kv transmission line linking the Three Gorges Dam hydroelectric project to the national grid. China's South China State Grid, which operates the electrical grid in southern China, said repairs to the entire network would not finish until the end of March. In the meantime, customers will see intermittent outages.

The AP cited government data for the 4 weeks of snow and ice storms, saying they killed more than 80 people, leveled 300,000 homes, and laid waste to 222 million acres of crops.

Newspapers and television reports around the world showed key transport systems paralyzed just as millions of migrant workers tried to go home for the Lunar New Year holiday.

Similarly, Iran faces major delivery problems despite its abundance of natural gas. For several years, it has dangled before the world market huge LNG projects to bolster its international standing and bring in much needed cash. Despite occasional announcements, however, none has yet proceeded to construction. (See OGJ's special report on global LNG beginning on p. 20.)

The country uses much of its natural gas along with imports from Turkmenistan for pressure maintenance at several older oil fields. And it also flows gas to households for heating—which is where winter 2007-08 comes in again.

Turkmenistan, in a contract dispute with Iran in late 2007, first reduced then entirely shut off gas supplies. Reports said dozens of people in remote northern areas died from a cold snap at the same time that drove temperatures to near –25° C.

What is wealth for?

These two energy-rich countries are certainly not the only ones ever to suffer from a conjunction of extreme weather and inadequate delivery infrastructure. And no one takes satisfaction in their peoples' misfortunes.

What is striking about these events, however, is how neither country was able to marshal its huge energy resources early or quickly enough to alleviate citizens' suffering.

China might well be excused based simply on the size of the population it must manage; with the possible exception of Russia, no other country has such numbers spread over such distances.

Iran, on the other hand, has neither the population nor the distances to hamper its efforts. Its international bluster and Western economic sanctions have hampered development of its natural gas to the detriment of its people.

When winter storms hit both regions, neither country's huge hydrocarbon reserves were able to alleviate suffering.

So what is wealth for? ✦

The oil price floor

As the price of crude oil flirts again with its $100/bbl threshold, the question naturally arises: How high can the price go? But brush away the superficialities, and market changes give reason to wonder how low the price might sink.

Demand for oil can't rise as fast as it did during 2004-07 indefinitely. Yes, populous countries like China and India are industrializing, craving oil and other energy. Yes, the global population is growing. Yes, these changes expand the energy market structurally.

But supply struggles to keep up. Part of the reason is geologic: The global petroleum resource, however defined, whatever its size, has reached a stage of development at which new supply tends to be difficult to find and expensive to produce. Much oil remains—more than anyone at any given time can attest. But it isn't cheap. And the world continues to need growing amounts of it.

Main constraints

Geology, however, is far from the main constraint of the moment. Limits on capital, labor, materials, and availability of exploration and development opportunities curb supply growth even more. Since 2003, the world has needed 1-1.5 million b/d of new oil supply each year—more than that in 2004. Production capacity, despite strong natural declines in mature areas like the US and UK North Sea, has grown. But it hasn't grown fast enough to prevent a strong increase in prices.

The trend can't last. As demand pressure builds against limits on supply growth, and as prices therefore rise, the market inevitably responds by shedding demand and, to the extent it can, boosting supply. It's doing so now.

In their monthly market reports for February, two important reporting agencies note an important turn in the oil market. Citing the global economic chill, the International Energy Agency trimmed by 200,000 b/d its forecast for average 2008 oil demand from the projection it made in January. "Just as the demand shock of 2004 shaped the oil market for the next 3 years," IEA says, "so too could the pending [economic] slowdown." And capacity additions this year and next will lift spare capacity, a vital source of surge supply that for several years has been perilously low.

The US Energy Information Administration, while lower in its 2008 demand forecast than IEA, sees a similar change. "Higher production outside the Organization of Petroleum Exporting Countries and planned additions to OPEC capacity should more than offset expected moderate world oil demand and relieve some of the tightness in the market," it says. EIA projects a doubling of global spare production capacity to 4 million b/d by the end of 2009.

Rising supply and moderating demand growth mean lower prices, of course. No one should be stunned by this news. Nor should anyone think that last week's price spurt, the result more of news events than of market fundamentals, changes the outlook. The ingredients for an inevitable softening of the market are in place.

So how far might the price of crude oil—absent a supply cataclysm—fall? The answer depends partly on how far the global economy falls, if that's what it's destined to do. Pointing to tight oil supplies in the developing world and rising service costs, IEA says corporate analysts are "suggesting companies are preparing for a sustained $60-80/bbl world."

The floor

The practical floor price of crude oil may lie near the low end of that range. It's the level at which Saudi Arabia feels enough financial pressure to lower oil production in support of the crude price. In its Global Oil Report, the Centre for Global Energy Studies analyzes the published Saudi budget for 2008 and concludes that the kingdom, to meet spending plans and retire debt at the 2007 rate, needs an OPEC basket price of $62/bbl. CGES calls that "the oil price floor for 2008, below which it is unlikely the oil price will stay for long."

As always, the oil price can fall as well as rise—but perhaps not as far as it has in the past. ✦

Lenders likely to tighten LNG project financing

David Wood
David Wood & Associates
Lincoln, UK

For several years prior to 2004, the LNG industry was a buyers' market, and buyers were in the driver's seat with respect to pricing terms and flexibilities introduced into LNG sales agreements. Since then, however, LNG has moved strongly into a sellers' market due to strong gas demand and delays in sanctioning and constructing new liquefaction capacity. Many analysts see a sellers' LNG market prevailing well beyond 2010.

Some of the largest project financings closed in 2004-06 were in the LNG sector—along the whole supply chain. Many involved large components of bank debt secured at modest margins. In addition, during the same period, several liquefaction projects that had entered the postcommissioning phase were able to refinance in the highly competitive bank lending market, achieving lower lending margins.

Despite such a recent golden age for the borrowing parties in LNG project finance deals, recent events seem to be conspiring to mark a turnaround in financing conditions. Fig. 1 illustrates the pressures and risks offsets at the upstream end of the LNG supply chain in 2007 by the sellers' market and unprecedented high oil and gas prices.

Several events have had a major impact on financing:

- The US subprime debt crisis of August 2007 and the consequential global tightening of debt markets.
- Fiscal instability and toughening terms for international oil companies (IOCs) in upstream gas supply contracts.
- Rampant and sustained oil and gas industry cost inflation (2005-07).
- Devaluation of the US dollar by some 67% against the euro since 2002.
- Volatility and future uncertainty in gas markets, in terms of both supply-demand fundamentals and price. For example, the UK LNG market has deteriorated with the commissioning of new pipelines in 2006; the Japanese market for LNG strengthened in 2007, with significant loss of nuclear power capacity; and the US LNG market remains uncertain because of possible increases in domestic gas exploration and production and the delays in building key LNG receiving terminals.
- Less security of offtakes underpinning LNG sales contracts.
- Substantial delays and massive cost overruns in some large liquefaction projects such as Sakhalin II and Snohvit.
- Lack of skilled personnel and the unavailability of experienced engineering, procurement, and construction (EPC) contractors.
- Difficulties gaining regulatory approvals to build new LNG receiving terminals in key markets: California and New England.

Despite a strong global LNG demand and a lack of sufficient supply increases, these events have substantially increased the risks and costs for lenders, which may lead to increased lending margins and make debt financing for LNG projects more difficult to secure.

Impact on projects

LNG projects typically are quite

capital-intensive. In addition, they are influenced by multicomponent, long supply chains; require a long period of capital expenditure during the planning, design, engineering, procurement, and construction phases before there is any income; and due to their large size and complexity, are nearly always multiparticipant projects.

For all but the largest IOCs, project financing is required as part of a funding package for LNG infrastructure development. The IOCs and national oil companies (NOCs) often together form special-purpose companies to engage in project finance for LNG projects—especially for upstream activities such as field development and liquefaction and for shipping—in order to leverage their deployed capital and spread financial risk. Having creditworthy IOCs involved provides a means for less creditworthy NOCs to secure access to project debt at more-favorable terms than they could secure on their own.

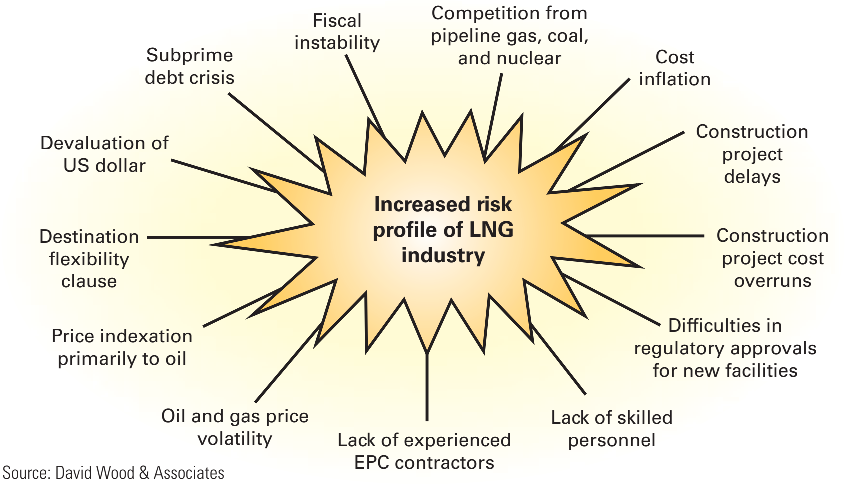
Large gas field development projects have loan collateral that can be evaluated based on the associated field reserves. Gas volumes available for loan valuation are usually the proved reserves, although in recent years some lenders have been willing to add at least a fraction of probable reserves.

Due to the very large investments, long payback periods, and large volumes of reserves that must be processed by the typical liquefaction project to achieve payback, the project's recoverable hydrocarbon reserve collateral is not liquid until the liquefaction plant's postcommissioning stage is reached. Gas reserves cannot be monetized without all of the upstream and liquefaction facilities plus (usually long-term) LNG purchase agreements, and transportation and handling contracts along the supply chain.

Although there is a primary focus on potential project revenues, lenders for liquefaction and regasification projects are frequently preoccupied with credit support for project finance. Key issues here are the creditworthiness of the seller and the buyer, or their parent

UPWARD PRESSURES ON LNG PROJECT LENDING MARGINS

Fig. 1



Source: David Wood & Associates

organizations. The concern is the risk to future project revenues from nonperformance by any party, including EPC contractors and suppliers. If the borrower's counterparty in the purchase agreement is not well capitalized or creditworthy, lenders usually seek another creditworthy entity to provide some form of financial guarantee.

In supply chains where the LNG purchasers include utilities in countries such as India, China, and Mexico without established international credit ratings, additional guarantees become essential to secure project finance. LNG project loan terms typically have long durations of a decade or more following the commissioning of the facilities. Credit-ratings triggers may be involved in loan terms; if the borrower's credit rating deteriorates during the long repayment period, for example, a higher loan repayment dedication or loan margin may be applied.

Despite such limited loan collateral issues, it has become commonplace for greenfield and expansion, base-load liquefaction plants to obtain limited recourse or nonrecourse project financing. This usually has been achieved on the back of long-term sales agreements to creditworthy LNG buyers, incorporating take-or-pay and minimum or floor gas price provisions. This type of exposure for equity and debt providers requires conservative project evaluation and risk analysis. In the competitive lending market of 2004-06, lenders became less conservative. Expectations in late 2007, however, were that they may again become more conservative.

Global finance trends

Trends in the pricing of commercial loans to Qatar's LNG projects over the past decade are indicative of global LNG project finance trends. In the mid-1990s Qatargas-1 project financing attracted a margin of 165 basis points (bp), compared with Rasgas-1 bank loan margins of 95-200 bp. Rasgas-1 refinanced on better terms in 2004.

The Qatargas-2 project—a joint venture of Qatar Petroleum, ExxonMobil, and Total—in 2004 marked a resurgence in commercial banks' appetite for large LNG project financings at the arranger and syndication level, as illustrated by the oversubscription of that offering, with 36 banks acting as mandated lead arranger.

Qatargas-2 was able to secure commercial bank finance at margins of 50-125 bp, followed in 2005 by Rasgas-2 and 3 project financings with bank loan margins of 45-65 bp. The downward trend in borrowing costs continued with the Qatargas-4 project sponsored by Qatar Petroleum and Shell in 2006 leveraging its project finance with bank loan margins of 30-60 bp.

It now seems unlikely that this downward trend in borrowing costs can be sustained (Fig. 2).

Another trend is the emergence of nontraditional lenders for LNG financing. In the past decade LNG financings have gone beyond traditional lenders in order to finance politically more challenging projects. Export credit agencies, a traditional resource for political risk insurance in developing markets, have also provided direct debt finance and encouraged commercial banks into projects by removing some of the credit risks of the host countries.

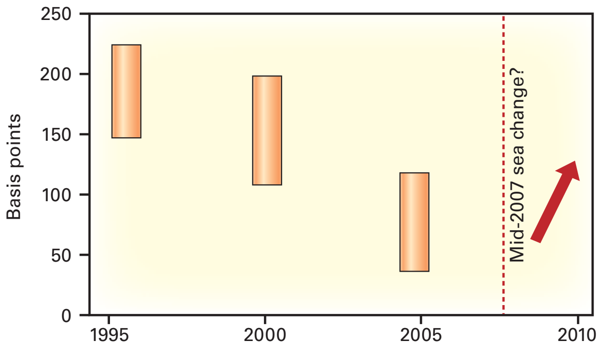
Multilateral lending agencies—regional and international development banks such as World Bank, European Bank for Reconstruction and Development, and African Development Bank—have also provided limited funding to developing countries for both LNG and pipeline gas projects in recent years. Islamic banks, benefiting from deposits from clients with oil revenues, have invested heavily in the Middle East LNG sector in recent years. Such lenders, although content to join syndicated loans, have yet to act as lead arrangers. Consequently they have depended on the risk appetite of the traditional lead energy banks in selecting projects deemed worthy of debt finance.

Debt raised through bonds issued on the capital markets provides borrowers with less flexibility but come with fewer obligations. For this reason such bonds have been used mainly in the LNG sector in combination with bank loans to provide more flexibility, as in the Qatar LNG projects, and have focused on tried and tested technologies deployed by robustly creditworthy organizations.

However, capital market fallouts from the 1998 Asian financial collapse made those markets cautious about funding LNG projects while the main market for LNG remained focused in Asia. Several large bond issues connected with the Qatar projects in 2004-06 seemed to be leading a reemergence of capital market financing of liquefaction projects. However with current industry trends, plus more-complex and risky pricing and cargo destination flexibility, it seems likely that bond investors will remain apprehensive that the evolving LNG industry remains too risky.

BANK LENDING MARGIN TREND TO LARGE LNG PROJECTS

Fig. 2



Source: David Wood & Associates

Competitive refinancing

The strong appetite of lenders for LNG projects led to some postcommissioning loan refinance of liquefaction projects benefiting from reductions in project risk profiles at the time. For example:

• The margins reported in July 2007 on the $720 million oversubscribed commercial bank tranche of the Spanish Egyptian Gas Damietta liquefaction plant 15-year refinancing package were 60-90 bp, and on two $125 million European Investment Bank tranches were 50-55 bp. To place these in context, they should be compared with margins of 60-150 bp for liquefaction train two of the Egyptian LNG (ELNG, July 2005) project and with margins of 85-235 bp for ELNG liquefaction Train 1 in 2003.

• Oman's Qalhat liquefaction plant managed to refinance its debt in 2006 to reduce borrowing costs from the higher 55-110 bp to 45-90 bp, with lenders accepting lower project risks in the postcommissioning phase of the project and a more competitive and liquid lending market.

Competition among the big energy lenders, which made such reductions in borrowing costs for LNG projects, is unlikely to be so intense in the future.

Other opportunities exist, however. Recently profitable short-term cargoes, which account for some 12% of the global LNG market, have attracted IOCs to adopt the role of LNG aggregator. This enables them to establish a more integrated perspective of the value chain, from which, as LNG producers, shippers, receivers, and gas marketers, they control the cargo destination and optimize profitability. This is the model for Atlantic LNG (Trinidad and Tobago) and some Qatar and Egypt LNG projects aimed at targeting gas into the highest priced market at any given time. This model is difficult for lenders because it lacks secure long-term offtake agreements. IOCs that have pursued it successfully have mainly financed the uncontracted required shipping through equity rather than debt.

Cost inflation

Although gas liquefaction projects contain some peculiarities, evaluating them must be based on sound financial and economic analysis, which is common to all project decision-making.

Although this has always presented challenges for gas liquefaction projects, the problem has become critical since 2005. This is primarily because, after a period of sustained decline in unit capacity terms due to increasing economies of scale, the size and cost of a world-class, base-load gas liquefaction plant has dramatically increased due to rising steel, nickel, and other materials and labor costs impacting much of the oil and gas industry.

Gas liquefaction facilities are built of high-cost, critical-process components, and they frequently require innovative technology tailored to specific geographic environments. That was the case with Snohvit and Sakhalin II facilities. Such components tend to suffer from the highest inflation rates.

In 2003, base-load gas liquefaction process trains were constructed for less than \$200/tonne/year of plant capacity, but by 2007 costs had risen to above \$600/tonne/year of plant capacity. Consequently several projects have had final investment decisions delayed, and many financiers are having second thoughts about financing projects associated with rapidly escalating budgets. In 2006 the absence of new liquefaction project sanctions exacerbated the sellers' market. In 2007 and early 2008, companies finally made investment decisions for new liquefaction projects in Peru (led by Hunt Oil) and in Angola (led by Chevron), but both projects had increased budgets.

In such circumstances careful evaluation of project costs, technical and nontechnical risks, project schedule, and efficiency of design are critical. An LNG plant, either liquefaction or regasification, that is not complete and capable of delivering the throughput that will enable it to meet its sales contract requirements has essentially no value as an asset against the loan. The 75% complete Dabhol regasification plant, for example, sat uncompleted during 2001-06 following the unraveling of Enron's sales agreement with its power plant customer.

The salvage value of even the best available gas processing technology installed in a remote location is very low. With the intention of completing the facility in 2007, India's state-owned gas company GAIL and its power utility NTPC Ltd. acquired the Dabhol regasification plant by paying a discount of about 70% of the debt outstanding to the original EPC contractors and suppliers, including Bechtel and GE. This example underscores the point that the only value in such projects is the future expectation of revenue from gas sales after the facilities begin operation.

Changing risk profile

A comprehensive and holistic risk analysis of all LNG facilities is essential for both equity and debt finance participants to build the level of confidence such participants require to sanction future investments. The problem is that the LNG supply chain and market have become more complicated in recent years, changing the risk profile in ways that make lenders nervous. Further changes in the risk exposure for LNG project financing continue to materialize.

Even in 2006 some analysts were commenting that LNG buyers were continuing to call the shots, being less willing to accept rigid floor price and take-or-pay volume guarantees. European buyers for many years had made progress seeking more-flexible pricing provisions linked to gas-on-gas competition instead of fuel-oil replacement. The expectation then was that LNG around the world would continue to move away from the traditional crude oil-linked price indexing and toward gas market pricing.

The strengthening sellers' market and booming oil prices changed that in 2007. LNG suppliers see no compelling reason to move away from crude oil price indexing. Japan in 2001 had secured price stabilization in long-term contracts through its S-curve price index back to oil in the days of the buyers' market.

During 2007 Japan was forced by market conditions in recent long-term contracts to accept straight-line price indexation approaching parity to oil prices, which translated into gas prices of some \$11/MMbtu in late 2007. Although some Japanese buyers want to change price indexation from the traditional Japanese Crude Cocktail oil price benchmark and use NYMEX Henry Hub gas prices instead, few sellers want to move away from oil price indexing with oil prices hovering around \$100/bbl. Some observers expect the Henry Hub benchmark to play a greater role in LNG price indexing, particularly in Asia, over the coming years. Although this has been the case with some short-term trades and cargo diversions, it may not be for future long-term contracts.

Natural gas prices at Henry Hub in the US, at the National Balancing Point in the UK, and short-term cargoes into Japan and South Korea have fluctuated widely in recent years, leading to future cash flow uncertainty for equity and debt investors. Market dynamics in late 2007 suggested that growing gas demand and insufficient growth in LNG supply should provide upward pressure overall on prices.

In certain markets, however, where gas-on-gas competition is intense—such as new gas import pipelines versus new LNG receiving terminals in the UK—periods of oversupply can be expected. In recent years LNG project lenders have been willing to accept more price risk.

The Qatargas-2 project marked the first occasion in which price risk was passed through to lenders, with the sales agreement for the first train shipping gas into the UK gas market at a price with no floor price guarantee. Strong demand in Asia has provided Qatargas with the extra cushion of being able to divert some gas originally contracted for UK and US markets in that direction. That may be necessary from time to time, even in a predominantly sellers' market to avoid potential losses associated with periodically being forced to sell some cargoes at lower prices in the Atlantic basin.

The no-floor-price provisions in gas sales to the UK were deemed acceptable to lenders in 2004-05 after marketing studies showed strong future demand in the UK coupled with decreasing domestic supply, as well as sound project economics. What happened in the UK market during winter 2006-07—oversupply from pipeline gas, leading to sustained low gas prices—cast such analysis in doubt, however. It is doubtful whether lenders will be quite so willing to accept price risk in the current market. However, lenders' attention has been drawn primarily upstream, with concerns about escalating project budgets and long-term fiscal stability now more acute than ever. These factors are likely to justify increases in lending margins.

Destination flexibility

Achieving destination flexibility has become popular in LNG customer sales agreements. Initially this was driven by the buyers' perspective in terms of being able to match contracts with actual demand. Later LNG suppliers also sought destination flexibility to benefit from short-term arbitrage opportunities. From either perspective this adds potential risk for project lenders if the flexibility is to the advantage of the party other than the one to whom they are lending. Even lenders to liquefaction projects selling fob need reassurance both that the LNG buyer and its contracted shippers are able to handle the base-load contract volumes and that no adverse impacts to the seller will result from granting destination flexibility to that buyer.

Lenders for buyer and seller could be exposed to loss of revenue, additional costs, and facilities disruption when cargo diversions result from destination flexibility provisions' being invoked. Risk and economic analysis of LNG contracts with destination flexibility are more complex and uncertain for equity and debt investors in LNG infrastructure. Thus financing will probably become more difficult and costly to secure for parties adversely affected by destination flexibility clauses.

Project ship financing

The decision to own ships directly or to lease them from a shipping company partly owned by the project sponsor (NOC, IOC, or both) is often driven by tax issues and the constraints of the upstream gas production license or contract. Financing the construction of LNG ships under long-term charter to an LNG supply chain has for many years been a low risk venture. Loans to such projects in recent years have rarely involved lending margins above 60 bp, and some multiship financings with robust IOCs have been secured at less than 30 bp.

Not all LNG shipping has proved to be without risk. Technical problems associated with leaking insulation have proved problematic for some recent constructions. However, it has been those ships built on a speculative basis with no long-term time charter agreement in place that have resulted in substantial losses for some shipping companies.

The short-term market for LNG shipping is volatile and for much of 2004-07 was oversupplied. Shipping companies with no equity positions in LNG have been unable to adopt the strategies of some IOCs that capitalize on short-term and spot markets, as they have been unable to secure cargoes.

Because long-term supply contracts dominate the LNG industry by some 88%, noncontracted vessels cannot yet secure regular cargoes. Japan's sudden surge in demand for short-term cargoes since July 2007 has improved the situation. In the prevailing market it is highly unlikely that LNG vessel construction projects can secure bank loans unless they have long-term charter contracts.

Commercial banking may struggle to sustain the enthusiasm it has shown for financing international LNG projects in recent years unless some of the risks and complexities highlighted in this article are satisfactorily mitigated by asset owners and equity investors along the full length of the LNG supply chain. ✦

The author

David Wood (woodda@compuserve.com) is the principal consultant of David Wood & Associates UK, specializing in the integration of technical, economic, risk, and strategic information to aid portfolio evaluation and management decisions worldwide. He has more than 25 years of international oil and gas experience spanning technical and commercial operations, contract evaluation, and senior corporate management. Industry experience includes work for Phillips Petroleum, Amoco, and Canadian independents, 3 years in Colombia, and 4 years in Dubai. During 1993-98 he was UK managing director for Lundin Petroleum and then Morrison Petroleum.

CERA: Industry aims to fuel world, lower GHG emissions

Paula Dittrick
Senior Staff Writer

The global oil and gas industry faces the simultaneous goals of producing more energy while lowering emissions of greenhouse gases (GHGs), speakers told Cambridge Energy Research Associates annual conference in Houston.

Natural gas, both pipeline gas and LNG, appears to be a fossil fuel favorite in industry's race to meet rising energy demand.

Michael Stoppard, CERA senior director of global gas, forecasts world LNG liquefaction capacity will grow by almost one-third to 341 billion cu m in 2 years. He expects 58 LNG ships will be added to the existing 251-vessel fleet during 2008.

Linda Cook, Royal Dutch Shell PLC executive director of gas and power, said LNG trading volumes will increase because of an anticipated increasing gap between domestic production and demand in the US, Europe, and other countries, including China.

"Recent studies indicate that by 2025, we could see a gap of 15 to 20 bcfd between US natural gas production and demand," Cook said. "The actual size of this gap will depend on the degree to which domestic production can be extended."

Cook called upon industry to develop new technology, improve energy

"Recent studies indicate that by 2025, we could see a gap of 15 to 20 bcfd between US natural gas production and demand. The actual size of this gap will depend on the degree to which domestic production can be extended."
—Linda Cook, Royal Dutch Shell executive director, gas and power

efficiency, and unlock more difficult-to-reach resources. She called upon governments to provide industry access to areas now off-limits and to coordinate GHG emissions regulations.

Jim Mulva, ConocoPhillips chairman and chief executive officer, said energy producers have a responsibility to provide sustainable energy, saying industry's knowledge of fuels can help in research to reduce the carbon intensity of fuels. "Climate change and energy security are complex global issues," Mulva said.

Separately, Larry Nettles, attorney with Vinson & Elkins LLP, commented on anticipated US regulation on GHG emissions. Nubuo Tanaka, executive director of the International Energy Agency, discussed cost estimates on reducing GHG emissions worldwide.

Supply constraints

Industry must overcome various obstacles, agreed Shell's Cook and other oil company executives speaking at CERA. They noted that the US and Mexico have large prospective areas to which the oil and gas industry has restricted or no access.

"Essentially all of the US Atlantic and Pacific coasts and the eastern Gulf of Mexico are off limits for exploration," Cook said. "What little exploration has been done dates back 30 years—when we had no deepwater drilling capacity, no supercomputers, no submarine robots, and no 4D seismic models."

Sometimes, local opposition is the biggest problem, Cook said. For instance, Shell's attempt to drill in the Beaufort Sea off Alaska was blocked last year by a lawsuit questioning the drilling program's environmental impact.

"The US isn't alone in this," Cook said. "Local opposition exists in other places such as Canada, some countries in South America, the Netherlands, Ireland, and Australia."

ConocoPhillips's Mulva said that unconventional forms of energy, including oil shale, are available but that unconventional oil sources also could see access problems in the future.

"The economy needs a carbon price signal. Most of the current US proposals are for cap-and-trade. Such a system should recognize that carbon offsets are available not only here, but worldwide."
—ConocoPhillips Chairman and CEO James Mulva

"These are higher on the carbon-intensity curve, which adds to climate concerns and strengthens the antidevelopment movement," Mulva said. "This movement will only grow as we are forced to rely on more unconventional oil to meet consumer demand. The consequence could be even further restrictions on access—and the spiral downward would accelerate."

Escalating costs for upstream projects is another obstacle. Cook said industry has experienced significant cost increases and unplanned construction delays for major projects. Meanwhile, contractors sometimes add significant risk premiums to bids, she said.

"This is unsustainable," Cook said. "Productivity needs to be improved. Delivery time for major equipment needs shortening. Costs need to come down, and uncertainty needs to be reduced. If the industry as a whole fails to do this, the pace of new projects will inevitably slow."

Because upstream projects are long term and require huge investments, Cook said oil companies base their financial decisions in part upon which governments are likely to honor contract commitments and provide stable investment climates.

GHG regulations

If governments are going to require the energy industry to reduce GHG emissions, Cook said industry should be allowed to do it in the most economic way possible.

She called for "wise and coordinated carbon dioxide legislation, taking into account the life-cycle impacts of energy sources and consumption." Cook said, "A tonne of CO_2 emissions reduced in China is as good for the environment as one in the US."

She later told reporters she hopes GHG regulations can be coordinated at a national level in the US and then also coordinated on a worldwide level.

Mulva said the US government should strive for a national carbon management solution that will influence international policy as well.

"Our preliminary analysis suggests that investment of around $50 trillion would be needed for a 50% reduction in emissions, on top of what would be required under a 'business as usual' scenario."
—IEA Executive Director Nobuo Tanaka

CERA: Stage set for more global gas market

Paula Dittrick
Senior Staff Writer

The stage appears set for natural gas to become more of a global energy commodity in 2008 and 2009 than in the past, largely because of an expanding LNG industry, Cambridge Energy Research Associates said at its annual conference in Houston.

"The LNG armada has already set sail," said Michael Stoppard, CERA senior director for global gas, during a Feb. 13 news conference. "In 2007, we saw the ability of the LNG market to respond to global events," he said, referring to a July 16, 2007, earthquake that caused the shutdown of a Japanese power plant and the outage of a major North Sea gas pipeline serving the UK.

Stoppard foresees LNG growth to continue to 2010 based on investment decisions made years ago. He is uncertain about LNG's pace of growth beyond 2010.

Despite the current LNG momentum, Stoppard said a need "absolutely" exists for the proposed Alaska natural gas pipeline. CERA believes an Alaska pipeline could not be put into operation until after 2020, and that LNG will help fulfill US gas demand until then.

Stoppard expects global liquefaction capacity to increase to 341 billion cu m from today's 262 billion cu m within 24 months. This stems from investments at Qatar's Ras Laffan along with projects in Russia, Yemen, Australia, and Indonesia.

World LNG shipping capacity is expected to increase by more than 50% by 2010, he said. More LNG vessels will allow for expanded arbitrage opportunities, and a larger fleet presents the opportunity for using ships as floating regasification and storage vessels.

Meanwhile, investment in regasification terminals is rising at a faster pace than the associated liquefaction. That is because regasification represents 10-15% of LNG supply chain costs, Stoppard said.

He believes the number of regasification facilities always should exceed liquefaction facilities. Surplus regasification is essential for sellers wanting to move shipments between regions.

"For buyers, regas is the ante to sit in on the global gas procurement game," Stoppard said. "The expanding number of countries considering building LNG import facilities ranges from Brazil and the Netherlands to Pakistan and New Zealand."

"The economy needs a carbon price signal," he said. "Most of the current US proposals are for cap-and-trade. Such a system should recognize that carbon offsets are available not only here, but worldwide.

"Another key step by government," Mulva said, "would be to make fossil fuels more environmentally acceptable. It could do this by promoting carbon capture and storage. To do so, government must first create a regulatory framework that incorporates sufficient economic incentives."

In a separate session, Vinson & Elkins attorney Nettles said he believes US regulations on GHG emissions will be pointed primarily toward fossil fuel producers, refineries, and the midstream gas business rather than toward vehicle manufacturers or consumers.

Congress is expected to pass legislation to limit GHG emissions, Nettles said, adding that it's more apt to come in 2009 than in 2008. The US Environmental Protection Agency then would be called upon to calculate the level of emissions from using various fuels.

"We're going to have an army of carbon accountants," Nettles told OGJ. "I can see jobs for fuel auditors in the future." He foresees the establishment of a federal GHG registry that would track emissions.

Nettles said a cap-and-trade system is likely to include allocation of free allowances each year to certain industries, such as coal-fired electric power plants. These free allowances would be provided for a few years only as a form of transition assistance.

The percentage of allowances distributed would decline each year at different rates for different industries and eventually there would be an auction-allowance distribution system.

Current discussion among lawmakers indicates that oil and gas producers probably would get no allowances while refineries and gas processing plants would get only small allowances.

"It's a way to impose a tax on certain fuels without calling it a tax," Nettles said.

CERA Chairman Daniel Yergin told OGJ that economists generally favor a carbon tax over a cap-and-trade system. Yergin expects the US "will have some carbon regime within a few years."

IEA's Tanaka said international negotiations for a GHG emissions reduction target has generated much publicity, but he noted that the establishment of a target alone will not solve the problem.

The European Union, Japan, and Canada have pledged to reduce emissions by 50% in 2050. In December, 178 countries at the UN climate conference in Bali signed what Tanaka calls the "Bali roadmap, which takes up where the Kyoto treaty leaves off."

"What is needed is practical action to transform our energy system," Tanaka said, adding that improved energy efficiency is fundamental. In separate speeches, both Tanaka and Cook indicated the oil and gas industry can be a leader in improved energy efficiency.

The IEA believes a 50% cut in global emissions means the world would have to both reduce CO_2 emissions from electric power generation and reduce the carbon intensity of transportation eightfold, Tanaka said.

"Our preliminary analysis suggests that investment of around $50 trillion would be needed for a 50% reduction in emissions, on top of what would be required under a 'business as usual' scenario," Tanaka said. "This amounts to roughly 1% of total gross domestic product from 2005-50." ✦

CERA: Action needed now on demand, supply fronts to avoid crisis, Hess says

Sam Fletcher
Senior Writer

Oil companies, oil-producing countries, and consumers need to act now to avoid the oil crisis that is coming within the next 10 years, said John B. Hess, chairman and chief executive of Hess Corp.

"It is not only a matter of demand. It is not only a matter of supply.... We need to take steps on both fronts, and we need to start today," Hess told an overflow crowd Feb. 12 at the Cambridge Energy Research Associates' annual energy conference in Houston.

"Given the long lead times of at least 5-10 years from discovery to production, an oil crisis is coming and sooner than most people think. Unfortunately, we are behaving in ways that suggest we do not know there is a serious problem," Hess said.

That's partly because of conflicting viewpoints. "Some say that there is a large endowment of resources and that there is nothing to worry about. Some say that we have already hit peak oil, and there's little we can do. Others say that the rapid development of renewables will fill the gap between demand and supply and reduce our carbon footprint in the process," Hess noted. However, he said, "It is imperative that we change our mindset, our sense of urgency, or the consequences will be severe."

On the demand side, Hess said, "We need to improve fuel efficiency in transportation and increase investments in breakthrough technologies to make fuel-cell vehicles a reality." As for supply, the Organization of Petroleum Exporting Countries and non-OPEC producers need to increase long-term investments "to grow production greater than currently planned to ensure we avoid a supply shortfall in the next 10 years and the calamity that would ensue," he said.

"Each of us has the responsibility to act in the long-term global interest rather than short-term self interest so that we leave a more secure world for future generations," Hess said. "Resolving this issue through greater global collaboration can be a model for managing other future shortages, such as water, and benefit the global community. The more interdependent we are, the greater our chances of having a sustainable future together."

Demand

Most demand is for transportation fuels. In the US, there is an average fuel mileage requirement of 23.4 mpg for passenger cars and 17.7 mpg for light trucks and sport utility vehicles, "all powered by an internal combustion engine that is fairly energy inefficient, with less than 20% of fuel actually converted to useful energy," Hess said.

The federal government has mandated that fuel economy standards increase to 35 mpg by 2020 and new hybrid vehicles are now on the US market. "But unless there is a major breakthrough beyond these improvements, such as the introduction of a commercially and technically proven fuel-cell car, we should not expect to lower demand," Hess warned.

In the developing countries of the world, the problem is worsening with the fast-growing demand for transportation. Goldman Sachs Group Inc. estimates the number of cars on the road will soar to 500 million in China and 600 million in India by 2050. "That's 1.1 billion vehicles in two countries that 3 years ago had fewer than 20 million cars total—creating an overwhelming increase in the need for automotive fuel," said Hess.

"Given the long lead times of at least 5-10 years from discovery to production, an oil crisis is coming and sooner than most people think. Unfortunately, we are behaving in ways that suggest we do not know there is a serious problem."
—Hess Corp. Chairman and Chief Executive John B. Hess

Countries outside the Organization for Economic Cooperation and Development now account for 40% of total oil demand and are expected to reach 50% of world demand by 2020.

"Current population of the world is 6.6 billion and is projected to reach 9 billion by 2050. As the population in developing countries grows, the demand for oil for personal transportation will increase, too. In many cases, the political decision has been made to put subsidies on gasoline, which inflates demand even more," said Hess.

Meanwhile, a $20-100/bbl surge in oil prices in recent years has failed to weaken world demand for crude because consumer incomes have grown faster than energy expenditures. "While energy's share of personal spending in the US is 6%, it is still much less than food, which is 14%; housing, 15%; and medical expenses, 17%. In fact,

CERA: Refiners face change in liquids supply composition

Sam Fletcher
Senior Writer

The refining industry faces new reconfiguration and investment challenges to avoid shortages of diesel, heating oil, and jet fuel while minimizing the risk of a decline in refining capacity utilization, said officials of the Cambridge Energy Research Associates in Houston. Growth in liquids supply capacity will be "more than sufficient" to match the volumetric increase in demand, but the "cocktail" of hydrocarbons in the liquids supply will change, with light liquids accounting for 32% of the total supply in 2020, up from 19% in 2007, CERA said.

"While refined product demand growth becomes increasingly concentrated in the middle of the barrel, particularly for diesel and jet fuel, CERA believes that light liquids, including natural gas liquids, condensates, and—to a lesser degree—biofuels, gas-to-liquids, and coal-to-liquids will dominate supply growth between now and 2020," said Peter Jackson, global oil senior director at CERA. Light liquids yield no fuel oil and only modest volumes of distillates. While some components of the crude oil supply, such as extra-heavy oil, will increase, the overall crude supply, excluding condensate spiked into crude oil, is projected to flatten after 2010.

Because refineries are designed for optimized yield based on a specific mix of feedstocks, changes in supply composition will have implications for utilization rates and yields. Contrary to conventional wisdom, CERA officials said, new supplies of heavy and sour crudes from the Middle East, Latin America, and Canada's oil sands will be balanced by light crude streams from Eurasia and Africa, medium-to-light deepwater oil, and a good portion of Canadian heavy oil upgraded and marketed as light syncrudes. As condensates separated from wet gas at the wellhead rise to 12% of total liquids capacity volume by 2020 and are partly spiked into the crude, the overall feedstock density should not decrease, CERA reported.

At best, total refinery feedstock would grow by only 0.6%/year during 2010-20, much lower than the expected overall demand growth of 1.6%/year. "Therefore, if refiners continue to build crude processing capacity on the 1.6% rate, refining utilization rates and margins would fall," CERA said.

"Rising demand for gasoline and diesel in recent years has led refiners to plan additions of as much as 11 million b/d of capacity to convert residual fuel oil into light products. However, CERA estimates there may be only 6 million b/d of residual fuel oil available for that new conversion capacity," the analysts reported.

Middle distillate products (diesel, heating oil, jet fuel, and kerosine) are projected to account for more than half of world oil demand growth during 2007-20. However, light liquids—the largest additional component of liquids supply—yield only an average of 20% middle distillates, resulting in a middle distillates deficit of about 3 million b/d and a gasoline supply 3 million b/d higher than demand. "The global refining system has the challenge to adapt its configuration to cope with this significant mismatch," said CERA officials.

"As we move beyond 2010, the key challenge for the refining industry will be adding the appropriate type of conversion capacity—particularly hydrocracking—and not necessarily adding more volumes of simple crude distillation capacity," said Olivier Abadie, CERA's downstream director. "In the dynamic oil industry, investment responds to market signals. The degree to which refiners invest in adequate conversion capacity will be critical in successfully addressing this significant change in the composition of global liquids supply."

even after the recent increase in prices, gasoline on a per unit basis is still three times less than the cost of Evian water and 10 times less than a Starbucks latte," said Hess. "We are currently consuming 86 million b/d [of crude], and we project that oil demand will continue to grow between 1-1.5 million b/d each year for the next decade, at least. Recessions may interrupt this growth, but only temporarily."

"As the population in developing countries grows, the demand for oil for personal transportation will increase, too. In many cases, the political decision has been made to put subsidies on gasoline, which inflates demand even more."

Supply

"Since 1980, discoveries have not replaced our annual global crude oil production," Hess noted. "Discoveries are getting smaller and [are] located in more difficult environments, such as the deepwater Gulf of Mexico, Brazil, and West Africa, where companies are now drilling in water depths of up to 7,000 ft and searching for targets that are in some cases more than 30,000 ft deep. Such numbers were unimaginable 10 years ago and speak to the industry's extraordinarily innovative technology to meet increasingly complex challenges to find, develop, and produce crude oil."

He said, "We need to find a new production province like the Alaska North Slope or Angola every year to ensure that we can grow our oil resource base to support increases in production for future generations. We stopped making such meaningful discoveries during the late 1990s."

There is concern whether non-OPEC producing countries can maintain their supply role of a few years ago. According to Hess, US oil production peaked in 1970. North Sea production peaked in 2000. Mexico peaked in 2004. "Within the next few years, conventional non-OPEC production will reach a plateau. In fact, 60% of the world's oil production is from countries that have already peaked," Hess warned.

Renewable fuels, natural gas liquids, and unconventional oil resources such as oil sands and oil shale "need to be encouraged," Hess said. However, he said, "Their contributions to supply are not material enough to bridge the gap in oil requirements over the next 10 years."

With OPEC now down to 2.5 million b/d of spare capacity, Hess said, "We no longer have the safety margin for supply interruptions and demand spikes to ensure price stability. OPEC, with approximately two thirds of the world's proven conventional crude reserves and one third of its production capacity, certainly has the resource base to relieve the pressure." However, he said, "All oil producers—OPEC and non-OPEC alike—simply are not investing enough today to ensure sufficient capacity to meet oil needs in the next 10 years."

Conservation and climate

Hess said, "We need to make significant progress in conservation. The growing population of hybrids and an overall improvement in automotive miles per gallon is helpful, but we need to spend more money on research to make hydrogen fuel-cell vehicles a commercial reality so that the average fuel economy of a new passenger car could increase to the equivalent of 80 mpg or better. Anything we can do in terms of fuel efficiency in transportation would have the important added benefit of helping to solve another critical challenge the world faces—climate change."

He said the US "with 5% of the world's population and 25% of its oil consumption needs to take the lead by continuing to encourage fuel efficiency and improvement in mileage standards while driving for a technological breakthrough. With the US setting the example, hopefully, developing nations could also do their part by moving away from subsidies that send a false signal to their consumers about the real cost of energy and artificially inflate demand."

Hess said, "We must increase investment. In 2007, global E&P investment was estimated to be approximately $350 billion, having grown about 15% each year over the previous 5 years. This increased investment has helped offset field declines and added new production." But given the long lead times from investment to production, he said, "The current sum that both OPEC and non-OPEC nations are investing is far below what is needed to ensure sufficient production for our future."

"We need to find a new production province like the Alaska North Slope or Angola every year to ensure that we can grow our oil resource base to support increases in production for future generations. We stopped making such meaningful discoveries during the late 1990s."

With oil demand growing 1-1.5 million b/d, global crude supply capacity will fall short of global demand between 2015-20. "While the International Energy Agency predicts global demand to average 98.5 million b/d in 2015, based upon current behavior, I do not see how we will meet this projection," Hess said.

Another challenge is the growing cost and reduced availability of equipment, supplies, and services needed to increase production. "All producers have felt the impact of the rapid rise in costs, as rates for steel and offshore drilling rigs have skyrocketed. For example, a deepwater rig that cost $100,000-200,000/day in 2002 today costs $500,000-600,000/day—if you can find one available. Even if the supply industry were able to increase its investment, the significant lag time would still mean a shortfall in terms of meeting future requirements," said Hess.

There also is a shortage of trained and experienced manpower, with US upstream employment down from 700,000 people in the early 1980s to 400,000 today. "The project delays our industry is seeing today result in part from workforce shortages and inexperience. While enrollments in engineering programs have begun to increase, they remain significantly below levels of 25 and 30 years ago," Hess said. "We are replacing our 30- and 40-year veterans with recent graduates. Even if we stepped up our investment levels today where they need to be, we simply do not have the skilled workforce to support the many projects that may be needed." ✦

IEA sees boost in peak OPEC flow from '08 projects

Production projects due on stream this year in members of the Organization of Petroleum Exporting Countries represent peak gross capacity additions of 3.1 million b/d of crude oil and other liquids, says the International Energy Agency (see table).

Last year, OPEC members started up projects with peak total-liquids capacities of 1.25 million b/d.

In its February Oil Market Report, IEA says OPEC members' ability to produce crude oil alone, net of declines in existing fields, could increase by 840,000 b/d during 2008.

NGLs and condensate represent 42% of the peak-capacity estimates for 2008 projects, compared with 20% last year, IEA says.

The agency points out that the time between start-up to plateau output varies from 1-2 months for some projects to 24 months or more for others.

"The net change in OPEC capacity in 2008 is of course markedly less than implied by gross additions starting up in 2008 because of the lag before plateau output is attained and also the

MAIN OPEC CAPACITY PROJECTS DUE ON LINE IN 2008

Country	Project	Peak crude (1,000 b/d)	Peak NGL (1,000 b/d)	Peak condensate (1,000 b/d)
Angola	Kizomba C-Mondo	100		
Angola	Kizomba C-Saxi/Batuque	100		
Indonesia	Kerisi-Hiu			20
Iran	Darkhovin II	110		
Iran	Khesht	35		
Iran	Jufeyr I	25		
Iran	Salman	50		
Iran	Masjid e Suleiman expansion	15		
Iran	Azadegan I	50		
Iran	Pars 6-8			120
Iran	Pars 9-10			80
Iran	Pars 9-10		16	
Iraq	Taq Taq	20		
Iraq	Majnoon increase	50		
Kuwait	Burgan water treatment, etc.	40		
Kuwait	Sabriyah			50
Libya	NC 186 ramp-up	20		
Libya	Waha EOR	20		
Libya	El Shahara ramp-up	10		
Libya	Elephant ramp-up	25		
Nigeria	Akpo			180
Nigeria	Agbami	250		
Qatar	Al Shaheen increments	100		
Qatar	RasGas Train 6			50
Qatar	RasGas Train 6		25	
Qatar	Qatargas Train 4			160
Saudi Arabia	Khursaniyah	500		
Saudi Arabia	Khursaniyah			80
Saudi Arabia	Khursaniyah		220	
Saudi Arabia	Shaybah	200		
Saudi Arabia	Hawiyah NGL		300	
Venezuela	Corocoro	75		
Total		**1,795**	**561**	**740**

Source: International Energy Agency

offsetting impact of mature field decline," it says.

"Moreover, stretched drilling capacity and installation and service crew availability will likely continue to strain project deadlines again this year."

OPEC members also might defer project starts if they believe global oil demand is declining.

"The proliferation of potential additional liquids volumes in 2008 holds forth the prospect that tight OPEC spare capacity could temporarily ease, even if not everything comes to fruition on schedule," IEA says.

Low spare production capacity and low global inventories are signs of the market tightness that has kept crude oil prices high.

IEA estimates sustainable OPEC capacity to produce crude oil—the output level that members can reach with 30 days and maintain for at least 90 days—at 35.04 million b/d. It estimates January OPEC production of crude oil at 32.02 million b/d.

Although IEA has lowered its forecast for 2008, OPEC output of NGLs remains on a strong climb. The agency predicts OPEC NGL production this year will average 5.18 million b/d, up 365,000 b/d. It earlier expected the increase to be 620,000 b/d.

The scale-back reflects a delay in the start-up of the gas phase of Saudi Arabia's Khursaniyah oil and gas field, which is partly offset by expectations for faster buildup in gas from Qatar's Dolphin project. ✦

US House Dems reintroduce bill taxing oil majors

Nick Snow
Washington Editor

US House Democrats reintroduced a bill Feb. 12 to fund renewable energy tax incentives by increasing major oil companies' taxes. Plans originally called for debate by the end of that week, but scheduling conflicts made it necessary to postpone that until after the Presidents' Day recess on Feb. 18.

Sponsors portrayed the proposed taxes as an end to subsidies for an industry that made record profits in 2007 as consumers paid record prices for petroleum products. "Instead, we need an energy plan that reduces our dependency on foreign oil and invests in clean, renewable technology that will create jobs here in America," Ways and Means Chairman Charles B. Rangel said.

He noted that the bill, HR 5351, contains tax credits to promote renewable energy production from wind, solar, geothermal, cellulosic ethanol, and biofuels, many of which are due to expire at yearend. "This bill extends critical tax credits for the production and use of renewable energy while also encouraging families to invest in technology that conserves energy," Rangel said.

The bill's two revenue provisions are directed primarily at major oil companies. The first would deny tax credits under Section 199 of the federal tax code, allowing US businesses to deduct production costs so they are better able to compete with foreign firms receiving government subsidies, to "large integrated oil companies." It also would freeze domestic production income deductions for independent producers and smaller refiners at 6%, the current level. Sponsors said this would raise $13.57 billion over 10 years.

Foreign tax credits

HR 5351's second revenue provision would raise another $4.08 billion over 10 years by closing what sponsors said is a loophole that allows producers to manipulate their foreign extraction income to achieve better results under US foreign tax credit rules. It would require US producers operating overseas to use the ascertainable market values at the nearest point to a well to calculate foreign extraction and oil-related income. It also would require that where a foreign government collects taxes that are limited in their application to oil and gas taxpayers, the taxpayers treat such taxes as oil and gas taxes subject to the foreign oil and gas extraction income credit limitation in the US tax code.

The bill does not include a provision of earlier House bills that would have returned the geological and geophysical expense amortization period to 7 years by repealing the 2005 Energy Policy Act provision, which reduced it to 5 years. The measure had 32 cosponsors when Rangel introduced it.

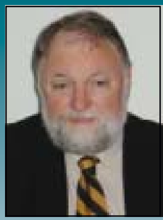
Oil and gas industry associations immediately responded. "This bill, like the prior three or four which have been similar, still makes the mistake of using oil and gas tax provisions to pay for new tax expenditures for other forms of energy. The question is not whether to move forward on these new forms of energy, but whether it makes sense to take capital from investment in existing American energy businesses," said Lee O. Fuller, vice-president of government relations at the Independent Petroleum Association of America, on Feb. 13.

Mark Kibbe, a senior tax analyst at the American Petroleum Institute, found it interesting that House Democrats this time chose a provision repealing Section 199 of the tax code for oil and gas firms from a December bill and another changing the foreign tax credit for US oil and gas firms from an earlier House bill that passed in August. "It's still a $17.65 billion tax on the oil and gas industry, which we think is a particularly poor choice for Congress to make, particularly when it just passed an economic stimulus bill," he told OGJ on Feb. 13.

Kibbe also questioned the idea that the latest bill affects only major oil companies and large refiners. "Clearly, that's not true because they've elected to include the freeze on '199' for smaller companies, including small refiners. They've been saying that more small refineries are needed, which aren't an attractive investment already but would be even less attractive if this investment incentive was repealed," he said. ✦

WATCHING GOVERNMENT

Nick Snow, Washington Editor



Troubling attitudes

Shell Oil Co. Pres. John D. Hofmeister discovered some troubling attitudes as he met with local business and government leaders during his most recent visits to 50 US cities.

"People have embraced $3/gal gasoline. They haven't embraced the oil industry. We're more than disliked; we're disrespected, and it's the industry's own fault," he told reporters during a stop in Washington, DC, on Feb. 14.

That makes the oil and gas industry an easy target for some politicians who use oil companies' high profits to justify punitive legislation, he said, adding, "Bad public policies for the purpose of spiting the oil companies hurt consumers."

Hofmeister also is concerned by substantial beliefs that the US is running out of oil, and that biofuels will solve the problem. The first ignores the 100 billion bbl of technically recoverable resources within this country and the 1 trillion bbl trapped in Colorado, Wyoming, and Utah's oil shale deposits. The second overlooks considerable logistical and technological challenges in making biofuels commercial.

More than fuel

"We think there's a lot that can be done with biofuels and refinery additives, but the problem is not just with the fuel. If miles driven increase or if engine technology doesn't change, there won't be much carbon reduction," Hofmeister said.

Shell does not oppose taxes generally because it considers them a cost of doing business, he said, adding that the company doesn't even mind levies to help finance new technologies because it fully intends to be a leading participant. But the company dislikes recurring proposals to tax only the five biggest US oil companies.

"Taking money from these companies because they've been successful is objectionable. If a tax was imposed across the entire industry, that would be another matter," the Shell executive said.

When Congress considered dramatically expanding the Renewable Fuels Standard in 2007, Shell expressed strong concern that the technology did not exist to meet such an aggressive goal, he said. It also pressed for an "off-ramp" in case it became obvious that the mandate would not succeed. Its biggest argument has been the significant differences between pilot plants and commercial production.

'We don't fear it'

That does not mean that Shell opposes a role for alcohol in motor fuels, Hofmeister said. "We've been in the ethanol business for 30 years. We don't fear it. But we believe that more of it needs to come from waste products, such as the corn stalk instead of the kernel." Hofmeister said failure to recognize that oil and gas will continue playing a major part in meeting near-term US energy demand is probably the biggest single domestic policy mistake made.

"Since our independence, homeland security has been a priority of this country. So has economic security. Energy security should be on the same platform. Without it, homeland and economic insecurity increase," he said. ✦

Alaska progressing on gas line, FERC tells Congress

Nick Snow
Washington Editor

Alaska's selection of a preferred applicant to build a huge natural gas pipeline highlighted the Federal Energy Regulatory Commission's fifth progress report to Congress on the project.

It noted on Feb. 19 that the state chose TransCanada Pipelines Ltd. from five applicants under criteria set in the Alaska Gasline Inducement Act (AGIA), which the legislature passed and Gov. Sarah Palin signed into law in May 2007. TransCanada filed jointly with Foothills Pipe Lines Ltd. to build a line from Alaska's North Slope to TransCanada's hub in Alberta.

FERC Chairman Joseph T. Kelliher said the commission was pleased with the state's progress in choosing a preferred applicant since the federal energy regulator's last such report on Aug. 15. The 2005 Energy Policy Act contained a requirement for FERC to periodically submit reports to Congress on the project's progress.

"I am hopeful this will further encourage development of the Alaskan natural gas pipeline project, and FERC stands ready to act," Kelliher said.

ConocoPhillips Co. also submitted an application Nov. 30, which it acknowledged would not meet all of the requirements under AGIA but expressed hope that it would be considered anyway because it would bring initial gas to markets in mid-2018, according to FERC. Palin rejected it, saying the state would require all applicants to adhere to AGIA requirements.

Keep the project moving

ConocoPhillips said on Feb. 14 that it would reassess how best to advance the project as described in its application. "Despite the lack of progress with the State of Alaska, as an initial step ConocoPhillips will continue its planning and contracting efforts in preparation for a route reconnaissance and environmental studies starting in June 2008. It is important that we take advantage of this summer field season and keep this project moving ahead," said Jim Bowles, president of the company's Alaska division.

Palin responded that Alaska would continue to evaluate TransCanada's application and would not permit negotiations with ConocoPhillips to affect its final decision. "As for the gas side of this project and the requests ConocoPhillips has made, we are more than willing to engage in a discussion about the gas terms at the appropriate time," she continued.

"Last year, we made available a package of gas terms as a part of the AGIA legislation. We are open to changing those terms as long as they are fair, reasonable, and based on data," Palin said. Moving to an open season would provide necessary data to make sound decisions on those gas terms, she added.

LNG project options

FERC also said there have been developments connected with an LNG proposal. The Alaska Gasline Port Authority, a municipal entity created by the City of Valdez, the Fairbanks North Star Borough, and the North Slope Borough, proposed construction of a gas pipeline from Prudhoe Bay to Valdez, where the gas would be liquefied and exported.

Alaskan officials rejected the Port Authority's request to reconsider an earlier determination that the group's application was incomplete. However the officials agreed to thoroughly evaluate LNG project options as part of their determination whether a gas pipeline that goes through Canada sufficiently maximizes benefits to Alaska's population and merits receiving an AGIA license, FERC's report said.

Alaska has held a series of public meetings across the state about the TransCanada proposal and AGIA during a 60-day comment period that concludes Mar. 6. Alaska's legislature is conducting hearings of all five proposals submitted under AGIA and has invited companies that did not submit AGIA applications to testify. FERC's report said state officials will then decide whether the proposal merits issuance of an exclusive AGIA license, in which case Palin would submit the license to the legislature for final approval, possibly in April. Legislative action to approve the license would have to come within 60 days, and the license could be issued as soon as June, the report suggested.

FERC said other signs of progress since Aug. 15 are the federal coordinator's continued discussions with stakeholders and a technical conference that FERC's staff held in January to discuss third-party contracting requirements and expectations in preparing an environmental impact statement about the project. ✦

Shell tables Nigerian restructuring plans

Uchenna Izundu
International Editor

Shell Petroleum Development Co. (SPDC) has suspended its plans to restructure its joint venture in Nigeria following a request from Nigeria National Petroleum Corp. (NNPC) to resolve its oil production problems and improve efficiency. The development leaves in limbo the jobs of 5,000 employees, most of whom are Nigerians.

Shell had announced last November plans to reduce costs by cutting jobs and to boost efficiency and productivity in its JV, which it operates and shares with NNPC, Total, and Agip, as militants and vandals' attacks on its oil and gas facilities in western Nigeria have shut down 470,000 b/d of oil capacity for the past 2 years. Shell estimated that slimming down the organization will save $200 million/year.

A Shell spokesman told OGJ it could not say for how long it would suspend its restructuring, adding that it was continuing talks with NNPC about the problems in western Nigeria. "NNPC has asked for more information about our plans. We don't know how many jobs will be affected by the restructuring as we haven't finished working out the details. Figures in the press that it would be 3,000 are pure speculation."

NNPC head Abubakar Yar'Adua told a parliamentary hearing Feb. 18 that, although it appreciates the production challenges Shell is facing, NNPC had not been consulted before Shell began the exercise. According to Nigerian reports, the federal government plans to bail out Shell and other such companies through a special financial package that would be arranged shortly.

Shell, one of the major operators in Nigeria, has had to struggle to implement its projects in Nigeria because of insecurity in the Niger Delta and because NNPC has failed to contribute its share of funds to the JV. Rising production costs also have exacerbated the problems.

Mutiu Sumonu, Shell's managing director, told the parliamentary committee that the restructuring was crucial to Shell JV's survival and would create a synergy between SPDC and Shell Nigeria Exploration & Production Co.

He was quoted in reports as saying: "We used to produce 1 million b/d but due to the Niger Delta crisis, we are struggling to meet up with half of that. There is no access to our production in the west, and we have maintained our staff strength up until this moment. We took a look at our future development plan covering 2008-12 and discovered that business is already half of what it ought to be. The whole business output requires that we take some action in the interest of the business." ✦

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

South Korea's diplomacy

South Korea's new government has become keenly aware of the need to pursue diplomacy in securing its supplies of oil and gas—especially from Iraq.

For South Korea, being resource-poor and one of the world's leading consumers of oil and gas, diplomacy is a necessary skill to develop, especially following its talks with the Kurdish regional government (KRG).

In fact, Seoul's first foray into the labyrinths of Middle Eastern oil and gas diplomacy has not met with much approval at home. In a recent editorial, the Korea Times conceded that the incoming government's vow to focus on resource diplomacy is welcome.

It said the need to make all-out efforts to secure natural resources, particularly oil, can hardly be overemphasized. South Korea, the world's 10th largest energy consumer, relies on foreign suppliers for 97% of its demand, with slightly more than 4% coming from its own oil fields abroad.

Falling short

What's left is how to put the new diplomacy into action in the most effective ways, but the paper said recent efforts by President-elect Lee Myung-bak "fell somewhat short of expectations in this regard."

Lee met Nechirvan Barzani, the head of KRG, who sought cooperation in oil development in the Kurdish region. Lee's transition team said a memorandum of understanding to explore a reserve of some 2 billion bbl was the "first fruit" of its resource diplomacy.

The Korea Times disagreed. "It's questionable whether Lee should have met the Kurdistan leader, considering the Iraqi central government lately took issue with a similar previous MOU as infringing on its authority," the paper said.

"Equally uncertain," it intoned, "is how the meeting will affect negotiations between SK Corp. and Baghdad to resume Iraq's crude exports to the nation's largest refinery that have since been suspended."

That suspension came into play earlier this month when Iraqi Oil Minister Husayn al-Shahrastani threatened that international oil firms would be blacklisted in his country if they signed contracts with the KRG.

Unpalatable agreement

It remains to be seen how al-Shahrastani will react to the most recent news coming from the meeting between the Kurds and the South Koreans. On Feb. 20 Lee's government said South Korea's development of oil fields in northern Iraq is likely to surpass the agreement signed with the Kurds on Feb. 14.

It said Barzani notified Lee's transition team of his desire to expand the scope of the oil field development program to 3 billion bbl from the initially agreed 1.5-2 billion bbl, while spending on social projects for the region would jump to $5 billion from the earlier $2 billion.

There's a lot at stake here as al-Shahrastani knows. If the Koreans get away with this deal, then others will try, too. Clearly, to make the agreement even slightly palatable to the Iraqi oil minister, Lee's government will have to deploy all the diplomacy it can possibly muster up. ✦

Mexico's oil decline rate to steepen through 2010

Eric Watkins
Senior Correspondent

Mexico will face difficulties in producing crude oil over the coming 2 years, according to a media report, which claims that Cantarell and Ku-Maloob-Zaap (KMZ) fields will decline simultaneously in 2010.

"As we move toward that scenario," said El Financero newspaper, "Cantarell's decline became more pronounced in 2007, when it stopped producing an average of 304,000 b/d. It declined by 234,000 b/d in 2006 and 101,000 b/d in 2005, the paper reported.

According to the paper, that reduction contributed to a drop of 174,000 b/d in the country's total production in 2007, compared with a decline of 78,000 b/d in 2006 and 50,000 b/d in 2005.

Although KMZ's oil production average increased by 123,400 b/d in 2007, representing a 30.6% increase over 2006, it is not offsetting much of Cantarell's decline because its increase made up for only a third of the decline in Cantarell, El Financero said.

Officials at state-owned Pemex expect KMZ to reach its highest production level in 2010, averaging 800,000 b/d of crude oil. Thereafter, its decline will begin, along with that of Cantarell.

Pemex officials commented that Chicontepec, comprising onshore wells, could compensate for part of the decline in both fields. It currently produces 100,000 b/d, which could swell to 500,000 b/d by 2010.

"Nevertheless," El Financero said, "because of the characteristics of the terrain where Chicontepec is located, crude oil extraction will be very difficult."

According to Sener, the 2007-16 Crude Oil Market Outlook prepared by the Energy Information System of the Energy Secretariat, in any scenario—high or low—Cantarell's production will average 917,000-921,000 b/d during 2006-16, with an average annual decline of 14.1%.

The Sener scenario says Chicontepec and KMZ will partially make up for expected declines in Cantarell, although it will be impossible to maintain production at the levels reached in previous years.

In Sener's low scenario, it is estimated that Chicontepec will increase its production rate by 32%/year. The increase in volume by 2016, however, will be 360,000 b/d, compared with the figure obtained in 2006, "which would mean that this project would be incapable of making up for the drop in production at the exploitation and Cantarell projects."

El Financero concluded that, "in the scenario of decreasing energy production, a more pronounced decline is expected in the northeast marine region, where the most productive assets are found, and effects are also anticipated in the southwest marine and south regions, which will have reductions of 40% and 20%, respectively." ✦

BG lifts Tupi reserves estimate; Petrobras mum

Brazil' Petroleo Brasileiro SA (Petrobras) has declined to comment on revised production estimates BG Group has made concerning the supergiant Tupi oil discovery in the Santos basin.

"We will not comment on those projections,"said a Petrobras spokesman, apparently referring to comments made by BG Chief Executive Officer Frank Chapman that production at the offshore field could reach 1 million boe/d when fully developed.

Petrobras reported late in 2007 the discovery of as much as 8 billion bbl of light crude in Tupi field off Rio de Janeiro. The estimated reserves could make Brazil a major world oil exporter.

However, BG Group now estimates total hydrocarbons in place on the Tupi discovery to be 12-30 billion boe or

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more, up from its own earlier estimates of 1.7-10 billion boe gross hydrocarbons in place.

BG's revised reserve estimate was reported in a statement concerning the company's long-term growth strategy that was released ahead of the presentation of its fourth-quarter results.

BG also said the Carioca discovery made in the Santos basin in 2007 had further prospects still to be explored, including two with "very large potential," the Corcovado and Iguacu complex.

Petrobras holds a 65% stake in Block BM-S-11 where Tupi was discovered and is the operator. BG has a 25% stake, and Portugal's Galp Energia holds 10%. ✦

Albania

Bankers Petroleum Ltd., Calgary, agreed to acquire 50% of a private company that holds the exclusive right to evaluate and redevelop Kucova heavy oil field in south-central Albania.

The private company, Privatco, has an agreement with state Albpetrol ShA and a license from Albania's National Agency of National Resources. The terms of the petroleum agreement are basically the same as those that govern Bankers' agreement for Patos-Marinza oil field.

The deal is to close soon, and Bankers has until June 30, 2008, to exercise an option to acquire the other 50% interest.

Original oil in place at Kucova was 490 million bbl of 17° gravity oil, of which about 6% has been produced. Kucova is geologically similar to Patos-Marinza, with multiple stacked sandstone reservoirs at 150-1,400 m with oil of various gravities.

Kucova, 30 km northeast of Patos-Marinza, averaged 400 b/d at the end of 2006. It was discovered in 1928 and has more than 1,700 wells.

Redevelopment by Bankers would involve updating surface and downhole equipment, wellbore stimulations, recompletions, waterflooding, and thermal recovery.

Falkland Islands

Prospects identified from 850 sq km of 2007 3D seismic on PL032 and PL033 in the North Falkland basin could contain a mean 1.9 billion bbl recoverable, estimated directors of Rockhopper Exploration PLC.

Other leads are under investigation, and prospects identified on PL023 and PL024 could have an estimated 2.5 billion bbl recoverable.

The new mapping identified five hydrocarbon plays on the acreage and confirmed the presence of multiple drilling targets.

The 3D seismic also revealed that one of the exploration wells Shell drilled in 1998—which among other oil shows encountered a thin sand with good hydrocarbon shows—is located at the edge of a fan prospect that appears to thicken towards its center. The directors believe that this thicker part of the fan prospect could contain commercially viable hydrocarbon accumulations.

Rockhopper plans to conduct AVO analysis, imaging studies, geochemical modeling, further detailed log analysis, depth conversion, and reservoir modeling.

Niger

Security situation permitting, CNPC International (Tenere) Ltd. plans to shoot seismic and drill the Facai-1 exploratory well in May to test a Cretaceous play in the northeastern Tenere rift basin in Niger.

The location is 100 km north of the Saha-1 and Fachi West-1 wells drilled in 2007. Facai-1 is to test the Cretaceous Donga formation and synrift sandstones, equivalent to those found at the base of Saha-1, in a faulted anticlinal trap.

The seismic program is expected to target Cretaceous and another newly identified play and to mature other prospects and provide infill on play trends in the sparsely controlled subbasin north of Facai-1, said 20% interest holder TG World Energy Corp., Calgary.

The other play is a shallower Cretaceous sand east of the deeper Cretaceous sand fairway to be tested by Facai-1.

Manitoba

Tundra Oil & Gas Ltd., private Winnipeg operator, plans to unitize and waterflood Sinclair oil field in the Williston basin in southwestern Manitoba and might inject carbon dioxide later.

Tundra, which has a 36-well pilot waterflood in 4-8-29w1 and 9-8-29w1, plans to Tundra hopes to complete unitization by the end of February and start water injection at the end of May in a 192-well program on 12 sq miles. That will include eight wells owned by Crown Point Ventures Ltd., Vancouver, BC, in 15-8-29w1.

Recovery is expected to grow from 10% of OOIP by primary means to as much as 20% with waterflooding and 30% or more with CO_2 and waterflooding, Crown Point said.

A future expansion could include Crown Point's eight wells in 3-9-29w1.

Utah

Thunderbird Energy Corp., Calgary, acquired 50% working interest in a 5,000-acre land package adjacent and north of the company's producing Gordon Creek gas field in central Utah.

The property roughly doubles Thunderbird's land position.

Gordon Creek field, with four producing and six shut-in wells, a gathering-compression system, and more than 10 km of pipeline, is upstructure from Drunkards Wash, Utah's largest gas field and largest coalbed methane field.

North Amethyst, first White Rose satellite to be developed

Guntis Moritis
Production Editor

North Amethyst is the first of several White Rose field satellite discoveries that Husky Energy Inc. plans to develop off Newfoundland.

Husky's August 2007 development plan is now under review by the Canada-Newfoundland and Labrador Offshore Petroleum Board and, if it is approved, development drilling may commence in mid-2008. For drilling these subsea tied-in wells, the company recently secured Transocean Inc.'s mobile semisubmersible drilling unit GSF Grand Banks.

The petroleum board approved development of another satellite area, South White Rose extension, in September 2007. Also Husky is evaluating results of delineation drilling conducted in 2007 for West White Rose prior to submitting a development application for the project.

White Rose

White Rose field produces to the SeaRose floating production, storage, and offloading (FPSO) vessel. The SeaRose has a disconnectable turret for ice avoidance. Oil production from the field began on Nov. 12, 2005.

Husky, the operator, has a 72.5% working interest in White Rose, which lies on the eastern margin of the Jeanne d'Arc basin, about 350 km east of St. John's (Fig. 1). Petro-Canada holds the remaining 27.5% interest in the field.

The field has three pools: North, West and South Avalon (Fig. 2). The South Avalon was the initial pool developed in the $2.35 billion project.

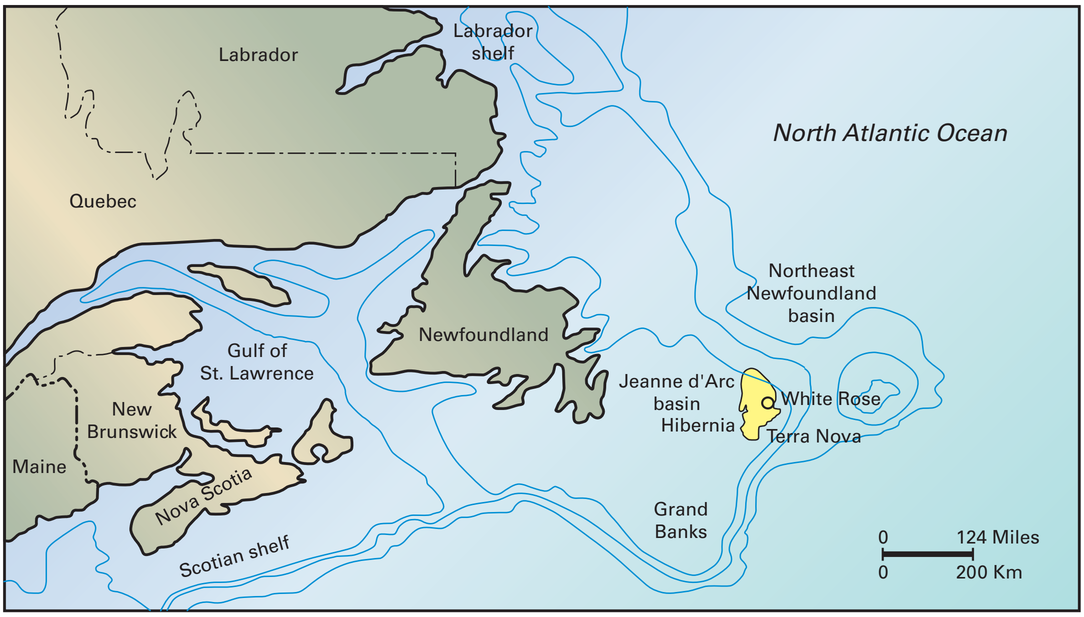
South Avalon is in 120 m of water, and Husky expects to recover 200-250 million bbl of 30° gravity oil from the pool.

Husky's base production profile for White Rose predicts that the SeaRose will begin reaching the end of production plateau in 2008. As spare production capacity becomes available, subsea tie-back wells will start using this spare capacity.

The North Amethyst satellite tie-back involves a new glory hole with a capacity for up to 16 wells. In its August 2007 development plan, Husky esti-

WHITE ROSE FIELD

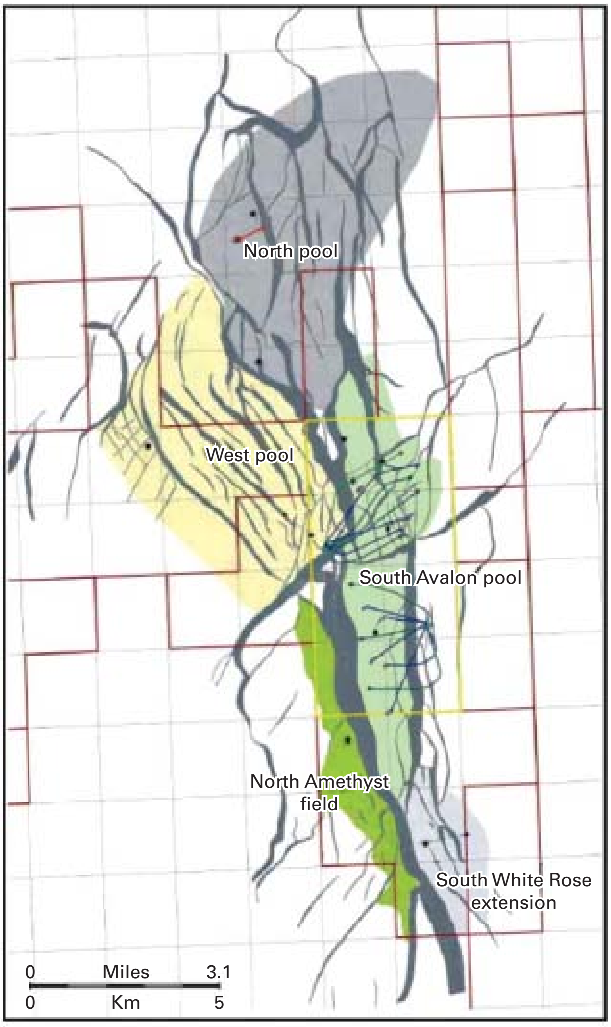
Fig. 1



Source: Husky Report SR-SRT-RP-0002, North Amethyst Satellite Tie-Back to SeaRose FPSO Development Plan, August 2007

North Amethyst field

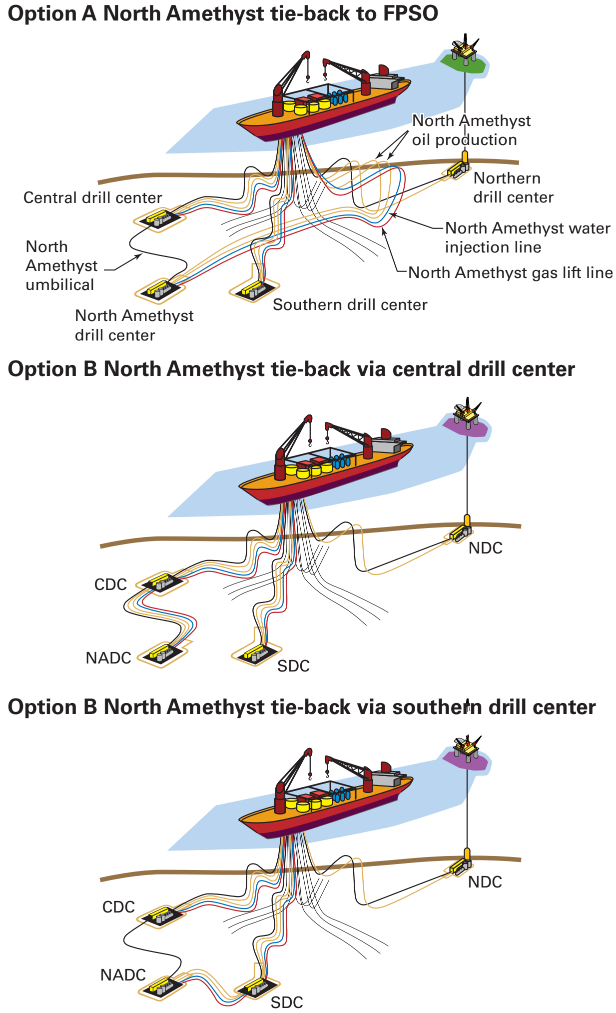
Fig. 2



Source: Husky Report SR-SRT-RP-0002, North Amethyst Satellite Tie-Back to SeaRose FPSO Development Plan, August 2007

Tie-back options

Fig. 3



Source: Husky Report SR-SRT-RP-0003, White Rose Development Plan Amendment SeaRose FPSO Modifications, August 2007.

mates that the P50 (50% probability) recoverable oil from North Amethyst is 70 million bbl out of the 256 million bbl of oil in place. The plan expects the development will have a $1.3 billion (Can.) capital cost. Husky's base-case estimate is that North Amethyst's wells will have a maximum oil production of 62,900-75,500 b/d.

North Amethyst will produced from the Ben Nevis formation, which is 600 m shallower then in the South Avalon pool. In North Amethyst, a gas cap overlies the oil column and the properties are similar to those in the South Avalon.

The plan expects South White Rose and North Amethyst together to have 19-21 wells, including 7-8 horizontal oil producers, 10-11 water injectors, and 2 deviated gas injectors.

Husky plans for the water injection to support reservoir pressure in North Amethyst and will inject produced gas from North Amethyst into North Avalon for storage. Excess gas from South Avalon already is being injected into North Avalon. Husky expects to recover the injected gas from North Avalon in the future.

Husky's development plan includes two possible scenarios of tying back the North Amethyst satellite (Fig. 3). In one case, satellite wells would tie back to the Sea Rose with dedicated flowlines and risers terminating at the buoy. This option requires modifying the FPSO turret, buoy, and topsides to accommodate the new flowlines, risers and umbilical. Also this case requires the Sea Rose to be disconnected and brought to shore for the modifications, possibly in summer 2010. In this case, Husky expects first oil from North Amethyst in fall 2010.

In the second scenario, North Amethyst would tie back through existing subsea infrastructure. This option would not require turret modifications and would delay topsides modifications to later, according to Husky's proposed plan.

SeaRose FPSO

Husky advanced the planned maintenance turnaround for the SeaRose from the original August 2008 date to first-quarter 2008. The work entailed shutting in production in late January and early February for 13 days.

Husky said that it brought the schedule forward to address the problem of sediment buildup in the low-pressure separator, which had curtailed production to about 90,000-95,000 b/d. After the turnaround, production increased to about 130,000 b/d, Husky reported.

Combining the planned turnaround with the cleaning of the low-pressure separator, Husky expects the annual White Rose production in 2008 to be about the same as previously estimated. ✦

Pure rolling of bit cones doubles performance

Yuri A. Palashchenko
Consultant
Moscow

CLASSIC BIT KINEMATICS—3

The first two parts of this series showed that roller cone bit design analysis can predict cone behavior when heel teeth have equal pitch and how bit kinematics are modeled differently when the heel teeth on roller cones have varied pitch (OGJ, Feb. 4, 2008, p. 46; Feb. 11, 2008, p. 42).

This third of four articles discusses the concept of structural and technological well-bottom racks formed by roller cone rock bits and studies the performance of the bits interacting with the well bottom in the process of pure rolling behavior of the cones.

Structural rack

We based our theory of the well-bottom rack formation process upon the assumption that each cone began to roll its own sector of the hole bottom while supported by a single tooth of the cone heel row. We also assumed that the rack profile formed by the bit did not depend upon rock mechanical properties and its surface conditions but was determined only by the cone design and always had the same number of "teeth." Let's call this the "structural" rack.

Equations

$$Z'_{a1} = \frac{(\Sigma N_k) - 1}{3};\ Z'_{a2} = \frac{(\Sigma N_k) - 2}{3};\ Z'_{a3} = \frac{(\Sigma N_k) - 3}{3};$$
$$Z'_{a4} = \frac{(\Sigma N_k) - 4}{3};\ Z'_{a5} = \frac{(\Sigma N_k) - 5}{3};\ Z'_{a6} = \frac{(\Sigma N_k) + 1}{3} \quad (1)$$

$$\frac{iZ}{n} = N \quad (2)$$

$$i_a = \frac{108.5 \text{ rpm}}{69 \text{ rpm}} = 1.57 \quad (3)$$

$$i_a = \frac{Z_r}{Z} \quad (4)$$

Nomenclature

$i = \frac{D}{d}$ = the gear ratio of the cones at pure rolling
D = the bit diameter, mm
d = the gauge tip diameter of the cone, mm
Z = the number of the heel teeth on each cone
N = integer
n = the number of the bit cones
Z_r = number of craters on the well bottom rack

Since the rock bit kinematics are determined by the bottom-well rack profile, the gear ratio and the extent of skidding of the cones, discussed earlier in this series, would also be structurally determined.

We have twice suggested possible corrections to rock bit kinematic analysis:

- When we pointed out the higher probability of slowing rotation of the cones in incompetent formations, notwithstanding their structurally incorporated accelerated rotational speed.
- When we noted the phenomenon of the transformation of the leading cone of the given bit induced by the variation of the well-bottom rack "teeth" number.

Technological rack

Now, let's determine the fixed limits of possible deviations in the rock bit

Versions of structural rack and gear ratios for different bits

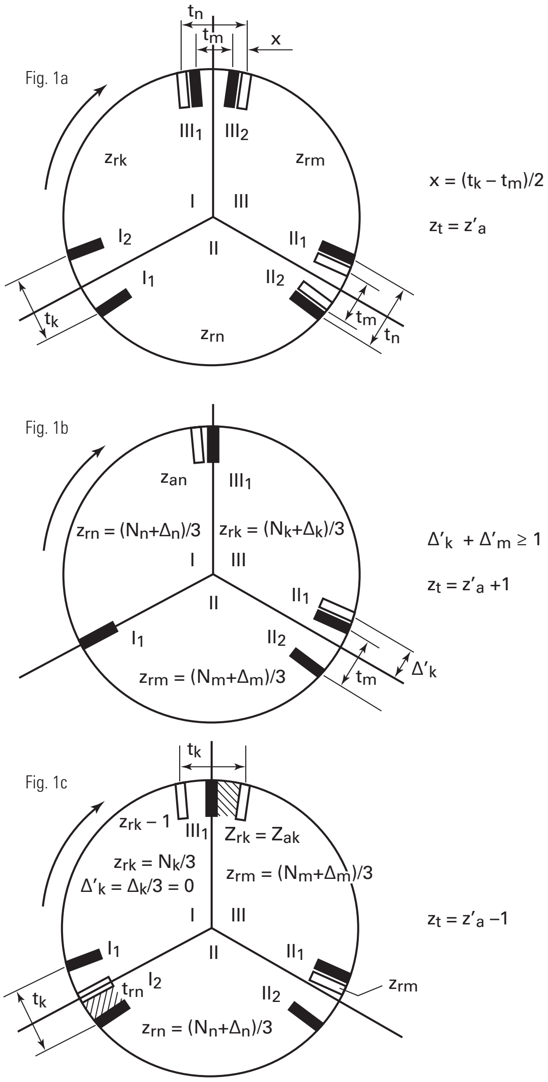
Table 1

		$Z'_{a1} = \frac{\Sigma N_k - 1}{3}$		$Z'_{a2} = \frac{\Sigma N_k - 2}{3}$		$Z'_{a3} = \frac{\Sigma N_k - 3}{3}$		$Z'_{a4} = \frac{\Sigma N_k - 4}{3}$		$Z'_{a5} = \frac{\Sigma N_k - 5}{3}$		$Z'_{a6} = \frac{\Sigma N_k + 1}{3}$	
Bit type	**Cone**	Z_t	i_t	Z_t	i_t	Z_t	i_t	Z_t	i_t	Z_t	i_t	Z_t	i_t
B-151T	I	—	—	—	*1.6	—	—	—	—	—	*1.55	—	1.65
	II	32.3	—	32	1.52	31.6	—	31.4	—	31	1.48	33	*1.57
	III	—	—	—	1.45	—	—	—	—	—	1.41	—	1.5
B-190T	I	—	*1.5	—	—	—	—	—	1.45	—	—	—	—
	II	30	1.58	29.7	—	29.1	—	29	*1.53	28.6	—	30.6	—
	III	—	1.43	—	—	—	—	—	1.38	—	—	—	—
K-190T	I	—	—	—	1.45	—	—	—	—	—	1.4	—	1.5
	II	29.3	—	29	*1.53	28.6	—	28.3	—	28	*1.48	30	1.58
	III	—	—	—	1.38	—	—	—	—	—	1.33	—	1.43
K-214T	I	—	*1.61	—	—	—	—	—	*1.55	—	—	—	—
	II	29	1.53	28.6	—	28.3	—	28	1.48	27.7	—	29.7	—
	III	—	1.45	—	—	—	—	—	1.4	—	—	—	—

*The "leading" cone gear ratio.

Technological rack, sector analysis

Fig. 1



kinematics, putting aside our assumptions, and review the formation of the real, not structural, well-bottom rack in the drilling process. Let's call this the "technological" rack.

If, at the initial moment that the bottom-well rack is formed, all cones contact the hole bottom by two teeth, instead of one tooth, this case would not differ from the initially assumed case. This is because the difference in the cone kinematics would only be in the calculated numbers of the rack teeth, $N_k + \Delta_k$, change for the value x/t. In other words, they will equal $N_k + \Delta_k + x/t$, where $x = (t_m - t_k)/2$, while even equal heel teeth pitch would not make much of a difference because x = 0 (Fig. 1a).

This means that if the cones begin to form the rack on the bottom of the hole, all of them supported by the same number of the heel teeth, then the rack will correspond to the "structural" type.

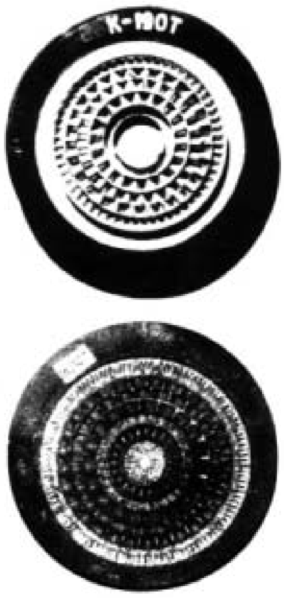
The moment the cones touch the well bottom with their heel rows, their second-row teeth also contact the well bottom (when spudding from a flat, horizontal surface, multicone bits may initially bear only against their second rows). Actually, at the initial moment of the well-bottom rack formation with the heel rows, each of the cones may arbitrarily bear against either one or two of the heel teeth. And that determines the character of the technological rack profile in each individual drilling episode.

If fractional parts of the estimated rack teeth number at two adjoining sectors (when considering a three-cone bit, each rack sector adjoins the other two) added up are equal or close to 1, ($\Delta'_k + \Delta'_m = 1$ or $\Delta'_k + \Delta'_m \approx 1$ or $\Delta'_k + \Delta'_m > 1$) and if, at the beginning of the rack formation, one of the cones is supported by a single heel tooth while the other rotationally successive bit cone is supported by two teeth contacting the rock, then the actual technological rack teeth number will exceed that of the structural rack by 1, as shown in Fig. 1b.

If the estimated quantity of the teeth

Test rack formed on steel*

Fig. 2



*Using K-190T and K-214T bits.

in some sector of the rack for the given cone is equal to an integer, i.e., $z_{rk} = z_{ak} = N_k/3$ (at $\Delta_{k\approx0}$)or z_{rk}, and if that cone at the beginning of the rack formation is supported by two contacting teeth while the other rotationally successive cones are supported by one and two teeth accordingly, then the actual number of the technological rack teeth will be less by one than that for the structural rack. This is because a half of the "tooth" from both sides of the considered sector will be twice subtracted from the value $Z_{rk} = Z_{ak}$. Fig. 1c, which illustrates this, showing that from the sector of the cone I that has $Z_{rk} = N_k/3$ and, at the beginning of the rack formation, is supported by two teeth, I_2 and I_1, one "tooth" with its two halves (Fig. 1c, shaded) behaves as if migrating into the adjoining sectors of the rack where the number of teeth has remained constant.

In the general case, to avoid a detailed analysis of all possible combinations of positions of the contacting teeth of the cones, the number of the basic technological rack versions for the given bit may be found formally using Equation 1 which can yield six values of the actual "teeth" number for

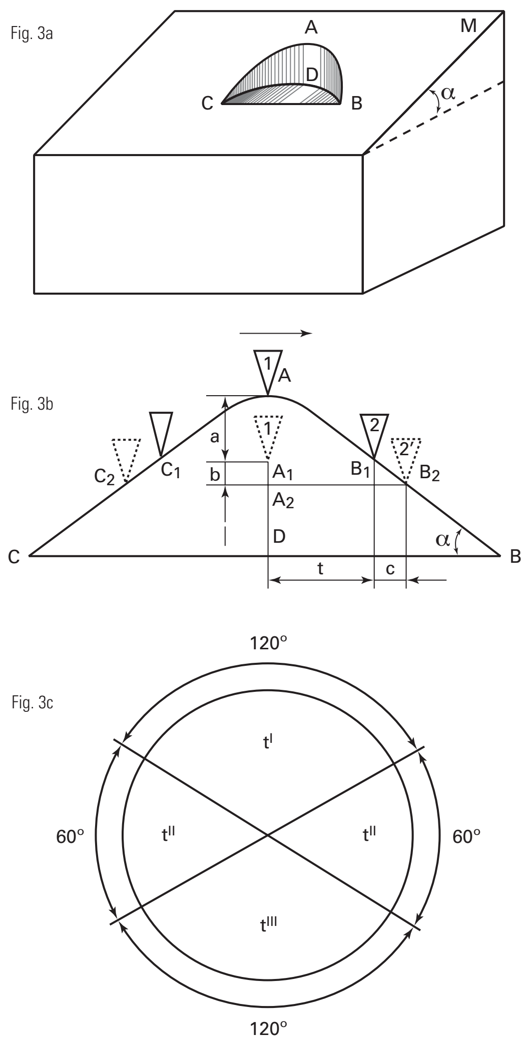
PROBABILITY OF RACK FORMATION

Table 2

Bit type	$P_{(Z)}$		
B-151T	$P_{(31)}$ = 1/2	$P_{(32)}$ = 1/3	$P_{(33)}$ = 1/6
B-190T	$P_{(28)}$ = 1/6	$P_{(29)}$ = 1/2	$P_{(30)}$ = 1/3
K-190T	$P_{(28)}$ = 1/2	$P_{(29)}$ = 1/3	$P_{(30)}$ = 1/6
K-214T	$P_{(27)}$ = 1/6	$P_{(28)}$ = 1/2	$P_{(29)}$ = 1/3

HOLE BOTTOM SEGMENTS FOR INCLINED ROCK SURFACE

Fig. 3



*Hole bottom segments for inclined rock surface at the very bottom of 3a-b-c

the rack, Z'_a. At that, the number of the basic versions will be determined by the quantity of integral Z'_a values.

Commercial bit variation

Table 1 supplements the table on characteristics of commercial bits already published in Part 2 of this series (OGJ, Feb. 11, 2008, p. 42). The earlier table presents structural kinematic parameters of four different bits (B-151T, B-190T, K-190T, and K-214T). Table 1 records possible versions of the technological rack and their corresponding gear ratios, and notes the "leading" cones.

We see from Table 1 that each bit can form a well-bottom rack with different technological values for the teeth, Z_t:

- B-151T bit can have three basic technological values for the teeth, Z_t = 31, 32, and 33.
- B-190T bit can have two values, Z_t = 29 and 30.
- K-190T bit can have three values, Z_t = 28, 29, and 30.
- K-214 bit can have two values for the "teeth," Z_t = 28 and 29.

Taking into account the fractional values of Z'_a that tend towards one or another value of Z_t or which can constitute an additional Z_t value leads to the conclusion that for each version of the rack there exists a different probability for its formation.

Table 2 shows the probabilities of rack formation at the given teeth number for the four commercial bits, $P_{(Z)}$.

Table 3 shows the most probable numbers of technological rack teeth and their corresponding technological gear ratios for the cones of the four bit types.

In most cases, the data in Table 3 reveal conformity of the technological and structural racks for the B-190T bit, while the B-151T, K-190T, and K-214T bits are more prone to form the technological rack with one less tooth than the number of teeth of the corresponding structural rack. This means that the cones of the latter three bits are subject to excess skidding.

Tooth migration

The data also indicate that the two similar bits, B-190T and K-190T, manufactured at different plants, vary in their kinematic parameters, as previously published.[1]

This difference reflects the fact that the estimated teeth number of one of the rack sectors for the B-151T, K-190T, and K-214T bits is equal to or very close to an integer, and that may result in migration of one of the rack teeth, which is not observed for the B-151T bit (OGJ, Feb. 11, 2008, p. 42; Table 1).

Moreover, the B-151T, K-190T, and K-214T bits exemplify a firm trend of this kind of tooth migration and therefore such correlation of the estimated rack teeth numbers should be avoided in bit design. In particular, the gauge tip diameter of the K-190T

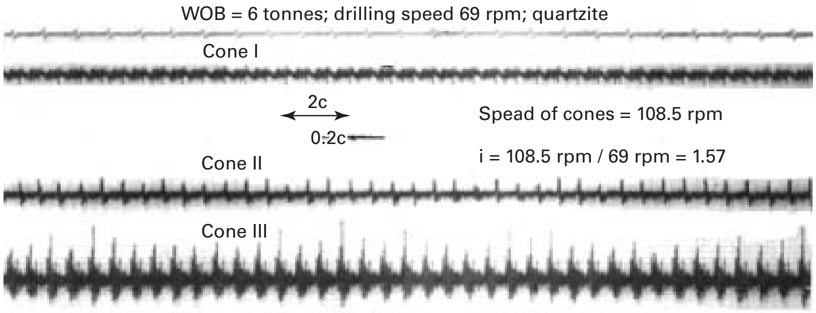
TECHNOLOGICAL, STRUCTURAL RACK COMPARISON

Table 3

Bit type	Z_t	i_t Cone I	Cone II	Cone III	i_{theor}	Leading cone
B-151T	31	1.55	1.48	1.41	1.573	I (t_{max})
B-190T	29	1.45	1.53	1.38	1.532	II (t_{max})
K-190T	28	1.4	1.48	1.33	1.513	II (t_{max})
K-214T	28	1.55	1.47	1.40	1.573	I (t_{max})

Oscillogram, 21B-151T bit*

Fig. 4



*Top to bottom, shows relative rotation speed of first, second, and third cones.

bit cones should not equal 125.59 mm, but should be 124 mm, as it is in the B-190T bit.

The difference in the B-190T and K-190T bit kinematics caused by a slight variance in the gauge tip diameters of their cones (only 1.59 mm) leads to different results in performance, as revealed during their stand tests[1] and affirmed in field practice. It is well known that the efficiency of K-190T bits lags behind that of B-190T bits.

Fig. 2 shows the character of the rack formed by the K-190T and K-214T bits when drilling steel hole bottom on a test drill stand at the Kuibishev specialized bit design office in Russia. Comparing these pictures with a previously published image (OGJ, Feb. 4, 2008, p. 46; Fig. 3), which shows the hole bottom formed by the B-190T bit, we see unambiguous confirmation of the substantial difference in kinematics of the bits.

If the rack formed by the B-190T bit is clear-cut and even along the entire metallic bottom, then the bottoms formed by the K-190T and K-214T bits lack the rack rolled by the heel and central rows due to their excessive skidding. Consequently, the B-190T bit destroys the whole surface of the hole bottom with equal efficiency while the K-190T and K-214T bits just hang up on the second rows of their cones.

For the K-190T and K-214T bits, the increased skidding of the heel and central rows does not promote a higher rate of well-bottom destruction and results in excess wear. Simultaneously, the bit bearing is subject to a more intensive wear since the increased skidding of the cones predetermines their increased torque. It is well known that during cone rotation, the moment of rock resistance is equal to the moment of frictional forces in the bearing. This explains the fact that during drilling in field conditions both the cutting structure and the bearing of the K-190T bits are, as a rule, less wear-resistant than those of the B-190T bits.

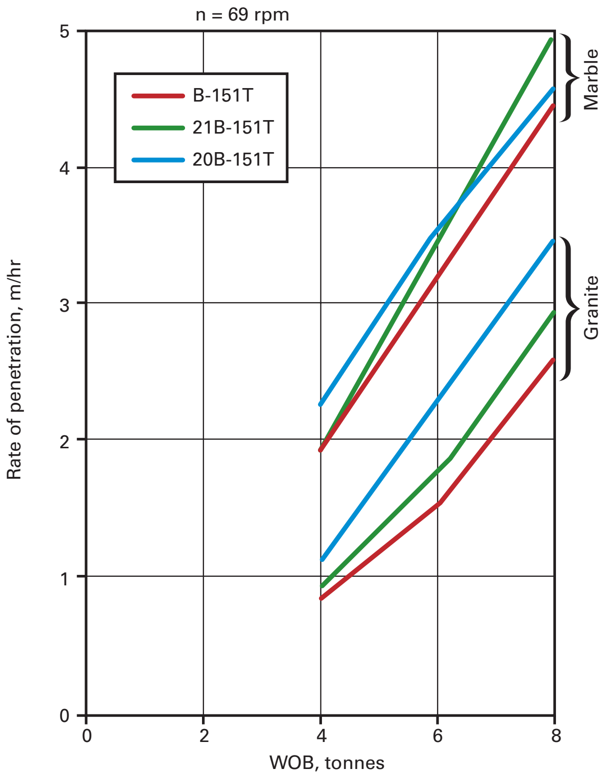
Bit efficiency

Hence, an important conclusion may be drawn that kinematics and consequently, the efficiency of rock bits, are very closely related to accuracy in their manufacturing and may vary, regardless of whether they are within design tolerances. It is not accidental that problems of bit manufacturing quality impact their performance and are subject to investigation.[2]

Besides this, the bit kinematic parameters will vary due to wear of the gauging sides of the cones during drilling. In particular, skidding of the cones' heel rows will progress, making their wear even more pronounced. It's obviously necessary to solve the problem of bit gauge loss while drilling with milled-teeth drillbits.

ROP comparison, three bits

Fig. 5



Cone arrangement

It's important to note some other peculiarities of the rock bit kinematics.

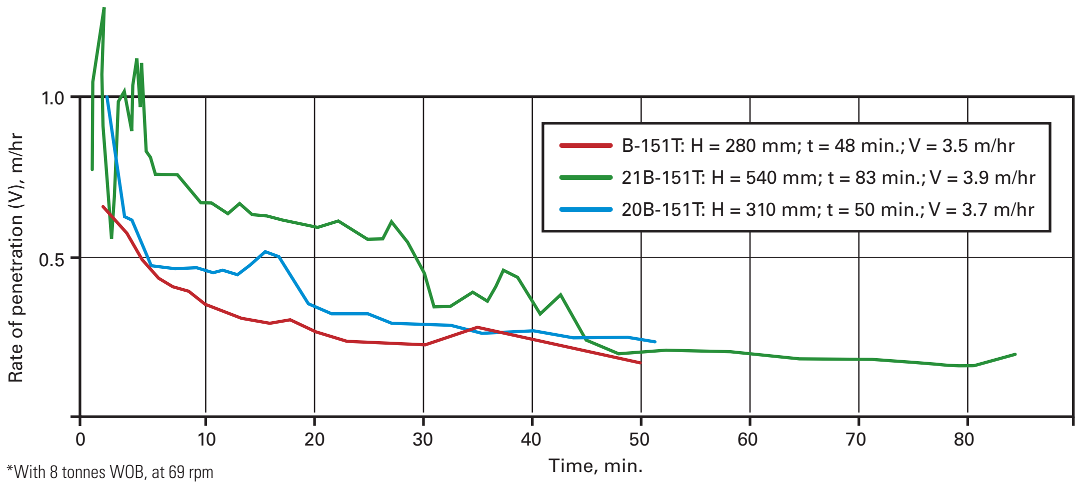
Mating of the peripheries of the well-bottom sectors is accompanied by rearrangement of the rack teeth at points of major skidding of the cones with their completing teeth. Unsteady cone rotation may be observed at the onset of drilling, manifested as a variation of cone gear ratios due to possible deviation of the character of the formed rack from its technological profile. This especially applies to rock formations of reduced hardness where the rack is less stable than in hard rock.

Moreover, since the character of the rack profile, as stated above, is influenced by the interrelated distribution of the contacting teeth of the cones at the beginning of formation of the well bottom, the rack profile will also depend upon the order in which the bit cones are assembled (direct or reverse).

The direct order is a clockwise arrangement of cones I, II, and III as observed from the well bottom. The reverse order has a counterclockwise arrangement. The change in cone arrangement alters the order of mating of the rack sectors and may affect the technological rack teeth number.

BIT PERFORMANCE EFFICIENCY*

Fig. 6



*With 8 tonnes WOB, at 69 rpm

Besides, the bit kinematics will be influenced by the interrelated distribution of the cones with maximum and minimal pitch of their heel rows. If the cone with t_{max} follows directly after the cone with t_{min}, then during drilling in rock of reduced hardness, the cone with t_{max}, when moving in the sector that has been rolled by the cone with t_{min}, may slow down instead of accelerating (as discussed in Part 1).

However, if during the bit rotation, the sector formed by the cone with t_{min} is first entered by the cone with medium pitch and followed by the cone with t_{max}, provided that the cone with medium pitch, due to minor difference between t_{med} and t_{min}, will be capable of accelerated rotation, then, having broadened and deepened the craters in the sector with t_{min}, it also promotes favorable conditions for accelerated rotation of the cone with t_{max}.

Of course, the absolute pitch sizes of the heel teeth will affect the size of ridges between the rack craters, depending upon the bit's diameter and type. Naturally, the smaller the pitch size, the higher the probability of the ridges shifting (according to Part 1). Then, during drilling of softer rock, the cone with t_{max} will be more prone to slowed rotation, rather than acceleration.

Consequently, a seemingly insignificant factor, such as the order of the cone arrangement in the bit, may affect the bit performance and its durability.

Rock surface effect

The character of the technological rack profile is also influenced by the condition of the rock surface during spudding of the well. This is significant in both test-stand conditions and real well drilling.

If the rock surface is not horizontal, which is typical for many test-stand drilling setups with natural stone blocks, then at the beginning of drilling, the bit will create some part of the future hole bottom in the form of a segment that will gradually enlarge as the bit deepens to full circle. At first, axial load on the hole bottom will be transferred through one of the cones. Then, two cones will simultaneously contact the rock and, at last, the bit will be supported by the three cones at the full hole bottom.

The diagram in Fig. 3a shows the hole bottom segment CDB during spudding from the surface M having inclination, α. CAB is the line intersecting the inclined surface M and the part of the wall of the intended hole. The schematic in Fig. 3b shows the developed views of the arc for the segment CDB in the form of a straight line and an elliptical arc CAB in the form of two semiarcs: the descending AB and the ascending CA.

If the spud surface was horizontal, the hole bottom rack formed by the heel rows in the section CDB would have the pitch, t, corresponding to the heel teeth pitch of one of the three cones which had initial contact.

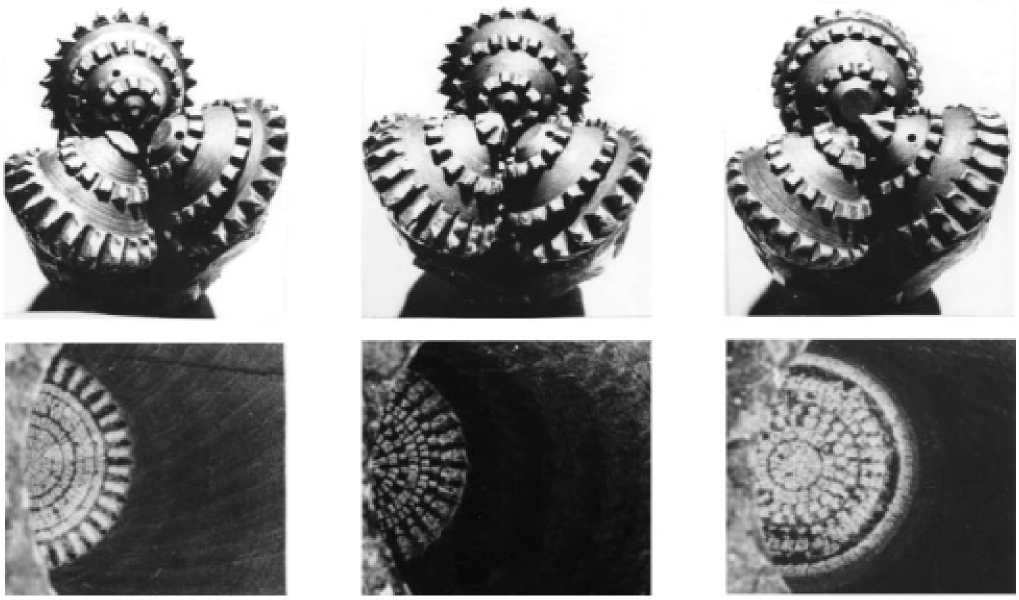
During actual spudding, the teeth of this cone move along the descending section AB in the direction of the cone rotation shown by the arrow. Consequently, Tooth 2, due to the rearrangement of its loading will slip along the inclined plane at slowed B_1B_2, which will be confined by translational movement of the bit equal to $b = A_1A_2$. The movement of the bit while deepening $a = AA_1$, corresponds to the moment of Tooth 2 touching the inclined plane and will depend upon the cone number simultaneously contacting the well-bottom segment and the value of the axial load. Due to Tooth 2 slippage, the well-bottom rack pitch increases for the value $c = b \cdot ctg\alpha$ and will be equal to $t' = t_k + c = t_k + b \cdot ctg\alpha$.

A similar picture will be observed on the side of the ascending section CA, the only difference being that the teeth will slip along the inclined plane

BIT WEAR, THREE BITS

Fig. 7

21B-151T bit Fig. 7a | **20B-151T bit** Fig. 7b | **B-151T bit** Fig. 7c



and accelerate.

Thus, spudding from an inclined surface will result in rolling the sector of the rack with pitch t', and then, when two cones contact the well-bottom segment, the rack pitch on both sides of the segment will slightly decrease due to the decreased translational movement of the bit (at constant axial load) and will have the value t'', which will decrease once more, to a value t''', when all the three cones come into contact with the well bottom.

Pitch size

Finally, the well-bottom rack will again have three different pitch sizes that will be distributed in four sectors, as shown in Fig. 3c, at the following correlation of their values: $t' > t'' > t'''$. All three values, t', t'', and t''', may be higher than the calculated values of the rack pitch, t_k, even if spudding was started by the cone with minimum pitch of the heel teeth.

The difference between t', t'', t''', and t_k may be regulated by the axial load. At a high axial load $t'>t''>t'''>t_k$, while at a low axial load $t' \approx t'' \approx t''' \approx t_k$. However, even in the latter case, the number of the teeth in the technological rack may vary when compared with the rack that would be formed during spudding from a horizontal surface, due to the disturbance of the strict periodicity of the three rack sectors.

Thus, during spudding from inclined surface, a common trend of increase in the rack pitch appears, i.e., the number of the rack "teeth" decreases. This inevitably results in increased skidding of the cones and their intensive wear.

A similar result can be expected during spudding on a surface with varying roughness.

Drilling conditions

Under actual drilling conditions, the lithological profile usually consists of alternating rock types with varying hardness that may dip at different bedding angles. Consequently, when the drill bit encounters a layer of harder rock during drilling, the situation will be similar to that of spudding on an inclined block surface, and the rack teeth number will decrease.

When a bit encounters a softer formation, the rack profile may also change. Clearly, the well-bottom rack profile does not remain stable during drilling but changes according to the lithologic sequence encountered. The bit kinematics will vary.

This explains the significant scatter in drilling performance data for commercial rock bits when they are run in "identical" conditions in actual wells. Peculiarities of bit kinematics for each run will be diverse. This is also the reason for observed variations in the character of the bit wear during drilling in test stand and actual conditions, and of the wide versatility of the bit wear types in deep well drilling.

The last factor affecting the profile of the technological rack implies the bit tearing off the well bottom during drilling, followed by an abrupt increase in the weight on bit. This may involve considerable chattering of the bottom-hole assembly. Torn off the well bottom, the teeth may arbitrarily hit the rack, partially destroy it, and create another set of teeth.

Relief stripes

On the sides or walls of the well, we see relief stripes related to the well-bottom rack problem.

Multiple-pitch cones, as a rule, provide for heel teeth slippage accompanied by widening of the rack craters in one or more directions and at each revolution of the bit, the rack profile will gradually shift in plane. The direction of the rack shift will depend upon the correlation between the values and directions of skidding of the different cones.

Since the cone movement is for the most part slowed, the rack profile shift will generally be directed opposite the bit rotation. However, the rack profile may still shift in the direction of the bit rotation. This can be determined by correlating the technological gear ratios of the cones at any point during drilling. The rack shifting behavior will match the inclination of the relief stripes on the well wall.

In the case of equally pitched cones, the well-bottom rack may wander and the relief stripes may vary in inclination.

Pure rolling

The analytical study of drill bit kinematics which was discussed in Part 1 permits us to conclude that duirng design of toothed rock bits it is possible to select geometric parameters of cones that will provide minimal teeth skidding along the well bottom (OGJ, Feb. 4, 2008, p. 46). The actual gear ratio of the cones should correspond to pure rolling.

In the case of multicone cutter bits, pure rolling would be peculiar only to heel rows. In the single-cone cutter bit design pure rolling would occur for all rows. Such cone design is especially important for milled-tooth bits because it can substantially increase their wear resistance and efficiency during drilling of abrasive rock.[3]

Corresponding to this condition are cones with equal pitch of their heel teeth; these may be determined by the correlation[4] shown in Equation 2.

Thus, for the B-151T bit, which has the value i = 1.57, the actual cone gear ratio would be close to pure rolling at Z = 21, corresponding to the teeth pitch t = 14.3 mm (OGJ, Feb. 4, 2008, p. 46, Table 2).

Experimental bits

To verify this idea, the Verkhneserginsky bit plant manufactured several experimental bits. Based on the commercial B-151T multicone cutter bit, the experimental cone bits with equally pitched heel rows included the 21B-151T bit with heel tooth number Z = 21, and the 20B-151T bit with heel tooth number Z = 20.

The 20B-151T bits were built to

HOLE BOTTOM PATTERNS* Fig. 8

Fig. 8a

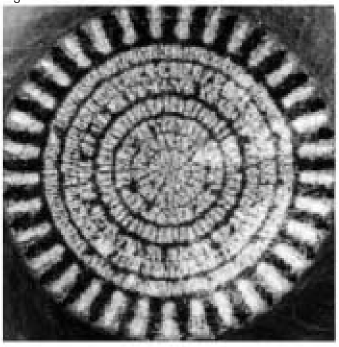
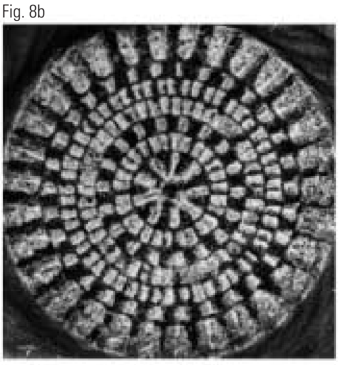


Fig. 8b



*Experimental bits. Upper pattern (a) formed by 21B-151T bit; lower pattern (b) formed by 20B-151T bit.

verify the conclusion stated in Part 1, which considered that if all bit cones had even number of equally pitched heel teeth, then their actual gear ratio tended to equal 1.5 (OGJ, Feb. 4, 2008, p. 46).

The experimental 21B-151T and 20B-151T bits as well as the commercial B-151T bit were tested on a drill stand in quartzite with WOB of 4.6 tonnes and 8 tonnes. The rotational speed of the drill stand spindle was 69 rpm. The borehole was flushed with water.[5]

The bits were equipped with variable-induction pickup that recorded the rotation rate of each cone while drilling by means of a light-beam oscillograph.

The oscillograph in Fig. 4 shows the rotation speed for the 21B-151T bit and its first, second, and third cones (from top to bottom).

The figure shows that the rotational speed of each of the cones is 108.5 rpm, irrespective of the weight on bit. Consequently, Equation 3 shows the actual gear ratio for each cone, and it corresponds to pure rolling mode of the cone heel rows.

The actual gear ratio of the cones was calculated based on the number of craters on the well-bottom rack, Z_r, as shown in Equation 4.

During drilling with the 21B-151T bit, the number of craters on the well-bottom rack, $Z_r = 33$, corresponds to a gear ratio, $i_a = 1.57$.

But during drilling with the 20B-151T bit, the well-bottom rack had 30 craters. Consequently, the gear ratio is $i_a = 1.5$, which neatly corresponds to the analytical results.

Rock destruction

In addition to studying experimental bit kinematics, it was interesting to investigate the rock-destroying capability of the bits, their wear characteristics, and performance efficiency.

The rock-destroying capability of the experimental bits as compared to that of the commercial bits was studied during drilling in marble and granite with a WOB of 4.6 tonnes and 8 tonnes and a bit rotational speed of 69 rpm.

Fig. 5 plots the varying, initial ROP of the experimental bits vs. WOB duirng drilling in marble and granite. The data confirm that the experimental bits with equally pitched heel rows of the cones have better rock-destruction capability compared with the commercial bits when drilling in medium-hard and hard rock.

We also studied the performance efficiency of the bits while running them to wear in quartzite with WOB of 8 tonnes at 69 rpm. The time plot of the drilling-rate decrease for the experimental and commercial bits shows the superiority of the 21B-151T bits performance and wear resistance (Fig. 6). The mean meterage per 21B-151T bit was 540 mm at the mean rate of penetration of 3.9 m/hr. For the commercial bits, the meterage per bit was quite a bit less, only 280 mm at 3.5 m/hr.

Bit wear

Fig. 7 shows the wear and hole-bottom patterns of the 21B-151T, 20B-

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151T, and B-151T bits. A comparison of these drawings shows that the heel teeth of the 21B-151T bits have considerably less wear, despite drilling nearly twice as far as the commercial B-151T bits.

Fig. 8 presents the hole bottom patterns formed by the experimental 21B-151T (Fig. 8a) and 20B-151T bits (Fig. 8b). These patterns illustrate the clear-cut peripheral rack formed by the 21B-151T bit, which visually confirms the lack of any skidding of the heel rows along the hole bottom, in contrast to the skidding seen with the 20B-151T bit. This once again confirms that the equality of the cone heel teeth numbers is necessary but not a sufficient condition to reduce their skidding.

Equal heel teeth numbers on the cones provide only their equal skidding, which may be rather high. As a result, the performance and wear data for the bits with equally pitched heel teeth on their cones may even lag behind the bits having different cone-heel teeth numbers. ✦

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Global LNG trade to 2020 marked by uncertainty

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Jensen Associates
Weston, Mass.

The current outlook for LNG is probably more uncertain than it has been for many years. This is the result of several factors, among which are:

- The speed with which LNG demand, particularly in North America, Spain, and the UK, has developed.
- The inherently slow response time of LNG supply to the sharply increased demand signals
- The supply lags have created a shortage of LNG supply relative to expectations.
- The burst in demand for new plant capacity, which has taxed the capabilities of experienced design and construction contractors and sophisticated machinery suppliers. This has led to a sharp "demand pull" inflation on capital costs. Costs are not only much higher than expected, but the potential for cost overruns and construction delays has increased. It is not clear how severely this has affected plans of the many projects that are under active consideration.
- The sharp increase in world energy prices. The effect of these higher prices on gas demand and on interfuel competition is not well understood.
- The uncertainties raised by environmental concerns. Pressures to limit coal utilization may tend to favor gas-fired power generation despite higher gas prices. This is a particularly important issue in China, where absent government policy intervention, high-priced gas would find it very difficult to compete with low-cost coal.
- The persistence of difficult geopolitical issues surrounding the natural gas export policies of a number of countries, such as Bolivia, Nigeria, Iran, Russia, or Venezuela. It is difficult to foresee the roles the countries will play in LNG supply between now and 2020.
- And last, but not least, the fact that LNG demand is inherently sensitive to small changes in world gas supply-demand balances. Where LNG is the "swing" source of gas supply for a gas importing country, small changes in its indigenous gas supply or demand magnify the effect on its LNG imports.

These uncertainties make it unrealistic to expect any forecast—no matter how well done—accurately to predict specific LNG trade flows out to 2020. This article, however, summarizes a recently completed projection—in three scenarios—of world LNG trade to 2020 done by Jensen Associates for the California Energy Commission.

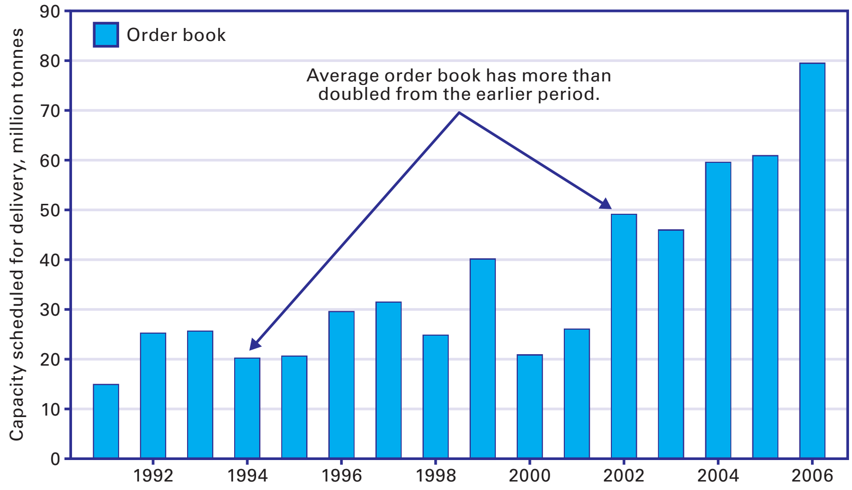
More conservative

If one can generalize about most published world and regional gas forecasts, they tended to become more optimistic about gas demand in the 1990s as the enthusiasm for gas-fired combined cycle power generation took hold. Then, supply problems in North America and the North Sea injected a note of supply concern into many estimates.

Initially, the tendency of most forecasts was to retain much of the demand optimism while transferring some of the responsibility for gas supply to imported LNG. During this period, demand estimates tended to remain high, and LNG tended to substitute for some of the projected loss of indigenous

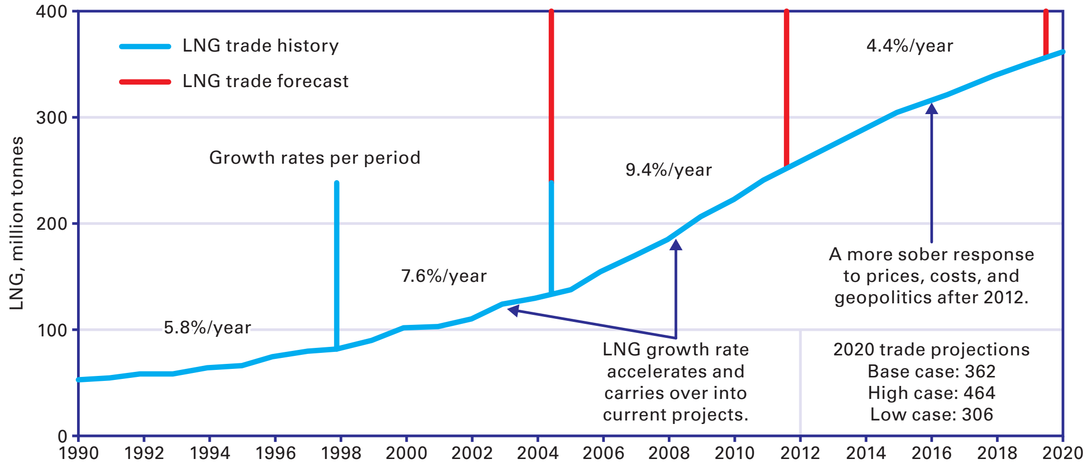
ORDER BOOK'S RISING PRESSURE

Fig. 1



ONE PROJECTION OF WORLD LNG TRADE*

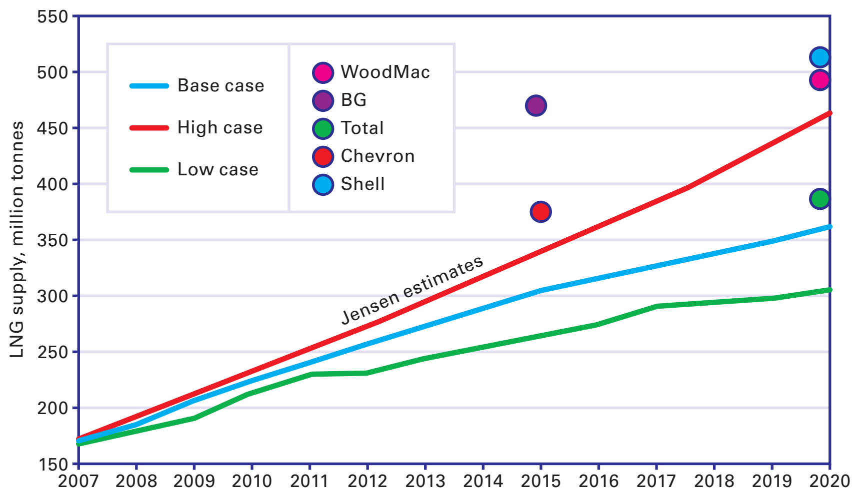
Fig. 2



*Jensen Associates base-case estimates

LNG GROWTH SCENARIOS

Fig. 3



natural gas.

But there was a growing recognition that supply was the principal determinant of the growth of world LNG trade. Now, in a more common forecast pattern, estimates reduce the amount of gas for future power generation and are more conservative about LNG trade.

At the same time that forecasts were adjusting to supply constraints, the rapid increase in world energy prices threatened to blunt the growth of overall energy demand and alter the balance between fuels in interfuel competition. This added an additional conservative element to the forecasts.

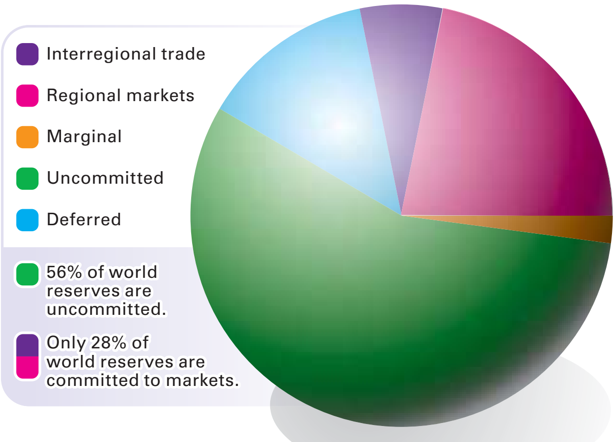
The two major governmental organizations that publish world energy forecasts—the International Energy Agency and the US Energy Information Administration—both publish projections of future world gas supply and demand. A review of their projections over the past several years reveals a trend towards reduced expectations for total world gas demand and for interregional gas trade.

For EIA, it is possible to compare its expectations of total world gas consumption for 2020 in both its International Energy Outlook 2002 (IEO2002) and its IEO2006. Total consumption shows a decline of 7.4% between the forecasts made 4 years apart.

For the IEA, a comparison of total consumption for 2030 (IEA does not project 2020 in both documents) is possible for its World Energy Outlook 2002 (WEO2002) and its WEO2006. Its total consumption projections decline 7.8%. But indicating the sensitivity of trade to the new, higher priced environment, its projection of interre-

World's proved gas reserves: yearend 2005

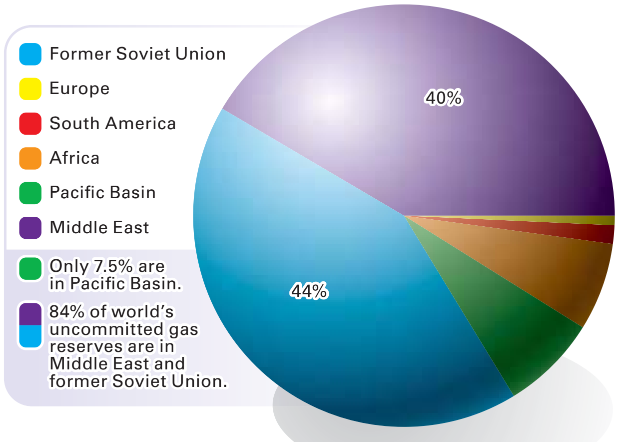
Fig. 4



Total proved reserves: 6,348 tcf
Source: Jensen Associates estimates

World's uncommitted gas: yearend 2005

Fig. 5



Total uncommitted gas: 3,604 tcf
Source: Jensen Associates estimates

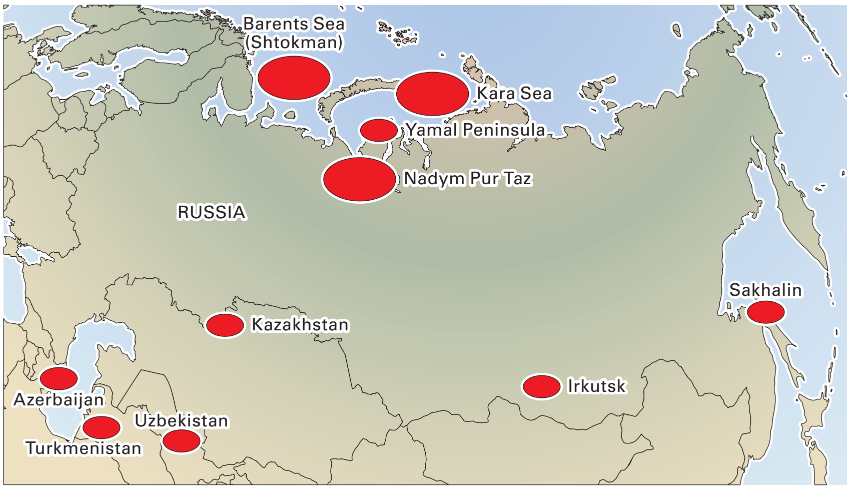
gional gas trade declines by 22.4%.

This pattern of declining gas demand and LNG trade forecasts over time is significant. It suggests that some LNG demand estimates made during the early 2000s might now be regarded as too optimistic and therefore unsuitable for a base or reference case. It is this view that has led our study to start with the most recent governmental projections to form the base case and utilize some of the earlier, more optimistic estimates, to develop a "high" scenario.

It is important to recognize that our projections are on the low side compared to many public projections of future LNG trade. Their conservatism results from two underlying assumptions. We accept the IEA's and EIA's view that higher prices have reduced expectations of gas demand and world gas trade. But we are impressed that many of the LNG supply problems—high costs, technological challenges, and geopolitical concerns—may slow the process of making supply available.

Major FSU gas export basins

Fig. 6



Escalating costs

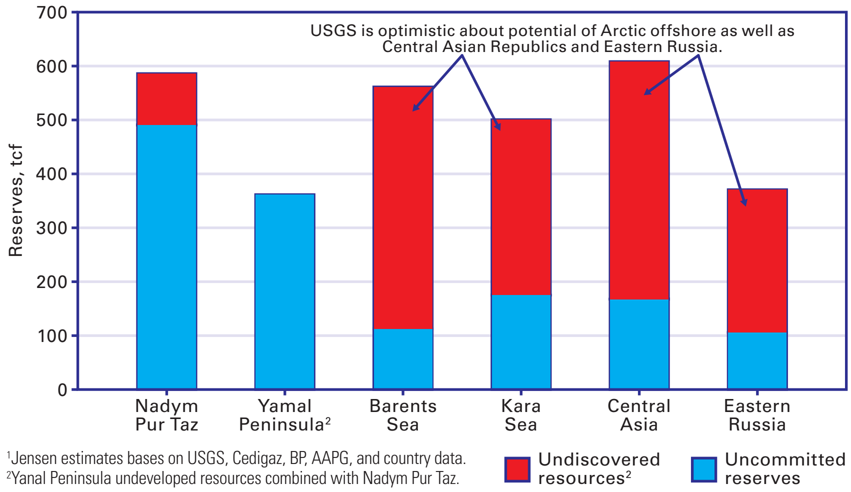
For an extended time, design improvements in liquefaction plants and tankers had the effect of reducing costs. As recently as 2003, it was common to assume that this was a "learning curve" effect and would continue.

But this perception of steadily falling costs for LNG has been dashed in recent years. The surge in demand for LNG that began in the late 1990s has taxed the capabilities of experienced engineering-procurement-construction (EPC) contractors and manufacturing capacities of firms supplying some of the sophisticated materials and machinery required for LNG. The result has been a very large supply bottleneck for construction of new plants.

There are a very few EPC contractors with the experience to handle the complex construction that LNG requires, and they are effectively overloaded. While one might expect over time that new entrants in the field would learn to become reliable suppliers, the risks in the short term are that projects built by the newer contractors will fail to come in on time and on budget. Meanwhile, "demand pull" inflation has hit the industry and reversed the long period of declining costs.

The reason for the "crunch" on the suppliers is evident in looking at the growth in demand for new capacity. With a typical 4-year design and construction period for most LNG plants, the plants scheduled to come on line over the next 4 years might be described as the "order book."

MAJOR UNCOMMITTED FSU GAS RESOURCES: YEAREND 2005[1] Fig. 7



UNCOMMITTED MIDDEL EAST GAS RESOURCES: YEAREND 2005[1] Fig. 8

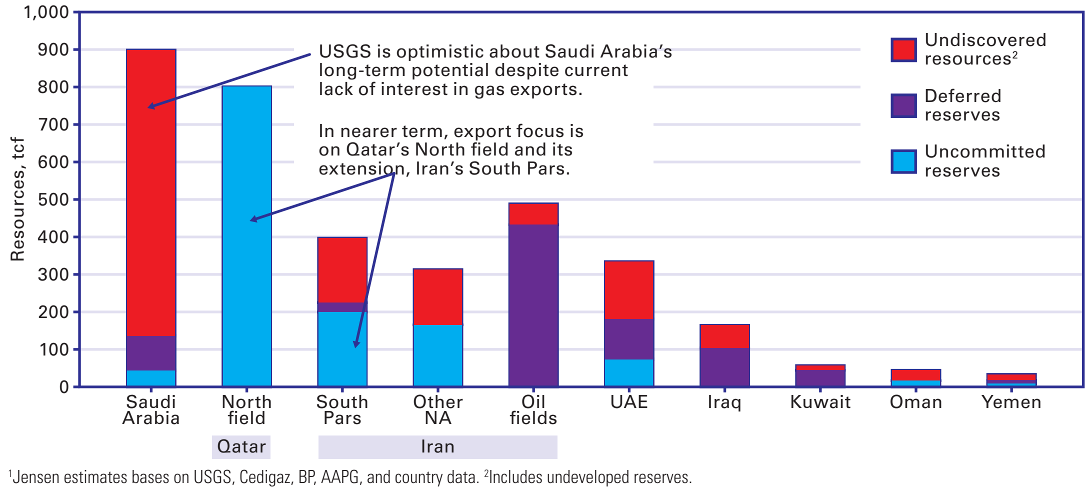


Fig. 1 shows the order book has more than doubled since 2002 from the period 1991 to 2001, graphically illustrating the pressures on the suppliers.

It is extremely difficult to get reliable estimates of what is happening to costs at present. What is apparent is that there is a wide dispersion in costs for liquefaction plants that are currently under construction.

There are also a number of "problem trains" that have dramatically higher costs than one might expect from trends in historic cost patterns. It is difficult to separate the special problems that have escalated construction costs of these plants from the current pressures on costs that are applicable to construction costs in general.

Norway's Snohvit, Russia's Sakhalin II projects, and a new Iranian North Pars construction bid are reported in the trade press to have costs in the range of $1,000 to $1,222/tonne of liquefaction capacity. A reasonable range of costs for these projects in 2000 construction environment might have been $250-300/tonne. Current costs for those projects—assuming no problems—would probably be more than double those levels.

Both Snohvit and Sakhalin II experienced very large cost overruns, but both are Arctic projects and seem to have experienced "learning curve" problems. The Iranian bid is for a project whose government is under international sanctions and has difficulty getting competitive bids from experienced EPC contractors.

It is always dangerous to assume that "cost shock" levels are permanent and will persist throughout the period of a long-term forecast. But it is very difficult to determine what a more stable long-term cost structure might look like.

What is apparent, however, is that the current high-cost environment has reduced the order level for new LNG liquefaction capacity that might be expected to come on line in 2012 or later. If this pattern persists, new capacity expected to become available beyond 2012 will be in doubt.

If the burst in new orders 2002-06 has set the stage for a surge of new LNG capacity 2010-12, the current ordering pattern suggests a dip in new capacity beyond 2012.

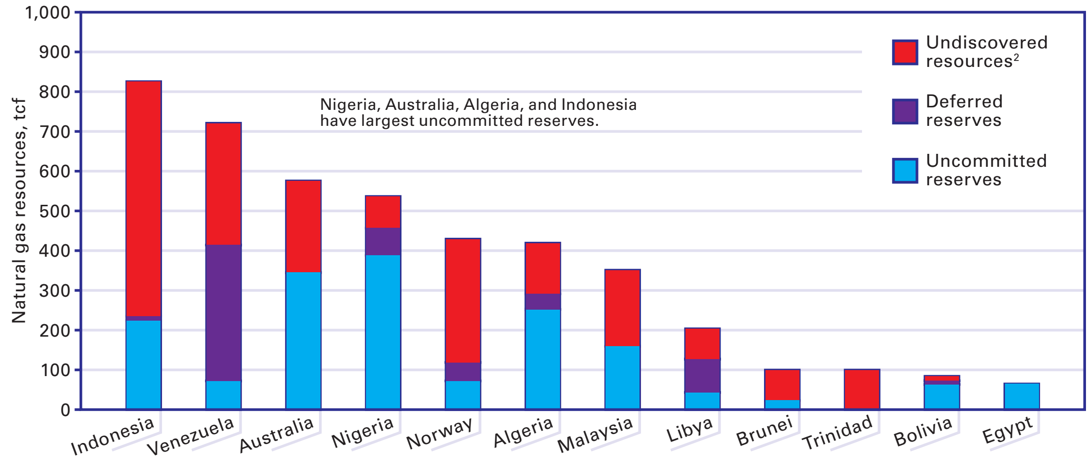
The forecasts

In all three scenarios, the approach was first to develop a forecast of LNG trade as a "control" and then to match sources and markets to the projection. The starting point for the reference case was the gas projections in IEA's WEO2006. Although it provided a basis for the overall projections, the forecast made use of many other sources to arrive at its final estimates.

The base-case estimate for 2020 is 362 million tonnes (Fig. 2); the scenario range is 306-464 million tonnes.

UNCOMMITTED GAS RESOURCES[1]

Fig. 9



[1]Jensen estimates bases on USGS, Cedigaz, BP, AAPG, and country data. [2]Includes undeveloped reserves.

not by Gazprom, as in the West, but with participation of international oil companies. Shell has operated Sakhalin II, ExxonMobil Sakhalin I, and a BP affiliate the Kovykta field near Irkutsk.

The Russian government used severe cost overruns on Sakhalin II and environmental issues to reopen its licensing agreement with Shell. Following very difficult negotiations, Shell ultimately relinquished control of the project to Gazprom (OGJ Online, Dec. 21, 2006).

Subsequently, Russia reopened the licensing agreement with a BP subsidiary for Kovykta. These moves suggest that the Russia wants to reexert centralized control over East Siberian and Sakhalin reserves.

The country appears to be trying to develop a coordinated internal gas transportation grid from which it can serve both domestic and export markets. It has shown an interest in a pipeline system that would link Sakhalin and East Siberian reserves with its West Siberian reserves that serve Eastern and Western Europe. Such a system would give Russia the choice of LNG or pipeline exports as well as destination flexibility to serve Atlantic basin or Pacific basin markets.

But it is in the West where some of the Russian policy questions have the greatest potential impact on world LNG markets. In West Siberia, the Nadym-Pur-Taz region has been the workhorse of the Russian gas industry. Russia has three other, as yet undeveloped, major potential producing regions that hold much of the uncommitted gas: offshore Barents Sea containing the super giant Shtokman field; Yamal Peninsula; and offshore Kara Sea (Figs. 6 and 7).

It is important to note that this forecast is more conservative than most others (Fig. 3). Its conservative estimates reflect two basic assumptions:

1. It adopts the view of IEA and EIA that high prices have moderated the demand for natural gas and reduced the potential requirements for interregional gas trade.

2. It does not foresee early resolution to the industry's cost, geopolitical, and arctic technology problems.

Whence supplies?

World reserves of natural gas are very large and appear more than adequate to support gas exports far into the future. But many of those reserves are where economics, technology, or geopolitics raise questions about how quickly they will become commercially available.

Some portion of the reserves are already committed to markets, either for domestic consumption or contracted for export through pipeline or LNG infrastructure. Other gas is "deferred" because it is involved in oil production, either for reinjection, in gas caps in producing fields, or "long reserves" (dissolved gas that will not be produced until far into the future when the oil is recovered).

Fig. 4 shows our estimated market status breakdown of world gas reserves as of yearend 2005. Fully 54% of the world's reserves are currently uncommitted. While not all of the gas is available for current exports because producers reserve some of it to back up existing pipeline and LNG export contracts, uncommitted gas is the major source of new projects. Undiscovered resources will also become available at some time in the future, as will the deferred gas, as its involvement in oil production changes.

Eighty-four percent of the world's uncommitted reserves, however, as well as much of the undiscovered resource base are in the Middle East and the former Soviet Union (FSU; Fig. 5). It is significant that the FSU has historically exported entirely by pipeline, while the Middle East has exported its interregional volumes as LNG. We expect that future FSU exports will remain predominantly via pipeline and Middle East exports predominantly via LNG.

The start-up of Russia's Sakhalin II project next year will represent that country's first entry into LNG export. Sakhalin island is proving to be hydrocarbon-rich and is well situated to serve Pacific Basin LNG markets. But the question of how much of that resource is ultimately used to support LNG exports raises complex Russian geopolitical issues.

Russian gas projects in Sakhalin and Eastern Siberia have been developed, Nadym-Pur-Taz contains the world's second and third largest gas fields—Urengoi and Yamburg. But these two fields, together with another super giant—Medvezhye—are in advanced stages of depletion at a decline rate estimated at 2 bcfd/year.[1] In 2002 Gazprom brought another supergiant—Zapolyarnoye—on line to maintain production rates.

But Russia appears to want to tap the other major undeveloped producing basins before undertaking significant further market expansion. These new reserves are likely to be costly and, in the case of the Arctic offshore fields, technically difficult.

For a time, it appeared that Russia favored a pipeline from the Yamal Peninsula to Western Europe as the next step. Russia has alienated some of its major European customers, however, both through supply interruptions to the Ukraine (that were perceived by some as politically motivated) and Russian refusal to allow independent Russian producers access to Gazprom's pipelines, a third-party access policy the European Union strongly advocates. Some of the European interest in LNG is partly motivated by a desire to diversify away from too much dependence on Russian supplies.

Emergence of North American interest in LNG appeared to offer Russia a diversification option of its own. By shifting to the Shtokman field in the Barents Sea, Russia contemplated a landing at Murmansk that could supply an LNG export facility as well as be extended south to St. Petersburg, where it could supply both Russia's new Nordstream Pipeline under the Baltic and also a small proposed LNG facility at Primorsk.

More recently, Russia seems to have cooled somewhat on the idea of a Murmansk LNG export facility, although it still is interested in the Shtokman pipeline connection to the Baltic. It has not given up on the Yamal option, however.

Development of Shtokman faces a technological challenge because of its Arctic offshore location. Several international oil companies were attempting to join with Gazprom to develop Shtokman. Although the Russian government at one point rejected their overtures, they appear to be back on the table with the signing of an agreement with Total (OGJ Online, July 13, 2007) and StatoilHydro (OGJ Online, Oct. 26, 2007).

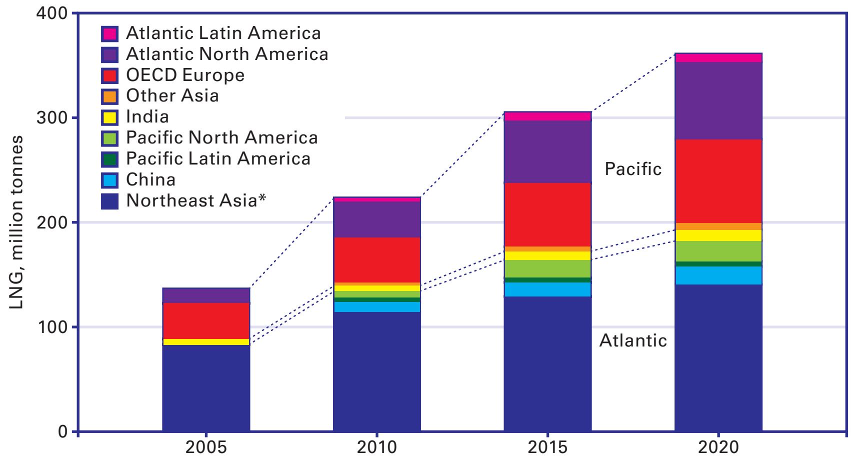
The uncertainties involving Russia's gas export plans have a substantial impact how Atlantic basin LNG develops. If Russia decides to concentrate on pipeline exports, which it knows best, and if the European customers grow more comfortable with Russian gas policies, it would have two effects on future LNG trade: It would reduce Russia's LNG offerings, but it also would reduce European competition for LNG. Europe has the pipeline as well as the LNG option. North America and most of the Pacific basin must rely on LNG for interregional trade.

The Middle East accounts for 40% of both the world's proved reserves and its uncommitted reserves. But 61% of the region's uncommitted gas is in a single gas field shared between Qatar (the North field) and Iran (South Pars). If one adds in the uncommitted gas elsewhere in Iran, those two countries account for nearly 90% of the Middle East's uncommitted gas (Fig. 8).

Qatar began its first LNG exports in

Base case projections of world LNG demand

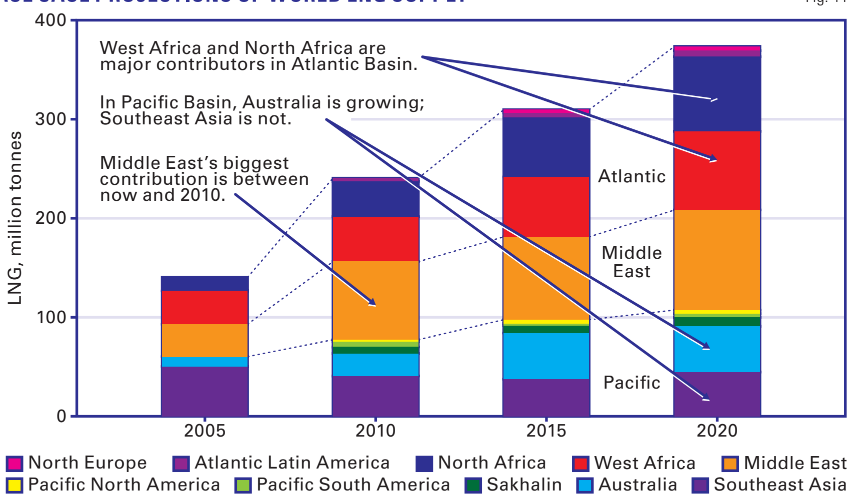
Fig. 10



*Northeast Asia, which once dominated LNG trade, is now growing less rapidly than Atlantic.

Base case projections of world LNG supply

Fig. 11



1997 and has elected an aggressive policy of LNG expansion since that time. It is expected to account for nearly 40% of the entire world's increase in capacity 1996-2011.

Qatar has adopted a "wait and see" policy for further LNG expansion beyond that point, however, both to digest the consequences of its rapid growth and better to understand how the complex gas field behaves. Thus what has been the engine of recent Middle East LNG supply growth will be switched off, for how long it is difficult to tell.

The United Arab Emirates (Abu Dhabi) and Oman are also LNG exporters, and Yemen has an active project under way. But the early outlook for expansion from these sources over the forecast period is limited.

The US Geological Survey is very optimistic about undiscovered gas resources in Saudi Arabia, but that country has not yet found that gas nor shown any interest in gas exports. As long as Qatar maintains its decision against expansion beyond 2011, further Middle East LNG growth 2011-20 will have to come largely from Iran.

That country faces two issues that do not apply to Qatar: It has a very rapidly growing domestic market (fueled in part by subsidized pricing policies) and it needs gas for reinjection into its complex oil fields. It is developing South Pars on the basis of 20 (perhaps as much as 23, if the gas proves to be there) production blocks of about 1 bcfd each.

Five of the first eight blocks are designated for domestic markets and three for oil field injection. Exports will not be implemented until Blocks 9 and 10 come on stream at some point in the future. Five LNG projects have been proposed for subsequent North Field blocks, as well as several that would utilize other Iranian gas fields.

The issue of whether to export LNG is of itself controversial within Iran, but the largest barrier to Iran's development of LNG is the international political climate. The imposition of sanctions on Iran, which have recently become more binding with the standoff over nuclear enrichment, denies Iran access to technology and most international markets. Although the current geopolitical standoff will presumably not last forever, it is very difficult to put any realistic time line on when Iranian projects are likely to be commercialized.

Other countries have significant available reserves for LNG export Fig. 9. But geopolitical issues that inhibit LNG development are not unique to Russia and the Middle East. Bolivia, Libya, Nigeria, and Venezuela have substantial gas reserves and potential LNG projects under consideration. But each of them faces geopolitical problems in developing new LNG projects.

Our base case assumes that some of these geopolitical problems will be resolved and some of the supply potential will be realized. But the bulk of the supply limitations that define our low case comes from projects that have been proposed for these regions.

Regional implications

The base case envisions a world LNG demand growing to 362 million tonnes by 2020 from 138 million tonnes in 2005. While Atlantic basin markets will grow much more rapidly over the period than the Pacific basin markets, they still will not surpass the Pacific over the forecast period (Fig. 10).

The three biggest importing regions—Northeast Asia, OECD Europe, and the North American Atlantic Coast—among them account for more than 80% of world trade. Despite their potential importance, China and India account for only 5% and 3%, respectively.

Qatar dominates LNG supply additions out to 2011but has adopted a "wait and see" policy for further expansion beyond that point. While it is probable that Qatar will revisit that conservative policy at some point, it is speculative to include further Qatar supply beyond 2011 (Fig. 11).

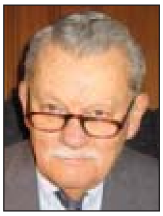
Beyond 2010, the greatest contributions to base-case supply come from North Africa, West Africa, and Australia. Southeast Asia, given some of the problems in Indonesia, does not show significant growth.

Indonesia, which was the world's largest LNG supplier as recently as 2005 until being surpassed by Qatar, shows virtually no growth in the forecast. The country is grappling with the desire to use more of its gas domestically, and we expect it to limit export growth to new projects. On the other hand, Australia emerges as the second largest supplier after Qatar by 2015, followed closely by Nigeria. ✦

Reference

1. Stern, Jonathan, The Future of Russian Gas and Gazprom, Oxford Institute for Energy Studies, 2005, p. 9.

The author



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Emerging Asia-Pacific LNG markets must sort pricing, supply uncertainties

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Preliminary data for 2007 show that worldwide LNG trade grew by 7.9% to 172 million tonnes. The Asia-Pacific market accounted for about 65% of worldwide LNG trade, or 112 million tonnes. LNG imports into Asia increased by 9.6% because of strong demand from both established markets (Japan, Korea, and Taiwan) and emerging markets (India and China).

This article will analyze LNG demand outlook for emerging buyers and potential new buyers (Singapore, Hong Kong, and Thailand). Fig. 1 presents LNG demand for the region through 2015.

India's gas consumption has been increasing rapidly and future demand outlook remains strong. Having become in 2004 Asia's fourth LNG buyer, India has imported 8.5 million tonnes/year (tpy) in 2007, according to preliminary data.

While domestic gas demand will increase further, LNG demand growth will depend on its price competitiveness relative to coal, piped gas, and fuel oil. In short, it is difficult for India in the future to pay what established markets—ones that have already become dependent on LNG—will have to pay.

Meanwhile, China has become Asia's fifth largest LNG importer with the inaugural cargo arriving at China's sole operating terminal at Guangdong from Australia's Northwest Shelf (NWS) project in May 2006. Estimated 2007 Chinese imports are 2.9 million tonnes.

The country has long had ambitious plans for LNG imports. Like India, however, its ambitions have increasingly encountered the reality that LNG has become increasingly scarce and expensive. A couple of years ago, nearly every province along the coast planned to import LNG. Many of these plans, however, have been dealt a hard blow by rising gas prices since 2005 and have been shelved.

As demand for gas continues to increase, China has relied more on domestic sources to meet its need. In the long run, however, China still has the potential to be an important player in the Asian LNG market.

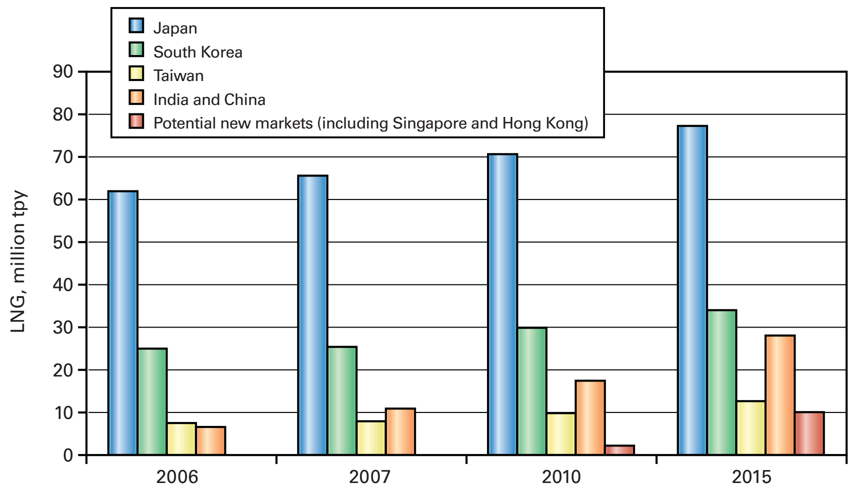
Other Asian countries, such as Singapore, Hong Kong, and Thailand, are planning to import LNG as well. Singapore's government approved a project to build a 3-million-tpy LNG terminal by 2012. Hong Kong has decided to build a 3-million-tpy receiving terminal, with LNG imports possibly commencing in 2012. Thailand is another potential LNG market by 2017.

India

Currently, gas consumption in India stands at nearly 4.0 bscfd. Demand has grown at about 9.2%/year between 1995 and 2006. Despite this high growth rate, natural gas only accounts for a 6% share in the total primary energy consumption mix, due

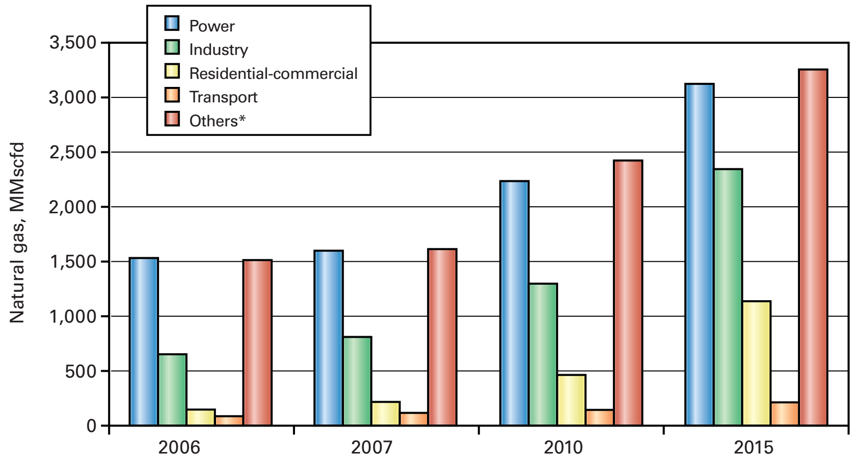
ASIA-PACIFIC LNG DEMAND OUTLOOK

Fig. 1



OUTLOOK FOR INDIA'S CONSUMPTION

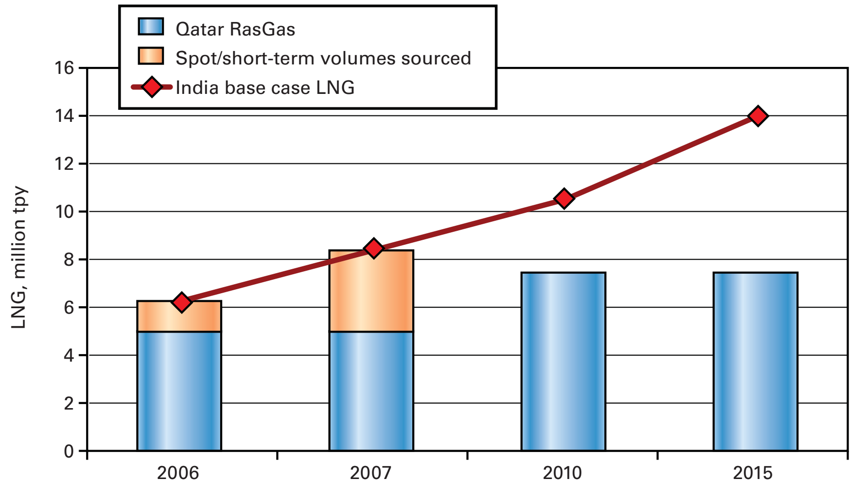
Fig. 2



*Includes fertilizer use, LPG/C2-C3 shrinkage, and nonspecified others; excludes distribution losses.

INDIA'S LNG CONTRACTS VS. DEMAND OUTLOOK

Fig. 3



to the dominance of coal and CR&W (combustible renewables and & waste) sources of energy. Two factors will play a key role in determining future gas demand—supply of gas and the affordability for Indian consumers.

We believe gas demand in India is infinite at $2-3/MMbtu but limited at $6-7/MMbtu. It is a question of what prices are affordable to which sectors. Power generation and fertilizer production are mature sectors for gas and are partly subsidized by the government. On the other hand, the industrial and city gas sectors are emerging markets with higher affordability.

Fig. 2 shows that the power sector has the largest share of gas consumption, accounting for 38.6% in 2006. Based on our assumption that overall electricity demand will grow at an average growth of 5.5-6%/year through 2015, gas consumption in the power sector will grow at 8-9%/year through 2015.

Gas use in power generation, however, will be heavily influenced by price and would have to compete with domestic and imported coal. The preferred price for gas in the power sector is less than $6/MMbtu (delivered) in order to keep generation costs at 5.6-6.7¢/kw-hr. Beyond the $6/MMbtu price, demand for gas in power generation would decline significantly. We project that increased volumes of domestic gas (mainly from offshore basins on the east coast) will be used for power generation.

Industrial users (such as steel and petrochemical industries, glass and ceramic companies, electronic device manufacturers, and others) are significant users of gas. Gas-consumption growth in the industrial sector will be strong due to the higher affordability of this sector. Gas-consumption growth in the industrial sector will be about 15-16%/year between now and 2015.

The "other" sector, consisting of the fertilizer industries and LPG/C_2-C_3 shrinkage, is the second largest gas consumer (accounting for 38% in 2006) in India. Growth in the fertilizer sector will be due to new gas-based urea plants, as well as conversion of naphtha-based plants to gas. Overall, "other" sector will grow at about 7-8%/year through 2015.

The transport sector is likely to show strong growth in gas consumption with growing CNG usage. This follows the decision of the government of India progressively to extend the CNG program to more than 10 cities. Consumption in the sector will grow by 9%/year through 2015.

Domestic gas consumption, then, will grow at 13-14%/year through 2010 before slowing to 8-9%/year between 2010 and 2015. Thus, India's gas demand will be 6.6 bscfd by 2010, rising to 10.0 bscfd by 2015.

LNG demand outlook

India became the fourth LNG importer in Asia in January 2004, with LNG imports entering the Petronet LNG Ltd. (PLL) terminal at Dahej. These imports were from Qatar's RasGas at 4.3 million tonnes in 2005 and an estimated 5.0 million tonnes in 2006.

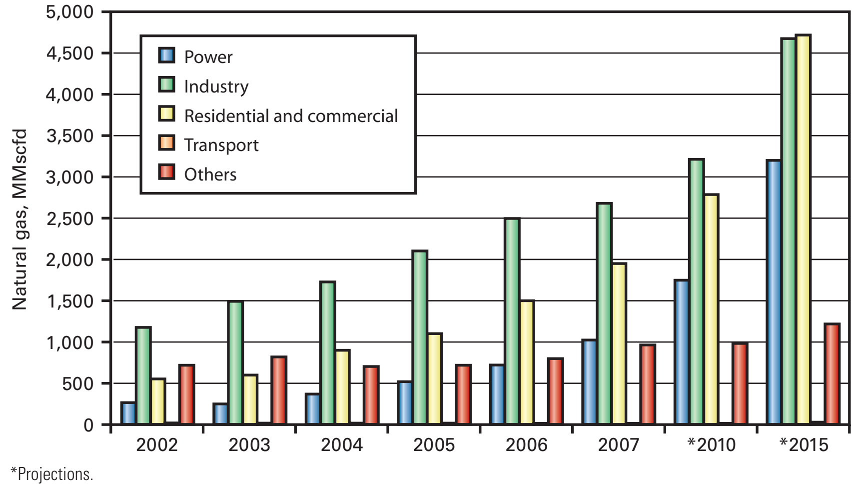
Shell's Hazira terminal began operating in early 2005 and has been importing spot cargoes. Further spot volumes were from various sources, thereby bringing India's total imports to 4.5 million tonnes in 2005 and 6.2 million tonnes in 2006. In 2007, India's total imports will likely be 8.5 million tonnes (consisting of 6.8 million tonnes to Dahej and 1.7 million tonnes to Hazira).

The future of LNG demand depends on its price competitiveness compared with coal, piped gas, and fuel oil. The recent discovery of gas by Reliance Industries Ltd. (RIL) of 30-50 tcf in the KG basin is bound to bring about changes in the competitiveness of piped domestic gas relative to LNG imports. KG Basin will not be sufficient, however, to meet India's growing gas demand, and gas imports (in the form of LNG or piped gas) will be necessary.

There is a pipeline import possibility from Iran that presents, however, many hurdles to clear for this option. For now, India has backed down from signing the Iran-Pakistan-India pipeline agreement after failing to reach an agreement on the gas price and transit fees through Pakistan.

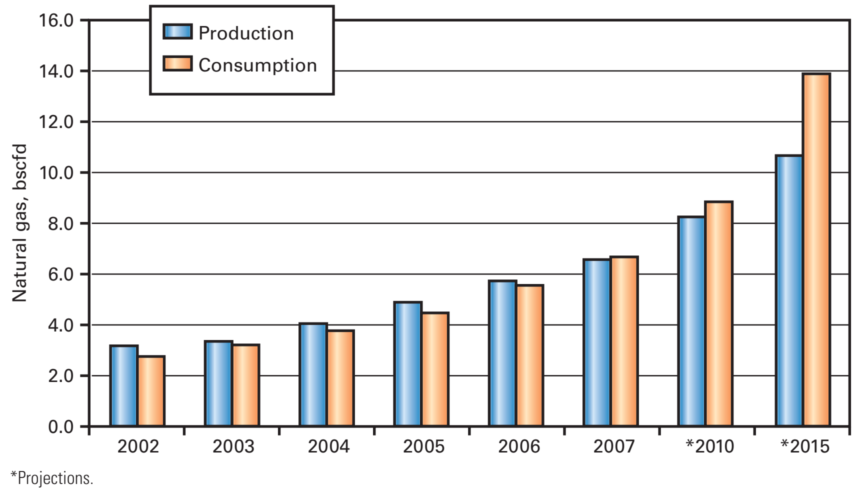
But things could change. Although pipeline-gas import volumes could be potentially substantial, LNG imports will remain essential, as there is a significant amount of uncertainty and instability associated with the pipeline imports from Iran. In our base-case scenario, India's total LNG imports will rise to 10.5 million tpy by 2010 and to 14.0 million tpy by 2015.

Outlook for China's consumption Fig. 4



*Projections.

Production, consumption outlook for China Fig. 5



*Projections.

LNG contracts

Currently, India has two long-term sales and purchase agreements (SPAs) and one short-term contract.

1. The first contract was signed between Petronet and Qatar's RasGas for 20 years, in which RasGas would supply 5 million tpy of LNG on FOB basis. Petronet and RasGas signed a side letter of agreement in August 2006 that covers the increase of the contractual volumes up to 7.5 million tpy from 2009.

2. In June 2005, Iran and India (by GAIL and IOC) signed an LNG deal—5 million tpy for 25 years starting in December 2009. The LNG export deal has not been approved by the Iranian High Economic Council, however, while progress on the upstream side in Iran has been very slow.

As a result, there is no agreed price, delivery time, or firm commitment. In our view, the chances of Iran LNG coming to India prior to 2015 are slim.

3. On a short-term basis, Qatar's RasGas has been supplying Petronet about two cargoes/month since July 2007. This agreement will last until September 2008, with a possible extension to December 2008.

Fig. 3 summarizes India's supply and demand balance until 2015. LNG imports will continue increasing as the government further deregulates the gas sector and the affordability of Indian consumers rises. India's uncommitted demand (demand less existing LNG contract volumes) will likely increase toward 2015, while there is spot demand in the future.

China

In 2006, China's natural gas use reached 5.6 bscfd, up substantially from 1.5 bscfd in 1990 and 2.3 bscfd

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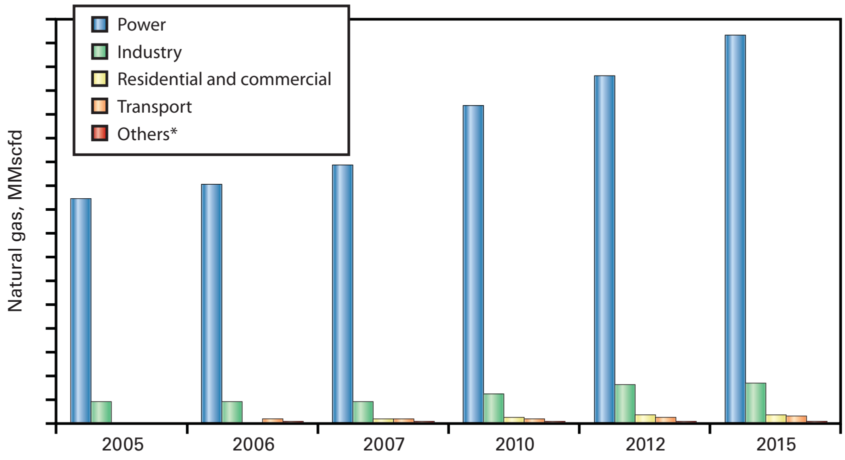
SINGAPORE'S DEMAND

Fig. 6



*Includes oil refineries and nonspecified others; excludes distribution losses.

CHINA'S EXISTING LNG CONTRACTS

Exporter	Contract volume	Start-up date	2006	2007	2010	2015
			Million tonnes/year			
NWS	3.3	2006	0.7	2.4	3.7	3.7
Tangguh	2.6	2009	—	—	1.5	2.6
MLNG	3.0	2010	—	—	1.0	3.0
Total	**8.9**	–	**0.7**	**2.4**	**6.2**	**9.3**
FGE base-case LNG demand forecast			0.7	2.9	7.0	14.3
China uncommitted demand			—	0.5	0.8	5.0

in 2000. In 2007, China's natural gas consumption is likely to have reached 6.7 bscfd, nearly 21% higher than for 2006.

Between 1990 and 2006, China's total natural gas consumption advanced at an average of 8.7%/year, faster than the growth of primary energy consumption as a whole. As a result, natural gas's share of primary commercial energy (including noncommercial biomass) mix rose from to 2.7% in 2006 from 1.6% in 1990. China's share of natural gas in total primary energy consumption, however, is far below the regional average in Asia-Pacific.

While natural gas only accounted for less than 3% of the total primary energy consumption in 2006, it plays an important role in China's chemical industry (fertilizer) and in regions that are close to gas producing fields. In 2006, the estimated share of industrial natural gas use was 45%. Within the industrial sectors, chemical use for natural gas (mostly in fertilizer plants) accounted for 40% of consumption. The residential and commercial sector ranked second in natural gas use at 27% of the total. Electric power and heating accounted for around 13% of total natural gas use in 2006.

China's gas consumption, led by residential and commercial power and by industrial sectors will grow rapidly. Natural gas consumption as a whole will grow by 10.6%/year on average, between 2006 and 2015 under our base-case scenario. As a result, the share of natural gas in China's total primary energy consumption will increase to 4.6% in 2015 from less than 2.7% in 2006.

LNG demand outlook

The first cargo from Australia's NWS project arrived in China at the end of May 2006, at the 3.7-million-tpy Guangdong LNG (GDLNG) terminal, operated by Guangdong Dapeng LNG, a joint venture between CNOOC and BP. For 2006 as a whole, 11 cargoes of LNG were imported by China, totaling 0.7 million tonnes.

During the first 11 months of 2007, China imported 44 cargoes of LNG totaling 2.7 million tonnes, including 37 cargoes from Australia and 7 spot cargoes from Algeria, Nigeria, and Oman.

As Fig. 4 shows, China's future natural gas consumption growth is likely to come from domestic production, which is supplemented by LNG imports and imports of pipelined gas. In 2007, China's estimated LNG imports are slightly less than 3 million tonnes.

Under our base-case scenario, China will import 7.0 million tonnes of LNG in 2010 and 14 million tonnes in 2015 (Fig. 5). This scenario also means China has growing amounts of uncommitted LNG demand over the next couple of years beyond the existing contracts.

LNG contracts

Currently, China has three firm LNG SPAs, one for Guangdong LNG, one for Fujian LNG, and one for Shanghai LNG (the latter two terminals are under construction). In addition, PetroChina reached two separate agreements with Royal Dutch Shell PLC and Woodside Petroleum, respectively, for future LNG supply.

After a series of international bidding rounds, Australian LNG won the bid; the source of supply to Guangdong is the NWS gas project in Australia. The SPA was signed between CNOOC and Australian LNG on October 2002. The Fujian LNG SPA was signed in September 2002 between CNOOC and BP for supply from the Indonesia's Tangguh gas project. The contract volume is 2.6 million tpy for 25 years. The originally planned start-up year was 2007, but it has since been delayed.

The Shanghai LNG SPA was signed on July 31, 2006, with Malaysia LNG Tiga. Shanghai LNG Co. Ltd. is a joint venture between Shenergy Group Ltd. (55%) and CNOOC Gas & Power

(45%), a wholly owned subsidiary of CNOOC. The contract volume is about 3 million tpy for 25 years.

The accompanying table summarizes China's supply and demand balance until 2015.

In early September 2007, PetroChina signed a binding heads of agreement (HOA) with Shell for 20 years of LNG supply at 1 million tpy. The HOA covers the key terms of the transaction and the two parties are aiming to conclude a SPA in the near future.

Also in September 2007, PetroChina signed a nonbinding agreement including key commercial terms with Woodside for 15-20 years of LNG supply at 2-3 million tpy from the proposed Browse basin gas reserves. The agreement is subject to conditions, including final investment decisions on both Gorgon and Browse projects and relevant government approvals.

Separately, two Chinese state oil companies have signed a preliminary agreement with Iran. Sinopec has a memorandum of understanding (MOU) with Iran LNG for 10 million tpy. Iran LNG has marketed more gas than the project can supply, however, and is facing indefinite delays. PetroChina has an HOA with Pars LNG for 3 million tpy over 25 years, but there has been little progress lately for executing the agreement.

China currently has one LNG terminal in operation, Guangdong, which has been quietly expanded to 5 million tpy recently from 3.7 million tpy. Two terminals are under construction: Fujian (2.6 million tpy) and Shanghai (3.0 million tpy). Fujian is nearing completion and may be operating this year if spot deals are made.

In addition, China has at least four terminal projects approved by the National Development and Reform Commission (NDRC) of China, which is the decision-making body on LNG business. Moreover, nearly a dozen projects are proposed. Unless supply contracts are secured, however, many of these projects will be seriously delayed.

The biggest problems facing the Chinese natural gas industry and future growth of natural gas use lie in these areas: prices, market developments, distribution networks, and foreign investment in China.

Globally, oil and gas prices are entering high plateaus. Rising LNG prices have delayed all but a few terminal projects in China in the recent past. Natural gas use for power generation is still a big problem. China's natural gas market is fragmented with multiple rules and price regimes. The market needs to be developed further to facilitate the expansion of natural gas use. Lack of a distribution network or lack of investment in a distribution network for various cities may hinder town-gas use for years after the pipelines are in place and LNG terminals are built. China is also still lagging behind in providing proper fiscal and price regimes to attract foreign investment in the country's upstream sector, gas pipelines, and town gas. It has a long way to go.

Potential markets

Three markets present possible growth areas for LNG in Asia.

Singapore

Natural gas currently accounts for about 18% of Singapore's primary energy consumption, while oil dominates the balance. By 2015, natural gas will likely account for around 18% of its primary energy consumption, mainly due to increased demand from the power sector.

Singapore relies on gas imports for supplies, as there are no domestic gas fields. Imports are from three pipelines: one from Malaysia, one from Indonesia's offshore West Natuna fields, and another from Indonesia's Sumatra fields.

Before 1992, Singapore's power was generated solely by petroleum products. Since the start of natural gas imports, however, gas's share of power generation has risen dramatically to around 74% in 2007, from around 18.5% in 2000. Its market share will reach 83% by 2015.

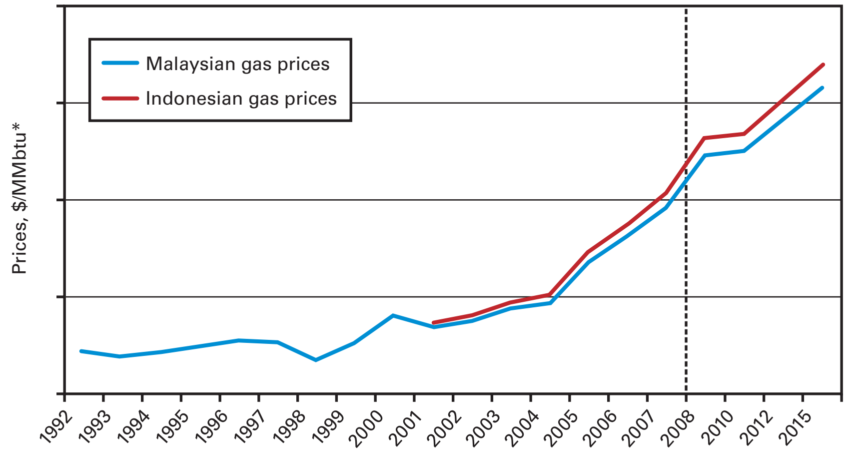
Gas use in the power sector will post an average growth of around 5%/year from 2007 to 2015. For the same period, industrial sector demand will increase by 5.1%/year on average. The two fastest demand growth rates will come from transportation and residential sectors albeit from a small base (Fig. 6). Overall, gas consumption will post an average growth of 5%/year.

Prospects for LNG

A small-scale LNG receiving terminal in Singapore makes sense, as a

SINGAPORE GAS PRICES

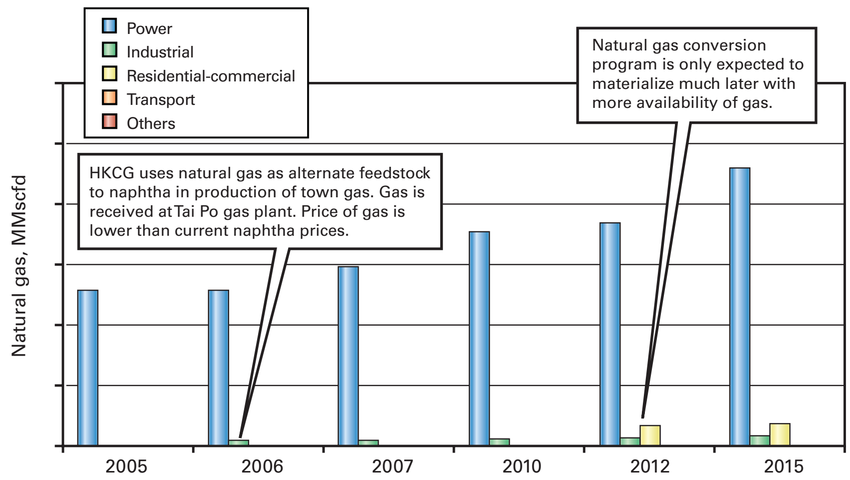
Fig. 7



*1992-2007, annual average; 2008-15, estimated annual average.

HONG KONG'S DEMAND

Fig. 8



means of diversifying gas supply and creating price competition for piped gas imports. The price of piped natural gas is currently very high because it is linked to high-sulfur fuel oil, which has increased in price due to a variety of factors including rapid growth in Chinese fuel-oil imports (Fig. 7).

When gas imports first started in the early 1990s, from Malaysia, gas prices were in $2-3/MMbtu. This stimulated demand growth for the fuel in power generation. Prices today, however, have moved in tandem with increased oil prices—and increased fuel-oil prices—resulting in average import prices at around $10/MMbtu.

Singapore's government approved the project to build a 3-million-tpy LNG terminal (capacity capped at 6 million tpy) by 2012. Exclusive LNG import license will go to the aggregator, which is expected to be chosen by April 2008. This exclusive right will lapse only in 2018. While Singapore expects to import 1 million tpy of LNG by 2012, rising to 3 million tpy by 2018, we believe the buildup in import volumes may likely be slower at 2 million tpy by 2018.

Hong Kong

Natural gas's share accounts for 15% of Hong Kong's primary energy consumption in 2007, while the balance is dominated by oil (47%) and coal (34%). By 2015, natural gas will likely account for about 22%, mainly due to increased demand in the power sector.

Gas demand as of 2007 stands at around 325 MMscfd, with almost all volumes consumed in the power sector and marginal consumption in the industrial sector (for the production of town gas). This will eventually change, as there are plans for Hong Kong to introduce natural gas to the residential and commercial sector while increasing city gas use.

Introduction of natural gas in the residential and commercial sector was originally to come online in 2006-07. Because of technical (lack of infrastructure) and gas supply issues, however, the natural gas conversion program will only move ahead sometime around 2012 when LNG imports commence (Fig. 8).

The main driver for natural gas growth in the future will derive from environmental concerns. As power companies in Hong Kong are the main sources of pollution, the shift in preference away from coal and petroleum products toward gas has been prevalent in the economy.

Currently Hong Kong imports gas from two sources:

1. China's Yacheng 13-1 field via a 778-km gas pipeline.

2. Regasified LNG received through the Guangdong LNG terminal.

Declining field production from Yacheng field and increasing demand for Guangdong LNG in China will reduce gas for exports to Hong Kong.

Prospects for LNG

With a shortfall in contracted gas supply occurring as early as 2012, Hong Kong has decided to build a 3-million-tpy LNG receiving terminal by Hong Kong utility CLP Holdings Ltd., mainly for power generation. As with Singapore, Hong Kong pays international prices for oil products and has a threshold for internationally priced LNG. FGE forecasts Hong Kong LNG imports will commence in 2012 with a minimal import of 0.5 million tpy, rising to around 1.5 million tpy by 2015.

Thailand

Thailand's natural gas demand has grown dramatically over the last 2 decades. From 1990 to 2000, natural gas demand grew at an average 13.5%/year, while from 2000 to 2005 demand slowed slightly to 8.9%. Natural gas has the second largest share of Thailand's primary energy consumption, accounting for 27% of the country's demand, outweighed only by oil (47%), followed by coal, combustible renewables and waste, and hydropower. Although oil will continue to dominate all fuels in absolute numbers, natural gas will post strong growth averaging 4.9%/year 2007-15 compared with oil at 3%/year

The power sector dominates Thailand's gas demand. In 2007, it accounted for 68% of gas demand followed by the others sector at 21%—which primarily consists of gas processing plants—and the industrial sector at 11%. Within the power sector itself, natural gas as a fuel made up 70% of power generated followed by coal (21%) and hydro (5%). Thailand also imports around 3% of its electricity, while fuel oil and diesel oil constitute only 2% of power generated.

Thailand currently imports gas solely from Myanmar via the Yadana and Yetagun pipelines under long-term take-or-pay contracts. In 2008, Thailand will begin to import gas via the Malaysia-Thailand joint development project from Blocks A-18 (400 MMscfd), while delivery of gas from B-17 and B-17-01 will begin in first-half 2008 at 135 MMscfd for the first 10 years.

Prospects for LNG

Since domestic production cannot keep up with rising domestic demand, Thailand increased its import dependency from Myanmar. That dependency on pipeline gas imports has raised the issue of supply security, however, and PTT PLC has set up a subsidiary, PTTLNG, to handle LNG issues for the country.

PTT's initial enthusiasm for the LNG terminal was tempered, however, by higher prices reflecting the emerging LNG sellers' market in 2006. Nevertheless, PTT still appears keen to proceed with the planned 5-million-tpy receiving terminal at Map Ta Phut in the Rayong Province. The company has announced that it will spend nearly $1 billion to construct a deepsea port and receiving terminal at the planned site by 2011.

PTT also signed a preliminary agreement in July 2006 to receive 3 million tpy of LNG from Iranian Pars LNG, reflecting thereby the company's desire for an LNG project. Such uncertain issues, however, as Iran's ability to supply LNG in the near future and whether Thailand can pay market rates led FGE to extend its base-case scenario forecasts of LNG imports to 2017 with initial volumes at around 1.3 million tpy. ✦

The authors

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Equipment/Software/Literature

New sealing and flange isolation gasket

The new LineSeal sealing and flange isolation gasket is designed for extreme critical sealing applications.

The 316 stainless steel cored gasket features G-10 retainer material and a PTFE (Teflon) seal as a standard. It seals all pressure ratings through ANSI 2500 class and API 15,000 psi service, while withstanding carbon dioxide or hydrogen sulfide.

The gasket is available as a stand alone product or as part of a high quality flange isolation kit.

Source: **Pipeline Seal & Insulator Inc.,** 6525 Goforth St., Houston, TX 77021.

New offshore launch and retrieval system

Deep Down Inc., Channelview, Tex., has delivered a launch and retrieval system (LARS) that the firm believes to be the deepest class rated unit of its kind in the world.

The 4,000 m rated LARS is specially designed for subsea load handling, lifting and tensioning, and launch and retrieval of specialized underwater equipment—including remotely operated vehicles (ROVs)—in ultradeep and harsh subsea environments. Special functions include autovariable speed control (load dependent), wire spooling and guide systems, grooved drums, emergency release capabilities, gravity lowering, emergency hoisting abilities, and a water-cooled drum to reduce heat on the umbilical.

The safe working load of the LARS is 28 tonnes, and the system is capable of delivering payloads at speeds of up to 76 m/min. It also features a specially designed wraparound level wind sensor system that allows for more sensitive yet smoother operation in rugged, high-load, ultradeepwater applications.

The 4,000 m LARS was sold to Perry Slingsby Systems Inc., Jupiter, Fla., for integration with Perry's new 4,000 m rated ROV.

Perry sold the integrated unit to Paris-based Veolia ES Special Services Inc., which has placed the system on Veolia's newly built DSV MT-6016 Swordfish marine vessel. The new ship is custom designed to allow Veolia to take on more complex subsea construction and dive-support projects. The Swordfish also has a 3,000 m rated LARS leased to Veolia with a Perry ROV.

A second 4,000 m rated LARS is expected to be delivered to Perry as soon as factory acceptance testing has been completed. The second LARS will also be sold to Veolia with a Perry ROV.

Source: **Deep Down Inc.,** 15473 East Freeway, Channelview, TX 77530.

Services/Suppliers

Superior Offshore International Inc.,

Houston, has appointed E. Donald Terry as interim president and CEO following the resignation of James J. Mermis as president, CEO, and director. Mermis plans to join Kaplan Industry as its president of technical operations. Terry, with 45 years of experience in the subsea construction and commercial diving industry and currently an independent director of Superior, will serve until a successor is named.

Superior Offshore is a leading provider of subsea construction and commercial diving services to the offshore oil and gas industry.

Technip SA,

Paris, has named Kimberly Stewart vice-president, investor relations. Previously, she was head of investor relations at Faurecia, an equity analyst with Cheuvreux in Paris and London, and an equity analyst with Credit Suisse in London and New York. Stewart holds BA and MA degrees in international business from Evergreen State College and the University of Reading, respectively.

Technip is one of the top five firms worldwide in the field of oil, gas, and petrochemical engineering, construction, and services.

Jergens Inc.,

Cleveland, has appointed Jeff Martin as product manager for Kwik-Lok pins, inserts, and spring-loaded devices in the company's tooling components division. Previously, he operated his own business related to the machine tool industry. Martin has a BS in industrial technology from Ohio University. He replaces Matthew Schron, who has been named general manager of Jergens Industrial Supply (JIS).

Martin

Jergens comprises the tooling components division, JIS, and the ASG division, all located in Cleveland, and Acme Industrial in Chicago. It is a manufacturer and distributor of tooling components and workholding products.

Weinman GeoScience,

Dallas and Houston, has named John Maher manager of seismic processing in its Denver office. With more than 12 years of worldwide experience in all phases of land and marine processing, he specializes in the complexities and issues of the Rocky Mountain region. Previously, Maher worked at GX Technology (Axis) and WesternGeco.

Weinman provides expert consulting, seismic data processing, geophysical, geological, and engineering services to the oil and gas industry.

Delta Services,

Houston, has appointed Jeffrey M. Bender as vice-president in its retained search energy practice. He has more than 30 years of human resources leadership in the upstream oil and gas, refining, chemicals, and metals industries. Previously, Bender was vice-president, human resources, for Apache Corp. Prior to that, he worked for Vastar Energy Resources and ARCO.

Delta Services is a global energy retained executive search firm, providing retained search services, from senior-level petrotechnical individual contributors to executive-level management.

IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4 2-8 2008	Districts 1-4 2-1 2008	District 5 2-8 2008	District 5 2-1 2008	Total US 2-8 2008	Total US 2-1 2008	Total US 12-9 2007
	1,000 b/d						
Total motor gasoline	841	1,114	—	30	841	1,144	820
Mo. gas. blending comp.	453	611	—	30	453	641	611
Distillate	282	371	—	—	282	371	357
Residual	200	245	—	50	200	295	399
Jet fuel-kerosine	103	156	54	53	157	209	232
Propane-propylene[2]	139	261	21	24	160	285	150
Other	1,210	967	60	304	1,270	1,271	685
Total products	**3,228**	**3,725**	**135**	**491**	**3,363**	**4,216**	**3,254**
Total crude	**8,414**	**9,278**	**1,323**	**1,236**	**9,737**	**10,514**	**9,584**
Total imports	**11,642**	**13,003**	**1,458**	**1,727**	**13,100**	**14,730**	**12,838**

[1]Revised. [2]Data available only for PADDs 1-3.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

PURVIN & GERTZ LNG NETBACKS—FEB. 15, 2008

Receiving terminal	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	Liquefaction plant — $/MMbtu					
Barcelona	7.76	5.58	6.89	5.46	6.20	6.81
Everett	8.23	5.91	7.82	5.97	6.55	8.55
Isle of Grain	8.26	5.81	7.63	5.66	6.59	7.60
Lake Charles	6.06	3.89	5.81	4.09	4.42	6.73
Sodegaura	6.41	8.42	6.63	8.43	7.68	5.64
Zeebrugge	7.73	5.55	7.05	5.48	6.07	7.05

Definitions, see OGJ Apr. 9, 2007, p. 57.
Source: Purvin & Gertz Inc.
Data available in OGJ Online Research Center.

Additional analysis of market trends is available through **OGJ Online**, *Oil & Gas Journal's* electronic information source, at http://www.ogjonline.com.

OIL&GAS JOURNAL online research center.

OGJ CRACK SPREAD

	*2-15-08	*2-16-07	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	103.55	68.10	35.45	52.1
Brent crude	96.50	55.96	40.54	72.4
Crack spread	7.05	12.14	–5.09	–41.9
FUTURES MARKET PRICES				
One month				
Product value	105.20	68.24	36.97	54.2
Light sweet crude	94.12	58.45	35.67	61.0
Crack spread	11.08	9.79	1.30	13.3
Six month				
Product value	107.43	73.34	34.09	46.5
Light sweet crude	93.23	61.32	31.91	52.0
Crack spread	14.21	12.02	2.19	18.2

*Average for week ending
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

CRUDE AND PRODUCT STOCKS

District	Crude oil	Motor gasoline Total	Motor gasoline Blending comp.[1]	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane-propylene
	1,000 bbl						
PADD 1	13,551	65,889	34,350	9,447	47,951	15,342	3,709
PADD 2	61,793	53,985	17,839	8,343	30,760	1,468	11,860
PADD 3	155,999	67,923	31,653	12,385	30,912	13,794	19,591
PADD 4	12,749	7,041	2,183	606	3,044	417	[1]1,492
PADD 5	56,978	34,398	27,530	10,312	14,306	5,872	—
Feb. 8, 2008	**301,070**	**229,236**	**113,555**	**41,093**	**126,973**	**36,893**	**36,652**
Feb. 1, 2008	**300,004**	**227,487**	**112,804**	**41,166**	**127,139**	**36,459**	**38,493**
Feb. 9, 2007[2]	**323,889**	**225,156**	**100,782**	**39,295**	**133,327**	**41,279**	**40,483**

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

REFINERY REPORT—FEB. 8, 2008

District	Refinery operations Gross inputs	Refinery operations Crude oil inputs	Refinery output Total motor gasoline	Refinery output Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane-propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,395	1,437	1,683	83	475	132	65
PADD 2	3,245	3,206	2,336	206	988	58	209
PADD 3	6,989	6,802	3,102	711	1,930	313	692
PADD 4	563	558	299	26	167	12	[1]140
PADD 5	2,642	2,558	1,489	415	531	134	—
Feb. 8, 2008	**14,834**	**14,561**	**8,909**	**1,441**	**4,091**	**649**	**1,106**
Feb. 1, 2008	**14,705**	**14,492**	**8,739**	**1,495**	**4,037**	**663**	**1,091**
Feb. 9, 2007[2]	**15,076**	**14,836**	**8,907**	**1,429**	**4,080**	**661**	**1,006**
	17,436 operable capacity		**85.1% utilization rate**				

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

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Statistics

OGJ gasoline prices

	Price ex tax 2-13-08	Pump price* 2-13-08	Pump price 2-14-07
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	268.3	308.0	216.4
Baltimore	252.6	294.5	218.6
Boston	262.3	304.2	217.0
Buffalo	268.5	328.6	238.7
Miami	272.5	322.8	235.5
Newark	256.7	289.6	210.0
New York	244.1	304.2	225.7
Norfolk	249.4	287.0	209.5
Philadelphia	259.2	309.9	240.8
Pittsburgh	255.4	306.1	221.9
Wash., DC	267.6	306.0	226.9
PAD I avg	259.7	306.5	223.7
Chicago	287.3	338.2	247.9
Cleveland	250.8	297.2	225.9
Des Moines	254.7	295.1	214.7
Detroit	253.7	302.9	224.3
Indianapolis	255.0	300.0	229.5
Kansas City	251.1	287.1	208.9
Louisville	265.0	301.9	228.3
Memphis	247.6	287.4	207.5
Milwaukee	246.8	298.1	230.5
Minn.-St. Paul	253.7	294.1	223.4
Oklahoma City	248.3	283.7	209.1
Omaha	253.1	299.5	223.0
St. Louis	240.8	276.8	215.4
Tulsa	247.9	283.3	206.4
Wichita	237.8	281.2	215.7
PAD II avg	252.9	295.1	220.7
Albuquerque	253.8	290.2	214.6
Birmingham	257.0	295.7	212.2
Dallas-Fort Worth	249.5	287.9	215.1
Houston	253.3	291.7	209.8
Little Rock	247.6	287.8	213.8
New Orleans	253.8	292.2	212.4
San Antonio	248.6	287.0	204.9
PAD III avg	252.0	290.4	211.8
Cheyenne	243.8	276.2	204.9
Denver	247.8	288.2	212.0
Salt Lake City	254.8	297.7	212.3
PAD IV avg.	248.8	287.4	209.8
Los Angeles	249.3	307.8	262.1
Phoenix	248.7	286.1	227.0
Portland	255.1	298.4	248.1
San Diego	256.2	314.7	269.6
San Francisco	281.8	340.3	289.3
Seattle	256.9	309.3	258.8
PAD V avg.	258.0	309.4	259.2
Week's avg.	**255.0**	**298.5**	**224.7**
Jan. avg.	**260.9**	**304.5**	**225.3**
Dec. avg.	**257.0**	**300.6**	**228.5**
2008 to date	**259.3**	**302.8**	—
2007 to date	**181.4**	**225.0**	—

*Includes state and federal motor fuel taxes and state sales tax. Local governments may impose additional taxes.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

Refined product prices

Spot market product prices	2-8-08 ¢/gal		2-8-08 ¢/gal
Motor gasoline		Heating oil	
(Conventional-regular)		No. 2	
New York Harbor	228.91	New York Harbor	255.13
Gulf Coast	230.66	Gulf Coast	251.48
Los Angeles	242.16	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	218.69	ARA	261.38
Singapore	236.81	Singapore	245.95
Motor gasoline		Residual fuel oil	
(Reformulated-regular)		New York Harbor	165.79
New York Harbor	227.41	Gulf Coast	165.48
Gulf Coast	232.16	Los Angeles	179.03
Los Angeles	247.16	ARA	173.42
		Singapore	162.71

Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

Baker Hughes rig count

	2-15-08	2-16-07
Alabama	3	4
Alaska	9	11
Arkansas	40	40
California	32	34
Land	31	30
Offshore	1	4
Colorado	118	94
Florida	0	0
Illinois	0	0
Indiana	1	1
Kansas	10	12
Kentucky	8	9
Louisiana	144	202
N. Land	46	60
S. Inland waters	18	24
S. Land	31	45
Offshore	49	73
Maryland	0	0
Michigan	0	0
Mississippi	12	21
Montana	11	17
Nebraska	0	0
New Mexico	67	83
New York	6	9
North Dakota	54	33
Ohio	12	13
Oklahoma	195	178
Pennsylvania	20	14
South Dakota	1	0
Texas	875	814
Offshore	5	11
Inland waters	3	2
Dist. 1	23	24
Dist. 2	33	33
Dist. 3	65	54
Dist. 4	94	91
Dist. 5	180	154
Dist. 6	120	126
Dist. 7B	32	37
Dist. 7C	48	48
Dist. 8	132	110
Dist. 8A	19	25
Dist. 9	43	38
Dist. 10	78	61
Utah	42	45
West Virginia	28	29
Wyoming	73	73
Others—NV-3; TN-6; VA-3	12	10
Total US	**1,773**	**1,746**
Total Canada	**632**	**636**
Grand total	**2,405**	**2,382**
Oil rigs	339	267
Gas rigs	1,428	1,473
Total offshore	55	88
Total cum. avg. YTD	**1,755**	**1,721**

Rotary rigs from spudding in to total depth. Definitions, see OGJ Sept. 18, 2006, p. 42.

Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

Smith rig count

Proposed depth, ft	2-15-08 Rig count	2-15-08 Percent footage*	2-16-07 Rig count	2-16-07 Percent footage*
0-2,500	73	8.2	51	—
2,501-5,000	104	51.9	102	57.8
5,001-7,500	226	20.7	228	20.1
7,501-10,000	445	4.0	417	3.8
10,001-12,500	439	3.6	408	2.9
12,501-15,000	308	0.3	272	0.7
15,001-17,500	91	—	117	1.7
17,501-20,000	75	—	77	—
20,001-over	36	—	39	—
Total	**1,797**	**7.9**	**1,711**	**8.0**
INLAND	35		34	
LAND	1,709		1,615	
OFFSHORE	53		62	

*Rigs employed under footage contracts.
Definitions, see OGJ, Sept. 18, 2006, p. 42.

Source: Smith International Inc.
Data available in OGJ Online Research Center.

OGJ production report

	[1]2-15-08	[2]2-16-07
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	15	19
Alaska	695	760
California	655	669
Colorado	49	42
Florida	6	6
Illinois	27	23
Kansas	95	95
Louisiana	1,326	1,322
Michigan	15	16
Mississippi	50	54
Montana	91	95
New Mexico	166	161
North Dakota	115	116
Oklahoma	172	172
Texas	1,339	1,332
Utah	45	53
Wyoming	143	145
All others	59	67
Total	**5,063**	**5,147**

[1]OGJ estimate. [2]Revised.

Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

US crude prices

$/bbl*	2-15-08
Alaska-North Slope 27°	80.63
South Louisiana Sweet	98.25
California-Kern River 13°	82.80
Lost Hills 30°	90.90
Wyoming Sweet	87.00
East Texas Sweet	91.50
West Texas Sour 34°	84.50
West Texas Intermediate	92.00
Oklahoma Sweet	92.00
Texas Upper Gulf Coast	88.50
Michigan Sour	85.00
Kansas Common	91.00
North Dakota Sweet	83.75

*Current major refiner's posted prices except North Slope lags 2 months. 40° gravity crude unless differing gravity is shown.

Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

World crude prices

$/bbl[1]	2-8-08
United Kingdom-Brent 38°	91.52
Russia-Urals 32°	87.99
Saudi Light 34°	86.03
Dubai Fateh 32°	85.68
Algeria Saharan 44°	90.94
Nigeria-Bonny Light 37°	91.85
Indonesia-Minas 34°	92.48
Venezuela-Tia Juana Light 31°	84.32
Mexico-Isthmus 33°	84.21
OPEC basket	87.93
Total OPEC[2]	86.55
Total non-OPEC[2]	87.09
Total world[2]	86.80
US imports[3]	83.21

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume.

Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

US natural gas storage[1]

	2-8-08	2-1-07	2-8-07	Change, %
	bcf			
Producing region	643	670	686	–6.3
Consuming region east	1,072	1,138	1,173	–8.6
Consuming region west	227	254	267	–15.0
Total US	**1,942**	**2,062**	**2,126**	**–8.7**

	Nov. 07	Nov. 06	Change, %
Total US[2]	**3,456**	**3,407**	**1.4**

[1]Working gas. [2]At end of period.
Source: Energy Information Administration.
Data available in OGJ Online Research Center.

World oil balance

	2007 3rd qtr.	2007 2nd qtr.	2007 1st qtr.	2007 4th qtr.	2006 3rd qtr.	2006 2nd qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	21.03	20.97	21.07	21.09	21.25	20.91
Canada	2.40	2.28	2.34	2.26	2.31	2.20
Mexico	1.98	2.07	2.05	2.00	1.96	1.98
Japan	4.67	4.61	5.39	5.29	4.75	4.72
South Korea	2.06	2.12	2.35	2.32	2.04	2.04
France	1.93	1.85	1.97	1.95	1.93	1.87
Italy	1.63	1.67	1.69	1.71	1.68	1.65
United Kingdom	1.75	1.78	1.80	1.81	1.78	1.82
Germany	2.56	2.40	2.39	2.71	2.75	2.59
Other OECD Europe	7.56	7.27	7.36	7.54	7.46	7.29
Australia & New Zealand	1.09	1.07	1.09	1.10	1.07	1.06
Total OECD	**48.66**	**48.09**	**49.50**	**49.78**	**48.98**	**48.13**
NON-OECD						
China	7.69	7.62	7.43	7.53	7.24	7.30
FSU	4.39	4.49	4.41	4.49	4.40	4.20
Non-OECD Europe	0.73	0.78	0.85	0.78	0.72	0.77
Other Asia	8.64	8.83	8.74	8.82	8.54	8.71
Other non-OECD	15.34	15.03	14.75	14.49	14.74	14.45
Total non-OECD	**36.79**	**36.75**	**36.18**	**36.11**	**35.04**	**35.43**
TOTAL DEMAND	**85.45**	**84.84**	**85.68**	**85.39**	**84.62**	**83.56**
SUPPLY						
OECD						
US	8.40	8.53	8.43	8.40	8.38	8.34
Canada	3.35	3.33	3.42	3.39	3.31	3.16
Mexico	3.46	3.61	3.59	3.52	3.71	3.79
North Sea	4.27	4.48	4.80	4.76	4.51	4.71
Other OECD	1.56	1.54	1.50	1.55	1.55	1.44
Total OECD	**21.04**	**21.49**	**21.74**	**21.62**	**21.46**	**21.44**
NON-OECD						
FSU	12.56	12.60	12.61	12.46	12.26	12.07
China	3.87	3.96	3.92	3.81	3.85	3.87
Other non-OECD	12.06	11.77	11.40	11.73	11.91	11.70
Total non-OECD, non-OPEC	**28.49**	**28.33**	**27.93**	**28.02**	**28.02**	**27.64**
OPEC	**34.90**	**34.58**	**34.51**	**34.97**	**35.66**	**35.19**
TOTAL SUPPLY	**84.43**	**84.40**	**84.18**	**84.61**	**85.14**	**84.27**
Stock change	**–1.02**	**–0.44**	**–1.50**	**–1.28**	**0.52**	**0.71**

Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

OECD total net oil imports

	Oct. 2007	Sept. 2007	Aug 2007	Oct. 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	–1,088	–1,229	–1,187	–1,400	312	–22.3
US	11,628	12,282	12,119	11,810	–182	–1.5
Mexico	–1.217	–1,545	–1,406	–1,654	435	–26.3
France	1,792	1,707	1,831	1,742	50	2.9
Germany	2,289	2,236	2,249	2,565	–276	–10.8
Italy	1,689	1,681	1,717	1,664	25	1.5
Netherlands	797	1,084	1,029	1,073	–276	–25.7
Spain	1,539	1,700	1,674	1,523	16	1.1
Other importers	4,234	4,174	3,989	4,114	120	2.9
Norway	–2,165	–2,129	–2,332	–2,529	364	–14.4
United Kingdom	84	251	465	241	–157	–65.1
Total OECD Europe	**10,259**	**10,704**	**10,622**	**10,393**	**–134**	**–1.3**
Japan	4,825	4,503	4,933	4,879	–54	–1.1
South Korea	2,194	2,152	1,848	1,881	313	16.6
Other OECD	921	873	770	777	144	18.5
Total OECD	**27,522**	**27,740**	**27,699**	**26,688**	**834**	**3.1**

Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

OECD* total gross imports from OPEC

	Oct. 2007	Sept. 2007	Aug 2007	Oct. 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	543	536	501	357	186	52.1
US	5,606	6,250	6,106	6,073	–467	–7.7
Mexico	31	40	35	10	21	210.0
France	766	848	844	947	–181	–19.1
Germany	420	448	500	521	–101	–19.4
Italy	1,255	1,210	1,336	1,387	–132	–9.5
Netherlands	644	665	644	582	62	10.7
Spain	730	732	667	828	–98	–11.8
Other importers	1,292	1,266	1,269	1,345	–53	–3.9
United Kingdom	273	244	404	220	53	24.1
Total OECD Europe	**5,380**	**5,413**	**5,664**	**5,830**	**–450**	**–7.7**
Japan	4,326	3,927	4,229	4,181	145	3.5
South Korea	2,549	2,298	2,116	2,181	368	16.9
Other OECD	800	738	844	685	115	16.8
Total OECD	**19,235**	**19,204**	**19,495**	**19,317**	**–82**	**–0.4**

*Organization for Economic Cooperation and Development.
Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

US petroleum imports from source country

	Oct. 2007	Sept. 2007	Average YTD 2007	Average YTD 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	1,000 b/d					
Algeria	410	702	698	675	24	3.5
Angola	342	591	523	527	–5	–0.9
Kuwait	157	170	188	179	9	5.0
Nigeria	1,241	1,181	1,100	1,135	–35	–3.1
Saudi Arabia	1,400	1,560	1,455	1,457	–3	–0.2
Venezuela	1,388	1,333	1,357	1,448	–91	–6.3
Other OPEC	668	713	650	160	490	306.8
Total OPEC	**5,606**	**6,250**	**5,970**	**5,580**	**390**	**7.0**
Canada	2,411	2,502	2,432	2,314	118	5.1
Mexico	1,417	1,454	1,550	1,752	–203	–11.6
Norway	110	105	148	201	–53	–26.3
United Kingdom	287	185	289	280	9	3.3
Virgin Islands	357	384	335	326	9	2.7
Other non-OPEC	2,762	2,759	2,788	3,423	–635	–18.6
Total non-OPEC	**7,344**	**7,389**	**7,541**	**8,295**	**–755**	**–9.1**
TOTAL IMPORTS	**12,950**	**13,639**	**13,511**	**13,876**	**–364**	**–2.6**

Source: DOE Monthly Energy Review
Data available in OGJ Online Research Center.

Oil stocks in OECD countries*

	Oct. 2007	Sept. 2007	Aug 2007	Oct. 2007	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million bbl					
France	176	187	187	188	–12	–6.4
Germany	275	278	280	282	–7	–2.5
Italy	132	134	134	130	2	1.5
United Kingdom	102	99	104	103	–1	–1.0
Other OECD Europe	661	675	671	660	1	0.2
Total OECD Europe	**1,346**	**1,373**	**1,376**	**1,363**	**–17**	**–1.2**
Canada	197	199	191	183	14	7.7
US	1,707	1,719	1,718	1,769	–62	–3.5
Japan	629	630	641	654	–25	–3.8
South Korea	159	157	157	156	3	1.9
Other OECD	113	108	105	110	3	2.7
Total OECD	**4,151**	**4,186**	**4,188**	**4,235**	**–84**	**–2.0**

*End of period.
Source: DOE International Petroleum Monthly Report
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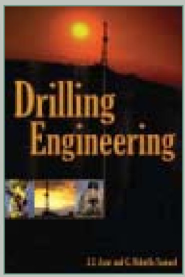

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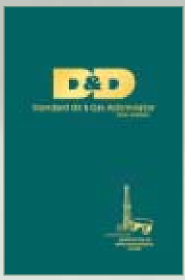

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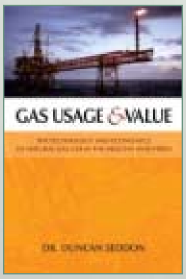

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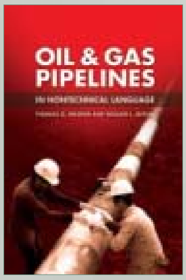

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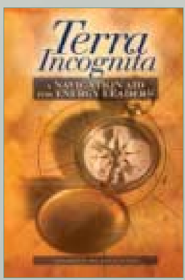

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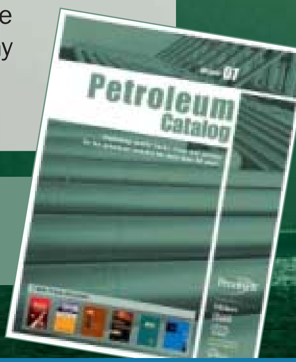

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Congress offers bad reasons for bad energy bill

Doing good things for good reasons is best; good things for bad reasons, lucky; bad things for good reasons, wrong; and bad things for bad reasons, stupid.

Taxing oil and gas to fund renewable energy is a bad thing to do. Lowering US dependency on foreign oil is a bad reason to do it.

"We need an energy plan that reduces our dependency on foreign oil and invests in clean, renewable technology that will create jobs here in America," said House Ways and Means chairman Charles B. Rangel in support of a new energy blunder.

The Editor's Perspective

by Bob Tippee, Editor

Rangel and fellow Democrats have revived an effort to raise taxes—they misleadingly say end "subsidies"—of oil and gas companies. Proceeds would pay for an extension of tax incentives for renewable energy (OGJ Online, Feb. 13, 2008).

The legislation would limit the use by oil companies of a tax credit that helps US companies compete abroad. It also would reduce the deductibility of non-US production taxes in calculations of taxable US income.

The combined effect is a tax increase on the oil and gas industry of $17.65 billion over 10 years—money that can't be invested in oil and gas supply.

By explicitly making them substitutes for rather than supplements to oil and gas, the legislation takes the worst possible approach to renewable energy forms. It forces Americans to use expensive energy in place of something cheaper.

And it wouldn't lower US dependence on foreign oil. Along with gains in output of renewable energy would come declines, thanks to the tax hikes, in US production of oil.

Rangel's other promises are equally hollow.

Renewable energy forms are not, as experience with ethanol is showing, the environmental panaceas their supporters say they are. And weakening the economy by forcing expensive energy into the market is no way to create jobs.

A sounder way to cut US reliance on foreign oil and create jobs—and to earn rather than spend public money—is to expand oil and gas leasing of federal land.

But congressional Democrats have their own way. And it's stupid.

(Online Feb. 15, 2008; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Greenspan: Odds favor recession

At Cambridge Energy Research Associates' annual energy conference in Houston, former Federal Reserve Chairman Alan Greenspan said there is a "50% or better" chance that the US will experience an economic recession that will curtail energy demand.

"We are at stall speed in the US but haven't yet seen the discontinuity that characterizes recession," he said. It is "quite remarkable," Greenspan said, that the US economy is able to do reasonably well with oil prices near historic highs. That's because "business was in such extraordinary good shape before this problem hit," that credit availability has not yet dried up for US industry.

Greenspan said, "Global warming is real, but its solution is going to be much more difficult than we'd like to admit. There's a presumption that we'll solve this [fuel and climate] problem with new technologies. I wish that were true." He warned that a "mandatory cap on carbon emissions risks capping energy inputs into the gross domestic product while lowering production and increasing unemployment." He said, "I'm a strong advocate of competitive market capitalism. It's the only viable system through which societies can produce significant material well being. However, with its increasing required conceptual inputs and technology, income inequality has risen. We cannot have a system, no matter how powerful, that doesn't have the support of the people."

In a separate study, economists at the Deutsche Bank AG, New York, reported core retail spending in the US was up just 1.4% in nominal terms over the past 12 months. "Such a reading, historically, has been consistent with recession," said Adam Sieminski, Deutsche Bank's chief energy economist in New York. He said: "The sharp slowdown in spending increases the likelihood that inventories will have to be pared back this quarter, in particular in the retail sector. The combination of faltering consumer spending alongside modestly rising retail inventories does not bode well for current quarter gross domestic product growth. For this reason, Deutsche Bank now sees more inventory liquidation this quarter relative to what we were assuming, enough in our view to push our estimate of current quarter real GDP growth from a flat reading down into negative territory, and one step closer to a mild recession."

However, Paul Horsnell at Barclays Capital Inc., London, noted supply-side changes have been the key source of energy price variability since 2004. Moreover, he said world oil demand now is concentrated outside the member nations of the Organization for Economic Cooperation and Development and primarily in the Middle East and China. "So the link from the day-to-day flow of US economic data onto oil demand has become an extremely tenuous one," he said.

Energy supplies

The International Energy Agency in Paris estimated crude supply growth outside the Organization of Petroleum Exporting Counties will average 970,000 b/d in 2008, with most of that growth coming in the second half of the year vs. 2007 growth that was front-end loaded. For a third consecutive month, IEA in February raised its forecast demand for OPEC crude.

Barlays Capital maintained its forecast of negligible non-OPEC supply growth in 2008. "Indeed, stripping out biofuels and Canadian oil sands, we expect conventional non-OPEC oil supply to fall," Horsnell reported. "For 2008, we see the major [non-OPEC supply] increments as coming from Brazil (314,000 b/d), Russia (203,000 b/d), and Azerbaijan (176,000 b/d)." However, he said, "The key thing about the three gainers (a combined rise of 693,000 b/d) is that they are offset by the three major sources of decline. We are currently projecting the combined decline in 2008 from Mexico, UK, and Norway to amount to 692,000 b/d."

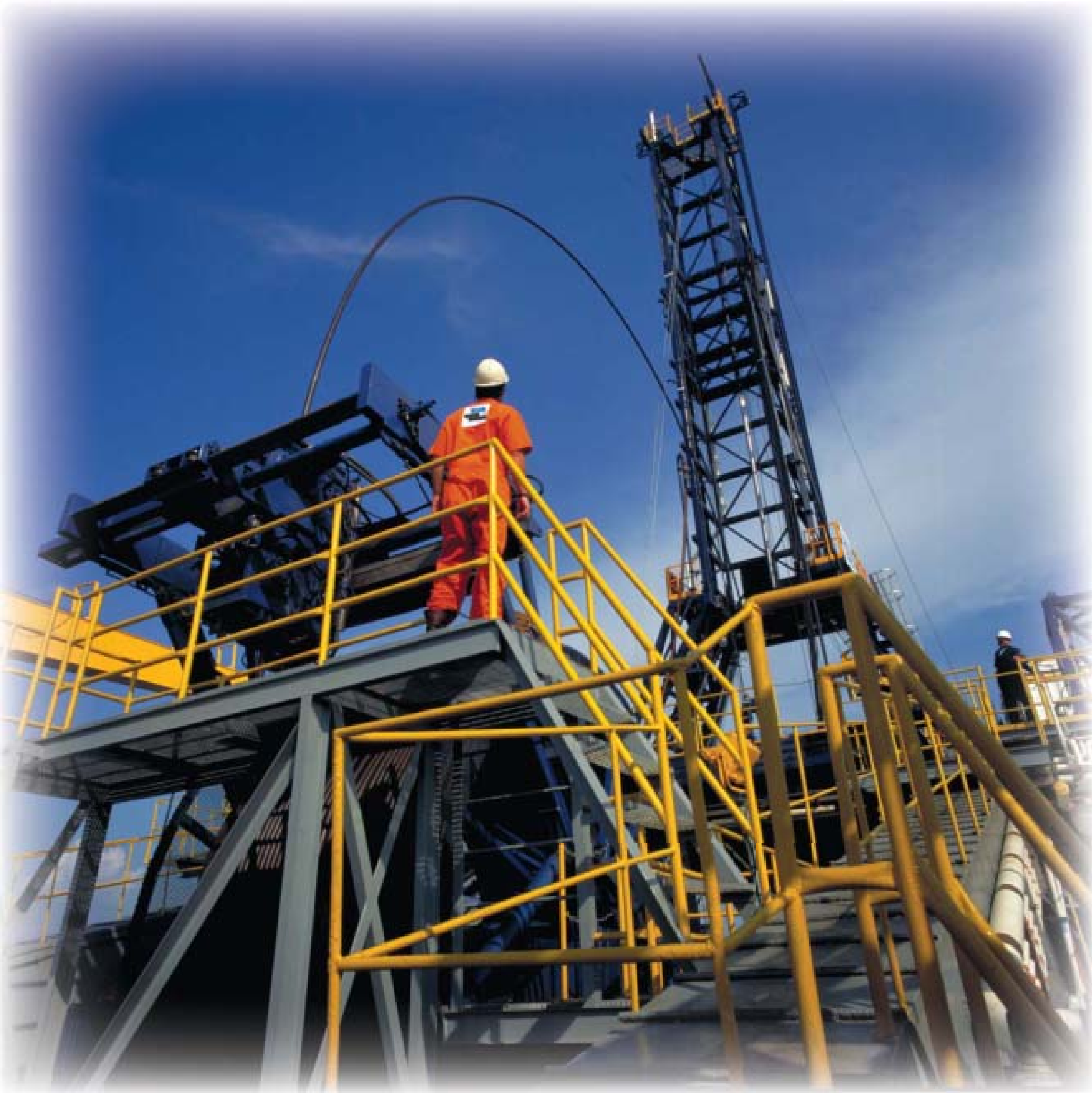
Horsnell said, "For conventional non-OPEC oil supply to fall outside of the former Soviet Union is not a new phenomenon; indeed output is already some 2 million b/d below the 2002 peak. However, a fall in conventional oil output across non-OPEC as a whole is a somewhat more noteworthy an event."

Deutsch Bank's Sieminski warned, "One matter to watch closely is growth in OPEC natural gas liquids that traditionally is added to non-OPEC supply because OPEC does not count NGL in quotas. The IEA's OPEC NGL forecast was revised lower for 2008 after reassessing Saudi Arabian start-up schedules. IEA and the US Department of Energy expect 300,000 b/d growth in 2008." He said growth forecasts for non-OPEC supply in 2009 also should be closely monitored. "The DOE is calling for 1.5 million b/d of basic non-OPEC growth next year, and an additional 600,000 b/d of OPEC NGL for a total 2.2 million b/d offset against demand for OPEC crude."

(Online Feb. 18, 2008; author's e-mail: samf@ogjonline.com)

Coiled Tubing Equipment & Services

Supplement to *Oil & Gas Journal* • February 25, 2008



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Technology Forum

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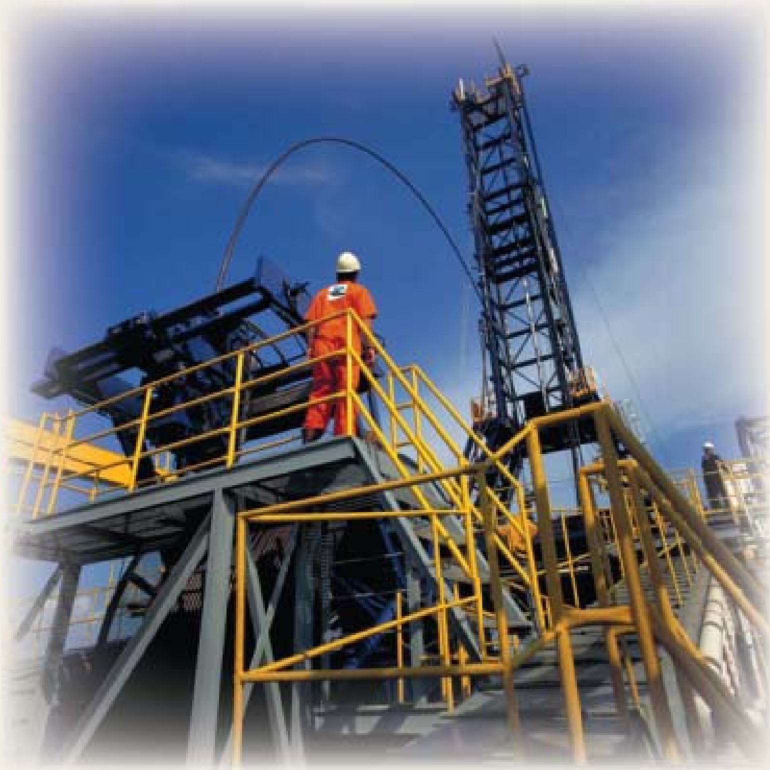


A hybrid coiled tubing drilling and well intervention unit developed by Baker Hughes is shown at work. Photo courtesy of Baker Oil Tools.

Oil & Gas Journal's Technology Forum series, produced by the OGJ Group Publisher, supplements the magazine with topical features on cutting-edge technology, services, and equipment, all expertly written from the technology provider's perspective. Inquiries should be directed to Bill Wageneck, Group Publisher, at billw@pennwell.com.

CT services gaining wider acceptance, but CT drilling lags in US

Coiled tubing drilling and servicing is among the fastest-growing sectors in the oil field service and supply industry.

The versatile tool has long been a staple of well intervention operations, such as workovers, stimulation jobs, completions, and downhole tool conveyance, to name a few. In particular, CT well servicing has made dramatic gains in the offshore sector in recent years.

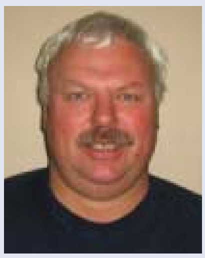
Although coiled tubing drilling (CTD) is widely accepted in Canada, the practice has made few inroads into the US market, especially the Lower 48. Consequently, CTD accounts for only about 15% of the overall CT service sector worldwide.

CT experts interviewed for this article expressed optimism that CT service work will continue to show robust growth and that CTD will find greater acceptance in the Lower 48. In addition, CT well intervention and drilling activity will continue to expand into new markets and into new applications in existing markets, those experts say.

Even a downturn in conventional drilling activity shouldn't inhibit the growth of CT services, they note, adding that the CT service sector could in fact benefit from such a downturn.

In Canada, the current downturn in conventional drilling activity is increasing the utilization of CT with rigless completions: "We are already seeing this with some of our customers. The use of our intermediate-size units has stayed busy, and in some area our work is increasing."

—*Dale Jehn, CTC/Builders Energy Services*



That is already the case in Canada, says Dale Jehn, general manager, CTC Energy Services division of Builders Energy Services Ltd., Calgary, where the current downturn in conventional drilling activity is increasing the utilization of CT with rigless completions.

"We are already seeing this with some of our customers," he says. "The use of our intermediate-size units has stayed busy, and in some areas our work is increasing."

CTD acceptance

The main challenge to overcome in gaining wider acceptance of CTD is in managing the cyclical pattern of adoption applied to CTD since the mid-1990s, says Gordon Mackenzie, product line manager for the Thru-Tubing Intervention product line of Baker Oil Tools.

"The potential to achieve significant reserve gains at an economic margin appears never to have been greater than in the present climate," he claims. "Where we see continued success in [CTD] operations is probably best evidenced by operations in Alaska, where the operator realized early that to achieve the perceived potential value that initial learning curves need to be accepted, the practice evolved and the course stuck to."

For Perry Courville, group manager for Halliburton Co.'s coiled tubing and hydraulic workover product service lines, a key challenge for CTD is the recognition that major differences exist in equipment requirements and specifications for drilling operations compared with the most common intervention applications.

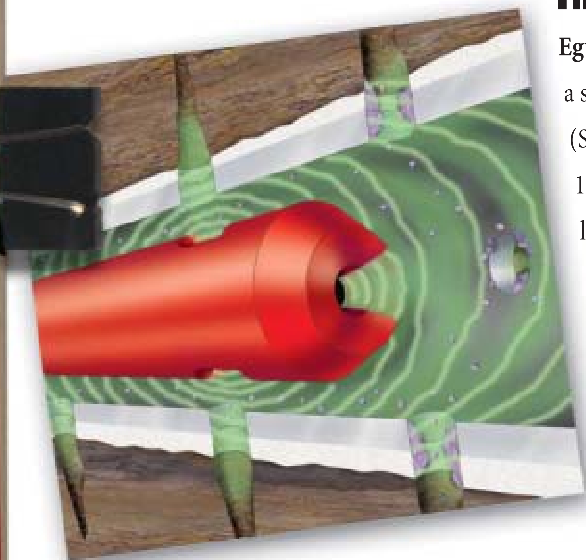
"The history of the evolution of using coiled tubing to replace jointed pipe for drilling is plagued with examples of force-fitting conventional intervention equipment into a drilling operation," he contends. "This force-fitting has often concealed the real upside of using coiled tubing for drilling. On the positive side, many recent examples see service companies focusing on the drilling applications with coiled tubing units that resembles a rig-like structure more than the conventional intervention unit. This hybrid concept permits the merger of the best of both configurations with minimal sacrifices in operational efficiencies."

Courville notes that logistics is another key challenge for coiled tubing in general but can become more of a challenge for CTD.

"The efficiency drivers for having coiled tubing equipment components unitized on trailers can pose a logistical challenge for the hybrid concepts as well. The coiled tubing reel and stored pipe weight is a challenge in both land and offshore markets as reel sizes, coil pipe lengths, and coil pipe diameter increase."

Blake Hammond, global product line manager for Weatherford International Ltd.'s Thru-Tubing division, contends that it

Pulsonix® Service in Straddled Formation Adds $27.4 Million in Value



The Challenge:

Egypt — Two Cretaceous sandstone reservoirs were completed as a straddled completion, accessed through a **Sliding Side-Door®** (SSD) valve. The operator had expected production of 1,000-1,200 BOPD, but the zone initially produced only 200 BOPD, and later declined further to an intermittent flow of 0-50 BOPD. Because the zones of interest were isolated from the main wellbore and only accessible through the SSD valve, direct access to the perforations was impossible.

The Solution:

Halliburton recommended improving the stimulation treatment with its **Pulsonix®** service, which combines coiled tubing efficiency with fluidic oscillator technology to treat damage and stimulate production. Using the Pulsonix tool, the team sent out acoustic pulses to help fatigue the suspected debris buildup in the zones. **Clay-Safe™ F** fluid and **Fines Control™** acid, part of the **Sandstone 2000™** acid system, were then pumped at 60 GPF and 28 GPF, respectively. Volumes were controlled to minimize the job cost, and **Clayfix™** material was used for over-displacing the acid and then again for the displacement stage.

The Results:

After stimulation, the well initially flowed at 1,500-1,600 BPD, without artificial lift. Production later stabilized at approximately 1,300 BOPD. The economic value created by the Pulsonix tool and the Sandstone 2000 system solution is more than $27.4 million, including $120,000 in reduced job costs. "Halliburton provided an excellent stimulation job," the operator wrote. "We intend to continue working with them to stimulate other wells"

"Halliburton provided an excellent stimulation job," the operator wrote. "We intend to continue working with them to stimulate other wells."

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Performance Profile 96

"The history of the evolution of using coiled tubing to replace jointed pipe for drilling is plagued with examples of force-fitting conventional intervention equipment into a drilling operation. This force-fitting has often concealed the real upside of using coiled tubing for drilling."

—Perry Courville, Halliburton

will take some time to overcome the widely held perception of CT as an intervention medium rather than as a drilling tool.

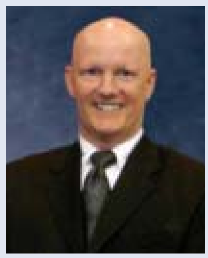
"But we also need to be cognizant of the fact that it is primarily an intervention tool," he adds. "There are not many ongoing [CTD] operations globally because of all of the technical challenges and its inefficiency when compared with conventional drilling methods. It has its applications, but those opportunities need to be thoroughly analyzed to ensure that CT is the right solution."

Unlike other CT interventions, the drivers for CTD differ greatly from reservoir to reservoir, where projects are often executed for non-reservoir specific reasons, says Sherif Foda, vice-president of coiled tubing services, Schlumberger.

"Since the early 1990s, CTD has been viewed as a project-specific, niche CT application, with only a handful of continuous operations conducted," he points out.

Foda contends that the main challenges to gaining wider acceptance for CTD are "an operator's noncontinuous work scope of only one or two wells on a trial basis, [which] limits the ability to incorporate the lessons learned from the first few wells to achieve better ROP and reduced days per well; the logistics and costs of land transport of large-size spools of coiled tubing; and the small completion tubing sizes of most of the current wells in the US [that] limit CTD applications with industry's existing technologies."

"Looking towards the future, intervention applications in general will expand and evolve. I am confident that the envelope of available CT technologies will also expand to consistently meet and perform in these new arenas."



—Gordon Mackenzie, Baker Oil Tools

Broader application.

CT services have become so ubiquitous in oil and gas operations, notes Mackenzie, that "today, there is hardly a wellbore practice performed in a traditional manner that cannot, or, in fact, is not being performed with coiled tubing.

"Looking towards the future, intervention applications in general will expand and evolve. I am confident that the envelope of available CT technologies will also expand to consistently meet and perform in these new arenas."

For example, Hammond notes that his company has participated in several pipeline remediation projects recently in which CT was deployed "quite effectively."

He adds, "This has set the stage for an increase in this activity due to the number of such operations pending, especially offshore due to MMS requirements."

CT will continue to evolve and replace jointed pipe in the deployment of certain applications, contends Courville.

"As we have seen coiled tubing branching off into drilling applications, coiled tubing is being used more frequently in fracturing applications," he says. "A special market segment of fracturing is starting to evolve, and that pinpoint-stimulation market segment is based primarily on coiled tubing being used as part of the process.

"In our estimation, in a comparatively short time, the coiled tubing fracturing market has passed the coiled tubing drilling market in numbers of units as well as market size. Coiled tubing service reliability has enabled that rapid expansion and will enable additional encroachments into applications and markets primarily perceived as jointed pipe applications."

Sherif Foda, vice-president, Schlumberger coiled tubing services, notes that CT has been used over the years for many nonwell applications, including pipeline and flowline interventions, river crossing boring, and mine-shaft deployment—"all of which have been executed to increase the utilization of CT equipment during periods of industry slowdown.

"With the exception of pipe/flowline intervention, very few have resulted in sustained businesses being created. However, in the future, CT could be the conveyance of choice for many other applications: testing wells, ESP deployments, extensive logging and perforating campaigns. This application would be progressively implemented according to the level of complexity (i.e., pressure and temperature categories, number of zones, CH vs. OH, etc.)."

Foda also sees CT being used on an expanded basis for drilling multilateral, radial boreholes to recover bypassed hydrocarbons.]

Efficiency, reliability focus of CT advances

New advances in technology, focused on improving coiled tubing efficiency and reliability, are driving growing acceptance of CT services in the oil and gas industry.

Experts interviewed for this article discussed the advances in CT technology that will have the greatest impact in a wide range of oil and gas operations.

Subsea installations

The subsea installation market segment receives much attention from service companies, although an end user in an operating company may have a completely different perspective, points out Perry Courville, group manager for Halliburton Inc.'s CT and hydraulic workover product service lines.

"A reason may be that an operator could be expecting the coiled tubing or slickline/e-line intervention company to be the dominant player in an intervention campaign," he explains. "But the reality is that the intervention company provides only a fraction of the technology and resources required to bring intervention capabilities to a subsea installation. The vast majority of equipment and associated costs of an intervention campaign are related to the vessel and its ability to intervene and monitor subsea tree activities. The related technologies to significantly impact this market should perhaps be framed from that perspective."

Courville notes that a compliant riser system for CT or a riserless system for slickline/e-line are opportunities for aiding the subsea intervention market.

"Even with these technologies, there are extensive interfacing issues on surface at the vessel to make the intervention process integrated and seamless," he says. "These may be the activities that do not present themselves to an operating company when their focus is on the well intervention process inside the wellbore."

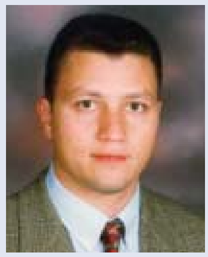
Frac jobs

CT is playing an increasingly important role in fracturing, proving to be a highly effective approach for both initial treatments and refracturing treatments, says Courville.

Known as pinpoint stimulation technology, CT-based fracturing has been proven to help reduce completion cycle time and lower completion cost per barrel of oil equivalent, he notes: "A key feature in some of these processes is the use of hydrajet perforating and fracture initiation, which improves near-wellbore connectivity to the fracture and allows for multiple fracture placements without tripping out of the hole."

Courville contends that one of the most successful and widely used techniques for unperforated, cemented-casing completions in vertical or horizontal wells, CobraMax service, is performed with a CT tubing-deployed hydrajet bottomhole assembly (BHA): "There are no packers or mechanical devices to set. The BHA is moved to the first target, and perforating is accomplished by hydrajetting via the coiled tubing. The annulus is closed in to enable breaking down the perforations, and the fracture treatment is pumped through the annulus. During the fracturing treatment, the coiled tubing is moved above the treatment interval and acts as a dead string for fracture diagnostics. A final proppant stage of noncrosslinked (linear) fluid with high proppant concentration is pumped to induce a near-wellbore proppant pack that further improves near-wellbore conductivity and develops a sand plug that serves as a diversion method for treatments further uphole."

> "Evolving CT from a conveyance technique to a technology platform for downhole acquisition, along with real-time-answer products, will add great value to CT applications, such as precision placement, depth accuracy, fill cleanout, underbalanced, and nitrogen kick-off operations."
>
> *– Sherif Foda, Schlumberger*



Cleanouts

CT wellbore cleanouts are probably still the number one use of coiled tubing, according to Gordon Mackenzie, product line manager for the Thru-Tubing Intervention product line of Baker Oil Tools.

"Wellbore geometry has a very big say in the success of this type of operation," he says. "In many situations, the ratio of CT OD to tubular ID can be very large. This ratio, along with available circulation rates through the coiled tubing, can lead to situations where available annular velocities are not great enough to allow for the optimal circulation of debris back to surface.

"I have started to hear and see of an increasing amount of operations and tool developments whereby the process of coiled tubing reverse circulation is being undertaken. Further technology development—particularly answering HS&E concerns and therefore increased industry acceptance—may move this practice towards more of a mainstream coiled tubing intervention practice going forward."

Real-time modeling, operations

Advanced monitoring and real-time fatigue modeling are paramount for giving the CT operator the information required to maintain safety margins during deep, high-pressure operations, according to Michael Bailey, product manager for Halliburton's CT and hydraulic workover product service lines.

"Advanced monitoring and real-time fatigue modeling are paramount for giving the CT operator the information required to maintain safety margins during deep, high-pressure operations."

— *Michael Bailey, Halliburton*

"Although design modeling gives an expected range of conditions, the actual job may not be executed in the exact manner in which the design may predict," he says. "InSite well intervention software continuously calculates tubing stress, cycle fatigue, fluid positions and downhole hydraulic conditions from real-time sensor data. This gives the operator a dynamic operating envelope that is continuously updated as conditions change."

Bailey notes that comparing real-time calculations to output from job design modeling software and other advanced features allows for comprehensive decisionmaking during the intervention.

"Real Time Operations centers and InSite Anywhere software enable transmitting sensor data and calculated parameters to office-based personnel worldwide for collaborative decisionmaking," he adds.

Taking intelligent operations a step further is Sherif Foda, Schlumberger vice-president of coiled tubing services, who contends that real-time control is "by far…the most important and exciting technology.

"Evolving CT from a conveyance technique to a technology platform for downhole acquisition, along with real-time-answer products, will add great value to CT applications, such as precision placement, depth accuracy, fill cleanout, underbalanced, and nitrogen kick-off operations."

Deployment efficiency

Foda also notes that CT applications are becoming more sophisticated, requiring longer assemblies to be deployed, a trend he expects to continue.

"Selective acid stimulations, conformance jobs, and highly extended-reach applications require use of tools such as inflatable packers or tractors, for example," he says. "The ability to rapidly and safely deploy such assemblies, under pressure, will impact the utilization of CT services. Efforts to address this challenge are necessary."

Bailey cites a significant advance in the ability to deploy tubing-conveyed perforating (TCP) guns via CT: "Halliburton's AutoLatch connector system is designed to mechanically join TCP gun sections together without rotation. The AutoLatch system can be operated with standard blowout preventer rams. This feature makes the connector ideal for use in snubbing guns into and out of the wellbore with coiled tubing or hydraulic workover. The connector can be used to run guns into and out of an existing production well to add perforations, and pull these guns without killing the well. Also, this connector will allow guns to be run into a new well, perforate the zone of interest, and pull the guns without killing the well (snub the guns out). This development helps enable rigless completions, enables perforating under- or overbalanced, is useful in monobore and horizontal completions, and allows the well to be produced while running and retrieving the guns."

Friction inhibition

Friction inhibition is critical to CT operations because of the simple issue of intervening into a wellbore and path that were generated with a much stiffer drill string, according to Bailey: "Reaching the target depth may necessitate a tractor assembly, but availability and costs associated with this technology can be counterproductive or prohibitive. "Friction-reduction products have been used with coiled tubing that were developed with jointed pipe in mind. But coiled tubing is inherently different from jointed pipe, and as with many other products for coiled tubing, the 'next generation' of that product is specific and focused on coiled tubing applications.

"The use of viscoelastic surfactants, such as Halliburton's CoilGlide agent, as a drag and torque reduction additive for coiled tubing services can extend the reach in deviated and horizontal wells without using a tractor and obtain higher set-down and pick-up forces at the BHA."

HPHT wells

The high-pressure/high-temperature environment (HPHT) has the potential for significant future impact on CT intervention applications, contends Mackenzie.

"Where workover motor work is concerned, the majority of current product offerings include a power (rotor/stator) section where the stator is lined with an elastomer," he points out. "Ultimately, temperature and elastomers have compatibility issues, and nonelastomeric motor technology with operating performance commensurate with today's motors will be required."

Also from an HPHT perspective, new technologies are required for allowing bridge plugs to be set in these environments, Mackenzie points out: "Many CT operations today involve the setting of both inflatable and mechanical bridge plugs. As these HPHT developments continue to grow and mature, the requirements for bridge plugs capable of true HPHT performance will escalate. Baker Oil Tools is address-

"Uniform-thickness power section technology has pushed the boundaries of conventional motor development and performance for CT applications."

— Blake Hammond, Weatherford

ing this technology gap in a number of ways, with one of the most significant being its introduction and continued development of Z-Seal Technology. This technology, a previous recipient of the [Intervention & Coiled Tubing Association European Chapter's] Intervention Technology Award, achieves the wellbore seal with the use of a metal-to-metal methodology rather than reliance on an elastomeric-based seal."

Extended-reach/multilateral wells

The main issue relating to CT in extended-reach applications regards the challenge of getting the coil and BHA to the required intervention depth while overcoming the effects of helical buckling and lock-up, and still be able to have any available set-down weight when there—if required—to perform the planned operation, says Mackenzie.

"I believe we will continue to see significant technology strides in the development of tractoring systems and other such methodologies, such as vibration-inducing tools to break friction lock-up," he says.

On the lateral front, one of the key issues today is to identify the required lateral location for entry and how to reliably and consistently get the CT and BHA to enter it, Mackenzie notes: "Some systems do exist today to help in this, but I would suggest there is still a technology gap to be filled here."

Fishing

It is likely that with the introduction of "smart fishing"—utilizing real-time mud pulse telemetry technology in threaded pipe applications—the industry will see further use of this technology applied to CT fishing operations, rather than just for CT drilling, claims Mackenzie.

"This mud pulse technology allows the elimination of wire, such as electric wireline or fiber optics from the ID of the CT workstring, to allow for real-time data communication," he says. "Similar to some other oil field operations, as these sensor packages continue to evolve, it is not inconceivable that CT intervention applications will be remotely monitored with the use of data and video links."

Motors

Uniform-thickness power section technology has pushed the boundaries of conventional motor development and performance for CT applications, says Blake Hammond, global product line manager for Weatherford International Ltd.'s Thru-Tubing division.

"Deploying small-diameter motors on CT can be challenging, but uniform-thickness power sections deliver the operator a far greater operating window before inducing a stall," he says. "That reduced stall sensitivity can often mean the difference between success and failure. The fatigue life of the CT is exhausted with each cycle across the gooseneck, especially while under high pressure, so each stall (which must be rectified by cycling the CT) can be very costly. Reducing stalls, especially in a high-pressure environment, can translate to huge savings to the client."

Tractor technology

Improvements in CT tractor technology will have a noteworthy impact on drilling extended-reach and ultra-extended-reach wells, according in Brian Schwanitz, vice-president, global sales and marketing, Welltec AS.

"As tractor technology continues to mature, the newest versions will have higher speed and reliability than current versions and will allow these difficult interventions to be more cost-effective and therefore easier to justify," he says. "This will then allow the industry to push the current limit of what CT can do in these wells."

CT drilling companies have been experimenting with using tractors for extending the limit of current reach (3,500–4,000 ft), notes Schwanitz.

"The tractor provides both additional weight on bit and control of the reactive torque, which reduces drilling efficiency," he says. "More-reliable and intelligent tractors will enable CT drilling to extend the range of applications, which is another good thing for the industry."]

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— Brian Schwanitz, Welltec