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Catalyst Report

Sustainability reports answer growing calls for information

Iraq licensing situation fluid as Kurdistan awards blocks

Shell Alaska readies ice-class drilling units for Beaufort Sea

Domestic gas statistics shape LNG policies

OIL&GAS JOURNAL

Oct. 1, 2007
Volume 105.37

Catalyst Report

Regular Features

Cover

New catalyst developments are helping refiners and petrochemical producers deal with the ever-changing landscape of the processing industry. New and improved catalyst formulations help produce cleaner fuels, reduce emissions, and improve overall plant efficiency. This week's special report, starting on p. 52, details some notable developments that have occurred since the last worldwide catalyst survey and report (OGJ, Oct. 17, 2005, p. 50). Cover photo from Haldor Topsoe.

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General Interest

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Drilling & Production

Processing

Transportation

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General Interest — *Quick Takes*

Senate committee begins energy bill discussions

After weeks of silence regarding a possible conference to reconcile differences between comprehensive energy bills passed by the US House and Senate earlier this year, the Senate Energy and Natural Resources Committee's staff began bicameral discussions about the contents of the measures.

Senate Energy and Natural Resources Committee Chairman Jeff Bingaman (D-NM), with the blessing of majority leader Harry M. Reid (D-Nev.), asked the committee's staff to host the discussions, a committee spokesman said on Sept. 20. "These meetings are not to decide the fate of any provisions, but to allow Senate staff to become familiar with the background of the House bill provisions, and vice versa," he said.

The discussions were scheduled to begin with Titles IV and IX of the House's 1,003-page energy bill and include related sections from the Senate's legislation. Talks would continue on Sept. 21 but recess at midday for Yom Kippur and resume on Sept. 24, with a goal of covering all the material in both bills by the end of that week, the committee spokesman said.

Suriname, Guyana maritime dispute settled

The International Tribunal for the Law of the Sea has settled a 6-year maritime boundary dispute between Suriname and Guyana, giving each country access to an offshore basin believed to be rich in oil and natural gas.

"The boundary for the most part follows the equidistance line between Guyana and Suriname," the Hamburg, Germany-based tribunal said. Guyana and Suriname lie side-by-side on the northeastern coast of South America, between Brazil and Venezuela.

Suriname had asserted a boundary further to the north and west, while Guyana had relied on the so-called equidistance line method of determining the boundary, which placed it farther to the south and east.

While the exact position of the ocean boundary between them had long been a subject of disagreement, it did not result in conflict until exploratory tests revealed potentially huge deposits of hydrocarbons beneath the sea bed.

In 2000 Suriname enforced its disputed claim by sending two gunboats to force CGX Energy Inc. to withdraw its drilling rig from the disputed area before it could drill under a license granted by Guyana.

According to the terms of the tribunal's ruling, Guyana gained sovereignty over 12,837 sq miles of the coastal waters, while Suriname received 6,900 sq miles.

Both Guyana and Suriname agreed to abide by the tribunal's ruling, and as a result both nations can also now proceed in further exploration of their respective ocean territories.

The US Geological Survey estimates that the coastal area off the two countries, referred to as the Guyana-Suriname basin, could hold reserves of 15 billion bbl of oil and 42 tcf of gas.

Paradigm to pay $1 million to settle FCPA issues

Paradigm BV, an exploration and production software supplier based in Amsterdam, said Sept. 24 it will pay $1 million as part of a settlement with the US Department of Justice for possible violations of the Foreign Corrupt Practices Act.

Paradigm said DOJ did not levy civil or criminal charges in the matter involving improper payments to government officials of various countries during 2002-07, which Paradigm voluntarily disclosed. No one in the company's current senior management was involved in the payments, it added.

Paradigm said it discovered the payments during due diligence for an anticipated initial public offering. The company said it immediately retained the law firm Skadden, Arps, Slate, Meagher, & Flom LLP to conduct a multicountry investigation and make the voluntary disclosure.

As part of the agreement, Paradigm said it also agreed to implement and enhance internal controls, retain outside compliance counsel, and cooperate fully with DOJ. ✦

Exploration & Development — *Quick Takes*

Colombia awards nine offshore blocks

Colombia's National Hydrocarbons Agency has awarded 9 of 13 offshore blocks in the Caribbean Sea that had been released for tendering.

State-owned Ecopetrol SA will participate in joint ventures with foreign partners in six of the concessions and has two others alone. BP PLC won the sole right to develop Block 5. Altogether, Ecopetrol won Blocks 11 and 12 outright, and will partner with Brazil's Petroleo Brasileiro SA (Petrobras), India's Oil & Natural Gas Corp. (ONGC), Hess Corp., and BP in six other blocks.

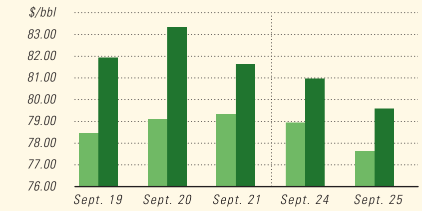
The companies have agreed to commit $5.3-5.8 million in exploration funding in return for 10-year oil and gas exploration rights, along with production rights for the lifetime of their fields.

The blocks awarded, the successful bidders, and the amounts of exploration investment committed, in millions of dollars, are as follows: 4, Petrobras, Ecopetrol, and BP, 5.5; 5, BP, 5.8; 6, Petrobras, Ecopetrol, and Hess, 5.3; 7, Petrobras, Ecopetrol, and Hess, 5.3; 8, Petrobras, Ecopetrol, and ONGC, 5.3; 9, Ecopetrol, 5.3; 10, Ecopetrol and ONGC, 5.3; 11, Ecopetrol, 5.3; and 12, Ecopetrol, 5.3.

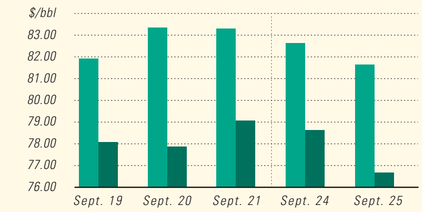
Blocks 1, 2, 3, and 13 received no bids.

Industry Scoreboard

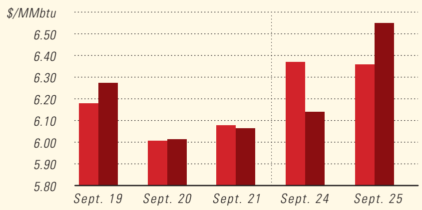
IPE BRENT / NYMEX LIGHT SWEET CRUDE



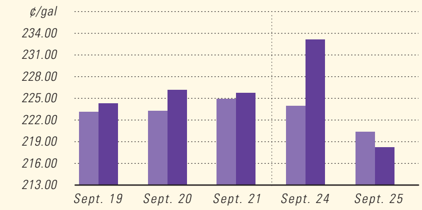
WTI CUSHING / BRENT SPOT



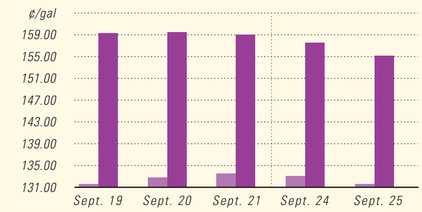
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



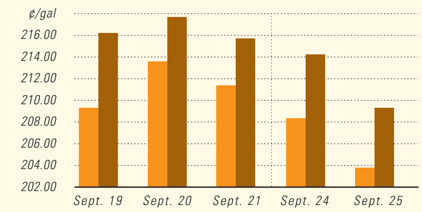
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE (RBOB)[1] / NY SPOT GASOLINE[2]



[1]Reformulated gasoline blendstock for oxygen blending,
[2]Nonoxygenated regular unleaded.

US INDUSTRY SCOREBOARD — 10/1

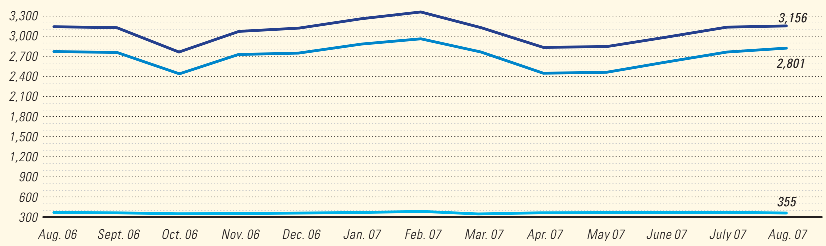
Latest week 9/14	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,461	9,417	0.5	9,321	9,223	1.1
Distillate	4,128	4,170	–1.0	4,222	4,150	1.7
Jet fuel	1,619	1,646	–1.6	1,622	1,621	0.1
Residual	794	659	20.5	766	712	7.6
Other products	4,921	5,035	–2.3	4,858	4,864	–0.1
TOTAL DEMAND	20,923	20,927	—	20,789	20,567	1.1
Supply, 1,000 b/d						
Crude production	5,088	5,170	–1.6	5,174	5,108	1.3
NGL production[2]	2,357	2,331	1.1	2,364	2,202	7.4
Crude imports	9,857	10,614	–7.1	10,043	10,134	–0.9
Product imports	3,300	3,888	–15.1	3,512	3,639	–3.5
Other supply[3]	1,049	1,120	–6.3	998	1,132	–11.8
TOTAL SUPPLY	21,651	23,123	–6.4	22,091	22,215	–0.6
Refining, 1,000 b/d						
Crude runs to stills	15,665	15,765	–0.6	15,278	15,278	—
Input to crude stills	15,900	16,195	–1.8	15,531	15,643	–0.7
% utilization	91.1	93.1	—	89.1	90.0	—

Latest week 9/14	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	318,775	322,649	–3,874	324,876	–6,101	–1.9
Motor gasoline	190,834	190,417	417	207,554	–16,720	–8.1
Distillate	135,527	133,963	1,564	148,670	–13,143	–8.8
Jet fuel-kerosine	41,602	41,533	69	42,210	–608	–1.4
Residual	37,115	36,793	322	42,513	–5,398	–12.7
Stock cover (days)[4]			Change, %		Change, %	
Crude	20.5	20.6	–0.5	20.4	0.5	
Motor gasoline	20.2	19.9	1.5	21.9	–7.8	
Distillate	32.8	32.0	2.5	35.9	–8.6	
Propane	54.0	57.4	–5.9	61.4	–12.1	
Futures prices[5] **9/21**			Change%		Change	%
Light sweet crude, $/bbl	82.10	79.33	2.77	61.07	21.03	34.4
Natural gas, $/MMbtu	6.30	6.11	0.18	4.86	1.44	29.7

[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.

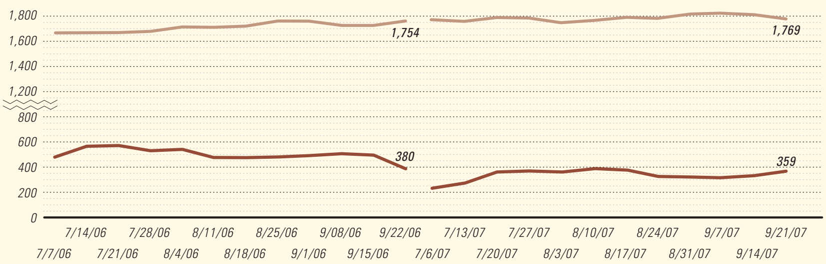
Sources: Energy Information Administration, Wall Street Journal

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

Petrobras reports success with Brazil fields

Petroleo Brasileiro SA (Petrobras) has tested 2,900 b/d of 27° gravity oil from its exploration well in deepwater Carioca field on Block BM-S-9 in the Santos basin off Brazil. The well also tested 57,000 cu m/day of gas. Both results were constrained by test equipment.

Carioca lies in 2,140 m of water 273 km off southern Rio de Janeiro state. It is near the Tupi discovery on Block BM-S-11, announced last October (OGJ, Nov. 20, 2006, p. 43).

The partners, Petrobras, Repsol-YPF Brazil SA, and BG Group, say the find is a significant one. For BG, this is the third well to find hydrocarbons in the new Santos basin presalt play, which has enhanced the company's confidence in the highly prospective area.

Petrobras has a 45% stake, Repsol-YPF 25%, and BG 25%.

Additionally, Petrobras has informed Brazil's National Petroleum Agency that the Xerelete heavy oil discovery in ultradeep water off Brazil is commercial. It tested flows as high as 2,500 b/d.

Xerelete—formerly known as Curió—was previously operated by Total SA, which made the discovery in 2001 over Blocks BC-2 and BMC-14 in the prolific Campos basin.

The 1-EPB-1-RJS exploration well, drilled in water 2,483 m deep, hit sandy, 17.5° gravity oil-bearing reservoirs at a depth of 3,478 m. It is Brazil's deepest subsea discovery to date.

Xerelete contains relatively heavy oil of 17-20° gravity. Preliminary geological studies suggest that Xerelete may extend for more than 26 sq km, holding an estimated in-place volume of some 1.4 billion boe. "Additional studies are being carried out to define this new field's production development project," Petrobras said.

Petrobras operates both blocks. It is working with Total on Block BC-2. On Block BMC-14, Petrobras and Total each hold a 50% stake.

Agiba tests oil well on Egypt's Meleiha block

Agiba Petroleum, operator of the Meleiha block in Egypt's Western Desert, has tested 1,000 b/d of dry crude oil from its exploration well in the Gawaher structure on the block. Production is expected to increase to 1,500 b/d.

"Appraisal of drilling results, adjustment of the field reserves, further drilling-out, and development of field infrastructure is presently going on," said Lukoil Overseas, a partner in the project.

More than 17 million tonnes of oil has been produced on the block during the last 30 years. The operating well stock is 141 units, 12 of which were drilled since the beginning of this year and are producing a combined 3,200 b/d.

In April, the Egyptian parliament ratified the extension of the concession agreement on Meleiha Block to 2024 (OGJ Online, Apr. 13, 2007).

Agiba Petroleum is a joint venture of Egyptian General Petroleum Corp., Eni subsidiary IEOC Production, and International Finance Co. Production-sharing contract interests are held by IEOC 56%, Lukoil 24%, and IFC 20%. ✦

Drilling & Production — *Quick Takes*

Woodside brings Thylacine gas project on stream

Woodside Petroleum Ltd. has brought on stream its Thylacine gas development in the Otway basin off western Victoria after the project's scheduled start-up had fallen behind by more than a year (OGJ Online, Oct. 20, 2006).

Production from Thylacine field, which lies in Tasmanian waters, is being piped ashore to a processing plant in Victoria. Geographe field, adjacent to Thylacine in Victorian waters, will be connected to the main offshore pipeline during a later development phase.

Thylacine will supply 980 bcf of gas to Victoria over an estimated 10 years. There also will be 100,000 tonnes of liquid petroleum gas and about 800,000 bbl/year of condensate. These products will be the main revenue earners for the project.

The commissioning phase is complete, and gas production will be increased to scheduled levels over the coming weeks.

Sales gas is transferred to TruEnergy's adjacent Iona gas plant to be piped onward to Melbourne and Adelaide. Condensate will be trucked to Shell Australia's refinery in Geelong, 50 km west of Melbourne.

Delays were concentrated in the onshore gas plant construction, which also inflated the project's Phase 1 cost by about 20% to almost $1 billion (Aus.).

This puts into question the original total budget for the project of $1.1 billion, as the Phase 2 connection of Geographe has yet to begin.

Santos brings Oyang field off Java on line

Santos Ltd.-operated Oyang oil and gas field off East Java has been brought on stream. Production rates are expected to stabilize at 8,000-10,000 b/d over the next few weeks.

Adelaide-based Santos holds 45% interest, while Cue Energy Resources, Melbourne, has 15%, and Singapore Petroleum, 40%.

Oil is being produced via a wellhead platform that houses five oil wells and two gas wells. Oil is processed on the Sea Good 101 production barge and piped to the Shanghai storage and offtake vessel.

Front-end engineering and design studies to develop Oyang gas reserves are now well under way, and a final investment decision is expected before yearend. First gas production is anticipated during first-half 2009.

Gas will be piped via a 55 km undersea pipeline to an onshore processing facility to be located adjacent to the existing Grati power station in East Java.

PT Indonesia Power will purchase the gas.

Santos said its nearby Wortel gas field, discovered in 2006 about 7 km west of Oyang, is likely to be incorporated into the gas development program, but that is still subject to further field appraisal, which is planned for first half 2008.

Talisman starts production from Duart oil field

Talisman Energy (UK) Ltd. has begun production from Duart oil field on Block 14/20b in the North Sea. The field lies 5 miles west of the Tartan platform and 116 miles northeast of Aberdeen.

Initial production, expected to exceed 6,000 b/d, was brought on 2 months ahead of schedule.

Duart field, discovered in 1988, was developed with a single well tied back to the Tartan platform. Duart oil will be exported via the Flotta system, together with other Tartan area production.

Prospective reserves of 6 million bbl are assigned to the northern section of the field.

Duart is an integral part of Talisman's plans to prolong the life of both the Tartan platform and the Flotta export system.

AGR to drill nine wells in UK North Sea

AGR Group will drill nine wells for various clients in the UK North Sea under contracts valued at $202.2 million.

AGR will use the Sedco 704 semisubmersible for an eight-well multiclient program, including operators Serica Energy PLC, Dana Petroleum PLC, Fairfield Energy Ltd., Century Exploration Ltd., and OMV AG. These wells will take a year to complete. Sterling Resources has contracted its Ensco 85 rig for a single well on Block 42/13 in the UK southern North Sea (OGJ Online, Sept. 24, 2007).

Sedco 704 will soon spud its first well following major upgrades to its drilling equipment and accommodation modules. The rig can operate in harsh environments and in as much as 1,200 ft of water, using an 18¾-in., 15,000 psi blowout preventer and a 21-in. OD marine drilling riser.

With the arrival of the Sedco 704 and Ensco 85 jack ups, AGR is now operating four drilling units on the UK continental shelf.

This year AGR plans to drill more than 55 wells in northwestern Europe, North Africa, West Africa, Middle East, the US, and Asia-Pacific.

Rigs under management this year include Stena Clyde, Wilcraft, Sedco 704, Bredford Dolphin, Byford Dolphin, Transocean Prospect, Maersk Giant, Ensco 80, Ensco 85, Ensco 92, Ensco 100, Ocean Spur, and Noble George Sauvagneau. ✦

Processing — *Quick Takes*

Motiva Port Arthur refinery expansion to proceed

Motiva Enterprises LLC, Houston, said a final investment decision has been made that allows the company to proceed with a 325,000 b/d expansion of its 285,000 b/cd refinery in Port Arthur, Tex.

The expansion—essentially adding the capacity equivalent to a new refinery—will increase the refinery's oil throughput capacity to 600,000 b/d, making it the largest refinery in the US.

The additional production capacity is expected to be online in 2010.

Motiva selected Bechtel Jacobs joint venture as the project's engineering, procurement, and construction contractor. Construction is scheduled to begin this year.

Rajasthan refinery no deterrent to Cairn's plans

Cairn India and India's state-owned Oil & Natural Gas Corp. (ONGC), partners in Barmer field in Rajasthan, said they will not "go slow" in constructing a preheated pipeline to carry the waxy crude from the field.

This is despite the Rajasthan government's saying it would build a refinery to process the oil, making the $750-million pipeline superfluous.

"The pipeline is the most feasible option and is likely to [be built] before the start of crude oil production," said a senior official of ONGC, Cairn's 30% partner in the oilfield.

He said building a refinery with a capacity of about 7.5 million tonnes/year "would take around 40 months, whereas work on the pipeline is expected to take just 18 months," he said.

A Cairn India executive revealed that 83% of the pipeline engineering design work has been completed and that tenders for construction would open soon.

The Scottish explorer's oil discovery in Rajasthan is the largest in the country since ONGC struck oil in Bombay High in 1972. Barmer field is expected to produce 150,000 b/d during its 4-year peak production period.

Although a refinery in Rajasthan would mean another buyer for the company's crude oil, "we know the economics of the refinery are dubious," the Cairn executive said.

ONGC agreed: "There is simply not enough crude oil in the field to justify a new refinery. The state consumes only 5 million tonnes/year of oil products. With new refineries coming up in Bina [in Madhya Pradesh] and Bhatinda [Punjab], there will be no market for the Rajasthan refinery.

The price of the oil also must be resolved. Its poor quality, Cairn says, likely will garner the companies about 10% less than the Brent benchmark. Refiners, however, hope for a discount of more than 20%. "The contract allows pricing to follow the international prices of similar oil," Cairn said.

The pricing will determine how cost-effective a preheated pipeline would be. If Cairn does not get a good price, the gains may not justify the cost of the pipeline.

A buyer has yet to be finalized, but Cairn executive said talks were under way "with almost all refineries. The Bhatinda and Bina refineries are keen on taking our crude oil."

ONGC said a realistic date for production to begin is yearend 2009.

ExxonMobil to expand Rotterdam aromatics plant

ExxonMobil Chemical Co. plans to expand its Rotterdam aromatics plant in Botlek, the Netherlands, making it the company's largest paraxylene production facility.

The expansion will increase the facility's production capacity by 25% for paraxylene and by 20% for benzene.

Construction is scheduled to begin this year.

The project involves building a heat-exchanger, reactor, and distillation column.

ExxonMobil will use its PxMax technology to produce paraxylene and benzene. The PxMax process improves selectivity, generates less waste, and reduces energy requirements in comparison to existing technologies.

The expansion project will be owned and operated by ExxonMobil Chemical Holland BV. ✦

Transportation — *Quick Takes*

Singapore plans Jurong Island LNG terminal

Singapore plans to build a $1 billion LNG terminal and regasification plant on a 30-ha site in southwest Jurong Island to diversify its natural gas imports.

Singapore Power subsidiary PowerGas, designated as majority owner and operator of the facility, expects to begin construction in 2009 and to have the plant operational by early 2012.

In early September, Singapore Minister of State for Trade and Industry S. Iswaran said at the LNG Supplies for Asian Markets conference that detailed engineering and construction should start immediately. The project was approved in August 2006.

Singapore, which relies on gas transported from neighboring Indonesia and Malaysia, is trying to diversify its sources of supply. Supplier Indonesia, in particular, has less gas to export as it seeks to meet domestic demand growth (OGJ Online, Mar. 1, 2007).

Iswaran said initial demand is expected to be 1 million tonnes/year in 2012 when the plant starts operations. It will take 4-5 years for the contracted LNG quantity to reach 3 million tonnes/year, he said.

PowerGas, currently in charge of the national gas pipeline grid, can ensure that the LNG terminal is efficiently integrated with the system and can help manage periodic gas demand and supply imbalances by adjusting supply from the terminal.

"But we have left the door wide open for other parties, both local and international, to join in," Iswaran said, suggesting that other players could partner with PowerGas as minority stakeholders.

Singapore also has launched a request for proposals from interested parties to bid on becoming the initial sole importer of LNG into the plant. The importer-consortium (or aggregator) will import an initial 3 million tonnes/year of LNG into the country.

Singapore's Energy Market Authority will select and appoint the aggregator from a short list of candidates by second quarter 2008.

Russia approves gas production, delivery to Asia

Russia's Industry and Energy Ministry has approved the Eastern Gas Program leading to the creation of a unified system for East Siberia's natural gas production and delivery to China and other areas in the Asia-Pacific.

The program will create four gas production centers in Sakhalin, Yakutia (Chayanda field), Irkutsk, and Krasnoyarsk territories, according to Anatoly Yanovsky, chief of the ministry's energy policy department in a Sept. 7 announcement.

Ministry officials said "absolute priority" will be given to meeting domestic needs, while the dates of the fields' development and respective exports will depend on the outcome of commercial talks between the companies involved.

Industry analysts said approval of the ministry's program guidelines essentially ratifies OAO Gazprom's plans for the region, including construction of LNG facilities on Sakhalin Island and direction of gas supplies from the ExxonMobil Corp.-led Sakhalin-1 project to the domestic market.

Turkmen gas may flow to Europe, bypassing Russia

Turkmenistan President Gurbanguli Berdymukhamedov said his country is ready to bypass Russia and begin selling some of its natural gas to Europe.

After meeting Sept. 19 with Austrian Economic Minister Martin Bartenstein, Berdymukhamedov said his country, "having multiple vectors in its energy policy and creating alternative export routes, including in the southern direction through the Caspian Sea, is prepared to deliver natural gas to European countries."

Turkmenistan's gas exports currently pass through pipelines operated by Russia's state-run OAO Gazprom, but Berdymukhamedov suggested that a new pipeline could be built from Turkmen gas fields to Azerbaijan.

Michael Baker wins federal Alaska gas line contract

Michael Baker Jr. Inc. was the successful bidder for a contract to assist the federal coordinator's office in the effort to construct a natural gas pipeline from Alaska to the Lower 48 states.

The firm has extensive Arctic oil and gas pipeline expertise, said Drue Pearce, federal coordinator for Alaska natural gas transportation projects, in announcing the award Sept. 12.

Michael Baker will help the federal coordinator's office establish a local presence in Alaska; develop an information management system to allow federal, state, and Canadian agencies to share data where appropriate; and help the federal coordinator's office incorporate lessons learned from construction of the Trans-Alaska Pipeline System and the former federal inspector's office to develop a strategy for constructing the gas pipeline, she said. ✦

Correction

Chesapeake Energy Corp.'s figures for oil and natural gas reserves and production were incorrectly stated in the OGJ200 report (OGJ, Sept. 17, 2007, p. 20). Following are the corrected figures and their respective rankings (in parentheses): US liquids reserves (in million bbl), 106.0 (21); worldwide liquids reserves, 106.0 (25); US liquids production, 8.654 (17); worldwide liquids production, 8.654 (20); US natural gas reserves (in bcf), 8,319.4 (4); worldwide natural gas reserves, 8,319.4 (6); US natural gas production, 526.5 (6); worldwide natural gas production 526.5 (7). Also in that report, in the Top 20 worldwide liquids reserves table, Marathon Oil Corp. should have appeared in the No. 9 position with 677.0 million bbl of liquids reserves. Newfield Exploration Co.'s worldwide liquids reserves should have been stated as 114.3 million bbl, ranking them at 22.

Letters

Emission ambition

I hope your Aug. 27 editorial, "Restating temperatures," (p. 19) moderates the global warming zealots, but so far it doesn't look like it has.

The Sept. 4 Wall Street Journal reported that, at the conclusion of a United Nations-sponsored climate meeting in Vienna the last week of August, diplomats issued a statement saying industrialized countries should try to cut their greenhouse gas emissions 25-40% below 1990 levels by 2020.

I just ran some quick calculations. US carbon dioxide emissions in 1990 were 4,978 million tonnes (International Energy Outlook, 2006, US Energy Information Administration). The 1990 US resident population was 249.623 million, so per capita CO_2 emissions were 19.9 tonnes.

Estimating the US population in 2020 is difficult because we don't know the level of immigration. However, if we assume an annual legal immigration of 1.116 million (the average over the most recent 3-year period, 2004-06), and a natural rate of increase of 0.565%/year, the US population will reach 340.3 million in 2020. The Census Bureau's projection for 2020 is 335.8 million, but this estimate was made in 2004 and does not reflect the increased level of immigration since 2004.

A reduction in CO_2 emissions to a level 25% below 1990 emissions would mean year 2020 emissions would be limited to 3,733 million tonnes. Because of the increased population, per capita emissions would have to fall to 10.97 tonnes. This represents a 45% reduction from 1990 levels—and this is supposed to be achieved in 13 years. Don't these idiots who call themselves diplomats know how to use a slide rule?

Incidentally, my estimates appear to be conservative. If per capita CO_2 emissions remained at the 1990 level of 19.94 tonnes, the 2020 population of 340 million would produce 6,790 million tonnes of CO_2. EIA's projection for year 2020 emissions is 7,120 million tonnes.

Donald F. Anthrop
Professor
San Jose State University

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.

2007

OCTOBER

IPLOCA Convention, Sydney, +41 22 306 0230, e-mail: info@iploca.com, website: www.iploca.com. 1-5.

Well Control Gulf of Mexico Conference, Houston, (979) 845-7081, (979) 458-1844 (fax), e-mail: jamie@pe.tamu.edu, website: www.multiphasre-research.org. 2-3.

ISA EXPO, Houston, (919) 549-8411, (919) 549-8288 (fax) website: www.isa.org. 2-4.

Rio Pipeline Conference and Exposition, Rio de Janeiro, +55 21 2121 9080, e-mail: eventos@ibp.org.br, website: www.ibp.org.br. 2-4.

ISA EXPO, Houston, (919) 549-8411, (919) 549-8288 (fax) website: www.isa.org. 2-4.

Kazakhstan International Oil & Gas Exhibition & Conference, Almaty, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 2-5.

Regional Deep Water Offshore West Africa Exploration & Production Conference & Exhibition, Luanda, +31 (0)26 3653444, +31 (0)26 3653446 (fax), e-mail: g.kreeft@energywise.nl, website: www.dowac.com. 2-6.

GPA Rocky Mountain Annual Meeting, Denver, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 3.

IFP Symposium The Capture and Geological Storage of CO2, Paris, +33 1 47 52 70 96 (fax), e-mail: patricia.fulgoni@ifp.fr, website: www.ifp.fr. 4-5.

IPAA OGIS West, San Francisco, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 7-9.

Annual European Autumn Gas Conference, Düsseldorf, +44 (0)20 8241 1912, +44 (0)20 8940 6211 (fax), e-mail: info@theeagc.com, website: www.theeagc.com. 9-10.

IADC Drilling HSE Europe Conference & Exhibition, Copenhagen, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 9-10.

NPRA Q&A and Technology Forum, Austin, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 9-12.

Deep Offshore Technology (DOT) International Conference & Exhibition, Stavanger, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepoffshoretechnology.com. 10-12.

International Bottom of the Barrel Technology Conference & Exhibition, Athens, +44 (0) 20 7357 8394, e-mail: Conferences@EuroPetro.com, website: www.europetro.com. 11-12.

The Athens Summit on Global Climate and Energy Security, Athens, +30 210 688 9130, +30 210 684 4777 (fax), e-mail: jangelus@acnc.gr, website: www.athens-summit.com. 14-16.

ERTC Petrochemical Conference, Brussels, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 15-17.

GPA Houston Annual Meeting, Kingwood, Tex., (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 16.

Global E&P Technology Summit, Barcelona, +44 (0) 20 7202 7511, e-mail: anne.shildrake@wtgevents.com, website: www.eptsummit.com. 16-17.

PIRA Global Political Risk Conference, New York, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 17.

PIRA New York Annual Conference, New York, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 18-19.

SPE/IADC Middle East Drilling and Technology Conference, Cairo, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 22-24.

World Energy & Chemical Exhibition and Conference, Kuwait City, +32 2 474 8264, +32 2 474 8397 (fax), e-mail: d.boon@bruexpo.be, website: www.www.wecec-kuwait.com. 22-25.

Annual Natural Gas STAR Implementation Workshop, Houston, (781) 674-7374, e-mail: meetings@erg.com, website: www.epa.gov/gasstar. 23-24.

Louisiana Gulf Coast Oil Exposition (LAGCOE), Lafayette, (337) 235-4055, (337) 237-1030 (fax), website: www.lagcoe.com. 23-25.

Pipeline Simulation Interest Group Annual Meeting, Calgary, Alta, (713) 420-5938, (713) 420-5957 (fax), e-mail: info@psig.org, website: www.psig.org. 24-26.

GSA Annual Meeting, Denver, (303) 357-1000, (303) 357-1070 (fax), e-mail: gsaservice@geosociety.org, website: www.geosociety.org. 28-31.

TAML Multilateral Knowledge-Sharing Conference, Reims, +44 (0) 1483 598000, e-mail: info@taml.net, website: www.taml.net. 29.

Expandable Technology Forum, Reims, +44 (0) 1483 598000, e-mail: info@expandableforum.com, website: www.expandableforum.com. 30-31.

Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Oct. 30-Nov. 1.

Chem Show, New York City, (203) 221-9232, ext. 14, (203) 221-9260 (fax), e-mail: mstevens@iecshows.com, website: www.chemshow.com. Oct. 30-Nov. 1.

Methane to Markets Partnership Expo, Beijing, (202) 343-9683, e-mail: asg@methanetomarkets.org, website: www.methanetomarkets.org/expo. Oct. 30-Nov. 1.

Calendar

NOVEMBER

IADC Annual Meeting, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 1-2.

✦Annual U.S. – Canada Energy Trade & Technology Conference, Boston, (781) 801-4310, e-mail: ellenrota@aol.com, website: www.necbc.org. 2.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwateroperations.com. 6-8.

IPAA Annual Meeting, San Antonio, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 7-9.

Regional Mangystau Oil & Gas Exhibition & Conference, Aktau, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 7-9.

GPA North Texas Annual Meeting, Dallas, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 8.

GPA North Texas Annual Meeting, Dallas, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 8.

SPE Annual Technical Conference and Exhibition, Anaheim, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 11-14.

World Energy Congress, Rome, +39 06 8091051, +39 06 80910533 (fax), e-mail: info@micromegas.it, website: www.micromegas.it. 11-15.

API/NPRA Fall Operating Practices Symposium, San Antonio, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 13.

Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 13-15.

Turkemenistan International Oil & Gas Conference, Ashgabat, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 14-15.

Annual Unconventional Gas Conference, Calgary, Alta., (866) 851-3517, e-mail: conference@emc2events.com, website: www.csugconference.ca. 14-16.

Australian Society of Exploration Geophysicists International Geophysical Conference & Exhibition, Perth, (08) 9427 0838, (08) 9427 0839 (fax), e-mail: secretary@aseg.org.au, website: www.aseg.org.au. 18-22.

ERTC Annual Meeting, Barcelona, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 19-21.

Asia Pacific Natural Gas Vehicle Conference & Exhibition, Bangkok, +66 0 2617 1475, +66 0 2271 3223 (fax), e-mail: angva@besallworld.com, website: www.angvaevents.com. 27-29.

✦DryTree & Riser Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.drytreeforum.com. 28.

IADC International Well Control Conference & Exhibition, Singapore, (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 28-29.

DECEMBER

International Oil and Gas Industry Exhibition & Conference, Suntec, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: osea@oesallworld.com, website: www.allworldexhibitions.com. 2-5.

Middle East Nondestructive Testing Conference & Exhibition, Bahrain, +973 17 729819, +973 17 729819 (fax), e-mail: bseng@batelco.com.bh, website: www.mohandis.org. 2-5.

International Petroleum Technology Conference, Dubai, +971 4 390 3540, +971 4 366 4648 (fax), e-mail: iptc@iptcnet.org, website: www.iptcnet.org. 4-6.

IADC Drilling Gulf of Mexico Conference & Exhibition, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 5-6.

Oil & Gas Maintenance & Technology Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilandgasmaintenance.com. 9-13.

Pipeline Rehabilitation & Maintenance Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilandgasmaintenance.com. 9-13.

PIRA Understanding Global Oil Markets Conference, New York, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 10-11.

2008

JANUARY

Middle East Petrotech Conference and Exhibition, Bahrain, +60 3 4041 0311, +60 3 4043 7241 (fax), e-mail: mep@oesallworld.com, website: www.allworldexhibitions.com/oil. 14-16.

World Future Energy Summit, Abu Dhabi, +971 2 444 6011, +971 2 444 3987 (fax), website: www.wfes08.com. 21-23.

API Exploration & Production Winter Standards Meeting, Ft. Worth, Tex., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 21-25.

API/AGA Oil & Gas Pipeline Welding Practices Meeting, Ft. Worth, Tex., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 23-25.

International Forum Process Analytical Technology (IFPAC), Baltimore, (847) 543-6800, (847) 548-1811 (fax), e-mail: info@ifpacnet.org, website: www.ifpac.com. 27-30.

SPE/IADC Managed Pressure Drilling & Underbalanced Operations Conference & Exhibition, Abu Dhabi, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 28-29.

Offshore West Africa Conference & Exhibition, Abuja, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshorewestafrica.com. 29-31.

Petroleum Exploration Society of Great Britain Geophysical Seminar, London, +44 (0)20 7408 2000, +44 (0)20 7408 2050 (fax), e-mail: pesgb@pesgb.org.co.uk, website: www.pesgb.org.uk. 30-31.

SIHGAZ International Hydrocarbon and Gas Fair, Hassi Messaoud, Algeria, website: www.sihgaz2008.com. Jan. 30-Feb. 3.

FEBRUARY

Middle East Corrosion Conference, Bahrain, + 973 17 729819, + 973 17 7299819 (fax), e-mail: bseng@batelco.com.bh, website: www.mohandis.org. 3-6.

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Suppliers' delivery issues

Angel White
Associate Editor

Over the past 12-18 months oil and gas companies have been operating in a suppliers' market. Prices for services and supplies have risen due to industry-wide material and labor shortages that have contributed to project delays and bottlenecks. Consequently, oil and gas companies are frustrated—but apparently more from late deliveries than from high prices, according to a recent report from EnergyPoint Research, Houston.

The company provides independent data about the oil and gas industry's satisfaction with the products and services it buys.

The firm's 2007 Drilling/Wellsite Equipment & Materials Customer Satisfaction report summarizes results from its recent customer service satisfaction survey covering manufacturers and providers of drilling and wellsite equipment and materials.

The independent survey, which was conducted from January through July 2007, is based on 2,319 evaluations by 636 respondents representing 176 exploration and production companies, drilling contractors, and upstream consultants worldwide. Suppliers were evaluated in the areas of total satisfaction, pricing, performance and reliability, engineering and design, availability and delivery, personnel, postsale support, and corporate capabilities. In its report, EnergyPoint pointed out, "One of the more fundamental aspects of the value equation for customers, [including oil and gas companies], is the ability of a supplier to deliver products on time and as specified."

A drilling contractor, one of the survey respondents, said, "Major equipment suppliers have been very weak performers for us. Quality issues are a major concern along with failures to meet promised deliveries."

Another respondent said, "Suppliers need to be more honest with customers rather than simply telling us what we want to hear. This is especially the case when it comes to delivery times."

In fact, many survey respondents this year rated suppliers lower for making delivery commitments they were unable to keep.

EnergyPoint contends, "Providers who have avoided overrepresenting delivery capabilities to buyers over the last couple of years, often at the risk of losing short-term business, have arguably enhanced their long-term relationships with these same companies."

Delivery issues

Several suppliers during the past 2 years have experienced varying levels of deliverability problems. Some of them identified in the EnergyPoint survey include Oil States International, Technip-Coflexip, and National Oilwell Varco.

National Oilwell Varco fared the worst, according to the survey. The company was rated last overall in the area of product deliverability.

Projects that have had delays due to supplier issues include the $1 billion Thylacine-Geographe gas development in the Otway basin off western Victoria operated by Woodside Petroleum; the Millennium gas pipeline project in Canada and the US operated by Columbia Gas Transmission Corp.; and, one of the more recent, the Long Lake oil sands development 200 miles north of Edmonton, operated by Nexen Inc.

Nexen said labor problems have delayed construction and start-up at Long Lake and increased the project's capital cost by 10-15% above the previous forecast of $5.3 billion. It explained that the project's sulfur-recovery unit is now slated for completion in first-quarter 2008 because of lower than expected labor productivity and difficulties securing sufficient labor, particularly pipefitters, to work on the sulfur-recovery unit (OGJ Online, Sept. 4, 2007).

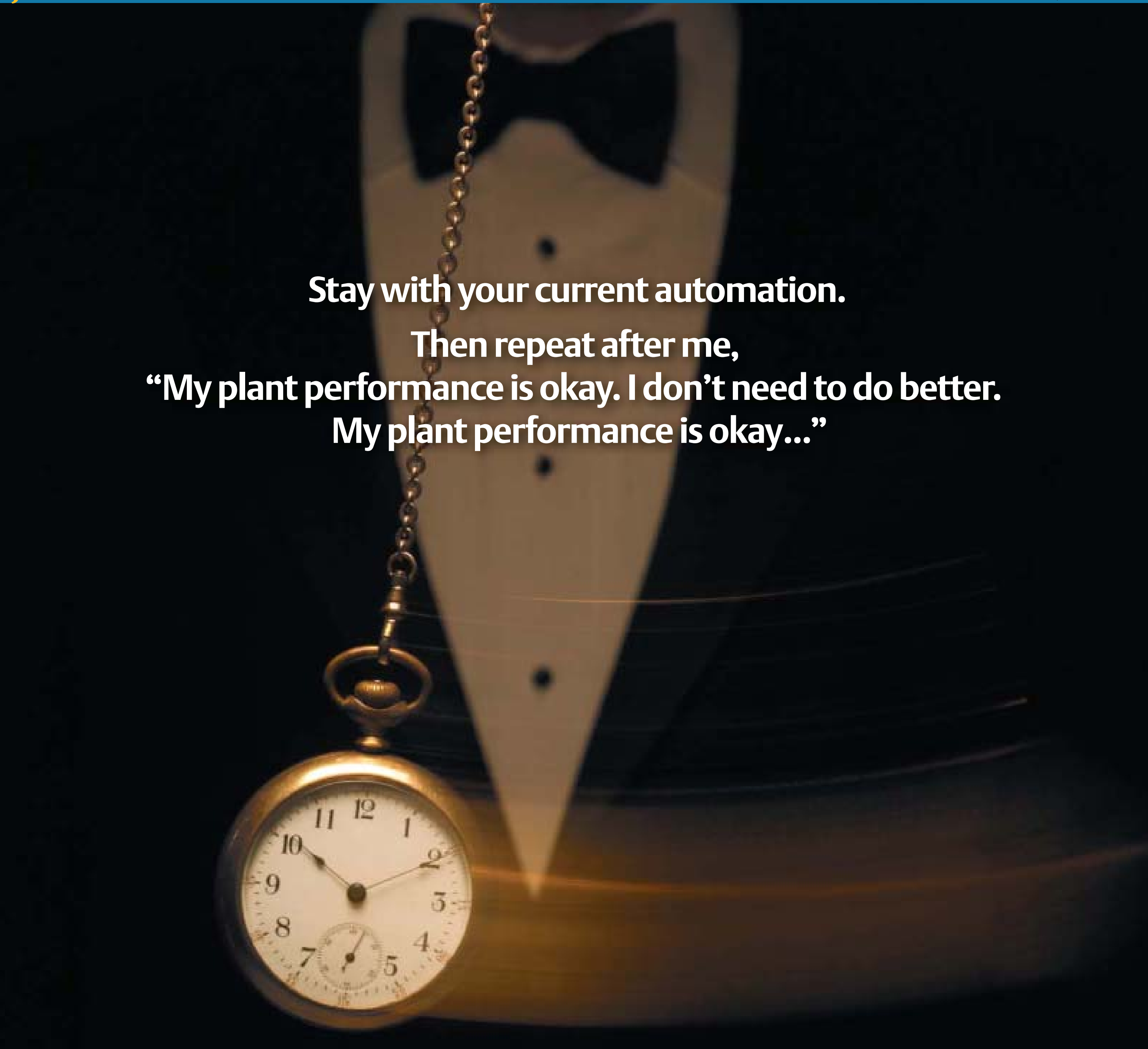
Top suppliers

Although this year the majority of the oil and gas suppliers surveyed saw their customer satisfaction ratings fall due to eroding quality, nagging production delays, and deteriorating service, some were still able to deliver.

Derrick Equipment, Houston, which manufactures solids and waste control equipment for oil and gas drilling, ranked number one overall in total customer satisfaction in the EnergyPoint survey. Derrick scored particularly high for product engineering, reliability, and performance. And in the words of one survey respondent, Derrick's field personnel are what make the company stand out. The company received specific acclaim for the initiative and service-oriented nature of its personnel and management. "There're always there when you need them," the respondent said.

Smith International, which captured the position of second place overall, stood out for its high-quality products, on-time delivery record, and presale and postsale service and support.

Rounding out the top five in the survey's overall rankings were Davis-Lynch, a manufacturer of downhole cementing equipment and the top-rated supplier in EnergyPoint's 2005 survey, along with tubular goods manufacturers Sumitomo Pipe & Tube and Vallourec & Mannesmann. ✦


Stay with your current automation.
Then repeat after me,
"My plant performance is okay. I don't need to do better.
My plant performance is okay..."

Editorial

Alberta faces decision

Alberta's government has arrived at a political intersection that's becoming too familiar. After delivery of recommendations from the Alberta Royalty Review Panel, it must choose between the market orientation that comes naturally and excess governance.

The problem isn't just that the panel wants to hike the royalty on oil, gas, and oil sands, beyond anyone's expectations (OGJ, Sept. 10, 2007, p. 17). It's that the recommendations shove energy politics in a vital producing region sharply leftward.

Oil sands hit

Royalty reform under the panel's recommendations would hit bitumen from oil sands harder than it would conventional oil and gas, largely through imposition of an "oil sands severance tax." In all three categories, the proposals would raise the total government "take"—the share of profits claimed by federal and provincial governments through royalty and taxes. The increases: to 64% from 47% for oil sands, to 49% from 44% for conventional oil, and to 63% from 58% for natural gas.

Government take, the panel says, "can be increased with Alberta still remaining an attractive investment destination." The important question is whether Alberta would be anywhere near as attractive an investment destination if it hiked royalty to the extent proposed as it would be if it left well enough alone.

The answer, of course, is no. By the panel's estimates, Alberta would collect about $2 billion/year more in total royalties under its proposals at current prices and production rates than it would under the status quo—an increase of 20%. This is money that can't be invested in oil, gas, and oil sands projects, costs of which are soaring. It's about 12% of the investment projected this year in oil sands and 7% of forecast capital spending in conventional oil and gas. The Edinburgh consultancy Wood Mackenzie estimates that the recommendations would slash the net present value of current and planned oil sands projects by $26 billion (OGJ Online, Sept. 25, 2007).

That seems not to concern the review panel. "Albertans do not receive their fair share from energy development," it asserts. "The royalty rates and formulas have not kept pace with changes in the resource base and world energy markets." Analysis proceeds from there, scarcely noticing such other changes as rising costs and toughening environmental regulation.

The panel reveals much about its orientation by linking Albertans' interests exclusively with provincial royalty receipts, as though wealth confers no advantage until it passes through government hands. In fact, Albertans benefit greatly from oil and gas production under the existing royalty regime. The finance ministry notes that oil and gas account for 20-50% of the Albertan economy, depending on industry definitions and economic measures. And the economy has been growing nicely. Last year Alberta's gross domestic product increased 6.8%, highest among Canadian provinces and territories. The projection this year is for growth of 4.1%, second behind Newfoundland. The ministry estimates Canadian GDP growth in both years at 2.7%.

A royalty hike certain to discourage oil and gas investment would slow Alberta's economic growth. To gloss over economic effects and focus on royalty-rate comparisons is to overlook much of importance to Albertans.

Transparency charges

Similarly suspect are allegations about accountability lapses. "The panel is unanimous in declaring that Albertans do not presently enjoy a transparent and readily evaluated royalty regime for oil and gas," the report declares, specifically criticizing governmental performance and industry compliance. These are serious charges. But they're supported only by vague complaints about answers the panel sought but didn't receive from the Department of Energy, isolated numbers it couldn't reconcile, cost data it couldn't find, and a consultant's worries about record-keeping that the panel didn't have time to investigate.

To the contrary, facts about Alberta's oil and gas industry have never been difficult to find. Maybe the accounting system strains under pressures of heavy activity. That can be fixed. But the sweeping claim about transparency is overstatement. Responding with a new level of bureaucracy would be overkill.

The panel's report is a blueprint for bigger government and slower economic growth. Albertans should hope it dies at the recommendation stage. ✦

Sustainability reports answer growing calls for information

Paula Dittrick
Senior Staff Writer

Oil and gas companies in growing numbers are issuing sustainability reports in response to demand for information on corporate governance and risk-mitigation.

Shareholders and industry observers expect companies to disclose business risks involving the environment, labor, human rights, other social issues, and anticorruption measures. Nonfinancial sustainability reports sometimes accompany annual reports and financial statements.

Accountants told OGJ that corporate social responsibility initiatives are responsible for generating sustainability reports, which disclose a wide range of information that varies widely between companies and also between countries.

Xavier Houot, a partner with Ernst & Young India in sustainability advisory services, said corporate disclosure of past financial performance isn't enough anymore. "Today, with increased emphasis on corporate governance across the world, with the appearance of new risks, the multiple forms of transparency and mitigating activities required have become a part of life," Houot said. "The world expects a proactive approach to sustainability from the corporate community and is concerned about environmental, climatic, labor, social, and other developmental challenges."

Statistics compiled by CorporateRegister.com Ltd., an online directory of corporate social responsibility and sustainability reports, indicate 99 oil and gas companies reported in 2006 compared with 26 in 1996.

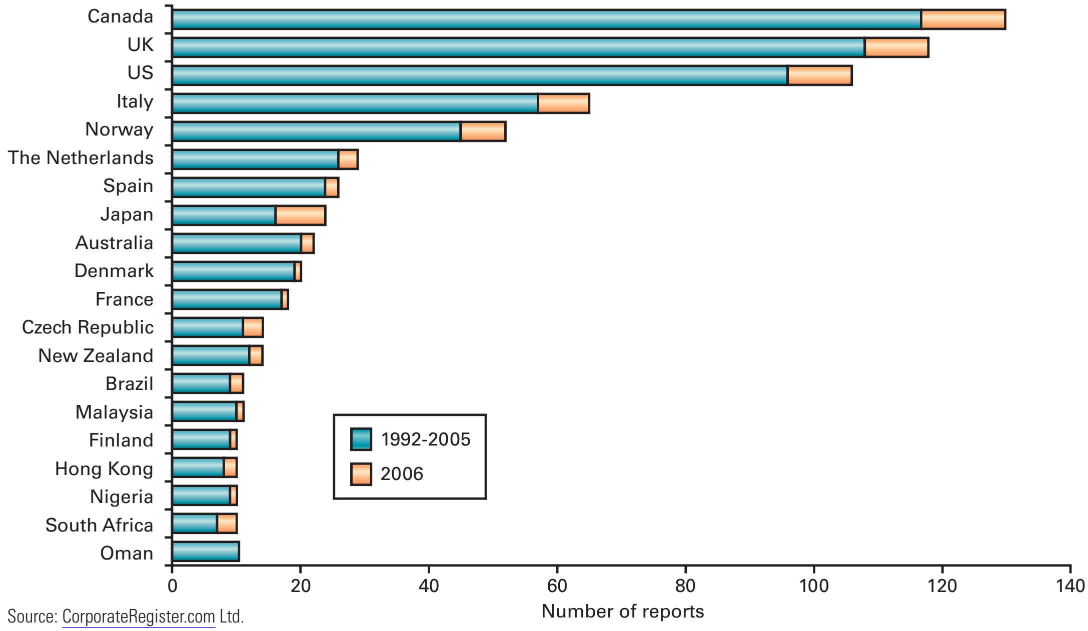
In a 2006 joint report, KPMG and the United Nations Environment Programme (UNEP) said more than half of the top 250 companies in the Fortune 500 list produce sustainability reports, with 75% of them citing economic reasons for the reports.

A separate study from CorporateRegister.com in 2007 shows 234 of the world's largest 300 companies produce a corporate nonfinancial report.

Oil and gas companies issue sustainability reports to communicate their progress on nonfinancial aspects of corporate performance.

France is among the countries calling for mandatory sustainability reports from publicly traded companies. The practice remains self-regulating by the companies in many countries, including India. KPMG annual surveys on sustainability reporting trends indicate South Africa is one of only a few developing countries that have considered sustainability reporting.

NONFINANCIAL REPORTING IN THE OIL AND GAS INDUSTRY



Source: CorporateRegister.com Ltd.

In the US, the Securities and Exchange Commission has some disclosure requirements that pertain to reporting sustainability issues. "As early as 1971, the SEC demanded disclosure of environmental data in SEC filings," the KPMG-UNEP report said.

Although the US Sarbanes-Oxley Act does not explicitly regulate the disclosure of environmental or social information, KPMG-UNEP said the act could enhance corporate transparency, encouraging sustainability information.

Evolving guidelines

The KPMG-UNEP report said ethics-oriented investment funds in the UK and US first screened companies during the 1980s based on corporate social and ethical performance. That focus increased after the Exxon Valdez oil tanker ran aground off Alaska.

"Following the 1989 Exxon Valdez disaster, the US-based Coalition for Environmentally Responsible Economies (CERES) developed the CERES-Valdez Principles on behalf of the Social Investment Forum," KPMG-UNEP said. "These principles introduced a tough set of environmental reporting guidelines."

Mandatory disclosure on environmental issues through local or site-level reporting was introduced with environmental legislation during the mid-1990s in the Netherlands, Sweden, Denmark, and Belgium.

Since then, sustainability reporting has increased with more comprehensive coverage. In 1997, CERES and UNEP launched the Global Reporting Initiative (GRI) to develop reporting guidelines for what GRI calls "the triple bottom line: economic, environmental, and social performance."

The first GRI guidelines were launched in 2002 with the latest incarnation, the G3 guidelines, launched in October 2006.

The guidelines seek to elevate sustainability reporting to the same rigor as annual financial reporting, the KMPG-UNEP report said.

CorporateRegister.com said 30% of all nonfinancial reports produced in 2006 followed the GRI guidelines. The number of corporate nonfinancial reports for all industries grew from fewer than 50 in 1992 to 2,265 in 2006.

The oil and gas sector is the third most prolific reporting industry, said Iain McGhee of CorporateRegister.com, based in London.

The most active reporting oil companies are based in Canada, UK, and US, he said (see figure).

France is the most commonly cited example of a mandatory approach because of its New Economic Regulations law, operative in 2003, which requires publicly traded companies to issue social and environmental information with their annual reports.

The UK also authorized mandatory reporting of nonfinancial performance factors. Businesses have until October 2008 to comply with provisions in the Companies Act of 2006, which formally outlines duties for corporate directors beyond financial reporting such as environmental concerns, employee matters, and social issues.

The KPMG-UNEP report said its research found more than 100 reporting requirements and standards in selected countries that addressed sustainability issues. About 50 of the 100 were mandatory requirements. Most of the selected countries were Organization for Economic Cooperation and Development members.

"However, these requirements remain largely fragmented and in most cases do not fit an integrated strategy to regulate sustainability reporting," KPMG-UNEP said. "Quite often laws were promulgated without any reference to sustainability reporting, yet—after the fact—such laws can be classified as a legal requirement for sustainability reporting because of the nature of the issues addressed."

Sustainability reporting varies considerably between companies and also between countries.

Reporting incentives

Speaking before the Sustainability Summit Asia 2006 in New Delhi, Ernst & Young's Houot said India has no mandatory sustainability reporting requirements, but he believes corporations benefit from reporting social and environmental performance.

Sustainability reporting builds stakeholders' confidence for Indian companies operating abroad that want to be perceived as meeting the same standards as their global peers, he said, adding that the practice also attracts socially responsible investors.

"It is the right time for Indian companies to seize the opportunity and adopt reporting practices," Houot said. "And why? What does not get reported does not get improved. What gets measured can be benchmarked, compared, improved, verified, and audited."

McGhee said the reporting history in the oil and gas industry has been characterized by a rapid evolution from single issue reporting, such as environmental issues only, to comprehensive multiple-issue reports covering social, environmental, and ethical issues in one document.

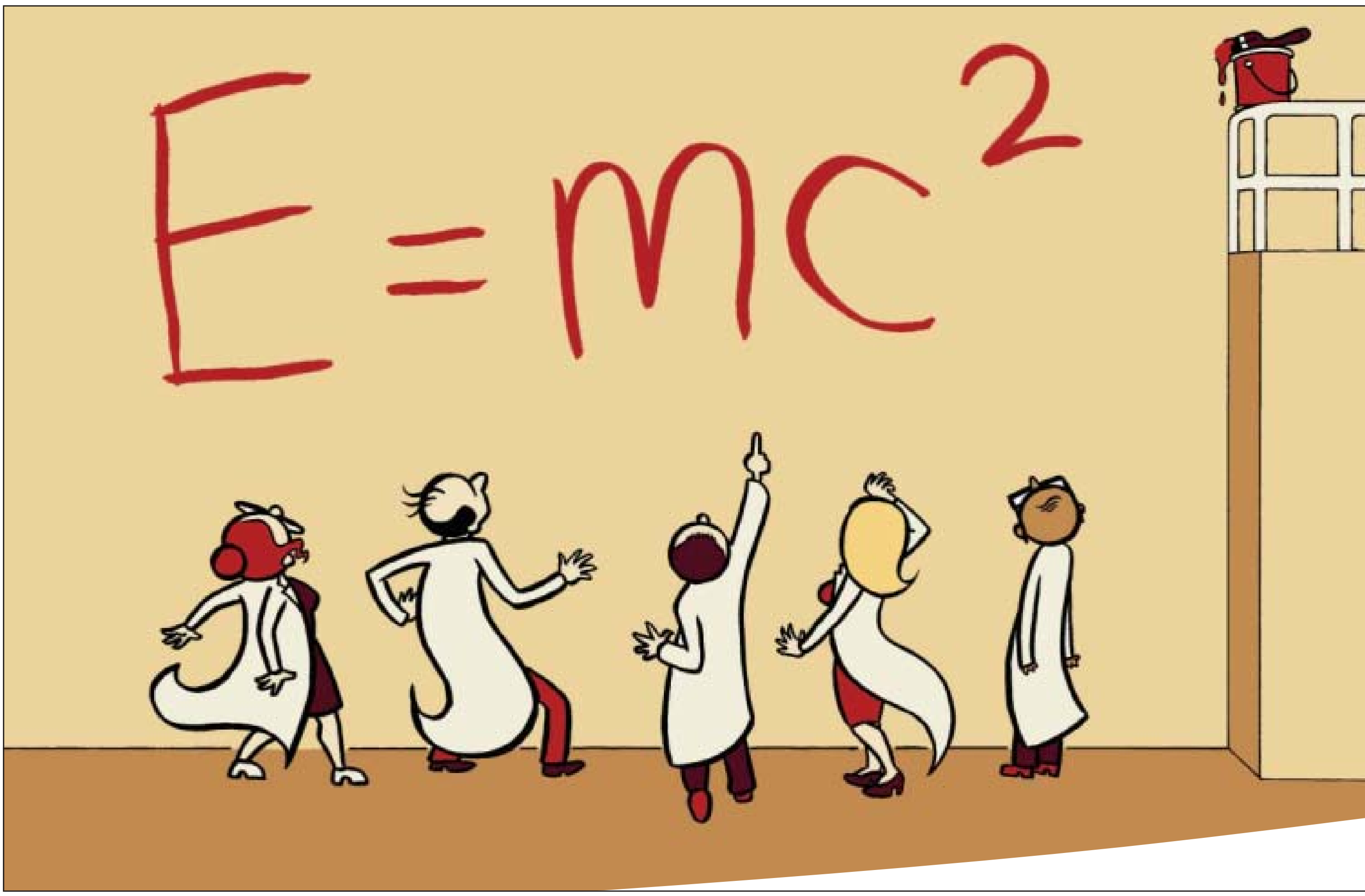
CorporateRegister.com reports that over 90% of the oil and gas company reports produced so far this year are multiple-issue reports.

Last year, Jantzi Research Inc. of Toronto released a report entitled "Oil and Gas in a Bull Market: The Shifting Sands of Responsibility." The report examined 23 oil companies worldwide on environmental issues, human rights, and other social issues.

That report ranked companies on their social and environmental performance, saying the top performers were dominated by European and Canadian companies. BP PLC received the highest score.

Jantzi rated companies on four categories: environment, community and society, human rights, and health and safety. The environment category was broken down into subcategories. Emphasis was given to corporate reductions in greenhouse gas emissions.

"Many US oil and gas companies are only in the beginning stages of acknowledging climate change as a corporate concern and business issue," the Jantzi report said. ✦



Companies adapt to expanded responsibility reporting

Paula Dittrick
Senior Staff Writer

Oil and gas companies are updating their tools for reporting environmental, health, and safety (EHS), and social issues.

This move is necessary as companies expand their corporate social responsibility (CSR) or sustainability reports.

Philippe Tesler, cofounder of EHS software provider Enablon, estimates that at least one third of oil companies worldwide have outdated nonfinancial reporting systems. He believes all companies will have either revamped or replaced their CSR and EHS management software by 2010.

"Companies who don't keep up will be less competitive and will not meet customer expectations," he told OGJ.

Reporting practices have changed dramatically since the late 1990s. For instance, consumers and managers expect real-time information to be available on company web sites.

"A few years ago, customers were satisfied when a company provided some example of good practices," Tesler said. "Customers now are requiring metrics...hard data and not just some evidence."

Of a move toward standardized metrics, Tesler said, "The current stage is comparable metrics—how do I compare one company with another one?"

Industry responding

The International Petroleum Industry Environmental Conservation Association and the American Petroleum Institute jointly issued the "Oil and Gas Industry Guidance on Voluntary Sustainability Reporting" in 2005.

It's intended as a voluntary reference or framework for oil and gas companies interested in reporting their environmental, health and safety, social, and economic performance, the groups said.

The guidance document is part of a bigger initiative toward reporting nonfinancial issues.

In addition, companies are working toward building consensus on what is being measured and how to report it.

A BP PLC global safety spokesman said BP and other major companies plan an October meeting to discuss standardizing metrics on reporting safety statistics, according to news reports.

Total AS Chemical Group already has changed its reporting procedures, said Christiane Vacher, Total Chemical envi-

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WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Chavez unveils a new whopper

A few weeks ago, we wondered if oil diplomacy was driving Venezuelan President Hugo Chavez over the edge. Back then, we noted that Chavez compared himself with Jesus, telling fellow leaders in the Caribbean that his country would supply them with oil at preferential rates (OGJ, Aug. 20, 2007, p. 34).

Chavez's boasting continues, with more recent claims that his government is launching the socialist gas revolution. According to Chavez, Venezuela possesses 80% of South America's gas reserves and 30% of the gas reserves in the Americas.

Recently Chavez said his administration would invest $18 billion to expand gas production to 11 bcfd over the next 5 years from 7 bcfd (OGJ Online, Sept. 19, 2007). Touting his country's assets, Chavez said Venezuela has proved gas reserves of 150 tcf onshore and 30 tcf offshore.

Production increases

Meanwhile, the volatile Venezuelan leader said his government also plans to increase the country's oil production to 5 million b/d in 2012 from its current 3.2 million b/d.

Oddly enough, he never seems to have mentioned any agreement from the Organization of Petroleum Exporting Countries, which Venezuela helped to found, about that production increase. And do you know something else? It seems that OPEC disagrees with the amount of oil Venezuela claims to produce.

Indeed, OPEC has openly—and very publicly—cut Venezuela's oil production ceiling allocation far below the output level claimed by the South American country and its loquacious leader.

On Sept. 21 OPEC, according to the latest figures on its web site, reduced Venezuela's ceiling by a whopping 24% to 2.47 million b/d—a lot lower than the 3.22 million b/d allocation the country had before the most recent OPEC meeting in early September. That added powerful weight to analysts, such the International Energy Agency, that have long said that Venezuela's production figure of 3 million-plus b/d of oil is inflated.

Public embarrassment

Venezuela has not taken the OPEC numbers lightly. Earlier this month, Venezuelan Oil Ministry officials met Fuad Al-Zayer, who leads OPEC's data services department, to get the figures changed. The visit made no difference. OPEC very clearly stood fast to its numbers.

A spokeswomen for Venezuela's oil ministry declined to comment on the ceiling cut other than to say that it was an issue only the oil minister could comment on himself.

No wonder she would want to distance herself from such a responsibility. How embarrassing since the organization which Venezuela helped to found is obviously distancing itself from the inflated claims of the country's government.

But Chavez just moves on. Last week, he insisted that Venezuela, the fourth largest supplier of oil to the US, will expand its petrochemicals industry during the next 5 years, lifting revenues to $100 billion/year.

"Venezuela is going to be a global petrochemicals power," Chavez said.

By gosh, do this man's whoppers never end? ✦

ronment coordinator.

Previously, Total compiled spreadsheets from 350 chemical sites worldwide.

"We used several consolidation files, which was not very convenient," Vacher said. Total Chemical now uses the same environmental reporting software in 29 countries.

"We needed a tool to analyze results according to different axes (legal, business, and geographical), and we also wanted to be able to collect information about greenhouse gas emissions in Europe or worldwide for example," Vacher said.

Trends

Enablon's Tesler said sustainability governance is a priority for executives who realize that they must be transparent on environmental and safety issues.

"It's no longer an issue for midlevel managers or the specialists," Tesler said. "It's an issue for the whole company."

Some European countries have laws regarding sustainability governance practices. In the US, the public demands it, he said.

"It's a financial issue. You can wait, or you can save money if you manage environmental governance," Tesler said.

He outlined these trends for the oil and gas industry:

- Compliance used to be unregulated, particularly in the US, but it is becoming more regulated worldwide. In the US, states are passing more environmentally related laws.
- Consumers demand transparency about corporate risks and liabilities, and customers demand environment-friendly products.
- Companies realize good environmental and safety processes lower costs and improve energy efficiency.
- Nongovernmental organizations expect companies to report the sustainability and social practices of their suppliers and contractors.
- Customers and investors expect information in real time online and not just once a year in a printed report.
- The public wants detailed disclo-

sure about what a company is doing. People living by a refinery expect safety information and emissions statistics.

"The next trend that we see coming is that companies disclose their targets," Tesler said. "They tell customers where they want to go tomorrow. It's something that companies are very aware of, weaknesses and solutions." ✦

Producers cautious about Alberta royalty proposals

The Canadian oil and gas producing industry is responding cautiously to recommendations for large royalty increases in Alberta.

The Canadian Association of Petroleum Producers labeled as "flawed" the recommendations of the Alberta Royalty Review Panel, which was established in February (OGJ, Sept. 10, 2007, p. 17).

"We are committed to staying focused on the facts and working constructively with government throughout this process," said CAPP Pres. Pierre Alvarez.

The panel made its recommendations, which include a new layer of royalty on rapidly growing production from Alberta's oil sands, to Alberta Minister of Finance Lyle Oberg.

"The basic assumption is that the size of the 'pie' will not change," Alvarez said. "Past experience, in this country and around the world, just doesn't support the panel's view."

The changes would raise the total government take—the federal and provincial governments' share of total profits from royalty and taxes—to 64% from the current 47% for oil sands, to 49% from 44% for conventional oil, and to 63% from 58% for natural gas.

Wood Mackenzie Ltd., Edinburgh, estimated that if implemented in full, the changes would cut the net present value of current and planned oil sands projects, discounted at 10%/year with a long-term Brent crude price of $50/bbl, by $26 billion.

"The higher than expected level of new taxation will cause concern among oil sands industry players already struggling to cope with spiraling costs," said Derek Butter, WoodMac head of corporate analysis. "This will further raise the already high economic break-even price of these projects, significantly raising the level of risk on what are huge initial capital outlays.

In addition to restructuring the Albertan oil and gas royalty regime, the panel recommended that the provincial government "implement the means to gather and assess the workings of all aspects of revenue policy and collection associated with energy resources in the province." This, it said, could take the form of a "super-ministry" or deputy leader reporting directly to the premier.

While the proposed accountability function would be expensive, the panel said, "The lack of having such a capability has had consequences that, in the panel's view, have been very costly along several dimensions."

It said a "data vacuum" and "seeming absence of oversight" became "obvious" during its review.

Major changes

Among the panel's major recommendations is an oil sands severance tax (OSST), applied at a rate of 1-9%, depending on the price of crude oil, beyond royalty.

The panel also recommended raising the net royalty rate after payout on oil sands production to 33% from 25% and adding a royalty credit based on 5% of the cost of upgrading facilities built in Alberta.

For conventional oil and gas production, the panel recommended generic royalty formulas based on production and prices.

Under the recommendations, royalty rates on small wells would decline while those on more prolific wells would rise.

CAPP pointed out that, at prices expected over the next year, all gas wells would pay higher royalties, "which will only make the current drilling downturn worse." ✦

UK oil industry expected to survive credit squeeze

Uchenna Izundu
International Editor

The UK oil and gas industry likely will survive the credit squeeze in the financial markets, a senior banker said in London, adding that the industry is important and cyclical.

Steve Mills, senior director of oil and gas project and export finance at the Royal Bank of Scotland, cautioned that it was still early to judge the full impact of the credit squeeze, but if there is a reduction in capital, people have a "good case to make that the UK has a great record in oil and gas."

Speaking at a breakfast meeting looking at successful entrants in the UK North Sea, he said, "I feel the banks will ride this comfortably because it is long-term and it's about regular cash flows."

As major international oil companies reduce interests in the mature UK North Sea to look for larger fields elsewhere, new entrants are important players in the basin because there is an estimated 20-25 billion boe yet to be produced, said Mills. Since the 1990s, new entrants on the UK Continental Shelf have contributed 40% of the investment and controlled 20% of the production there, according to trade association Oil and Gas UK.

However, new companies require money, assets, and people to build a successful business in the UK North Sea, and smaller entrants have more difficulty raising equity. Debt is available to operators, but small assets reduce senior debt capacity, Mills added, saying that abandonment guarantees erode debt capacity or use it inefficiently. Operators must have field-development plans in place if they are to secure bank capital. Rising costs—a general industry trend—are also a serious challenge, Mills said.

For Mike Wagstaff, chief executive of UK-based Venture Production PLC, which focuses on the UK North Sea, implementing gas projects has become challenging because of low gas prices compared with oil prices. "Cost production is acute," he said at the seminar. Venture recently tested gas production from its Chiswick gas field in the UK southern North Sea (OGJ Online, Sept. 19, 2007). "To get to the [gas-prone] southern North Sea, we need to do things differently to get costs down. The price of gas in the UK now is not as bad as thought at the New Year, [but] gas is over half of our business, and so we are concerned about it."

As demand for contractors' services soars in light of high commodity prices, contractors charge operators more, increasing operational costs. Wagstaff criticized current contractor practices as inefficient, calling for the industry and contractors to "rip up the way they do things." Nevertheless, "contractors here are not making the margins that they should be," Wagstaff added. "The net unit cost in the Gulf of Mexico is lower and contractors there make bigger margins."

Mergers of companies listed on the Alternative Investment Market in London have not occurred as quickly as was anticipated, as they vie to develop projects in the North Sea and raise finance, said Ernst & Young. But Venture Production in August offered to buy Wham Energy PLC because it has gas exploration assets in the UK southern North Sea.

At the seminar Wagstaff said that in a mature and consolidating industry, it is necessary to have size and scale to maximize resources. "I think consolidation will happen to bring down costs," he added. "I sympathize with AIM companies—it was difficult to access capital in 2004-05, and we're paying the price for that now. There is a tendency to underprice risk, and [the results] will be painful." ✦

China, Japan postpone dispute resolution talks

Eric Watkins
Senior Correspondent

Conflicting diplomatic schedules have caused Japan and China to postpone their next round of talks aimed at resolving a dispute over gas exploration rights in the East China Sea, according to Japanese Foreign Ministry press secretary Mitsuo Sakaba. No new date for talks has been decided upon, he said.

Sakaba said the gas dispute talks overlapped the six-party talks on North Korea's denuclearization that were scheduled to commence Sept. 19.

The two nations last met in June in Tokyo for working-level talks, and reports say they have been stepping up efforts to reach an agreement, as they are seeking to compile a plan by the fall to jointly develop the disputed gas fields.

One report said Japan had been sounding out the Chinese side on paying for half of the cost for developing the four gas fields on the Chinese side near what Tokyo calls the Japan-China median line in the East China Sea.

Tokyo's Sankei Shimbun newspaper said the proposal is expected to become an item on the official agenda of the Japan-China talks. If Japan's cost to transport gas by sea is not commercially profitable, selling Japan's share to China for cash is also being considered.

The proposal consists of two main parts:

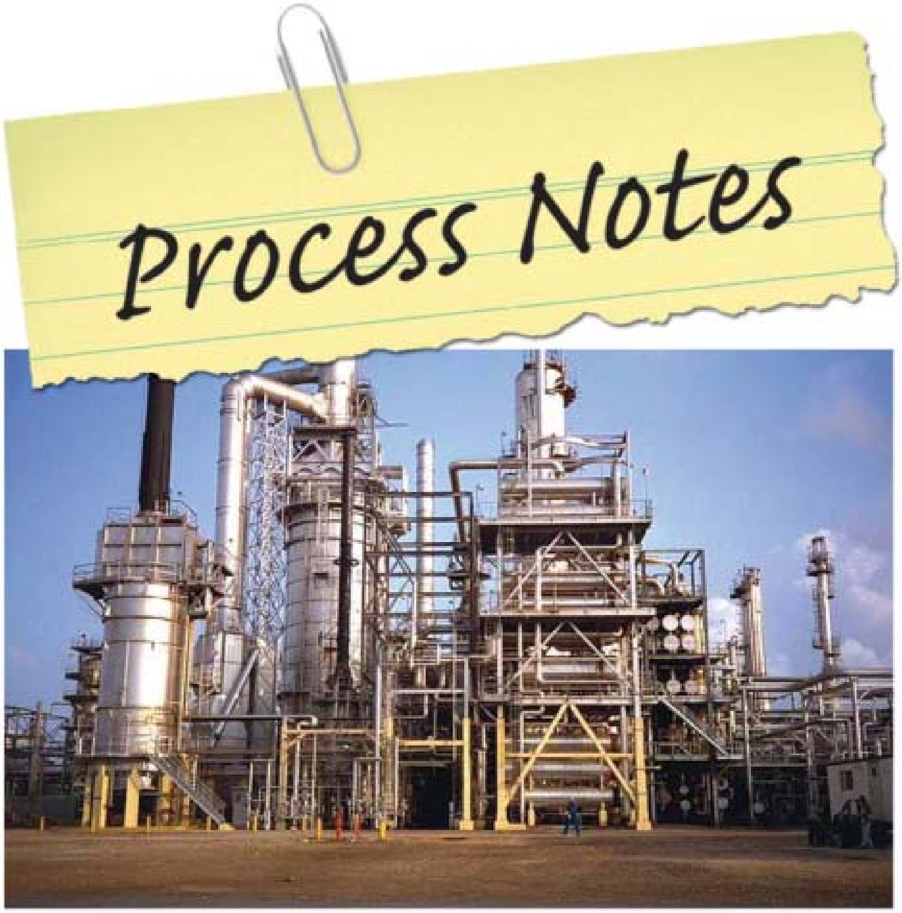
- Upon agreement on sharing the development cost, rights to the newly produced natural gas will belong to both Japan and China.
- With regard to subterranean resources that China has already extracted, the distribution ratio between the two sides will be decided based on data on subterranean structures, with China purchasing such resources from Japan. However, Japan will concede to China's lone development of gas fields whose subterranean structures do not extend over to the Japanese side.

The dispute stemmed from unsettled demarcation of the East China Sea where the waters claimed by the two countries overlap. The disputed sites are east of what Japan claims is the median line separating the 200-nautical-mile exclusive economic zones of the two countries in the East China Sea.

China does not recognize the median line claimed by Japan, saying its economic waters stretch to the end of the continental shelf. In April, China reiterated its claim, saying its exploration for oil and gas in the East China Sea does not fall into waters shared with Japan and can be conducted on a unilateral basis (OGJ Online, Apr. 12, 2007).

However, Japan hopes to engage in joint development of four gas fields whose subterranean structures are thought to bestride the median line: Shirakaba (Chunxiao in Chinese), Kashi (Tianwaitian), Kusunoki (Duanqiao), and Asunaro (Longjing).

According to a Japanese government official, the paper said, the Chinese side has already constructed drilling facilities for Shirakaba and Kashi, and it is highly possible that pipelines connecting the two fields with the Chinese mainland have already been completed. ✦



A Time for Grass Roots Thinking?

Within the past year or two spiking crude prices and surging refinery margins have led to overheated talk about increasing refinery capacity worldwide. Plans for construction of as many 60 grass roots refineries have been discussed. But stretched out lead times for major equipment and inflated prices, as well as declining margins and a final realization that there is not enough crude to meet demand, have brought sober thinking to the table. Recent societal changes in India and China do indeed indicate a need for new refineries but volatile politics in Latin America, looming demographic crises in Europe and explosive conditions in the Mid-East have rendered long range grass roots plans for these regions unrealistic.

Might it not be more prudent to revamp existing capacity? Many refineries have been over-designed from the start to compensate for poor process and equipment design, one way to compensate for a low level of equipment knowhow and a questionable reliance on vendors to design equipment. With the right revamp design, however, such excess capacity and equipment can be utilized to raise throughput, improve product quality and reduce energy consumption while minimizing new CAPEX. At the same time process changes can be made to adjust for the nasty crudes more and more entering the world market.

Revamps will succeed, however, only if a painstaking study is first made of existing plant to identify both limitations on present operation and opportunities for improvement. But such a study is not made sitting in the control room collecting operating history. It has to be done by revamp engineers getting their hands dirty helping operators gather field measurements. Only when these data are obtained can reliable computer models be put together and FEED package work begun. And note too that experienced revamp engineers have been able to fast-track jobs in months rather than years, producing revenue rapidly.

Prudent entrepreneurs will minimize funds at risk while meeting project objectives. At no time has such prudence been more needed than now. At no time has it been more important to think twice about grass roots projects.

For further discussion of revamps versus grass roots, ask for Technical Papers 142, 169, 186, 197 and 222.

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European Commission's energy legislation faces opposition

Doris Leblond
OGJ Correspondent

With its third legislative package on energy revealed Sept. 19, the European Commission is tackling head-on the nine countries opposed to ownership unbundling—the crux of its policy to open up energy markets to greater competition.

Nine countries oppose the proposed legislation that would separate the network operation of electricity and gas from supply and generation activities.

Aware that this will require "long and arduous negotiations" with countries expressing strong opposition to the measure, the commission has offered an alternative option. It is "the independent system operator" (ISO) system whereby integrated companies are given the option of retaining network ownership, provided their assets are operated by a fully independent company.

Implementation of ISO, however, is so complex and requires such close monitoring by energy regulators that unbundling opponents do not see it as a satisfactory alternative.

Energy Commissioner Andris Piebalgs insisted that both unbundling options would boost investment in new infrastructure, interconnection, and generation capacity, an argument refuted by large integrated companies such as Gaz de France, Electricite de France, E.On, which are generally backed by their governments.

As soon as ISO was announced, French, German, and Austrian governments opened fire against the measure, which would dismantle their energy champions. In France, Finance Minister Christine Lagarde said the government would retain a blocking 35% minority interest in the recently merged Gaz de France-Suez group and a golden share to "be able to counter the sale of any of Gaz de France's assets in France," including gas infrastructure.

Opponents to unbundling argue that competition and transparency in energy markets can be achieved through greater regulatory control and the increased clout and independence of National Energy Regulators, measures that are already in the energy package.

However, the commission's proposal to go further and set up an Agency for the Cooperation of National Energy Regulators that would have binding decision and controlling powers, is not meeting with enthusiastic acceptance. Intended to facilitate cross-border trade, the agency would oversee the application of community regulations but would also act as watchdog over network operators, namely the ISOs, and would be able to apply sanctions.

The countries do welcome the energy package's safeguards against the influence of non-EU countries that would try to assume control over an EU network. With an obvious eye on Gazprom and security of gas supplies, the commission has provided that companies from non-EU countries will "have to demonstrably and unequivocally comply with the same unbundling requirements as EU companies" to ensure a level playing field.

Subject to international obligations, the commission would be able to block any purchaser "which cannot demonstrate both its direct and indirect independence from supply and generation activities." This measure is in answer to growing concerns in the EU that if ownership unbundling of transport networks is pushed too far in the EU, it could harm supply security should these networks be acquired by non-EU buyers. It provides a sticky frame for Gazprom and Sonatrach, which are aiming to be operators on downstream gas distribution in some EU countries.

With the proposed energy package covering unbundling, regulatory oversight and cooperation, network cooperation, transparency, and record keeping, it is no wonder it has been met with comments both for and against it and has received no overall approval.

Ian Colin Lyle, chairman of the European Federation of Energy Traders' gas committee, was critical of the Agency for the Cooperation of National Energy regulators. He said he was unconvinced that the way "to deal with the inconsistencies in the operation of the EU gas grid" was to create a 27-member state gas Transmission System Operators, with the expectation that they would spontaneously produce market-friendly reforms and harmonization measures.

Jean-Louis Schilansky, president of the oil companies trade group Union Française des Industries Petrolieres and who also presides over the Energy Committee of France's Corporate Leaders Association (Mouvement des Entreprises Francaises), admitted that "the commission is right to aim for intensified competition on the energy market." But, he said, it should not be carried out to the detriment of the EU's being able to remain competitive and attractive as a market. "Our ambition is to direct the European energy markets towards sustainable development," he said. ✦

SEG: Geophysics role large in unconventionals

Alan Petzet
Chief Editor-Exploration

Geophysical methods will have important applications in commercializing unconventional oil and gas resources, a panel of geoscientists told the opening session of the Society of Exploration Geophysicists annual meeting Sept. 24 in San Antonio.

Chesapeake Energy Corp., which has the industry's largest land position in US gas resource plays, plans to shoot 3,100 sq miles of 3D seismic surveys at a cost of $168 million in 2007-08, said Larry Lunardi, the company's vice-president of geophysics since June 2006.

Chesapeake's 3D seismic surveys on the sprawling 18,000-acre Dallas-Fort Worth International Airport and in surrounding urban areas has found less extensive faulting than expected, a hazard to horizontal drilling for gas in the Barnett shale, Lunardi said.

The 60,000-lb. Vibroseis trucks posed no problems for the airport's 17-in.-thick aprons and runways, and gas withdrawal is not expected to result in subsidence because the shales are so tight, Lundari said.

The company is using microseismic techniques to monitor frac jobs and is tying microseismic information into its 3D seismic surveys.

Chesapeake has acquired 600 sq miles of airborne gravity gradiometry surveys in the Arkansas Fayetteville shale gas play and has found it helpful when combined with magnetic data, Lunardi said.

He foresees a wide role for geophysical methods because many of the gas shale plays Chesapeake is pursuing have wide vertical and lateral variability over short distances.

Improved techniques

Geophysical techniques will help the industry exploit smaller offshore fields, including nonturbiditic accumulations and "light" reservoirs, said J.M. Masset, Total SA senior vice-president, exploration and reservoir. Geophysical techniques are needed to improve oil recovery from offshore fields by as much as 20 percentage points, he said.

Improvements in seismic resolution are needed to enhance reservoir quality prediction and reduce the loss of energy at depth.

Electromagnetic techniques, when combined with seismic surveys, are helping companies map and characterize tar sand and heavy oil deposits, said Sverre Strandenes, group president, data processing and technology, Petroleum Geo-Services ASA.

He said the lead time for many research projects from initial idea to widespread commercial application is 16 years. Service companies are outspending major oil companies in research, and the overall industry needs to be more aggressive, Strandenes said.

Gas hydrates

The US Geological Survey has estimated 320,000 tcf of gas in place in hydrates in the US Exclusive Economic Zone, said Ray Boswell, a geologist with the US Department of Energy's National Energy Technology Laboratory. This is estimated to be one fourth to one half of the earth's volume of total organic carbon.

Gas in hydrates have proved to be detectable when they lie beneath permafrost, when their saturation is 50% or more, and when the reservoir is 25 ft thick or more, Boswell said. Bottom simulating reflectors have not proved as important as first thought but are still key objectives in geophysical exploration for hydrates.

Seven US government agencies are probing hydrates. DOE hopes to have completed research information packages for industry on arctic onshore hydrates by 2015 and on ocean hydrates by 2025. It plans to drill into hydrate deposits on Alaminos Canyon Block 818 and other Gulf of Mexico sites in 2008, Boswell said. ✦

IOGCC: EPA to measure VOCs from oil, gas fields

Paula Dittrick
Senior Staff Writer

US state and federal air quality and environmental agencies are contemplating how to better estimate and measure the level of volatile organic compounds (VOCs) emissions coming from oil and gas production facilities.

Bill Harnett, director of the air quality policy division of the US Environmental Protection Agency, outlined these efforts during a Sept. 24 speech to the Interstate Oil & Gas Compact Commission annual meeting in New Orleans.

VOCs can contribute to ground-level ozone levels. The EPA Office of Air and Radiation is considering a partnership with oil companies and environmental agencies of western states to conduct field tests that could start next year in two or three states that have yet to be determined.

The federal government probably will provide the initial funding, which Harnett estimates at $400,000 at least. Initial tests are likely to be in Colorado, Wyoming, or New Mexico.

The plan is to bag or tent possible sources of emissions and to measure the emissions over a number of days yet to be determined, he said. The process will be similar to emissions tests already done at refineries and chemical plants.

A draft methodology would be developed and distributed to the industry for comment. Testing will be primarily for VOC emissions leaking from equipment on production sites. Thousands of wells are being drilled or are scheduled to be drilled in the western US.

Better estimates needed

Harnett said regulators working on air quality models need better emissions estimates from oil and gas production. Another goal is to determine if oil and gas production is in compliance with federal and state standards, particularly in existing nonattainment areas under the National Ambient Air Quality Standard.

The US Bureau of Land Management needs better air emissions estimates to assess the possible environmental impacts of proposed leasing, he said. Information is needed from multiple states, fields, and from different types of equipment.

"We will be asking industry how to gather the best data of the greatest use to all," Harnett told IOGCC.

Recently, representatives of six states met with EPA and BLM representatives in Pinedale, Wyo., to discuss how to better estimate and measure emissions from oil and gas facilities, Harnett said.

That technical meeting was hosted by the Western States Air Resources Council, an organization representing 15 western states. Initial emissions field tests would not measure for greenhouse gas emissions. ✦

IOGCC: States best positioned to regulate CO_2 storage

Paula Dittrick
Senior Staff Writer

State governments are the logical entities to implement and administer regulations for carbon dioxide storage, the Interstate Oil & Gas Compact Commission Task Force on Carbon Capture and Geologic Storage said.

Lawrence Bengal, task force chairman, said the final report outlines a framework to help move carbon storage technologies forward. Bengal also serves as Arkansas Oil & Gas Commission director.

IOGCC released the task force's report to reporters on Sept. 26 following its approval at the organization's Sept. 25 business session of its annual meeting in New Orleans.

The task force proposes a state-administered carbon capture and storage (CCS) regulatory framework under the authorities of states wishing to participate. No state has a CCS law yet, but California, New Mexico, Texas, Wyoming, and at least five other states are considering CCS legislation, Bengal said.

The 30 IOGCC member states and four Canadian affiliate member provinces are well suited for CO_2 regulation because of their experience regulating oil and natural gas operations, particularly enhanced oil recovery, Bengal said.

The task force studied the resource management component of CCS involving reservoir management as well as health, safety, and environment. It also addressed guidance for a regulatory framework, but the task force did not address emissions trading.

"Following conservation, geologic storage of CO_2 is among the most immediate and viable strategies for mitigating the release of CO_2 into the atmosphere," Bengal said. "We envision that the report will result in a substantially consistent system for the geological storage of CO_2 regulated at the state and provincial level in conformance with national and international law."

Representatives of the US Environmental Protection Agency were observers of the task force, which worked for 4 years on the framework. The report suggests a "cradle-to-grave" method of regulatory CO_2 oversight, with the state being the proposed long-term caretaker.

Scott Anderson, an energy policy specialist for Environmental Defense and an observer to the task force, said model carbon storage requirements are rigorous. Anderson is with the Environmental Defense office in Austin.

"The IOGCC model rules will certainly be subject to revision as they are reviewed by more people and as more knowledge about geological sequestration is made," Anderson said. He called the report "a strong, major step forward in the ongoing conversation about how to do carbon sequestration right."

Recommendations

The report recommends that states and provinces solicit public involvement in the process, and that the process is as transparent as possible. Bengal said the life of the injection sites could be from 20 to 40 years.

The task force proposed a closure period and postclosure period to deal with long-term monitoring and liability issues. The storage site operator would be liable for 10 years after the injection site is plugged, unless otherwise designated by the state regulatory agency.

At the end of the closure period, liability for ensuring that the site remains a secure storage site during the post-closure period would transfer to the state. A trust fund funded by industry and administered by the state would provide oversight during the post-closure period. The trust fund would be funded by an injection fee.

Bengal said the state could handle the long-term caretaker role or it could hire a contractor to do that.

The IOGCC task force efforts were financed by the US Department of Energy and its National Energy Technology Laboratory. The task force now enters its third phase in which it plans to research property ownership issues and infrastructure guidance, particularly for pipelines. ✦

CFTC's timely look at markets

At a time when energy issues supposedly had moved into the background in Washington, DC, the US Commodity Trading Futures Commission quietly held a timely—some might say overdue—hearing.

The Sept. 18 event basically examined whether more oil and gas commodity markets need to be regulated. Several currently are not.

"In 2000, Congress created a tiered regulatory structure for the futures markets with passage of the Commodity Futures Modernization Act (CFMA). This calibrated structure has provided regulators with the proper flexibility and focus as we strive to keep pace with this industry's global growth," acting CFTC Chairman Walter L. Lukken said in his opening statement.

Energy markets have changed dramatically in 7 years, and CFTC's regulation should evolve as well, he said. While exempt commodity markets (ECMs) have increased competition and lowered costs for derivatives trading, "certain ECMs now function as virtual substitutes [for] regulated exchanges with tight correlation and linking of prices," Lukken said.

Different products

Witnesses said that the largest energy ECM, the Inter-Continental Exchange (ICE), developed as an electronic trading alternative to the New York Mercantile Exchange's open outcry trading. NYMEX Pres. James E. Newsome noted that the nation's largest regulated commodities exchange has developed its own electronic trading, which now is its main trading mechanism. Currently exempt markets that function like traditional exchanges and link prices to their products should be regulated, he said.

Jeffrey C. Sprecher, ICE's chairman and chief executive, said the exchange offers regulated futures and unregulated over-the-counter contracts.

Regulation may be appropriate for some of its cleared OTC contracts, such as its Henry Hub swap contract, that settle on a futures market contract price and are the true economic equivalent of an actively traded futures contract, he said.

But ICE also offers much less-liquid OTC products that do not fit that definition. "The level of regulation should fit the market in question," Sprecher said.

Speculators' role

Some energy market critics charge that speculators make prices more volatile. Natural Gas Supply Association Pres. R. Skip Horvath disagreed.

"In general, participation by speculative traders serves to further balance the supply-demand question via higher-risk market positions, which those interested in producing or consuming natural gas often do not wish to take. If it were not for such speculators, who actually smooth out delivered commodity prices over time and geography, price volatility could, most likely, be even greater," he said.

Many other questions were raised. The hearing probably won't be the final word on the subject, especially if gas and heating oil prices soar this winter. ✦

US GAO to study refining capacity, gasoline prices

Nick Snow
Washington Correspondent

The US Government Accountability Office has agreed to examine relationships between refining capacity and gasoline prices and demand in response to requests from Connecticut's congressional delegation and from US Sen. Charles E. Schumer (D-NY).

GAO received the two requests in mid-May and plans to merge them into a single inquiry to begin later this fall when qualified staff members are available, Gloria L. Jarmon, managing director for congressional relations, said in a Sept. 24 letter to Rep. Joseph Courtney (D-Conn.).

"Our nation's refiners have operated with little oversight for decades and have suffered little recourse for repeated outages and downtime," Courtney said in a joint announcement with other senators.

In their letter to GAO Comptroller General David A. Walker requesting an investigation, the delegation expressed skepticism that deferred maintenance led to reduced refinery utilization early in 2007 and suggested that "a calculated decrease in refining capacity could create an artificial shortage and drive up the cost to consumers."

The National Petrochemical & Refiners Association immediately took issue with the delegation's request. "Economists and national editorial pages have even warned Congress against passing so-called 'price gouging' legislation," said NPRA Executive Vice-Pres. Charles T. Drevna.

"The American public could be far better served if its elected officials would work with businesses instead of against them to craft a sensible and realistic energy policy to protect consumers by keeping supplies stable," he said. ✦

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8:15 – 9:45 am	Session 1 & Live Webcast
9:45 – 10:00 am	Coffee Break
10:00 – 11:30 am	Session 2 & Live Webcast
11:30 – 12:30 pm	Lunch
12:30 – 2:00 pm	Session 3 (closed session)
2:00 – 2:15 pm	Coffee Break
2:15 – 3:45 pm	Session 4 (closed session)
3:45 – 4:00 pm	Closing Remarks
4:00 – 5:00 pm	Networking Reception

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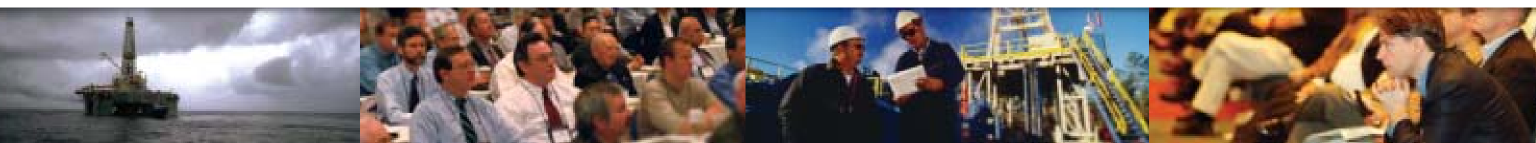

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Iraq licensing situation fluid as Kurdistan awards blocks

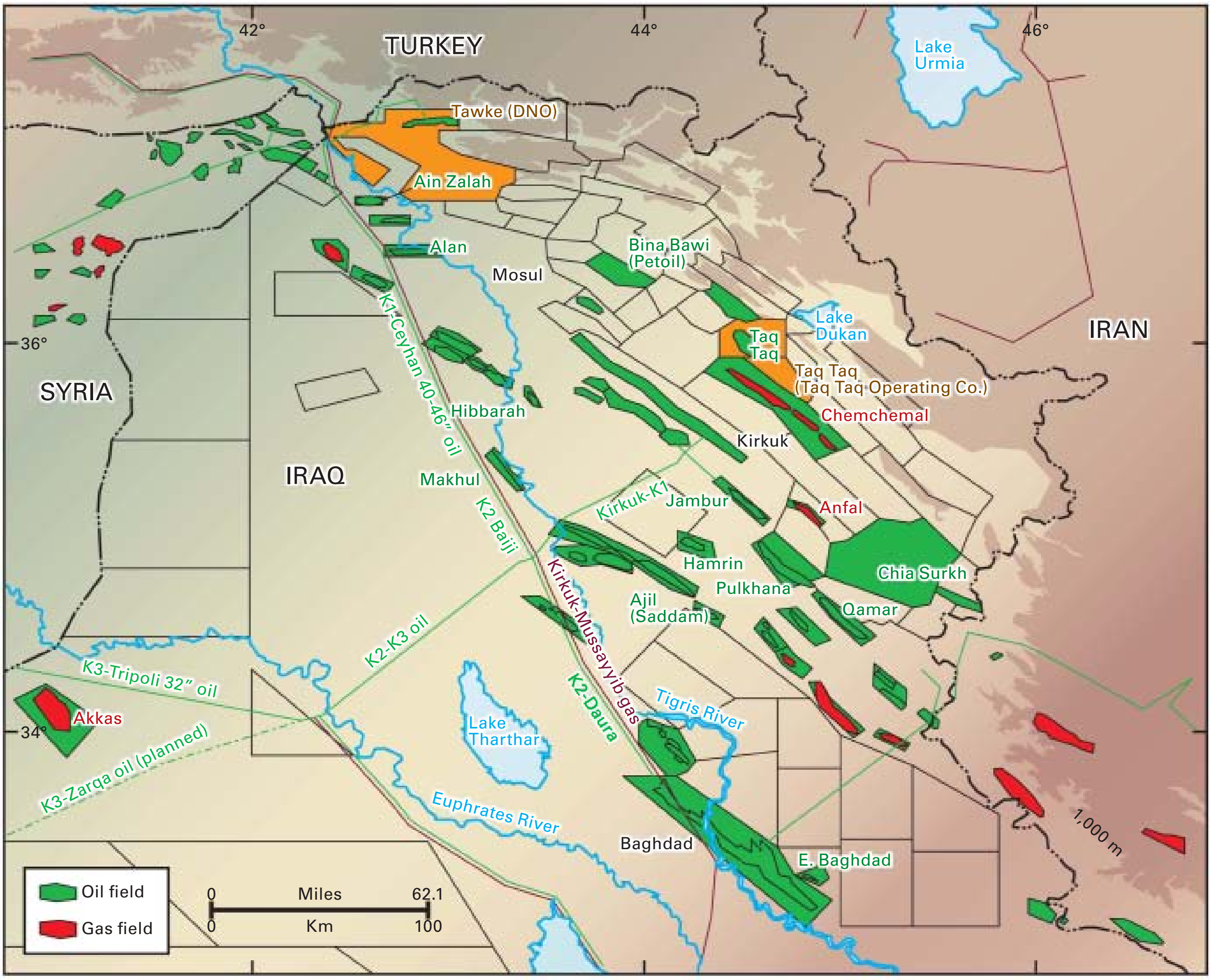
Major questions remain over the enduring legitimacy of production sharing contracts being signed by Iraq's Kurdistan Regional Government (KRG).

According to Iraq's draft federal petroleum law, the Kurdistan PSCs require Baghdad's endorsement, but federal Iraq has been unable to enact its own legislation. The prospect of the KRG deriving revenue from oil production is clouded by the fact that large-scale exports depend on pipelines owned and operated by the national oil company.

Nevertheless, early drilling on at least two of the PSCs appears to have established world class oil reserves and grabbed the notice of greater industry in a way not previously attained, said Wood Mackenzie consultants, Edinburgh, UK.

"Kurdish oil assets, which previously were thought to have limited capacity, are being proven by DNO, Genel Enerji and Addax to be prolific, regionally significant assets and not necessarily the poor relations to more established fields in the south of Iraq," Wood Mackenzie said in a September research report.

EXPLORATION AND DEVELOPMENT BLOCKS IN NORTHERN IRAQ



Source: After Wood Mackenzie Ltd.

Kurdistan developments

The KRG in Erbil has several more contracts ready for signature soon, noted Wood Mackenzie.

DNO ASA, Oslo, has already begun test production from Tawke oil field near Dihok north of Mosul (OGJ Online, Aug. 27, 2007).

DNO started extended test production from Tawke in June and reported output of 5,800 b/d in July and 6,900 b/d in August. The oil is trucked to the domestic market. DNO said it is entitled to all produced oil from Tawke, net after royalty, until it has recovered all project costs to date.

Meanwhile, Genel Energi AS and Addax Petroleum Corp. have tested appraisal wells at high rates in Taq Taq field east of Kirkuk (OGJ Online, Sept. 6, 2007). Oil in place has been estimated at 1.2-2.7 billion bbl, and reserves are expected to exceed 250 million bbl.

A development plan for Taq Taq involves a $1 billion-plus capital investment and a production plateau of more than 200,000 b/d and should be submitted in late 2007.

Dana Gas, Sharjah, UAE, won a service contract in April 2007 to appraise and develop Kormor and Chemchemal gas fields south of Taq Taq (OGJ Online, Apr. 25, 2007). Each field is believed capable of delivering several hundred million cubic feet of gas a day.

Hunt Oil Co. and Impulse Energy Corp., both private entities, were awarded a PSC on unspecified acreage in the Dihok area in September 2007 (OGJ Online, Sept. 14, 2007). The area is not believed to contain any proved reserves. Drilling could begin in 2008.

KRG's announcement of the award to Hunt and Impulse said that "revenues from this Kurdistan petroleum development will be shared by the KRG throughout Iraq, consistent with the Iraq constitution and the new oil and gas law of the Kurdistan Region."

The uptake

The Hunt-Impulse contract maintains the momentum of the KRG's licensing policy and expresses KRG's "frustration at the lack of progress toward a consensual oil and gas law, which would allow it to proceed with licensing and oil field developments in concert with the federal authorities," Wood Mackenzie noted.

Kurdistan's parliament approved its own regional oil and gas law in August 2007, and authorities outlined plans to offer 40 exploration blocks for competitive bidding.

"This raises the prospect of Kurdistan progressing the exploration and development of its oil and gas assets well ahead of the rest of Iraq," the Wood Mackenzie report said.

The Iraq Oil Ministry under Hussein al-Shahristani could exclude companies that do business in Kurdistan from participating in larger developments in southern Iraq.

"This may become less of a deterrent as concerns grow over southern Iraq's political future," the consultant said.

KRG pointed out that the Hunt-Impulse PSC is consistent with Kurdistan's petroleum law and with the draft federal oil and gas law promulgated in early 2007. ✦

Conventional targets sought in Palo Duro basin

Palo Duro Energy Inc., Vancouver, BC, said it is preparing an exploration program for fall in the Palo Duro basin using proprietary electromagnetic technologies.

Drilling will target Pennsylvanian and Permian reefs similar to those that have produced oil and gas at Wolf Flat and Gupton fields in Motley County, Tex. The company said the reefs are interpreted as forming along ancestral shelf margins of Canyon, Cisco, and Wolfcamp ages that developed in the central Palo Duro basin.

Other potential targets are Pennsylvanian (Atoka) quartz sandstones, such as those that yield gas at Rhombochasm field on trend with Palo Duro Energy's acreage (OGJ, June 8, 2001, p. 32).

The sands are interpreted to have been shed from the Amarillo-Wichita and Red River uplifts.

The company expects structural and stratigraphic traps. Source rocks are anticipated to be the underlying Lower Pennsylvanian (Atoka) shales being evaluated as fractured shale reservoirs in the Palo Duro basin by several companies, including Palo Duro Energy's partner, Bankers Petroleum Corp., Calgary.

Important shows and test rates have been encountered from many wells drilled in the Bend shale play in the past several years.

Numerous exploratory wells have encountered gas and oil shows in both the limestone formations and channelized sandstones, which indicates that the hydrocarbons generated from the Pennsylvanian shales have migrated along pathways, such as faults and fractures, into the younger rocks, the company said.

Palo Duro Energy is exploring for the traps that would have had sufficient sealing conditions to contain the hydrocarbons. The company is optimistic that the conventional prospects have large unrealized potential and will supplement the Bend shale resource play.

Palo Duro Energy, with an operations office in Houston, holds 27% interest in more than 400,000 net acres in the Palo Duro basin. ✦

Powder River wells to target oil in Mowry shale

Brigham Exploration Co., Austin, has formed a new Wyoming joint venture and signed a letter of intent for a work program to explore and develop more than 240,000 gross acres of deep rights with multipay potential, including the Cretaceous Mowry shale, in the southeastern Powder River basin.

Plans are to conduct a comprehensive technical evaluation by yearend and begin drilling on the acreage in 2008.

Brigham will initially retain a 100% working interest in the program.

Meanwhile, the company has fracture-stimulated various intervals in its three most recent horizontal Mowry completions. The Werner 1-14H and State 1-16H have both flowed back 60-70% of their frac load, while the most recently stimulated Mill Trust 1-12H has flowed back about 40% of its frac load.

Brigham plans to install production tubing and pumping equipment on all three wells over the next several weeks.

Brigham owns a 50% interest in the Mowry joint venture. American Oil & Gas Inc. holds 45%, and private firm North Finn LLC holds 5%. Brigham's acreage holdings in the play are about 65,000 net acres.

The company is scheduled to spud its third well for the year, the Krecji 1-32H, in early October. The results of the current completions will determine how quickly Brigham will commence the next well. The company said, however, it expects a very active program in the Mowry through 2008. ✦

Armenia

Transeuro Energy Corp., Vancouver, BC, spudded the Karmir-1 exploratory well on a gas prospect in the Armavir region of Block 2 in Armenia.

The country's first exploration well in 10 years, it is projected to 2,200 m and targets the Lower Sand Clay and Lower Multicolored Suite horizons.

The drillsite is within 3 km of the route of a recently installed domestic gas distribution pipeline, and the company and the government are discussing a connection in case the well finds gas.

Colombia

Colombia's ANH signed a technical evaluation agreement with Petrolifera Petroleum Ltd., Calgary, covering the 879,100-acre Sierra Nevada 2 area in the Lower Magdalena basin.

The block is north, east, and southeast of Petrolifera's Sierra Nevada 1 license and offsets known oil and gas accumulations. Sierra Nevada 2 carries a 14-month work commitment of reprocessing 650 km of seismic and geological and geophysical studies.

Namibia

The energy ministry approved the farming out by Tower Resources PLC's Neptune Petroleum (Namibia) Ltd. subsidiary of an 85% interest in the license that covers blocks 1910A, 1911, and 2011A to Arcadia Petroleum Ltd.

Arcadia, a financially strong London crude oil trading concern, becomes operator of the license in the Atlantic along the southern Walvis ridge (OGJ Online, Sept. 5, 2007).

Arcadia, in addition to reimbursing Tower 85% of certain historic costs, is to fund the cost of a recent 2D seismic shoot and its interpretation, a 3D program in 2008, an exploratory well, and an appraisal or second exploration well.

Israel

Zion Oil & Gas Inc., Dallas, let a $650,000 contract to Geophysical Institute of Israel to shoot 60 line-km of 2D seismic, gravity, and magnetic surveys over Zion's 78,000-acre Asher-Menashe exploration license in Israel.

The surveys are to help Zion select the optimal drillsite for an exploratory well on its Ramot Menashe (Menashe Heights) prospect and to upgrade the company's Nahal Me'arot lead, near the Asher-Atlit-1 well, into a drillable prospect.

Pakistan

Cathay Oil & Gas Ltd., Toronto, plans to explore for and develop coalbed methane and oil and gas in Sindh Province, Pakistan.

The company plans to create a basinwide geological model for CBM and a countrywide geological model for oil, gas, and minerals. Cathay signed an operational alliance with Schlumberger that will serve as the basis for a definitive master services agreement for the needed project management and related services.

Switzerland

Ascent Resources PLC plans to acquire a 22.5% interest in Perazzoli Drilling SRL of Italy that will provide Ascent with priority access to Perazzoli's rigs.

Ascent will gain the use of two rigs rated to 2,000 m and 3,600 m, an advantage under the current shortage of drilling contractors across Europe. Ascent expects to use the rigs 20% for its own account and contract them to third parties the rest of the time.

Ascent is discussing a farmout through which it plans to appraise the 1982 Hemrigen gas discovery on the 363.5 sq km Seeland/Frienisberg permit in Switzerland, where it also holds the 330 sq km Thun permit and the 1972 Linden discovery.

Ascent also holds a 736 sq km exploration permit in the Swiss Canton of Vaud through partner Swiss Petroleum, where BEB's 1962 Essertines well found 41.5° gravity oil and associated gas in a Jurassic reservoir.

Texas

Gulf Coast

Universal Energy Corp., Houston, said it agreed to acquire a 12.5% interest to casing point in Lone Oak, a Vicksburg 3D oil and gas prospect in Galveston Bay 9 miles northeast of Eagle Bay field.

The 3,526-acre prospect in the Houston salt basin has the same Vicksburg sandstone reservoir targets as produced at Eagle Bay and other fields in the trend, the company said.

Eagle Bay field has produced more than 110 bcf of gas and 10 million bbl of condensate from Vicksburg.

Shell Alaska readies ice-class drilling units for Beaufort Sea

Nina M. Rach
Drilling Editor

Drilling

Shell Offshore Inc. recently renovated and upgraded two arctic-class mobile drilling units to evaluate some of its Beaufort Sea leases.

Now Shell is leading the way back to the North American Arctic. Although it's an expensive place to work, higher prices justify the reentry, the company told OGJ in a series of exclusive interviews.

Shell was able to utilize vessels of the design originally used for the Canadian Arctic by Dome Petroleum in the 1970s. Dome's subsidiary Can-Mar built three drillships and the SDC drilling barge. Gulf Canada Resources subsequently built the Kulluk conical drilling platform in 1982, the Molikpaq, and four support vessels for arctic work. In 1989-1991, Shell worked in the US Chukchi Sea using Canadian equipment.

In this latest round of work, Shell added newer technology to older vessels in order to meet higher environmental standards and enhance performance and flexibility. The Shell Kulluk drilling platform now waits in waters off the Northwest Territories and the Frontier Discoverer drillship has been standing by in Dutch Harbor (1,500 mi away in Alaska's Aleutian Is.) for permission to drill in the US Beaufort.

Planning

The US Department of the Interior's Minerals Management Service developed a 5-year plan for the Beaufort Sea, 2002-07, to include three oil and gas lease sales: Sale 186 in September 2003, Sale 195 in March 2005, and Sale 202 in March 2007.

The MMS ultimately awarded Shell Offshore 84 leases in the Beaufort Sea, off Alaska, based on the company's bids

The Frontier Discoverer drillship is owned and operated by Frontier Drilling ASA, under contract to Shell Alaska (Fig. 1; photo from Shell Alaska).

in OCS Sale 195 for more than $44 million. Shell bid an additional $39 million earlier this year in OCS Sale 202.

When Shell began considering the Beaufort Sea lease sales, it had to evaluate economics, cost estimates, and feasibility of drilling. Keith Craik, Shell's drilling engineering manager in Anchorage, said not many drilling units were available to work in arctic conditions as severe as those in the Beaufort Sea. In 2002, Shell initially considered four:

- Two CanMar Explorer drillships stacked in Singapore.
- The SDC bottom-founded drilling barge, stacked at Herschel Island, west of the Mackenzie River delta and owned by Norway's Seatankers Ltd.
- The Kulluk drilling barge, stacked in McKinley Bay, east of the Mackenzie River delta, and owned by Seatankers.

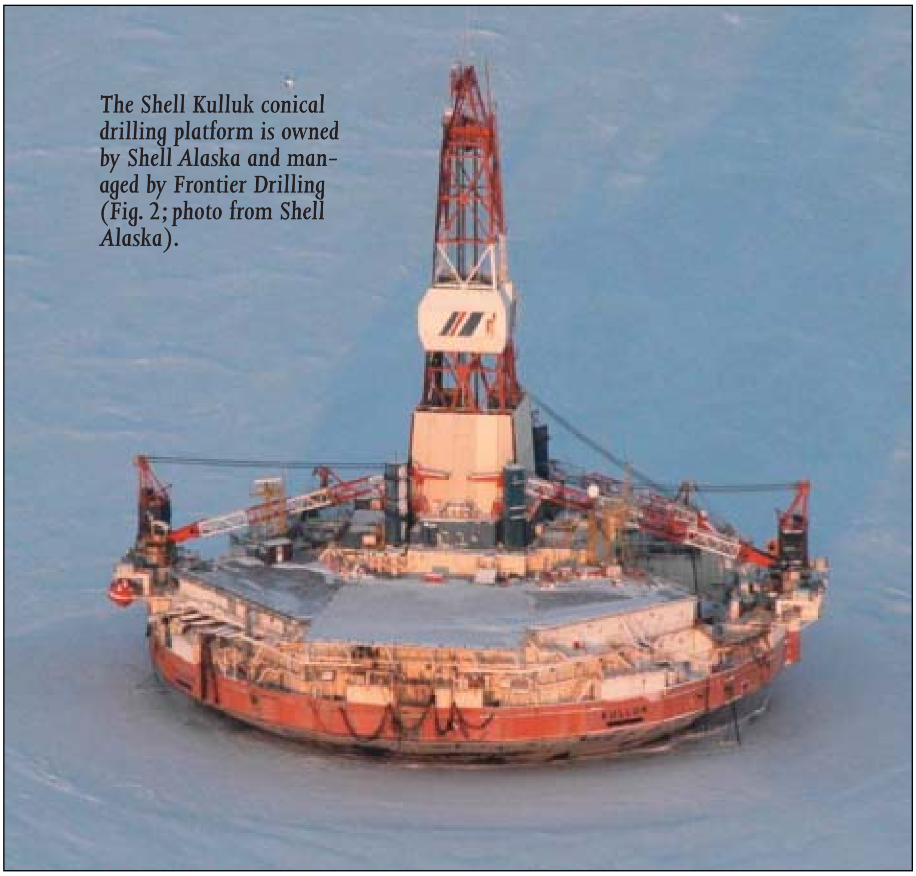
By 2005, Craik said, attrition reduc ed the selection to the SDC and the Kulluk, although a global search turned up a few DP arctic-class ships originally built to drill in the Barents Sea. Shell needed drilling units with conventional mooring equipment, however, to work in the shallow water of the Beaufort. The company decided that the SDC did not have the water depth capability necessary to carry out the potential drilling programs.

In summer 2005, Shell sent a team to evaluate the Kulluk, consisting of Shell foremen, marine and drilling engineers, a representative from DNV, and several service company field engineers. They spent a few weeks on the rig, assessing the integrity of the hull and the marine and drilling systems. In December 2005, Shell Offshore Inc. purchased the Kulluk from Seatankers.

Two-rig strategy

While looking at the Kulluk, Shell became concerned about its ability to drill a relief well, if necessary, according to Craik. The company decided it needed a second rig for this capability and was most interested in adding a drillship.

The drillship selected was owned by Norwegian drilling contractor Frontier Drilling AS, and the company was willing to convert it to an arctic-class vessel. Shell and Frontier wrote a contract to refurbish the Frontier Discoverer drillship in late December 2005 (Fig. 1).



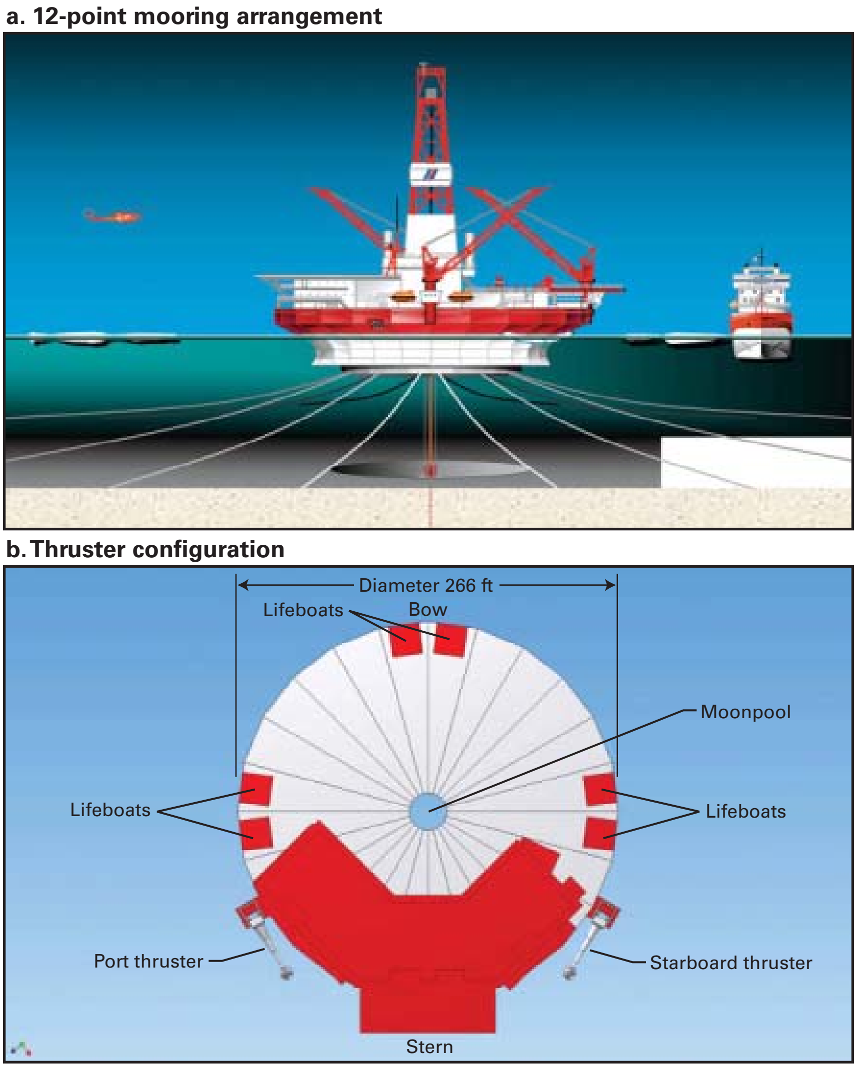
The Shell Kulluk conical drilling platform is owned by Shell Alaska and managed by Frontier Drilling (Fig. 2; photo from Shell Alaska).

Frontier Discoverer drillship specifications

Table 1

Length, overall	514 ft
Breadth, over sponsons	85.3 ft
Hull depth	37.9 ft
Operating water depth	1,000 ft with present equipment
Max. allowable variable deck load	6,687 tonnes
Mooring	Sonat Offshore Drilling roller turret mooring system, with symmetric 8-point pattern
Cranes	Two National OS435 cranes with 120-ft booms
	14.75 tonne capacity at maximum extension
	71.3 tonne capacity at minimum extension
Derrick	Pyramid, 170-ft, with 1.3 million lb nominal hook load capacity
Drawworks	Ideco E-2100, 2,000-hp
Top drive	Varco TDS-3S with GE 752 motor, 500 ton
Rotary table	National C-495 with 49.5-in. opening
Moon pool diameter	22 ft
Riser	Cameron RCK
Riser tensioners	Eight Schaffer 50-ft-stroke tensioners, each 80,000 lb
Drill string	20,000 ft, 5-in. diameter, G-105 pipe
Mud pumps	Two Continental Emsco Model FA-1600 triplex pumps
Solids control	MI Swaco System
Cement pumps	Halliburton Service Unit
Pressure control equipment	18¾-in. BOP stack, 10,000 psi
	Handled by a hydraulic, skid-based system on drill floor
Storage capacity:	
Liquid mud	2,400 bbl
Drill water	5,798 bbl
Bulk cement, barite (4 tanks each)	360 cu m
Potable water	1,670 bbl
Fuel	6,497 bbl
Accommodation	124 people

SHELL KULLUK MOBILE OFFSHORE DRILLING UNIT Fig. 3



In January 2006, the companies signed another contract for Frontier to manage and operate the Kulluk for Shell Offshore. The primary term of both contracts is for 3 years, from July 2007, with one 5-year, optional extension.

The renovation work on the Kulluk was accomplished in place, off Canada, in McKinley Bay. The Kulluk was supplied from Inuvik, Northwest Territories, by deHavilland Twin Otter planes using an ice runway, complete with windsock and lights. By May, the runway was abandoned because of the spring thaw; crew and equipment were flown to Tuktoyaktuk, where they transited to the rig transited to the rig.

Discoverer drillship

The original hull of the Frontier Discoverer drillship, a Sonat Offshore Drilling Discoverer Class vessel, was built in 1965 at Namura Zonshno shipyard in Osaka, Japan. The ship was converted to a drillship in 1976 at Avondale Shipyards in New Orleans.

Frontier Drilling AS hired Aker Arctic in Helsinki to do the hull design and modelling required to upgrade the Discoverer hull for arctic operations. Frontier coordinated the work, which included adding sponsons to stiffen the hull, internally strengthening the bow, and adding heat tracing and insulation to exposed lines.

"We envision Discoverer working in the summer, not winter," Craik said, when the temperatures range from –20°F to 50°F.

The Discoverer is turret-moored, with a symmetric, eight-point anchor pattern.

Thrusters allow the ship to rotate around the turret and face the bow into ice or weather.

The ship's draft during transit is 8.02 m, draft-while-drilling is 7.67 m, and the mean lightship draft is 5.8 m.

The 22.2-m octagonal helideck sits aft and has room for helicopters as large as Sikorsky 61N or 92N. The Discoverer quarters can accommodate 124 persons.

Following this drilling season in the Beaufort, the Discoverer will drill some wells for Shell Exploration & Production Asia (EPA) off Australia or Malaysia.

Kulluk platform

The Kulluk arctic floating drilling platform is shaped like a large, conical donut (Fig. 2). It was designed for Gulf Canada Resources Inc.'s Beaufort Sea drilling system division by Earl and Wright Consulting Engineers in San Francisco and Lavalin. It was built in 1982 by Mitsui Engineering & Shipbuilding Co. Ltd., at Tamano Works, Japan.

Gulf Canada commissioned the purpose-built vessel to extend the drilling season in the Beaufort. It was part of a fleet of six vessels operated by the company's arctic subsidiary, BeauDril.

The conical-shaped hull is nearly circular in plan view and was designed to deflect ice downward (Fig. 3a). It has 24 compartments, forming 24 sides, and a double hull and bottom to prevent hull breaches and pollution.[1] The 12-point mooring system was designed to resist the force of 4 ft of ice moving in any direction (Table 2).

Gulf Canada used the Kulluk to drill 12 wells at 7 locations in the Beaufort Sea from 1983-93, in 20-50 m water depths, working as early as late May to late December.

In 1992, Amoco Production Co.

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bought all of Gulf Canada's drilling assets, including the Beaudril fleet.

Arco Alaska Inc. used the Kulluk to drill the Kuvlum wells in 1992-93, about 16 miles offshore and 60 miles east of Prudhoe Bay (OGJ, Oct. 11, 1993, p. 27).

In 1993, Seatankers bought the CanMar fleet, including the Kulluk.

Shell Offshore purchased the Kulluk in 2005 and retained Frontier Drilling to supervise its upgrade and refurbishment, which was completed earlier this year. The ship was renovated in place in at the Tuktoiyuk sea buoy, Canada's McKinley Bay, in about 18 statute miles off Northwest Territories. Among the changes:

- New mud and solids control systems, including MI Swaco shakers.
- New choke manifold.
- Upgraded topdrive and iron roughneck.
- New communications system.

Bob Smith, Shell's drilling advisor based in Houston, said that there was very little corrosion or rust, but rubber products, such as hoses and seals, had seriously deteriorated.

The Kulluk's derrick has a catwalk, but no automated pipe-handling equipment. All drill pipe will be run as triples.

In 2006, Shell awarded a contract to Aker Arctic Technology to study and model the feasibility of adding thruster-aided propulsion to the Kulluk. The thruster design shows them installed slightly astem of midship (Fig. 3b).

Shell chose Houston's ThrustMaster of Texas Inc. to build thrusters and hydraulic power units. This was the largest kit ever built by Thrustmaster, supervised by Shell's marine advisor, Suman Muddusetti.

Smith said each thruster weighs about 62 tonnes and measures 62.5 ft by 13.6 ft by 10.1 ft (Fig. 4). They are full azimuth thrusters with shafts that can be rotated out of the water (90° from vertical to horizontal) when not in use. Thrusters enhance the vessel's maneuverability and control, provide the ability to navigate between drillsites, and extend the platform's operability in ice.

The thrusters were transported from Houston through the Panama Canal

Each of the two new thrusters built by ThrustMaster of Texas Inc. for the Kulluk weighs about 62 tonnes (Fig. 4; photo from Thrust Master).

Shell Kulluk platform specifications

Table 2

Radius of main deck	133 ft (40.5 m)
Radius of pump deck	98 ft (29.85 m)
Hull depth	60.69 ft (18.5 m)
Operating water depth	60-600 ft
Max. allowable variable deck load	7,000 tonnes
Power main	Three electric motive diesel engines, each rated at 2,100 kw
Power, emergency	One Cullen Detroit engine, 650 w
Mooring	1,220,000 kt, 20-tonne anchors 12-point system with acoustic quick-release devices on all 12 lines. 12 Hepburn electric single-drum winches, each driven by a GE Model 752-AR motor Band brake holding 415 tonnes
Cranes	Three Liebherr 805/8500 cranes, capacity 65 tonnes at 32-ft radius
Derrick	160 ft high, 40 ft x 40 ft
Drawworks	Ideco E3000, with three GE motors rated at 940 kw each
Top drive	Varco TDS-3
Rotary table	Ideco LR 49549.5 in. (1.257 m)
Risers (two)	600 ft of 21-in. diameter riser with slip joint and ball joints. Another complete 30-in. riser system with pin-connector and ball joints.
Riser tensioners	Four Western Gear tensioners, each 80,000 lb capacity
Drillstring	12,000 ft of 5-in. drill pipe (Grades E, S, and G-105)
Mud pumps	Two Ideco T 1600 triplex pumps
Solids control	Four MI Swaco Mongoose shakers Brandt SR3 desander SE 24 desilter MI Swaco centrifuge MI Swaco mud cleaner Alfa-Laval AX30 mud cooler
Cement pumps	Halliburton cement unit
Pressure control equipment	NL Shaffer 10,000 psi 18¾-in. BOP stack with two annular and four ram type preventers. Also, 15-in. BOP stack (not refurbished)
Storage capacity:	
Casing and drill pipe	1,400 tonnes
KC1 brine	2,012 bbl (319 cu m)
Liquid mud	2,589 bbl
Drill water	4,227 bbl
Bulk cement, barite (13 silos)	21,478 cu ft
Potable water	1,961 bbl
Fuel	9,995 bbl
Accommodation	108 people

The Chouest Nanuq is a new, ice-strengthened barge built in Louisiana for the Beaufort Sea work (Fig. 5; photo from Shell Alaska).

on the M/V Fennica, and installed in Canada in 2007, according to Cody Teff, Shell's drilling superintendent for the Kulluk. He said the Kulluk will winter in Canada, although the location has not been determined.

The Kulluk has quarters for 108 persons.

Icebreaker, support

Good ice management is necessary to enhance station-keeping performance of arctic drilling units, Shell stressed to OGJ. The company has contracted two Russian icebreakers and two Finnish and Swedish-flagged anchor handling-ice management vessels to accompany the two drilling units.

The I/B Kapitan Dranitsyn, owned by the Russian Federation and operated by Murmansk Shipping Co., is the primary icebreaker assigned to the Discoverer drillship. The conventionally propelled ship was built in 1982 at the Wartsila Shipyard in Helsinki, Finland. It was remodeled in 1994, upgraded in 1999 and received a passenger vessel certificate.

The anchor-handling vessel and secondary icebreaker for the Discoverer drillship is the Finnish-flagged Fennica, owned and operated by Finstaship. Built in 1993, the Fennica is 116 m long, 26 m wide, and draws 8.4 m. This vessel has reamers on the hull, which improve turning in ice, break a wider channel, and reduce rolling and midship friction.[2]

The anchor-handling tug supply (AHTS) M/V Vladimir Ignatjuk is the primary icebreaker assigned to the Kulluk platform. The ship is owned by the Russian Federation and operated by Murmansk Shipping Co.

Gulf Canada built this Canadian-designed vessel in 1982 at the Victoria Yard of the Burrard Yarrows Corp. in British Columbia. It was originally named the Arctic Kalvik when it worked in the Beaufort for Gulf Canada. It has an overall length of 88 m, breadth of 17.5 m, draft of 8.3 m, and accommodates 23 crew members. The Vladimir Ignatjuk is classified by Lloyd's Register of Shipping as a 100 A1 icebreaker tug and LMC icebreaking tow, ice class 1A super.

The anchor-handling vessel and secondary icebreaker for the Kulluk is the Norwegian-built AHTS M/V Tor Viking. This KMAR 808 vessel was built in 2001 and is owned and operated by Viking Supply Ships AS, based in Kristiansand, Norway, a wholly owned subsidiary of Kistefos AS. The Tor Viking is 83.7 m long, with a breadth of 18 m, and draft of 6 m.

In addition to the redundant icebreakers that protect the two drilling units, Shell has committed to three other vessels as part of its oil spill response (OSR) system, including the Affinity, an ice strengthened arctic oil tanker; the Arctic Endeavor barge with Point Barrow tug; and the Chouest Nanuq, a new, ice-strengthened resupply vessel.

The Nanuq (Inuvik for polar bear) is operated by Edison Choest Offshore, LLC, based in Pt. Barrow (Fig. 5). It was built by Choest during the past year at North American Shipbuilding in LaRose, La.

Sivulliq prospect

Shell anticipates using both the Frontier Discoverer and the Kulluk to evaluate the Sivulliq prospect in western Camden Bay, off Point Thompson. Sivulliq is in 90-110 ft water depth, about 45 miles east of Cross Island.

Sivulliq was previously called the Hammerhead prospect. The discovery well was drilled in 1985, followed by a confirmation well in 1986. MMS estimated the field contains 100-200 million bbl of oil.[3]

In February 1994, Shell acquired

Amoco Production Co.'s majority interest in the field, reaching a 100% stake (OGJ, May 1, 1995, p. 31).

In February 2007, the MMS approved Shell's plans to drill as many as four wells in the 2007 season, but continued court challenges have postponed drilling. Following a hearing on August 15, the 9th Circuit Court of Appeals granted an emergency stay, suspending Shell's Beaufort operations, in order to consider antidrilling petitions from several litigants, including the Alaska Eskimo Whaling Commission and the San Francisco-based Center for Biological Diversity. The court said there was an issue as to whether the MMS had complied with the 1970 National Environmental Policy Act in granting the offshore leases to Shell.

In early December, the 9th Circuit will review the consolidated petitions and rule on the merits of the suit against the MMS. One possible outcome is lifting the injunction against drilling in the Beaufort.

Despite the setbacks in carrying out the 2007 drilling plans, Shell's Travis Purvis, Alaska well delivery manager, said the company now intends to stay in the arctic for a long time. Alaska has become another "heartland" for Shell; "we're back in Alaska and our intent is to stay," he said. ✦

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Technology, efficiencies keys to resource expansion

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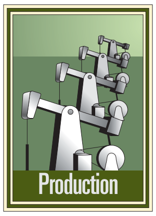


UNCONVENTIONAL GAS—4

At the core of every successful unconventional gas play are two common themes: the continuous search for improvements in technology and the relentless pursuit of cost and operating efficiencies.

These two themes have transformed the previously overlooked uneconomic resources in tight gas sands, coalbed methane, and gas shales into today's largest single source of domestic natural gas production.

The basic process, repeated over and over again, is that one or more new technology concepts lead to breakthroughs that transform the play from a technical curiosity to economic feasibility. Subsequent cost and operating efficiencies then permit aggressive commercial development and the extension of the play to less-favorable reservoir areas.

The evolution of per-well recoveries for unconventional gas plays attests to this cycle of initial technology breakthroughs followed by aggressive cost reductions.

At first, the per-well recoveries are relatively low. Then, they improve as a key technology concept is customized and applied to the particular reservoir properties of the gas play.

In the later, more mature stages of the play, per-well recoveries decline as companies pursue the less favorable reservoir portions of the play. Cost and operating efficiencies (gained during years of experience), however, allow the play to remain economic.

Table 1 presents an example of this technology and per-well performance cycle for two tight gas sand plays in the San Juan basin: the Pictured Cliffs, with 8.7 tcf of cumulative gas production, and the Dakota, with 6.7 tcf of cumulative gas production.

This fourth article in a six-part series on unconventional gas focuses on the importance of maintaining technology progress and further pursuing cost and operating efficiencies for unconventional gas development. The three previous parts in this series were in OGJ issues of Sept. 3, 2007, p. 35; Sept. 17, 2007, p. 64; and Sept. 24, 2007, p. 48,

Technology progress

Fig. 1 captures a number of key themes at the heart of technology progress in unconventional gas.

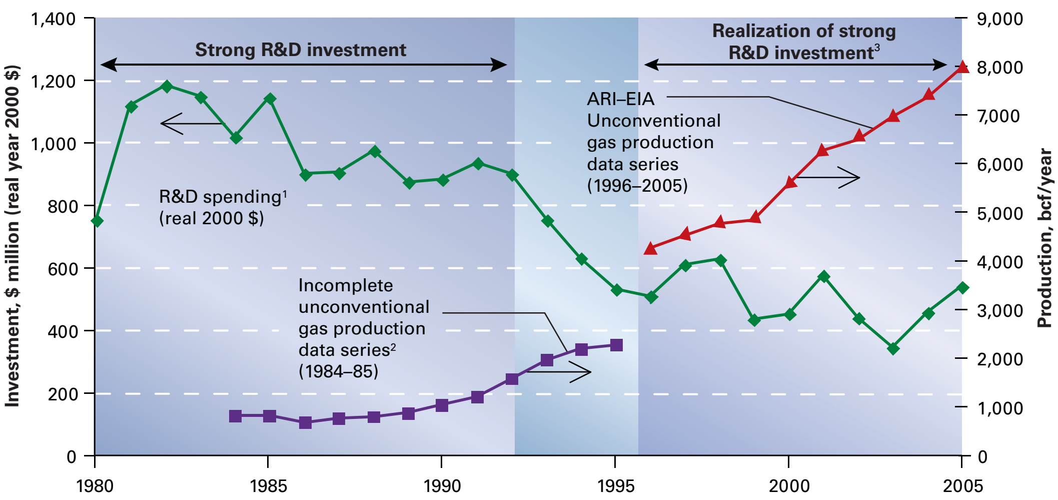
The first theme is the strong industry investment in oil and natural gas recovery research and development (R&D) that occurred during the 1980s and early 1990s. Fig 1 is based on data from 29 major US-based energy producing companies.[1]

Regarding these data, it is important to recognize that because a majority of these companies are multinational, most of this R&D investment was directed overseas to oil development and to deepwater technologies. Still, the trends in the data are instructive.

The recently issued NPC Global Oil and Gas Study puts the technology investment choices into clear perspective for large oil and gas companies:[1 2] "R&D dollars, like capital expenditures, follow the most attractive

R&D INVESTMENT

Fig. 1

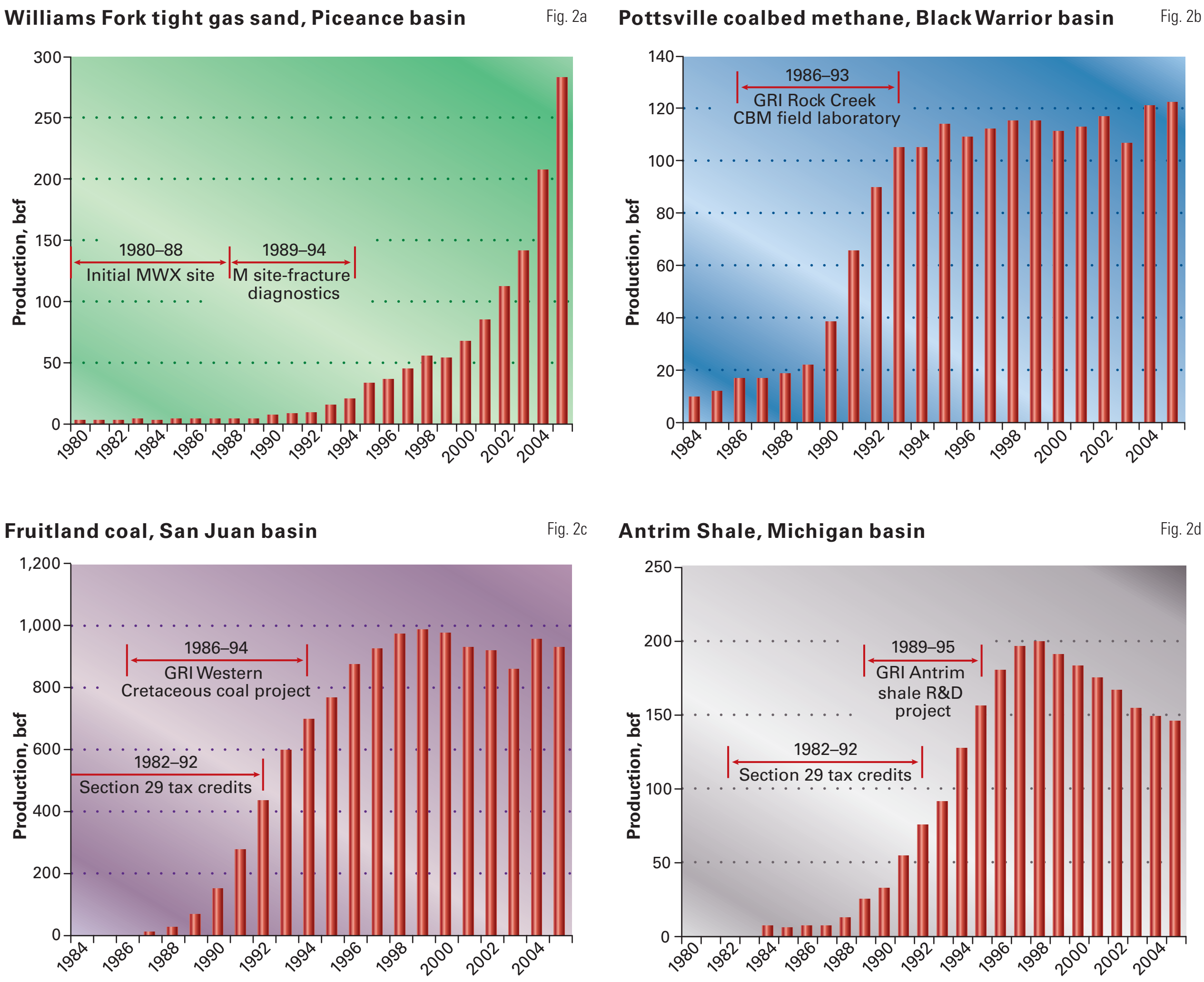


¹Source: EIA, 2007. ²Does not include data from six major unconventional gas basins. ³Assumes 16–year lag from technology concept to widespread commercial adoption, based on referral.

Source: Advanced Resources International

Field R&D, production growth

Fig. 2



opportunities, and these are increasingly found overseas." As such, "the percentage [of the R&D dollar] focused on US-specific needs is relatively small." Even smaller is the percentage of these R&D dollars directed to domestic unconventional gas, a resource that was, in the past, considered marginal by most of these major companies.

Second, an important portion of this post-R&D investment in unconventional gas was stimulated as cost share to key Gas Research Institute (GRI) and US Department of Energy (DOE) projects. These included GRI's Rock Creek multiple coal seams field laboratory in the Warrior basin that established the scientific foundation for coalbed methane and the DOE-GRI sponsored multiwell experiment (MWX) in the Williams Fork formation of the Piceance basin that subsequently provided the foundation for today's hydraulic fracture diagnostic technology and development of stacked tight gas sands.

Technology trends

Table 1

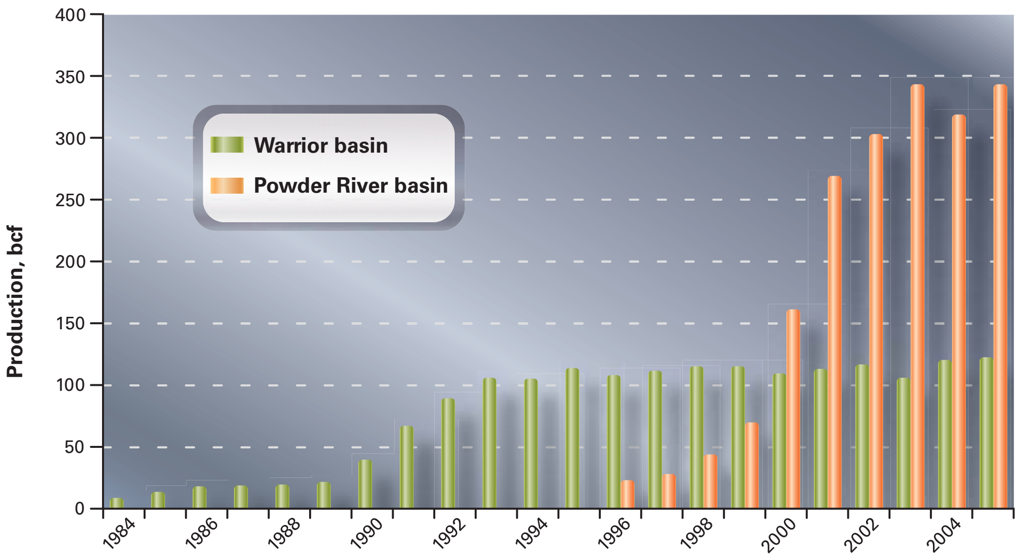
Time period (technology phase)	Pictured Cliffs	Dakota
	—— bcf/well ——	
1980-89 (initial efforts)	0.69	0.89
1990-95 (technology progress)	0.99	1.03
1996-99 (step-out development)	0.83	0.73
2000-05 (operating efficiencies)	0.51	0.58

These field-based R&D efforts were instrumental in building the knowledge base and technology for economically producing coalbed methane and tight gas sands. Large GRI and DOE R&D budgets in the 1980s and early 1990s helped define the technology needs and opportunities (concepts) in unconventional gas and brought down the risks of early technology application.

Third to note is the onset of increasing commercial-scale production of unconventional gas in the late 1990s. The timing of this delayed onset of increasing production reflects a second key technology finding in the recent NPC's Global Oil and Gas Study,[2] "Commercializing technology in the oil and

COALBED METHANE PRODUCTION GROWTH COMPARISON

Fig. 3



gas market is costly and time-consuming; an average of 16 years passes from concept to widespread commercial adaption."

Last is the onset of higher domestic natural gas prices, starting in year 2000, when Henry Hub spot prices consistently exceeded $4/Mcf. These higher prices along with earlier (1982-92) Section 29 tax credits, provided the capital and economic support for applying advanced unconventional gas technology at significant commercial scale.

Noteworthy examples of such technology breakthroughs include the concepts of stimulation through cavitation for the Fruitland coals in the San Juan basin fairway, application of slickwater-fracturing in the Fort Worth basin Barnett shale, and pursuit of low-resistivity tight gas sand pay in the Jonah and Pinedale fields in the Greater Green River basin.

Numerous examples demonstrate how field-based R&D efforts also can have an important impact on the pace of unconventional gas development. These examples include GRI's Rock Creek multiple coal seams completion project in the Black Warrior basin, GRI's Western Cretaceous coal seams project in the San Juan basin, GRI's Antrim Shale R&D program in the Michigan basin, and GRI's highly instrumental test well in the Barnett shale of the Fort Worth basin.

While these field-based R&D efforts helped build the base of science, they were most valuable in accelerating the commercial development of these four unconventional gas plays (Figs. 2a-2d).

A common noteworthy trait shared by each of these successful field R&D programs was the close partnership between an outside R&D team, a team with considerable independent financial resources and technical expertise, and one or more local operating companies to ensure that the R&D was focused on topics that had practical, value-adding impacts.

In our view, either party in isolation would not have achieved the same level of success in the same time frame. An R&D team, however well funded, could not produce the same results without the active involvement of field operators. By the same token, an operator (with limited R&D resources) likely would not have taken the risks of independently pursuing, rigorously evaluating, and then aggressively applying new, unproven technology concepts.

This brings us to an important, overall realization with respect to technology development partnerships—they help define and validate technology concepts and then help accelerate the pace of technology adaptation and application of these concepts to the basin-specific needs of each unconventional gas play.

Left to their own scientific interests and needs, operators would eventually define and validate the technologies required to unlock an unconventional play and then adapt this technology to their local reservoir settings. The issue is—with benefit of an R&D partner and pooling of industrial expertise, how much more quickly would this process evolve?

An empirical look at the growth in two pairs of plays, the Warrior and Powder River basin coalbed methane plays (Fig. 3), and the Antrim and Barnett gas shale plays (Fig. 4), helps answer this question.

In both cases, the former, less-prolific play received considerable field R&D attention and as a result achieved accelerated commercial-scale gas production. The latter plays, despite ultimately proving to possess superior productive and commercial qualities, took much longer to attain the same levels of gas production.

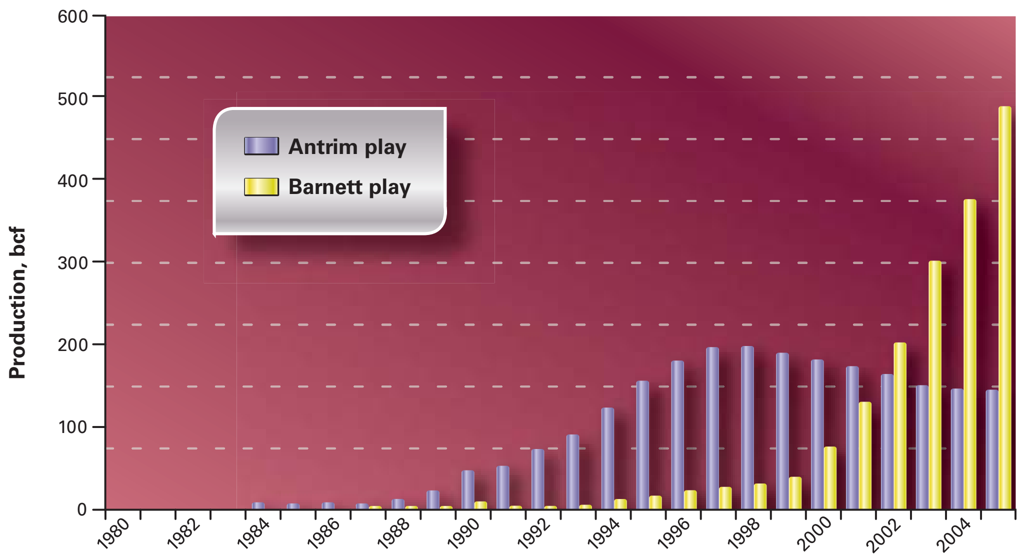
In the coalbed methane case, with the benefit of a strong GRI-sponsored field R&D program, the Warrior basin CBM production increased to 50+ bcf/year in 1991. In contrast, the more prolific Powder River basin play, even with the benefit of previously developed CBM science but without the benefit of a strong field-based R&D program, did not attain that production until 2000.

Similarly, the Antrim shale produced 50+ bcf/year in 1991, while the more prolific Barnett shale did not produce that much until 2000.

Thus based upon this anecdotal evidence, once a technology concept is shown to be valid, field-based R&D efforts can accelerate application of this technology to commercial levels by as much as a decade.

Gas shale production growth comparison

Fig. 4

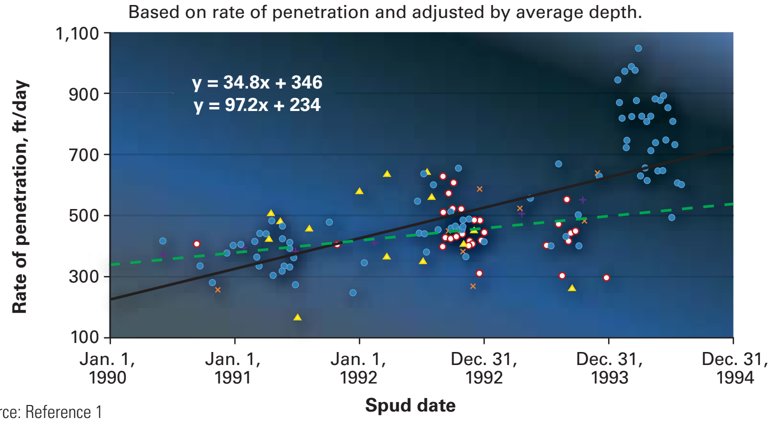


Improved rates of penetration

Fig. 5

Moxa arch learning curve, Dakota sand, Greater Green River basin

Note: Data points for comparable wells drilled in the area.
Based on rate of penetration and adjusted by average depth.



Source: Reference 1

Pursuing efficiencies

The concept of cost operating efficiency gains in unconventional gas development is well established. Examples include the 24 hr/day, 7 days/week frac-factory concept being implemented by Shell Exploration & Production Co. and Ultra Petroleum Corp. in selected tight gas sand plays in the Rocky Mountains; Southwestern Energy Inc.'s assembly of a customized drilling fleet for horizontal wells in the Fayetteville shale; and, the assembly-line process being implemented for drilling and completing Powder River basin coalbed methane wells.

Cost and operating efficiency gains are perhaps best illustrated by improvements in drilling penetration rates for a play over time. Fig. 5 illustrates this trend for drilling wells to the Dakota sand at the Moxa Arch of the Greater Green River basin during the 1990s. While the public domain lacks data that would rigorously document similar trends of learning and cost reductions for other areas of unconventional gas technology, such as hydraulic fracturing, their existence and importance nevertheless exist.

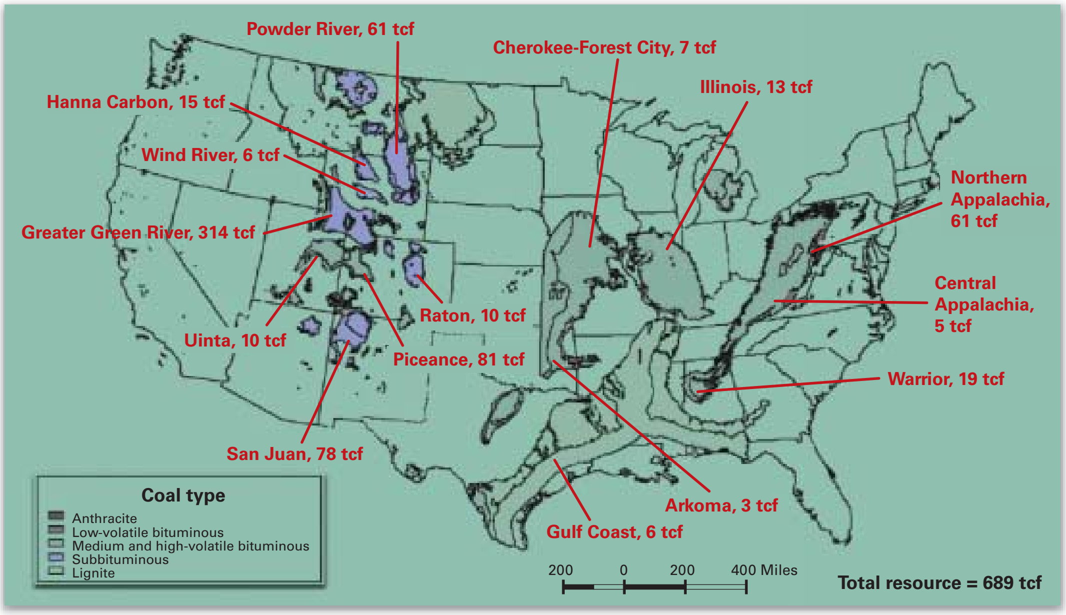
In today's economic environment of rapidly rising service and supply costs, it may not be possible to achieve absolute cost reductions via operating efficiencies. This does not mean, however, that companies are not realizing such gains. It means that costs are increasing faster than gains in efficiency.

This situation is unsustainable. At some point operational efficiencies need to again outpace increases in service and supply costs or a significant number of the unconventional gas plays will become prematurely uneconomic.

An important question is—who are the R&D entities that will develop the new concepts and help facilitate technology progress in unconventional gas in the timeframe required to meet rising demand for natural gas? DOE and GRI, the two organizations that funded prior publicly accessible R&D in unconventional gas, now lack fund-

US COALBED METHANE BASINS

Fig. 6



Source: Reference 2

ing. Private-sector funding for supply related oil and gas recovery has declined by two-thirds (in real dollars)[1] from its peak in the early 1980s to 2003, although an increase is noted in the past 2 years (Fig. 1).

Many companies that once had large R&D programs have either disbanded them or the companies disappeared as a result of mergers and acquisitions. Many of these internal groups that remain have been retooled into technical service providers, primarily in support of large-scale international operations.[3]

Fortunately, the Energy Policy Act of 2005 establishes funding for unconventional gas R&D at $14 million/year for the next 10 years, out of an annual R&D allocation of $50 million. While a valuable first step, given the host of technical issues to be addressed and the increasing contribution being made by unconventional gas (now producing nearly 24 bcfd) a more robust R&D program would deliver higher value.

The organization selected to oversee and manage this R&D is the Research Partnership to Secure Energy for America (RPSEA), a nonprofit corporation formed by a consortium of US energy research universities, industry, and independent research organizations. In the area of unconventional gas, RPSEA's goals are to:

• Increase the size of the technically recoverable unconventional gas resource base by 30 tcf.

• Convert 10 tcf of technically recoverable unconventional gas to economically recoverable gas.

• Pursue technologies for developing unconventional resources with minimum environmental impact.

• Emphasize science-building capacity and effective technology dissemination.

Technologies on horizon

As presented in the previous article, a significant marginally economic and uneconomic resource base exists for unconventional gas. The new and emerging unconventional gas plays that will require next-generation technology will likely include, among others:

• The deep poorly defined Upper Cretaceous (Mesaverde) tight gas sand plays in the Big Horn, Columbia, and Unita basins.

• The deep coals of the Greater Green River and Piceance basins, containing an estimated 400+ tcf of in-place resources; and the Tertiary coals of the Gulf Coast (Fig. 6).

• The Rocky Mountain gas shales along the Cretaceous-age seaway that stretches from the San Juan basin in the south to the Big Horn basin in the north, involving the Lewis, Mancos, Steele, and Cody shales.[4]

The technologies required to tap these currently undeveloped unconventional gas resources, in the authors' view, based on discussions with unconventional gas developers includes:

• Sweet-spot detection technologies that identify in advance the location of highly productive, naturally fractured fairways where the small-scale fracture system is open.

• Reservoir characterization methods that reliably identify the entire productive pay interval.

• Advanced well stimulation alternatives economically applicable to the low end of reservoir quality.

• Enhanced-recovery technology that uses carbon dioxide or nitrogen injection to accelerate and increase gas recovery from coals, shales, and possibly tight sands.[5]

With a vast untapped unconventional gas resource base, a strong demand for natural gas, a resourceful industry willing to explore and develop new unconventional plays, and an R&D organization willing to assist in technology development, many of the prerequisites for a second era of successful unconventional gas technology development are in-place.

What is now required is an appropriate level of human and capital investment to both create new unconventional gas technology concepts and then help accelerate their adaptation and widespread commercial application. ✦

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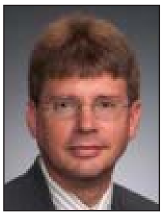
The authors



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Vello A. Kuuskraa's photo and biographical information appeared in Part 1 of this series (OGJ, Sept. 3, 2007, p. 35).

Clean fuels requirements increase catalyst demand

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Survey Editor

David Nakamura
Refining/Petrochemical Editor

Requirements for cleaner fuels, rising demand for refined products, and the need to meet more stringent environmental regulations continue to increase demand for refining catalysts.

As refinery utilization has increased, refiners have demanded longer-life catalysts that extend run lengths between turnarounds of key process units. New-generation reforming catalysts are achieving significantly longer cycles for high-severity operations.

Refiners are also demanding higher-severity hydrotreating catalysts to produce diesel that complies with new low-sulfur regulations.

"The future of the refining industry will be characterized by a substantial increase in crude and hydroprocessing capacity to meet the growing demand for clean fuels," according to UOP LLC Pres. and CEO Carlos A. Cabrera.

Worldwide catalyst demand in the oil and gas industry will reach $12.3 billion in 2010, according to a Freedonia Group study "World Catalysts to 2010." The growing demand for chemical, polymer, and refining catalysts is due to the need for more energy-efficient processes and products.

A different study, "Catalysts for Environmental and Energy Applications," from BCC Research, estimated that the global market for these catalysts was worth $12.2 billion in 2006. The study projected the catalyst market to grow to $13.0 billion in 2007 and $18.5 billion in 2012 for growth of 7.4%/year during 2007-12.

For the energy segment alone, of which 90% employ refining catalysts, the market will increase to nearly $5.0 billion in 2012 from about $3.2 billion in 2006, according to the BCC study. The study predicted that refining catalysts would lose market share because "other energy applications, particularly synfuels and biofuels, [will] consume increasing amounts of catalysts."

This article details some notable developments since the last catalyst survey (OGJ, Oct. 17, 2005, p. 50). Major events include two acquisitions, a hydroprocessing alliance, many new catalyst formulations in the market, and expansions to catalyst production capacity.

The complete list of catalyst suppliers and their current formulations can be found exclusively in the Refining Catalyst Compilation—2007 at www.ogjonline.com.

Divestitures, mergers

In June 2006, BASF AG acquired Engelhard Corp. and shortly after renamed it BASF Catalysts LLC. BASF first announced it was taking over the company in January 2006. It finally completed the acquisition after many months of negotiations.

"This rebranding signifies a key milestone in the integration process as it brings together BASF's brand strength and Engelhard's strong reputation for innovation and quality," according to Klaus Peter Lobbe, BASF Board member responsible for North America.

On Mar. 9, 2006, UOP LLC and Albemarle Corp. announced that they were forming a hydroprocessing alliance. The alliance, which also includes Albemar-


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OGJ subscribers can download free of charge the 2007 OGJ international refining catalyst compilation via Oil & Gas Journal's web site at www.ogjonline.com by clicking on the Resource Center tab, surveys, OGJ subscriber surveys, catalyst compilation, then logging in with user name and password.

le's joint venture Nippon Ketjen, will offer hydroprocessing technologies, catalysts, and services to help refiners meet projected increased demand for refined products and ultralow-sulfur fuels.

The alliance will specifically provide process and catalyst technologies for middle distillate hydrotreating, vacuum gas oil hydrotreating, mild hydrocracking, hydrocracking, and fixed-bed residue hydrotreating.

On Oct. 27, 2006, Sud-Chemie AG, Munich, announced that it was acquiring catalyst manufacturer Tricat Zeolites GMBH, Bitterfeld, Germany. No purchase prices was disclosed.

Zeolite catalysts help refiners manufacture high-octane gasoline, cold-resistant diesel, and high-grade intermediates used in plastics manufacturing. In the future, zeolite catalysts will also be used to produce propylene from natural gas instead of from crude, according to Sud-Chemie.

"This transaction enables us to satisfy the increasing needs of our customers for tailor-made zeolite catalysts," said Hans Jürgen Wernicke, member of Sud-Chemie's managing board. "Tricat Zeolites will become the Sud-Chemie Group's second major foothold for zeolite production, together with Süd-Chemie Zeolites in Richards Bay, South Africa."

Capacity expansions

On May 15, 2007, BASF announced it will expand the capacity of two FCC catalyst production plants in Savannah and Attapulgus, Georgia, to meet growing demand of petroleum refiners. The company estimated that worldwide demand for FCC catalysts will grow 2-4%/year during the next 10 years.

The planned capacity expansions will be operational in 2008.

The expansions will help BASF continue to create FCC catalysts with its distributed matrix structures technology, which allows BASF to develop catalysts with better yield performance.

Catalysts made with the DMS technology feature a structure combining optimized porosity with high activity. Petroleum feeds diffuse more effectively and precrack more efficiently on DMS catalysts than on traditional amorphous matrix FCC catalysts. This allows for high bottoms conversion with low coke, and higher yields of valued gasoline and other liquid products, according to the company.

On June 1, 2006, Albemarle announced that it broke ground on a new 10,000-tonne/year hydroprocessing catalyst production plant at its Bayport facility, Pasadena, Tex., and set the plant to begin production in first-quarter 2007.

"Refiner demand for our HPC products...is outpacing our current capacities, thus driving the need to increase capacities at our Bayport and Amsterdam plants, as well as the plant of our joint venture, Nippon Ketjen, in Niihama, Japan," said Huub Cuijpers, Albemarle HPC global business director.

"The capacity increase at Bayport is the most substantial of the three expansions, and is needed first and foremost to help meet rapidly building demand for our products in the Americas."

The company said it would also add a specialized production line at its Amsterdam plant; debottleneck its Bayport and Amsterdam plants; and make additional investments in its laboratories. The company is also considering a third debottlenecking project for Niihama.

New technology

On June 20, 2007, Albemarle and its partners ABB Lummus Global and Neste Oil announced that they had developed and tested a new higher-performance solid acid catalyst for the AlkyClean solid acid alkylation process.

According to Albemarle, the AlkyStar catalyst features 25% higher activity and 35% lower precious metal content than previous AlkyClean alkylation catalysts. It is based on a new zeolite concept.

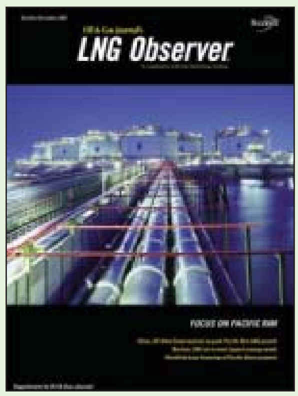
With the solid-acid alkylation process, no acid-soluble oils or spent acids

LNG Observer focuses on Pacific Basin

With this Oct. 1, 2007, issue of Oil & Gas Journal, many print subscribers are also receiving a copy of OGJ's quarterly supplement ***LNG Observer***. The fourth-quarter 2007 LNGO will also be available electronically at www.lngobserver.com after Oct. 5, 2007.

Produced with the widely respected GTI, Des Plaines, Ill., OGJ's ***LNG Observer*** aims at anyone interested or involved in the natural gas and LNG business. The final issue of 2007 devotes its main section, Issues, Trends, Technologies, to an examination of major issues in the industry's Pacific Basin markets.

If you are an OGJ print subscriber and would like also to receive a print copy of ***LNG Observer*** beginning with your Jan. 7, 2008, issue of OGJ, please write to OGJsub@pennwell.com to be added to the list.



are produced, and there is no need for product posttreatment.

On Apr. 4, 2006, UOP announced that its new R-98 catalyst increased gasoline production yields in its first commercial application. Hunt Refining Co., using the new catalyst in a fixed-bed platforming unit at its Tuscaloosa, Ala., refinery, has increased C_{5+} gasoline yields since using the catalyst in 2005.

Although the R-98 catalyst was developed for fixed-bed platforming units, the company expects it to perform equally well in other reforming units.

"The R-98 catalyst has improved our reformate yield from hydrotreated coker naphtha by about 2 vol %," said Steve Jackson, Hunt Refining Co.'s vice-president of refining and transportation.

The R-98 catalyst is currently operating in its second cycle at the Hunt refinery with similar activity and gasoline yields in both cycles, according to UOP.

The catalyst contains a proprietary promoter to boost yields compared to other commercially available catalysts. It is fully regenerable under typical regeneration procedures provided by UOP, resulting in multiple cycles of similar cycle length.

On Feb. 6, 2006, Albemarle and Fabrica Carioca de Catalisadores SA (FCC SA), a joint venture of Albemarle and Petroleos Brasileiro SA (Petrobras), announced a new family of FCC catalysts. The ReVolution family of FCC catalysts will help refiners process lower-quality crudes more efficiently due to the catalysts' ability to trap vanadium, according to the companies.

On Jan. 12, 2006, Haldor Topsoe announced that it had developed a new catalyst preparation technology that leads to highly active hydroprocessing catalysts. The new BRIM technology optimizes the brim site hydrogenation functionality and also increases the Type II activity sites for direct desulfurization.

Topsoe introduced two new nickel-molybdenum (NiMo) products based on the BRIM technology. TK-575 BRIM is a NiMo catalyst optimized for the high-pressure ultralow-sulfur diesel market, and TK-605 BRIM is a NiMo catalyst optimized for the high-performance hydrocracker pretreatment market.

At yearend 2005, Albemarle announced development and commercialization of a new FCC catalyst technology with its ADZT-100 zeolite. It also announced its new ACTION family of FCC catalysts, which is based on the ADZT-100 zeolite.

"This technology can be used by refiners to maximize the total volume of transportation fuels and other feedstocks they produce, maximize the octane of their gasoline, or some combination of the two," said Harm Scheepstra, Albemarle's FCC global business director. ✦

Nelson-Farrar cost indexes

Refinery construction (1946 Basis)
(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2004	2005	2006	June 2006	May 2007	June 2007
Pumps, compressors, etc.	222.5	777.3	1,581.5	1,685.5	1,758.2	1,751.1	1,840.8	1,846.5
Electrical machinery	189.5	394.7	516.9	513.6	520.2	522.3	515.0	517.7
Internal-comb. engines	183.4	512.6	919.4	931.1	959.7	958.8	973.9	973.9
Instruments	214.8	587.3	1,087.6	1,108.0	1,166.0	1,156.9	1,261.3	1,267.5
Heat exchangers	183.6	618.7	863.8	1,072.3	1,162.7	1,179.4	1,374.7	1,374.7
Misc. equip. average	198.8	578.1	993.8	1,062.1	1,113.3	1,113.7	1,193.1	1,196.1
Materials component	205.9	629.2	1,112.7	1,179.8	1,273.5	1,289.1	1,385.5	1,507.0
Labor component	258.8	951.9	2,314.2	2,411.6	2,497.8	2,479.3	2,576.2	2,593.6
Refinery (Inflation) Index	237.6	822.8	1,833.6	1,918.8	2,008.1	2,003.2	2,099.9	2,159.0

Refinery operating (1956 Basis)
(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2004	2005	2006	June 2006	May 2007	June 2007
Fuel cost	100.9	810.5	971.9	1,360.2	1,569.0	1,583.8	1,627.5	1,611.4
Labor cost	93.9	200.5	191.8	201.9	204.2	191.5	216.5	216.8
Wages	123.9	439.9	984.0	1,007.4	1,015.4	990.4	1,047.3	1,027.5
Productivity	131.8	226.3	513.3	501.1	497.5	517.0	483.7	474.0
Invest., maint., etc.	121.7	324.8	686.7	716.0	743.7	741.9	774.9	796.7
Chemical costs	96.7	229.2	268.2	310.5	365.4	372.2	380.9	390.2
Operating indexes								
Refinery	103.7	312.7	486.7	542.1	579.0	575.3	604.0	613.1
*Process units**	103.6	457.5	638.1	787.2	870.7	871.5	905.8	907.9

**Add separate index(es) for chemicals, if any are used. See current Quarterly Costimating, first issue, months of January, April, July, and October.*

These indexes are published in the first issue of each month. They are compiled by Gary Farrar, Journal Contributing Editor.

Indexes of selected individual items of equipment and materials are also published on the Costimating page in the first issue of the months of January, April, July, and October.

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Changes in indexes for nonmetallic building materials

Gary Farrar
Contributing Editor

Indexes for selected construction materials

Year, quarter	Non-metallic	Building brick	Fireclay brick	Iron castings	Clay products	Concrete ingred.	Concrete products
2004							
1st	810.1	1,204.8	1,342.4	1,151.3	839.4	888.7	745.3
2nd	818.7	1,199.7	1,355.9	1,178.6	836.2	903.7	751.0
3rd	831.7	1,229.7	1,357.6	1,199.3	850.8	916.5	765.2
4th	843.0	1,229.0	1,378.7	1,240.7	849.1	924.5	786.1
Year	**825.9**	**1,215.8**	**1,358.6**	**1,192.5**	**843.5**	**908.3**	**761.9**
2005							
1st	864.0	1,284.6	1,410.7	1,282.2	880.5	957.0	818.3
2nd	875.4	1,294.2	1,445.3	1,294.6	891.8	974.6	829.6
3rd	892.6	1,305.1	1,452.9	1,287.9	894.5	1,001.2	847.6
4th	913.6	1,322.7	1,455.4	1,295.4	908.5	1,009.2	869.9
Year	**886.4**	**1,301.7**	**1,441.1**	**1,290.0**	**893.8**	**985.5**	**841.3**
2006							
1st	941.2	1,376.9	1,516.2	1,332.7	937.1	1,061.0	891.7
2nd	967.6	1,409.1	1,544.9	1,344.3	950.1	1,084.9	921.0
3rd	984.8	1,415.0	1,547.4	1,357.5	956.0	1,106.3	934.7
4th	984.8	1,433.3	1,553.3	1,370.8	963.1	1,115.9	937.1
Year	**969.6**	**1,408.6**	**1,540.5**	**1,351.3**	**951.6**	**1,092.0**	**921.1**

The accompanying table shows how Nelson-Farrar indexes have changed during 2004-06 for selected basically nonmetallic building materials.

Data are included for the overall nonmetallic group, five nonmetallic materials, and iron castings.

Building brick and concrete ingredients indexes showed the greatest changes during the period.

Building brick, showing the greatest gains of the two, changed to 1,433.3 in the fourth quarter of 2006 from 1,199.7 in the second quarter of 2004. Concrete ingredients changed to 1,115.9 in the fourth quarter from 888.7 in the first quarter of the period tested.

Fireclay brick, iron castings, and concrete products showed more moderate changes, although none of the changes in the indexes was drastic. The fireclay brick index rose to 1,553.3 from 1,342.4 during the 3-year period. Concrete products changed to 937.1 from 745.3. During the same period iron castings changed to 1,370.8 from 1,151.3.

The smallest index change occurred in the clay products category, changing to 963.1 in fourth quarter 2006 from 839.4 in the first quarter of 2004.

The final category, the overall nonmetallic index, changed to a high of 984.8 during fourth quarter 2006 from 810.1. ✦

Itemized refining cost indexes

The cost indexes may be used to convert prices at any date to prices at other dates by ratios to the cost indexes of the same date. Item indexes are published each quarter (first week issue of January, April, July, and October). In addition the Nelson Construction and Operating Cost Indexes are published in the first issue of each month of Oil and Gas Journal.

Operating cost (based on 1956 = 100.0):	1954	1972	2004	2005	2006	May 2007	*References	Index for earlier year in Costimating and Questions on Technology issues
Power, industrial electrical	98.5	131.2	727.9	771.3	850.2	887.1	Code 0543	No. 13, May 19, 1958
Fuel, refinery price	85.5	152.0	944.5	1,288.9	1,523.6	1,548.9	OGJ	No. 4, Mar. 17, 1958
Gulf cargoes	85.0	130.4	1,250.7	1,635.4	2,023.9	1,905.7	OGJ	No. 4, Mar. 17, 1958
NY barges	82.6	169.6	1,130.7	1,539.6	1,837.5	1,937.2	OGJ	No. 4, Mar. 17, 1958
Chicago low sulfur	—	—	1,478.4	1,478.4	1,765.8	1,904.4	OGJ	July 7, 1975
Western US	84.3	168.1	1,427.7	1,941.5	2,358.1	2,502.5	OGJ	No. 4, Mar. 17, 1958
Central US	60.2	128.1	953.8	1,274.0	1,765.9	2,025.5	OGJ	No. 4, Mar. 17, 1958
Natural gas at wellhead	83.5	190.3	5,322.0	7,010.6	6,306.5	6,423.9	Code 531-10-1	No. 4, Mar. 17, 1958
Inorganic chemicals	96.0	123.1	504.9	562.9	686.8	725.8	Code 613	Oct. 5, 1964
Acid, hydrofluoric	95.5	144.4	414.9	414.9	414.9	414.9	Code 613-0222	Apr. 3, 1963
Acid, sulfuric	100.0	140.7	397.4	397.4	397.4	397.4	Code 613-0281	No. 94, May 15, 1961
Platinum	92.9	121.1	762.1	819.3	1,344.5	1,621.1	Code 1022-02-73	July 5, 1965, p. 117
Sodium carbonate	90.9	119.4	310.3	357.3	452.4	479.1	Code 613-01-03	No. 58, Oct. 12, 1959
Sodium hydroxide	95.5	136.2	529.6	529.6	620.1	656.6	Code 613-01-04	No. 94, May 15, 1961
Sodium phosphate	97.4	107.0	733.7	733.7	733.7	733.7	Code 613-0267	No. 58, Oct. 12, 1959
Organic chemicals	100.0	87.4	587.9	666.5	764.5	790.4	Code 614	Oct. 5, 1964
Furfural	94.5	137.5	848.1	961.9	1,103.1	1,140.8	Chemical Marketing Reporter	No. 58, Oct. 12, 1959
MEK, tank-car lots	82.6	87.5	408.3	625.0	625.0	625.0	Reporter	
Phenol	90.4	47.1	339.1	411.3	374.9	416.9	Code 614-0241	No. 58, Oct. 12, 1959

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Itemized refining cost indexes

Operating cost (based on 1956 = 100.0):	1954	1972	2004	2005	2006	May 2007	*References	Index for earlier year in Costimating and Questions on Technology issues
Operating labor cost (1956 = 100)								
Wages & benefits	88.7	210.0	984.0	1,007.0	1,015.4	1,047.3	Employ & Earn	No. 41, Feb. 16, 1969
Productivity	97.2	197.0	513.3	501.1	497.5	483.7	Employ & Earn	No. 41, Feb. 16, 1969
Construction labor cost (1946 = 100)								
Skilled const.	174.6	499.9	2,077.2	2,170.8	2,240.7	2,318.3	Eng. News Record	No. 55, Nov. 3, 1949
Common labor	192.1	630.6	2,747.1	2,863.5	2,971.7	3,055.2	Eng. News Record	No. 55, Nov. 3, 1949
Refinery cost	183.3	545.9	2,314.2	2,411.6	2,497.8	2,576.2	OGJ	May 15, 1967
Equipment or materials (1946 = 100):								
Bubble tray	161.4	324.4	1,329.6	1,409.4	1,484.0	1,579.0	Computed	July 8, 1962, p. 113
Building materials (nonmetallic)	143.6	212.4	825.9	886.4	969.6	1,004.3	Code 13	No. 61, Dec. 15, 1949
Brick—building	144.7	252.5	1,215.8	1,301.7	1,408.6	1,428.9	Code 1342	No. 20, Mar. 3, 1949
Brick—fireclay	193.1	322.8	1,358.6	1,441.1	1,540.5	1,608.2	Code 135	May 30, 1955
Castings, iron	188.1	274.9	1,192.5	1,290.0	1,351.3	1,427.9	Code 1015	Apr. 1, 1963
Clay products (structural, etc.)	159.1	342.0	843.9	893.8	951.6	964.1	Code 134	No. 20, Mar. 3, 1949
Concrete ingredients	141.1	218.4	908.3	985.5	1,092.0	1,174.0	Code 132	No. 22, March 17, 1949
Concrete products	138.5	199.6	761.9	841.3	921.1	961.7	Code 133	Oct. 2, 1967, p. 112
Electrical machinery	159.9	216.3	516.9	513.6	520.2	515.0	Code 117	May 2, 1955
Motors and generators	157.7	211.0	796.8	839.2	880.3	911.6	Code 1173	May 2, 1955
Switchgear	171.2	271.0	1,045.9	1,090.0	1,147.3	1,227.0	Code 1175	May 2, 1955
Transformers	161.9	149.3	486.0	537.1	612.5	696.9	Code 1174	No. 31, May 19, 1949
Engines (combustion)	150.5	233.3	919.4	931.1	959.7	973.9	Code 1194	No. 36, June 23, 1949
Exchangers (composite)	171.7	274.3	863.8	1,072.3	1,162.7	1,374.7	Manufacturer	Mar. 16, 1964
Copper base	190.7	266.7	816.2	992.1	1,059.4	1,241.9	Manufacturer	Mar. 16, 1964
Carbon steel	156.8	281.9	866.1	1,080.2	1,162.1	1,396.5	Manufacturer	Mar. 16, 1964
Stainless steel (304)	—	—	914.3	1,119.3	1,174.8	1,365.0	Manufacturer	July 1, 1991
Fractionating towers	151.0	278.5	1,065.1	1,157.2	1,207.2	1,276.6	Computed	June 8, 1963, p. 133
Hand tools	173.8	346.5	1,651.7	1,722.1	1,792.5	1,831.3	Code 1042	June 27, 1955
Instruments (composite)	154.6	328.4	1,087.6	1,108.0	1,166.0	1,261.3	Computed	No. 34, June 9, 1949
Insulation (composite)	198.5	272.4	2,230.4	2,228.6	2,257.4	2,268.3	Manufacturer	July 4, 1988, p. 193
Lumber (composite):	197.8	353.4	1,417.9	1,359.6	1,309.8	1,214.6	Code 81	No. 7, Dec. 2, 1948
Southern pine	181.2	303.9	1,040.7	998.6	984.3	856.2	Code 81102	No. 7, Dec. 2, 1948
Redwood, all heart	238.0	310.6	2,145.1	2,057.9	1,948.1	1,765.3	Code 811-0332	July 5, 1965, p. 117
Machinery								
General purpose	159.9	278.5	1,106.7	1,163.6	1,213.7	1,265.6	Code 114	Feb. 17, 1949
Construction	165.9	324.4	1,407.3	1,499.2	1,559.7	1,589.7	Code 112	Apr. 1, 1968, p. 184
Oil field	161.9	269.1	1,333.0	1,454.8	1,599.1	1,706.3	Code 1191	Oct. 10, 1955
Paints—prepared	159.0	231.8	907.4	975.3	1,040.8	1,082.9	Code 621	May 16, 1955
Pipe								
Gray iron pressure	195.0	346.9	2,301.2	2,580.2	2,687.9	2,706.3	Code 1015-0239	Jan. 3, 1983
Standard carbon	182.7	319.9	1,900.0	2,217.3	2,306.9	2,298.2	Code 1017-0611	Jan. 3, 1983
Pumps, compressors, etc.	166.5	337.5	1,581.5	1,685.5	1,758.2	1,840.8	Code 1141	No. 29, May 5, 1949
Steel-mill products	187.1	330.6	1,300.6	1,409.1	1,527.5	1,689.3	Code 1017	Jan. 3, 1983
Alloy bars	198.7	349.4	1,050.1	1,146.8	1,311.8	1,266.4	Code 1017-0831	Apr. 1, 1963
Cold-rolled sheets	187.0	365.5	1,278.4	1,462.5	1,658.4	2,075.6	Code 1017-0711	Jan. 3, 1983
Alloy sheets	177.0	225.9	665.0	760.3	862.4	1,079.2	Code 1017-0733	Jan. 3, 1983
Stainless strip	169.0	221.2	710.0	811.6	920.7	1,152.2	Code 1017-0755	Jan. 3, 1983
Structural carbon, plates	193.4	386.7	1,493.7	1,654.5	1,766.6	2,019.2	Code 1017-0400	Jan. 3, 1983
Welded carbon tubing	180.0	265.5	1,925.0	2,246.8	2,337.3	2,328.9	Code 1017-0622	Jan. 3, 1983
Tanks and pressure vessels	147.3	246.4	868.7	974.4	1,014.3	1,076.6	Code 1072	No. 5, Nov. 18, 1949
Tube stills	123.0	125.3	503.5	540.5	579.9	629.0	Computed	Oct. 1, 1962
Valves and fittings	197.0	350.9	1,660.6	1,738.2	1,839.6	1,930.8	Code 1149	No. 46, Sept. 1, 1940
Nelson-Farrar Refinery (Inflation Index)								
(1946)	179.8	438.5	1,833.6	1,918.8	2,008.1	2,099.9	OGJ	May 15, 1969
Nelson-Farrar Refinery Operation								
(1956)	88.7	118.5	486.7	542.1	579.0	604.0	OGJ	No. 2, Mar. 3, 1958
Nelson-Farrar Refinery Process								
(1956)	88.4	147.0	638.1	787.2	870.7	905.8	OGJ	No. 2, Mar. 3, 1958

*Code refers to the index number of the Bureau of Statistics, US Department of Labor, "Wholesale Prices" Itemized Cost Indexes, Oil & Gas Journal.

LNG TRADE—1

Domestic gas statistics shape LNG policies

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Looking closely at prevailing natural gas statistics for production, consumption, net export capability, and proved reserves of each country provides insight into how various countries' natural gas industries are evolving relative to each other and why.

These statistics also help to identify and explain the strategies being pursued by governments and national oil and gas companies in countries where the NOCs control their national industries. This first of two articles concentrates on analysis of these statistics.

Reviewing gas and LNG spark spreads in relation to electricity prices and competing fuels provides insight into the main gas consuming countries. The second, concluding article (next week) will focus on recent spark spreads in selected gas markets and what they reveal about existing and future LNG and gas strategies in those markets.

Statistical framework

Figs. 1 and 2 show the ratio of natural gas production to domestic consumption (P:C, exporters have a P:C ratio greater than 1) for key countries vs. their net natural gas export position (E–I, exports minus imports; a negative number for net importers and a positive number for net exporters). The bubble size for each country is proportional to its proven natural gas reserves.

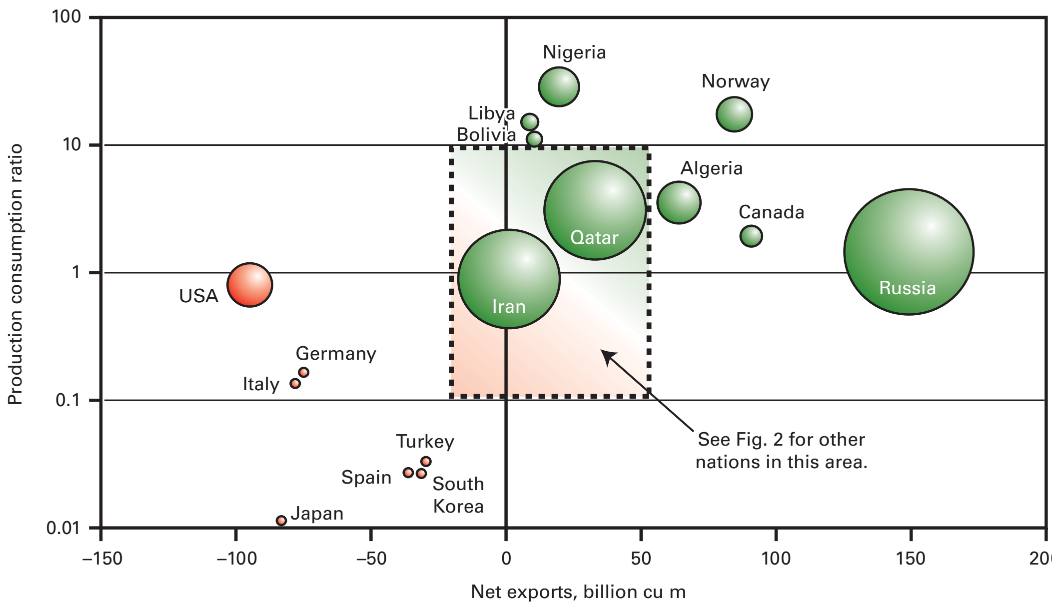
Fig. 1 highlights the countries with extreme positions, while Fig. 2 focuses on those lying closer to the origin or central region of the distribution (the vicinity of P:C = 1 and E–I = 0).

These graphs show a significant spread of positions, with the main gas importers trending broadly towards the lower left and the main gas exporters trending broadly towards the upper right. Some anomalies highlighted by these graphs, however, suggest certain countries are following gas strategies inconsistent with their proved reserves holdings. These anomalous countries, in most cases, allow politics to drive natural gas developments.

The P:C vs. E–I graphs referred to in this article compare and contrast gas strategies being followed by nations

NATURAL GAS STATISTICS, OUTLYING COUNTRIES

Fig. 1



Source: BP Statistical Review June 2007

and, where applicable, NOCs. The discussion focuses initially on those countries highlighted in the more extreme positions (Fig. 1) and moves on to the more centrally located nations (Fig. 2). In the case of some nations, Figs. 1 and 2 also suggest the directions in which countries are likely to move in the short term and long term if they adopt certain gas strategies.

Extreme positions

The two countries at the extreme ends of the net exports spectrum, the US and Russia, are moving in different directions in the gas industry. The US still holds significant reserves, but with consumption outstripping demand at an increasing pace it can be expected to trend further toward the lower left.

US strategy will focus on security and diversity of supply at competitive prices. Russia, on the other hand, holds the largest reserves and will trend further towards the upper right of such graphs in the future.

Russia's gas strategy, clearly manifest through the actions of Gazprom in recent years, focuses on diversifying its entry points into Europe by building new pipelines, reaching new markets with LNG projects, opening new markets by building pipelines to China from East Siberia, controlling gas exports from the Caspian states, and limiting access of its gas supply competitors to the Western European market.

High domestic gas consumption at low prices leads to a lower Russian production-consumption ratio than might be expected. Increasing exports, a shrinking population, and domestic energy efficiency measures will likely increase this ratio in the medium term. At the same time, however, Russia faces problems of timely investment into major infrastructure projects and overcoming large customers' suspicions of its political motives. A strategy involving strategic alliances with both large utilities and international oil companies with substantial gas sales positions in its key markets has emerged to address these problems.

Canada has benefited for more than 2 decades as the main gas exporter to the US. With falling reserves in traditional gas producing areas and increased domestic gas demand (including expanding demand for use in tar sand exploitation), however, Canada is unlikely to be able to move further to the upper right in Fig. 1, even with development of the Mackenzie Delta and Northern Territories gas resources.

Future strategies will focus on balancing domestic gas demand with exports to the US and preparing for a long-term future as a gas importer. Projects to build LNG receiving terminals show that Canada recognizes these issues. It also seeks to act as a gas transiting point for importing gas to the US, securing its own long-term supply sources along the way.

The main gas importing nations (Japan, Germany, Italy, Spain, South Korea, Turkey, etc.) plot distinctly in the lower left quadrant of Fig. 1 and are likely to move further in this direction as their demand for imported gas grows. Their bubble sizes on the graph clearly show their paucity of reserves.

Security and diversity of supply will continue to drive the strategies of these countries; with reliable suppliers unlikely to exploit periods of supply shortages for short-term.

Norway holds a position on Fig. 1 to which many gas suppliers aspire. Its low population and close geographic and political ties with Western Europe allow it to maintain this position. Its strategy focuses on developing further infrastructure ties with both Western and Eastern Europe and exploiting Barents Sea gas resources.

Norway's substantial gas reserves and ongoing investment through its partially state-owned company, Statoil, position it well to control the pace of key gas supply-chain developments and will allow it to move further into the upper right quadrant of Fig. 1 in the medium term.

Long-term cooperation with Gazprom with respect to development of the Barents Sea, however, has not yet emerged. The emergence of a strategic alliance between Statoil and Gazprom could have a major impact on global long-term gas supply dynamics.

Algeria has been exploiting its large gas resource base and proximity to southern Europe for several decades through pipeline and LNG projects. It has secured substantial capital investment in its gas sector by cooperation with IOCs, and continues to do so.

Algeria has in recent years followed a strategy, through its NOC Sonatrach, to extend its controlling share in projects involving IOCs and seek higher prices for its gas in tight-supply markets. This strategy may lead some of its customers to diversify and jeopardize future investments to expand infrastructure, thereby inhibiting its ability to achieve full market potential. Algeria, however, should move further to the upper right in Fig.1 over the medium term, driven by new pipeline, LNG, and potential GTL projects.

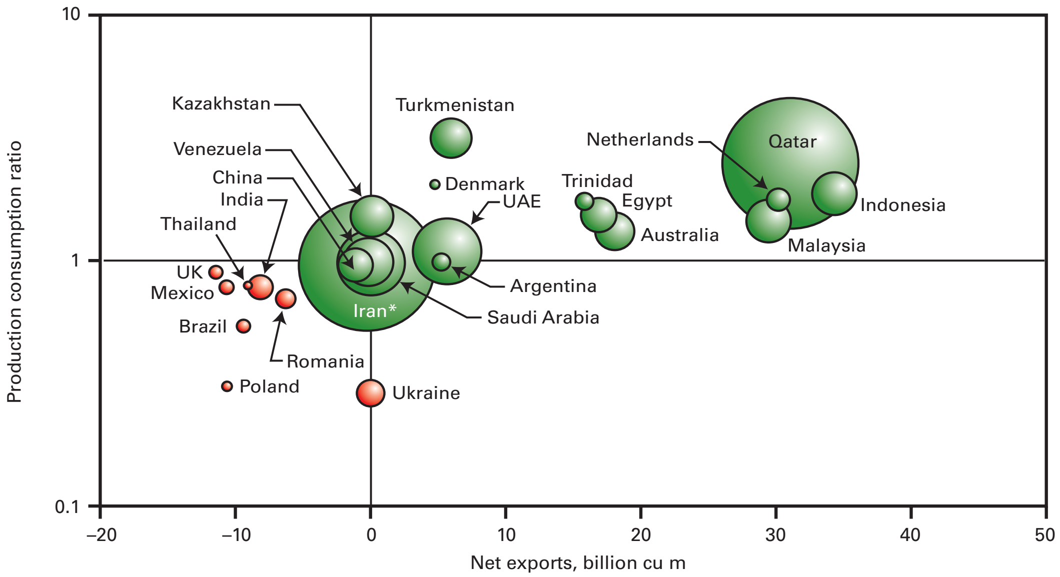
Nigeria's large gas resources and limited domestic use for them and, in spite of rapid growth in LNG, still limited exports, place it in an unusual position in Fig. 1. How fast this changes depends on how the country deals with unrest in the delta communities and if it recognizes the advantages of using domestic gas for power generation. As both gas exports and domestic consumption grow, Nigeria should move to the right on Fig. 1.

The National Nigerian Petroleum Co. continues to take a substantial interest in LNG development projects, cooperating with IOCs through production-sharing contracts offshore and joint-venture arrangements onshore. This strategy places the risk on the IOCs, which also provide the technology and investment. It has worked quite well for NNPC and is likely to continue.

In order to move right on Fig. 1 rather than up and right, however, NNPC might have to invest more directly in developing both its own gas use and the energy infrastructure integration of its Gulf of Guinea neighbors, relying less on IOCs for financing and developing

NATURAL GAS STATISTICS, COUNTRIES NEAR BALANCE

Fig. 2



*Also located at P:C=1 and net exports = 0: Azerbaijan, Bangladesh, Kuwait, Pakistan, Uzbekistan.
Source: BP Statistical Review June 2007

its domestic energy sector, particularly the building of gas-fired power plants.

Oman, Myanmar, Libya, and Bolivia lie in a similar position to Nigeria on Fig. 1, but with substantially lower gas reserves.

Oman's limited proved gas reserves will force its further movement to the upper right. State-controlled Petroleum Development Oman focuses on exploration in an effort to find more reserves and maintain or perhaps expand existing Oman LNG facilities.

The other three countries all have the potential to move straight to the right on Fig. 1.

Bolivia is unlikely to do so without political change, as state Yacimientos Petrolíferos Fiscales Bolivianos' nationalization strategies will likely inhibit foreign investment and additional gas export projects.

Libya's state-owned National Oil Co. is pursuing a recently adopted strategy of extensive cooperation with IOCs for exploration and production investment and technology. Libya must prove substantial additional natural gas reserves, however, to make significant movement to the upper right on Fig. 1.

The country's nearness to southern Europe suggests that Libya should be able to adopt similar gas development strategies as neighboring Algeria. Undertaking construction of the Green Stream gas pipeline to Italy in cooperation with ENI SPA demonstrates that Libya's future gas development lies in both pipeline and LNG exports, but remains reserve constrained.

Myanmar, through state-owned Myanmar Oil & Gas Enterprise, is also expanding exports and gas development through recently announced pipeline projects to China and the expansion of existing pipelines to Thailand.

Central examples

Qatar, with its massive gas resource base, is moving rapidly towards the upper right on Figs. 1 and 2. Large new capacity, including liquefaction plants, pipelines, and GTL and petrochemical projects should prompt a short-term rapid increase in net gas exports.

Qatar Petroleum continues to follow a strategy of diversification through close alignment with IOCs. In doing so it also maintains a large controlling interest in all gas development segments, including shipping. It is also actively seeking equity involvement in regasification infrastructure and other downstream assets along the LNG supply chain.

QP's main problems will be delivering its vast gas development projects on schedule and within budget and efficiently managing its vast portfolio of LNG assets. Political issues among Persian Gulf nations also may inhibit or delay continued planned gas infrastructure expansion by Qatar.

Iran and Venezuela remain rooted to the P:C = 1 and E–I = 0 spot in Fig. 1 despite vast gas reserves. Political issues dominate the gas strategies of both countries' state-owned companies. Both have been discussing LNG and GTL projects with IOCs for many years, but project-control issues and lack of confidence from IOCs that their investments would be honored within a stable legal framework have prevented any such projects from being completed.

Both countries have the potential to move well towards the upper right in Fig. 1, but without IOC involvement in project management, technology, and financial risk they are unlikely to do so in the medium term.

Both Iran and Venezuela have developed gas resources for domestic consumption, but their extreme political positions have impeded development of long-term relationships with international gas buyers, stunting the development of export markets.

Both countries are also actively negotiating long-distance, politically

problematic, gas pipeline initiatives: Venezuela's Gaseoducto del Sur, linking across Brazil to Argentina; and the IPI pipelines, linking Iran to Pakistan and India. The political and economic problems these projects face, however, may prevent either from being completed.

Saudi Arabia also lies at Fig. 1's origin, having followed a strategy of not exporting natural gas, but instead focusing on domestic energy projects and development of its petrochemical industry. State-owned Saudi Aramco has developed its gas resources in line with this strategy without the direct involvement of IOCs, one of the few nations to have succeeded in doing so.

No current indication exists that Saudi Aramco intends to adopt a gas export strategy or enter LNG supply.

An important trend affecting the Middle East region generally with respect to gas, and specifically with respect to LNG, is that the international oil companies are maintaining their hold on the technologies required to develop gas supply chains, leaving the NOCs under equipped to do so.

Also, by 2010, Saudi Arabia's domestic consumption of natural gas will reach 9-12 bcfd. Saudi Arabia and the Middle East in general are increasing their use of gas for generating electricity, one of the main reasons gas production is set for growth in both the Middle East and developing Asian nations, even amid uncertain exports.

Both China and India, two of the largest energy consumers in Asia, have worked to increase their natural gas supplies and develop the infrastructure needed to import gas, especially as LNG, into their markets. Their respective national oil companies, Chinese National Offshore Oil Corp. and Oil and Natural Gas Corp. Ltd., are participating in international upstream exploration projects for oil and gas, with a view toward increasing upstream supplies. Both have preliminary agreements for gas cooperation with Iran involving large scale LNG and pipeline projects.

Growing energy demand and the international strategies being pursued by these countries suggest that they will move further to the lower left on Fig. 2 as the gap between domestic supply and demand widens.

The Netherlands should move rapidly towards Fig. 2's lower left over the next few years, as domestic gas reserves become depleted.

It plans to build new LNG regasification plants to satisfy both future gas import requirements and to position Rotterdam as a significant Northwest Europe gas hub.

Indonesia should also move to the lower left as domestic energy demand and resultant gas consumption increase and reserves supplying existing liquefaction plants deplete in spite of ongoing development of the Tangguh LNG project. Indonesia's strategy focuses on exploring for more gas reserves in conjunction with IOCs and building domestic regasification plants so it can meet future demand for power generation.

Malaysia's domestic gas consumption poses less of a problem than is the case in Indonesia, but limited growth potential in proved reserves constrains its gas export potential. State-owned Petronas has long used international involvement, both upstream and downstream, simultaneously cooperating and competing with IOCs. The existing demands on its gas resource base will likely prevent Malaysia from moving much farther to the upper right on Fig. 2.

Australia and Egypt plot in similar positions on Fig. 2 and, underpinned by rapidly expanding gas resource bases evolving from ongoing successful offshore exploration programs, both should be able to use LNG developments to move further the upper right of the graph, probably changing positions with Indonesia within the next decade. September 2007 announcements of new LNG sales contracts, reportedly at high prices, for Australia's Gorgon (Shell-to-China) and Browse (Woodside-to-Japan) Northwest Shelf Projects have given that country's LNG industry new momentum.

Trinidad and Tobago plots in a similar position to Australia and Egypt on Fig. 2 but has a more problematic gas reserve base. Doubts about its ability to prove enough gas reserves to sustain further LNG expansion somewhat offset its advantageous position with respect to the North American market and its extensive recent expansions to its liquefaction capacity.

Its rapid LNG development strategy, however, has turned it into the largest gas exporter to the US. It seems likely that Trinidad and Tobago will continue to exploit whatever reserves it can develop to sustain that strategy.

The Caspian states all have the potential gas reserves to become significant gas exporters in the coming years, subject to pipeline development. Russia continues to have a significant political influence on Turkmen, Kazakh, and Uzbek gas exports, working against any movements that do not flow across its territory. At the same time, however, Azerbaijan has become a gas exporter through the South Caucasus Gas Pipeline into Turkey.

Their landlocked nature prevents the Caspian States from participating directly in LNG supply chains. But all have the potential to move significantly to the upper right on Fig. 2 by supplying pipeline gas to Europe, China, and Russia. To the degree that their own politics become involved in the process, however, this potential may be underrealized in the short-term.

The gas consuming nations in the lower left quadrant of Fig. 2 all seem destined to move rapidly further in that direction. The UK and Mexico are actively building new LNG regasification infrastructure to complement and diversify supply from their pipeline networks.

Mexico, if it adopted a cooperation strategy with IOCs and attracted investment and technology to explore and develop offshore Gulf of Mexico resources could potentially move into the upper right quadrant. But Pemex's iso-

lationist strategy seems set to continue, leaving Mexico to accept its position as a net gas importer. Perhaps reaffirmed strategic technical cooperation contracts between Pemex and Petrobras, and separately with Statoil, mark a change in this approach.

Brazil, Chile, Poland, and Thailand are planning to build strategically located regasification terminals to increase the security and diversity of their gas supplies away from existing import pipelines.

LNG import strategies in South America offer security and diversity of supply options that can mitigate the political and economic risks of relying on limited sources of pipeline supply. Both Brazil and Chile have learned the costs of overreliance on pipeline supplies from Bolivia and Argentina, respectively.

LNG is now plays an important role in the gas supply strategies of most countries identified on Figs. 1 and 2. Production, consumption, net export, and reserves trends and statistics, however, to not determine these strategies on their own. Strategies vary significantly based on the way gas is contracted and competes with other power generation fuels.

The second article in this series will use recent spark spreads between competing fuels in selected gas import markets to compare these strategies. ✦

The author

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Equipment/Software/Literature

New manifold for high-pressure instrumentation

The new Hi-Pro ⅜ in. bore double block and bleed manifold operates at as high as 15,000 psi cold working pressure.

The company says its unit is suited for deepwater drilling, methanol injection equipment, and laboratories where products are developed and tested under extreme conditions.

The manifold comes standard with 15,000 psi-rated MPI tubing ends that operate using the compression sealing technique. Units assemble in seconds by simply tightening a nut, and they are inherently vibration resistant. MPI tube end sizes of ⅜-¾ in. may be specified.

End connections are secured via the proprietary Tru-Loc mechanism, which helps guard against any connector movement when disconnecting connectors or instrument. Optionally, NPT-compatible male or female ends are available.

The manifold integrates two ball valves for isolation and one needle valve for venting, providing a standard double block and bleed configuration for interfacing instruments such as pressure or temperature transmitters. The valves are integrated within a 316 stainless steel one-piece body measuring 9.31 in. in length for the version with MPI tube ends.

Source: **Parker Instrumentation Products Div.,** 1005 A Cleaner Way, Huntsville, AL 35805-6708.

Process controller achieves new security certification

The Experion process knowledge system C300 process controller has achieved the new Mu Security Industrial Control Certification.

The certification is designed specifically for IP-based controllers and is closely aligned with the emerging ISA-SP99 security standards. It enables firms that rely on critical infrastructure or process control to ensure their network equipment and applications meet industry-defined benchmarks for safety, robustness, resiliency, and conformance, the company points out.

Experion is suited for use in oil and gas work, refining, chemicals, and power generation operations. The system integrates with safety measures dispersed throughout a manufacturing facility to reduce risk to employees and plant assets, increase process availability, and help improve regulatory compliance.

Source: **Honeywell International Inc.,** 101 Columbia Rd., Morristown, NJ 07962.

New interior coating for oil field equipment

A new interior coating has been developed for surface and downhole applications.

New InnerArmor coating technology promises an ultrahard, pinhole-free, chemically inert protective coating to the interiors of line pipe used to transport hydrocarbons, chemicals and alternative fuels; drill pipe, risers, and tubulars; downhole tools; subsea equipment; and surface piping, pumps, valves, chokes, and heat exchangers.

Source: **Sub-One Technology,** 4464 Willow Rd., Bldg. 103, Pleasanton, CA 94588.

Services/Suppliers

ModuSpec USA

Houston, has appointed Peter F. Lewand as vice-president and general manager. He will be responsible for operations in North America, Central America, and parts of South America.


Lewand

Lewand has over 25 years of industry experience, serving in various engineering and managerial capacities for Schlumberger and FMC Technologies. He received a BS degree in engineering from the New York Institute of Technology, and an MBA from the University of Texas-Dallas.

ModuSpec is an independent company providing risk management services since 1986. They are a world leader in equipment inspections and audits, having conducted over 4,000 rig inspections in 20 years.

Germanischer Lloyd AG (GL)

Hamburg, has announced its acquisition of the British company Advantica Holding, based in Loughborough. The acquisition strengthens GL's presence in the UK, Middle East, and US markets, and provides the company with a range of services to extend across the life cycle of oil and gas installations.

Advantica offers project consulting services for oil and gas production, storage, LNG terminals, pipeline engineering, combined with corresponding software solutions and consulting services for installation performance, maintenance, and process control.

Germanischer Lloyd's Industrial Services unit has focused on third party certification and inspection, independent design verification, production monitoring of components and installations, as well as risk-based inspections and condition surveys of production facilities, both onshore and offshore.

Schlumberger

Houston, has announced the acquisition of InnerLogix, a leading provider of data quality management software and services for the exploration and production industry. InnerLogix has offices in Houston and Stavanger.

Schlumberger is a leading global oil field services company, supplying technology, information solutions, and integrated project management to optimize reservoir performance.

Fulbright & Jaworski LLP

London, has announced that Andrew Hart has joined the firm as a partner in the London office. Hart will be part of the firm's global energy projects team. He earned his law degree from Edinburgh University.

Founded in 1919, Fulbright.& Jaworski LLP is a leading full-service international law firm with nearly 1,000 lawyers in 16 locations.

Statistics

Imports of crude and products

	Districts 1-4 9-14 2007	Districts 1-4 9-7 2007	District 5 9-14 2007	District 5 9-7 2007	Total US 9-14 2007	Total US 9-7 2007	Total US *9-15 2006
	1,000 b/d						
Total motor gasoline	942	1,004	69	12	1,011	1,016	799
Mo. gas. blending comp.	625	563	38	12	663	575	589
Distillate	307	302	—	50	307	352	471
Residual	335	267	—	114	335	381	511
Jet fuel-kerosine	127	112	73	82	200	194	292
Propane-propylene	360	239	2	1	362	240	147
Other	277	444	(11)	(11)	266	433	522
Total products	**2,973**	**2,931**	**171**	**260**	**3,144**	**3,191**	**3,331**
Total crude	**8,679**	**8,521**	**1,126**	**1,042**	**9,805**	**9,563**	**10,592**
Total imports	**11,652**	**11,452**	**1,297**	**1,302**	**12,949**	**12,754**	**13,923**

*Revised.
Source: US Energy Information Administration
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.

OGJ crack spread

	*9-21-07	*9-22-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	91.48	65.71	25.77	39.2
Brent crude	77.88	60.30	17.58	29.2
Crack spread	13.60	5.41	8.19	151.5
FUTURES MARKET PRICES				
One month				
Product value	90.40	67.11	23.29	34.7
Light sweet crude	81.79	61.61	20.18	32.8
Crack spread	8.61	5.50	3.11	56.6
Six month				
Product value	90.00	75.46	14.54	19.3
Light sweet crude	77.51	66.66	10.85	16.3
Crack spread	12.49	8.80	3.68	41.9

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

Purvin & Gertz LNG netbacks—Sept. 21, 2007

Receiving terminal	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	Liquefaction plant, $/MMbtu					
Barcelona	6.63	4.58	5.82	4.48	5.18	5.80
Everett	4.92	3.55	4.55	3.64	3.57	5.22
Isle of Grain	5.06	4.08	4.30	4.15	3.67	4.51
Lake Charles	3.72	2.53	3.54	2.70	2.94	4.34
Sodegaura	5.18	7.33	5.39	7.04	6.36	4.64
Zeebrugge	6.41	4.34	5.79	4.24	4.89	5.81

Definitions, see OGJ Apr. 9, 2007, p. 57.
Source: Purvin & Gertz Inc.
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	16,232	48,676	22,378	10,528	57,951	13,637	4,699
PADD 2	65,204	48,663	16,452	6,835	28,565	1,305	22,723
PADD 3	170,870	58,752	24,845	13,936	33,189	16,574	27,612
PADD 4	14,151	5,745	1,768	584	2,761	323	[1]2,703
PADD 5	52,318	28,998	20,366	9,719	13,061	5,276	—
Sept. 14, 2007	**318,775**	**190,834**	**85,809**	**41,602**	**135,527**	**37,115**	**57,737**
Sept. 7, 2007	**322,649**	**190,417**	**85,676**	**41,533**	**133,963**	**36,793**	**57,440**
Sept. 15, 2006[2]	**324,876**	**207,554**	**93,919**	**42,210**	**148,670**	**42,513**	**67,310**

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

Refinery report—Sept. 14, 2007

District	Refinery operations: Gross inputs	Refinery operations: Crude oil inputs	Refinery output: Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane-propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,533	1,567	1,935	87	523	145	57
PADD 2	3,423	3,414	2,166	204	925	71	190
PADD 3	7,440	7,248	3,184	676	1,961	291	633
PADD 4	539	538	274	28	156	16	[1]140
PADD 5	2,672	2,590	1,511	440	540	177	—
Sept. 14, 2007	**15,627**	**15,357**	**9,070**	**1,435**	**4,105**	**700**	**1,020**
Sept. 7, 2007	**15,795**	**15,564**	**8,911**	**1,396**	**4,130**	**714**	**1,090**
Sept. 15, 2006[2]	**16,250**	**15,953**	**9,156**	**1,460**	**4,385**	**584**	**1,036**
	17,448 operable capacity		**89.6% utilization rate**				

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

OGJ gasoline prices

	Price ex tax 9-19-07	Pump price* 9-19-07	Pump price 9-20-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	237.6	277.3	243.3
Baltimore	225.6	267.5	251.5
Boston	222.6	264.5	252.5
Buffalo	220.4	280.5	264.2
Miami	247.4	297.7	260.1
Newark	229.0	261.9	253.4
New York	219.6	279.7	268.4
Norfolk	224.6	262.2	230.5
Philadelphia	226.3	277.0	259.8
Pittsburgh	225.8	276.5	253.4
Wash., DC	241.1	279.5	264.5
PAD I avg	229.1	274.9	254.7
Chicago	267.1	318.0	273.5
Cleveland	236.5	282.9	220.8
Des Moines	233.7	274.1	210.1
Detroit	257.3	306.5	231.9
Indianapolis	247.7	292.7	221.8
Kansas City	245.4	281.4	218.2
Louisville	257.3	294.2	215.1
Memphis	222.3	262.1	233.6
Milwaukee	249.5	300.8	251.8
Minn.-St. Paul	252.7	293.1	228.2
Oklahoma City	244.4	279.8	216.0
Omaha	233.7	280.1	224.0
St. Louis	229.0	265.0	227.0
Tulsa	242.4	277.8	216.1
Wichita	231.2	274.6	220.9
PAD II avg	243.4	285.6	227.3
Albuquerque	239.7	276.1	243.6
Birmingham	227.7	266.4	220.6
Dallas-Fort Worth	227.0	265.4	216.2
Houston	233.3	271.7	219.8
Little Rock	227.5	267.7	223.5
New Orleans	233.9	272.3	245.5
San Antonio	228.0	266.4	237.4
PAD III avg	231.0	269.4	229.5
Cheyenne	246.9	279.3	258.2
Denver	246.6	287.0	268.6
Salt Lake City	241.5	284.4	276.7
PAD IV avg.	245.0	283.6	267.9
Los Angeles	218.1	276.6	270.2
Phoenix	248.3	285.7	241.3
Portland	241.3	284.6	269.3
San Diego	229.5	288.0	274.0
San Francisco	225.6	284.1	285.8
Seattle	228.3	280.7	278.7
PAD V avg.	231.8	283.3	269.9
Week's avg.	**236.0**	**279.6**	**243.8**
Aug. avg.	**237.2**	**280.8**	**296.7**
July avg.	**251.6**	**295.2**	**295.2**
2007 to date	**229.1**	**272.7**	—
2006 to date	**222.9**	**266.4**	—

*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

	9-14-07 ¢/gal		9-14-07 ¢/gal
Spot market product prices			
Motor gasoline		Heating oil	
(Conventional-regular)		No. 2	
New York Harbor	210.98	New York Harbor	219.13
Gulf Coast	211.60	Gulf Coast	216.75
Los Angeles	217.60	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	196.88	ARA	221.37
Singapore	196.48	Singapore	220.71
Motor gasoline		Residual fuel oil	
(Reformulated-regular)		New York Harbor	136.38
New York Harbor	205.48	Gulf Coast	147.02
Gulf Coast	210.10	Los Angeles	150.76
Los Angeles	218.60	ARA	133.05
		Singapore	146.83

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

Baker Hughes rig count

	9-21-07	9-22-06
Alabama	3	4
Alaska	5	6
Arkansas	48	26
California	36	33
Land	35	29
Offshore	1	4
Colorado	114	96
Florida	0	0
Illinois	1	0
Indiana	1	1
Kansas	15	7
Kentucky	11	9
Louisiana	164	198
N. Land	61	58
S. Inland waters	25	20
S. Land	26	44
Offshore	52	76
Maryland	1	1
Michigan	1	2
Mississippi	11	14
Montana	13	19
Nebraska	0	0
New Mexico	72	94
New York	6	7
North Dakota	44	37
Ohio	15	9
Oklahoma	194	196
Pennsylvania	16	14
South Dakota	2	3
Texas	832	788
Offshore	6	9
Inland waters	0	3
Dist. 1	26	24
Dist. 2	32	28
Dist. 3	56	58
Dist. 4	85	94
Dist. 5	186	139
Dist. 6	116	121
Dist. 7B	38	44
Dist. 7C	59	39
Dist. 8	115	91
Dist. 8A	18	24
Dist. 9	38	37
Dist. 10	57	77
Utah	41	45
West Virginia	33	26
Wyoming	79	112
Others—NV-3; TN-5; VA-31,769	11	7
Total US	**1,769**	**1,754**
Total Canada	**359**	**380**
Grand total	**2,128**	**2,134**
Oil rigs	305	299
Gas rigs	1,458	1,450
Total offshore	60	90
Total cum. avg. YTD	**1,760**	**1,623**

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	Rig count (9-21-07)	Percent footage* (9-21-07)	Rig count (9-22-06)	Percent footage* (9-22-06)
0-2,500	60	8.3	46	—
2,501-5,000	107	62.6	75	36.0
5,001-7,500	223	21.5	250	23.5
7,501-10,000	412	3.8	399	5.7
10,001-12,500	433	2.3	388	2.0
12,501-15,000	284	0.7	294	0.6
15,001-17,500	108	—	106	—
17,501-20,000	64	—	70	—
20,001-over	35	—	34	—
Total	**1,726**	**8.5**	**1,662**	**7.1**
INLAND	38		39	
LAND	1,634		1,556	
OFFSHORE	54		67	

*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

	9-21-07[1]	9-22-06[2]
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	15	20
Alaska	750	648
California	662	678
Colorado	50	61
Florida	5	7
Illinois	30	27
Kansas	94	97
Louisiana	1,292	1,401
Michigan	13	14
Mississippi	47	48
Montana	92	100
New Mexico	165	163
North Dakota	106	113
Oklahoma	165	172
Texas	1,310	1,342
Utah	44	49
Wyoming	141	143
All others	59	72
Total	**5,040**	**5,155**

[1]OGJ estimate. [2]Revised.

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

US crude prices

$/bbl*	9-21-07
Alaska-North Slope 27°	69.08
South Louisiana Sweet	82.50
California-Kern River 13°	70.45
Lost Hills 30°	78.25
Southwest Wyoming Sweet	74.62
East Texas Sweet	77.75
West Texas Sour 34°	72.25
West Texas Intermediate	78.25
Oklahoma Sweet	78.25
Texas Upper Gulf Coast	74.75
Michigan Sour	71.25
Kansas Common	77.00
North Dakota Sweet	69.25

*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]	8-31-07
United Kingdom-Brent 38°	70.22
Russia-Urals 32°	68.04
Saudi Light 34°	67.69
Dubai Fateh 32°	67.23
Algeria Saharan 44°	72.06
Nigeria-Bonny Light 37°	73.62
Indonesia-Minas 34°	72.84
Venezuela-Tia Juana Light 31°	66.44
Mexico-Isthmus 33°	66.33
OPEC basket	69.46
Total OPEC[2]	68.83
Total non-OPEC[2]	68.02
Total world[2]	68.46
US imports[3]	66.47

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume. NOTE: No new data at presstime.

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

US natural gas storage[1]

	9-14-07	9-7-07	Change
	bcf		
Producing region	931	915	16
Consuming region east	1,787	1,746	41
Consuming region west	414	408	6
Total US	**3,132**	**3,069**	**63**
	June 07	**June 06**	**Change, %**
Total US[2]	**2,580**	**2,617**	**–1.4**

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

PACE REFINING MARGINS

	July 2007	Aug. 2007	Sept. 2007	Sept 2006	Change	Change, %
	$/bbl				2007 vs. 2006	
US Gulf Coast						
West Texas Sour	16.61	14.20	13.76	8.24	5.51	66.9
Composite US Gulf Refinery	16.24	14.88	14.65	7.98	6.67	83.6
Arabian Light	14.35	11.33	10.30	7.19	3.10	43.2
Bonny Light	8.32	8.41	9.35	2.13	7.22	338.2
US PADD II						
Chicago (WTI)	21.33	20.24	14.92	6.65	8.27	124.4
US East Coast						
NY Harbor (Arab Med)	14.70	12.60	12.90	8.73	4.17	47.7
East Coast Comp-RFG	16.88	15.44	15.86	11.07	4.79	43.3
US West Coast						
Los Angeles (ANS)	13.79	8.73	9.25	9.70	–0.45	–4.6
NW Europe						
Rotterdam (Brent)	1.62	4.52	3.82	11.94	1.88	97.0
Mediterranean						
Italy (Urals)	8.82	8.15	10.12	6.71	3.40	50.7
Far East						
Singapore (Dubai)	8.05	6.71	7.00	(0.32)	7.32	2,322.6

Source: Jacobs Consultancy Inc.
Data available in OGJ Online Research Center.

US NATURAL GAS BALANCE DEMAND/SUPPLY SCOREBOARD

	June 2007	May 2007	June 2006	June 2007-2006 change	Total YTD 2007	Total YTD 2006	YTD 2007-2006 change
	bcf						
DEMAND							
Consumption	1,548	1,545	1,565	–17	12,006	11,247	759
Addition to storage	437	498	373	64	1,536	1,419	117
Exports	62	71	66	–4	404	357	47
Canada	27	35	23	4	222	162	60
Mexico	32	32	37	–5	157	162	–5
LNG	3	4	6	–3	25	33	–8
Total demand	**2,047**	**2,114**	**2,004**	**43**	**13,946**	**13,023**	**923**
SUPPLY							
Production (dry gas)	1,563	1,566	1,512	51	9,282	9,112	170
Supplemental gas	5	3	5	—	30	30	—
Storage withdrawal	48	39	62	–14	2,031	1,435	596
Imports	334	378	348	–14	2,256	2,062	194
Canada	253	284	286	–33	1,779	1,760	19
Mexico	—	—	—	—	18	3	15
LNG	81	94	62	19	459	299	160
Total supply	**1,950**	**1,986**	**1,927**	**23**	**13,599**	**12,639**	**960**

NATURAL GAS IN UNDERGROUND STORAGE

	June 2007	May 2007	Apr. 2007	June 2006	Change
	bcf				
Base gas	4,230	4,251	4,246	4,216	14
Working gas	2,580	2,179	1,720	2,617	–37
Total gas	**6,810**	**6,430**	**5,966**	**6,833**	**–23**

Source: DOE Monthly Energy Review.
Data available in OGJ Online Research Center.

WORLDWIDE NGL PRODUCTION

	June 2007	May 2007	6 month average – Production – 2007	2006	Change vs. previous year Volume	%
	1,000 b/d					%
Brazil	83	78	84	84	—	—
Canada	696	685	712	691	21	3.0
Mexico	418	413	414	437	–24	–5.4
United States	1,775	1,787	1,742	1,714	28	1.7
Venezuela	200	200	200	200	—	—
Other Western Hemisphere	199	213	208	212	–4	–1.8
Western Hemisphere	**3,372**	**3,376**	**3,360**	**3,338**	**22**	**0.6**
Norway	246	281	291	282	9	3.3
United Kingdom	123	152	154	159	–5	–3.2
Other Western Europe	111	10	10	11	—	–3.6
Western Europe	**379**	**443**	**456**	**452**	**4**	**0.8**
Russia	427	423	425	412	13	3.2
Other FSU	160	160	160	160	—	—
Other Eastern Europe	14	14	15	18	–2	–14.0
Eastern Europe	**601**	**597**	**600**	**589**	**11**	**1.8**
Algeria	340	340	340	298	42	14.0
Egypt	70	70	70	73	–3	–4.1
Libya	80	80	80	86	–6	–7.0
Other Africa	188	186	187	189	–2	–1.1
Africa	**678**	**676**	**677**	**646**	**31**	**4.8**
Saudi Arabia	1,439	1,439	1,439	1,439	—	—
United Arab Emirates	250	250	250	250	—	—
Other Middle East	870	870	870	900	–30	–3.3
Middle East	**2,559**	**2,559**	**2,559**	**2,589**	**–30**	**–1.2**
Australia	80	62	74	78	–4	–5.3
China	180	180	180	180	—	—
India	—	—	6	43	–37	–85.4
Other Asia-Pacific	172	171	179	187	–8	–4.2
Asia-Pacific	**432**	**413**	**440**	**489**	**–49**	**–10.0**
TOTAL WORLD	**8,021**	**8,065**	**8,091**	**8,103**	**–12**	**–0.2**

Totals may not add due to rounding.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

OXYGENATES

	June 2007	May 2007	Change	YTD 2007	YTD 2006	Change
	1,000 bbl					
Fuel ethanol						
Production	12,553	12,573	–20	71,150	54,013	17,137
Stocks	9,067	8,950	117	9,067	6,731	2,336
MTBE						
Production	1,694	2,003	–309	11,551	17,534	–42,462
Stocks	1,344	1,353	–9	1,344	1,912	–568

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

US COOLING DEGREE-DAYS

	Aug. 2007	Aug. 2006	Normal	2007 % change from normal	Total degree days Jan. 1 through Aug 31 2007	2006	Normal	% change from normal
New England	172	150	141	22.0	473	540	389	21.6
Middle Atlantic	245	239	202	21.3	694	738	598	16.1
East North Central	280	220	200	40.0	743	700	654	13.6
West North Central	344	289	258	33.3	954	987	840	13.6
South Atlantic	503	461	393	28.0	1,651	1,642	1,507	9.6
East South Central	562	477	376	49.5	1,549	1,493	1,286	20.5
West South Central	571	607	529	7.9	1,890	2,242	1,946	–2.9
Mountain	371	305	311	19.3	1,250	1,212	1,062	17.7
Pacific	261	207	200	30.5	653	767	577	13.2
US average*	**368**	**331**	**292**	**26.0**	**1,102**	**1,157**	**1,002**	**10.0**

*Excludes Alaska and Hawaii.
Source: DOE Monthly Energy Review.
Data available in OGJ Online Research Center.

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From the Subscribers Only area of OIL&GAS JOURNAL online research center www.ogjonline.com

Governor mistakes business move for price misbehavior

The governor of Connecticut has found yet another way for Americans to think self-destructively about energy.

Republican M. Jodi Rell has asked US congressional leaders to investigate Chesapeake Energy Corp. for "possible manipulation of the price of natural gas."

Earlier this month, with gas prices falling, Chesapeake said it would cut gross production by 200 MMcfd and trim its drilling program by yearend to 140-145 rigs from 155-160 (OGJ, Sept. 17, 2007, p. 100).

The Editor's Perspective

by Bob Tippee, Editor

"This practice, if true, is an unconscionable fleecing of US citizens by natural gas suppliers who 'elect' to reduce production in order to drive up prices paid by their captive customers," Rell railed in a letter to Senate and House committees.

She should be cheering, not griping. Thanks to several years of active drilling, gas production this year is ahead of last year's level.

Working gas in inventory is at the top of the 5-year range as the heating season approaches. Prices have subsided.

So Chesapeake made a business decision to ease an aggressive program. The affected production represents 0.3% of total US gas output, hardly enough to influence prices.

To Rell, it's "an outrage." She sounds like a Democrat.

Commendably, Chesapeake Chairman and Chief Executive Officer Aubrey McClendon called statements in the Rell rant "incorrect and reckless" and asked for an apology.

It's a sound request. Rell's accusations are as serious as they are groundless.

They cast Chesapeake, one of the country's busiest explorers for and producers of natural gas, in a sinister light it doesn't deserve. And they exploit a good-faith disclosure by the company for base political purposes.

In response to McClendon's call for an apology, the best Rell's press office could do was try to make a shin-kick sound like a handshake.

"I think we're going to have to agree to disagree," said spokesman Rich Harris.

At least Rell, who wants to replace 20% of the oil and gas used in Connecticut with alternative energy by 2020, acknowledges the link between production and prices. She should remember it the next time someone proposes federal oil and gas leasing off the East Coast.

(Online Sept. 21, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

A run of record high prices

The front month crude contract hit record highs in either intraday trading or closings—usually both—in eight consecutive trading sessions Sept. 11-20 on the New York Mercantile Exchange.

That run of escalating prices was even more outstanding since it started the same day that members of the Organization of Petroleum Exporting Countries voted to increase their oil production by a total 500,000 b/d effective Nov. 1. That decision excludes production by Angola and Iraq and affects only the other 10 members (OGJ Online, Sept. 11, 2007).

The October contract for benchmark US light, sweet crudes climbed from $77.49/bbl at the close of the Sept. 10 session on NYMEX to an intraday peak of $84.10/bbl and a closing price of $83.32/bbl on its expiration Sept. 20. The new front-month November contract dipped 16¢ to $81.62/bbl Sept. 21. In its last 8 days of trade, the October contract retreated only once, down 99¢ to $79.10/bbl in profit taking Sept. 14, but even then it set an intraday high of $80.92/bbl. From the start, the world oil market seemed to shrug off OPEC's promised production increase as primarily symbolic, since the 10 members now subject to quotas were estimated to have produced roughly 1 million b/d above the current ceiling in August. Subsequent factors continued to stimulate higher oil prices.

The October contract jumped above $82/bbl Sept. 18 on NYMEX after the US Federal Reserve cut its target interest rate by a larger-than-expected half of a percentage point to 4.75% to stem a possible slowdown in the US economy. That cut was on the high side of the reduction anticipated by most economists and plunged the dollar index to a record low. Meanwhile some analysts remained wary of possible inflation.

Benchmark US crude prices again were spurred higher Sept. 19-20 as a tropical storm began building in the eastern Gulf of Mexico. On Sept. 20, the US Minerals Management Service reported 5 of the 834 production platforms and 3 of 89 mobile rigs in the US sector of the gulf were evacuated. MMS officials reported offshore operators had shut in as much as 1.3 million b/d of crude and 1.9 bcfd of natural gas production from federal leases. By Sept. 22, however, crews were going back offshore after Tropical Storm Jerry came ashore in the Florida panhandle Sept. 21.

The Iranian factor

Meanwhile, on the international front, there were discussions Sept. 21 in Washington, DC, about possibly more sanctions on Iran in the ongoing attempt to get that country to abandon its uranium enrichment program. "While we expect the Russians and Chinese to continue to oppose new sanctions, it should make for more geopolitical sound bites. And this should continue into next week as the world leaders are gathering in New York for the United Nations general assembly," said Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland.

Barclays Capital Inc. analyst Paul Horsnell in London said, "International tensions surrounding Iran appear to be in the process of stepping up, with diplomacy moving further away from the carrot and closer to the stick." He sees 2008 "as the year of maximum danger, although it does not appear that the core issues themselves, or the core dangers in the situation, would necessarily change following the change of US administration."

Horsnell said, "We are placing a partial allowance for the worst of any Iranian-linked tension in the second half of 2008, having nudged our 2008 West Texas Intermediate price forecast up to $77/bbl from the previous forecast of $73.90/bbl."

Gasoline prices

Although crude prices have rallied steadily over the past month, gasoline prices have not moved as high or as quickly in the same time period. The October contract for reformulated blendstock for oxygenate blending (RBOB) fluctuated from $1.98/gal Sept. 10 on NYMEX to $2.11/gal as of Sept. 21. Raymond James analysts cite three reasons for this:

The decline in gasoline demand with US exiting the summer driving season.

The use of ethanol as a gasoline additive. Ethanol prices have dropped 30% in recent months.

Gasoline imports remain at a healthy level. However, they said, "If crude prices continue their upward trajectory, gasoline prices will inevitably follow. Also, the recently lowered interest rates should help in spurring economic growth, resulting in an increase in gasoline demand. Furthermore, with gasoline supplies still at historical low levels, any supply disruption has the ability to meaningfully pushed prices higher."

(Online Sept. 24, 2007; author's e-mail: samf@ogjonline.com)


There are 193 countries in the world.
None of them are energy independent.
So who's holding whom over a barrel?
The fact is, the vast majority of countries rely on the few energy-producing nations that won the geological lottery, blessing them with abundant hydrocarbons. And yet, even regions with plenty of raw resources import some form of energy. Saudi Arabia, for example, the world's largest oil exporter, imports refined petroleum products like gasoline.
So if energy independence is an unrealistic goal, how does everyone get the fuel they need, especially in a world of rising demand, supply disruptions, natural disasters, and unstable regimes?
True global energy security will be a result of cooperation and engagement, not isolationism. When investment and expertise are allowed to flow freely across borders, the engine of innovation is ignited, prosperity is fueled and the energy available to everyone increases. At the same time, balancing the needs of producers and consumers is as crucial as increasing supply and curbing demand. Only then will the world enjoy energy peace-of-mind.
Succeeding in securing energy for everyone doesn't have to come at the expense of anyone. Once we all start to think differently about energy, then we can truly make this promise a reality.
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WHAT NEEDS TO BE DONE
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• FIND MORE TRADITIONAL FUELS
• DEVELOP ALTERNATIVES AND RENEWABLES
– FOSTER OPEN MARKETS & TRANSPARENCY
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October-December 2007

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FOCUS ON PACIFIC RIM

China, US West Coast markets to push Pacific Rim LNG growth

Nuclear, LNG vie to meet Japan's energy needs

Flexibility keys financing of Pacific Basin projects

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OCTOBER-DECEMBER 2007

Korea Gas Corp.'s Incheon terminal is to undergo storage expansion in the next 5 years, along with two others terminals. Total storage capacity among the three terminals will increase by 72% to meet South Korea's growing demand for gas. Dependent entirely on LNG for gas supply, the country is the world's second-largest LNG buyer after Japan. Its demand is a primary driver of LNG activity in the Pacific Rim. This issue of LNG Observer devotes its main Issues, Trends, Technologies section (p. 3) to discussions of the region and its LNG growth. Photograph from Kogas.

Flaring, thermal power, and LNG

Warren R. True
Editor

Two reports in late summer have implications for the global natural gas industry, especially LNG.

In August, results of a major study of global associated-gas flaring helped clarify flaring's sources and magnitude. The Global Gas Flaring Reduction initiative released findings based for the first time on satellite observations of earth's surface.

Also in August, Algeria reported on plans to reduce its dependence on natural gas by using the sun's heat to produce electricity for export to Europe.

In both reports, implications for the struggle to reduce global production of greenhouse gases are obvious. Implications for continued supply of natural gas for LNG are more problematic.

GGFR; Hassi R'Mel

At the 2002 World Summit on Sustainable Development, the World Bank and the government of Norway joined forces to launch the GGFR initiative. Its goal was to eliminate gas flaring and venting.

GGFR is a "public-private partnership with participation from governments of oil-producing countries, state-owned companies and major international oil companies," according to "A Twelve Year Record of National and Global Gas Flaring Volumes Estimated Using Satellite Data" that recounts what GGFR is and how it went about collecting flaring information.

The objective of the study of gas flaring and its sources was "to investigate the use of earth observation satellite data for the detection of gas flaring and estimation of gas flaring volumes." The effort produced a series of "national and global estimates of gas flaring volumes" covering 1995-2006 for 60 countries and areas.

Of importance for the natural gas industry are the study's findings.

One major finding seems counter-intuitive to anyone familiar with the industry and the problem of flaring: Nigeria does not lead the world in flaring the largest volume. Satellite data indicate that "Russia has more than twice the gas flaring volume of Nigeria," says the report.

The second major finding is that flaring did not substantially increase—or decrease—over the years of the study, remaining "largely stable" in the range of 150-170 billion cu m.

Isolating 2004, which saw flaring of some 160 billion cu m, the study noted this amount compares to 25% of US natural gas consumption and represents "an added carbon emission burden to the atmosphere" of 84 million tonnes.

In a second, unrelated report that ran in many newspapers in August, the Associated Press covered Algeria's efforts to reduce its dependence on exporting natural gas and to turn increasingly to exporting thermally generated electricity. Just think how much of Algeria is bathed for long hours in sunlight and you begin to understand the country's logic.

Work on the first plant for thermally generated electricity began in July near Hassi R'Mel. The AP reports the plant, which could be operating by 2010, will be a hybrid, combining "gas and steam turbines with solar thermal input" to generate 150 Mw. Half will come from "giant parabolic mirrors" covering nearly 2 million sq ft.

The project's long-term goal, subject to solution of massive financial and technical problems, is to export as much as 6,000 Mw of solar-generated power to Europe through subsea cables to Sicily and Spain.

Implications

The GGFR report noted a "growing array of technologies to capture and make use" of natural gas currently being flared. Not the least of which is finding ways to move it to markets "using pipelines."

Pipelines? If gas now being flared or vented had access to pipelines, it wouldn't be stranded.

It's the growth of access to liquefaction that plays a larger role in reducing flaring. With much liquefaction construction under way and much more on order, the massive amounts of gas left in the ground or flared into the atmosphere will find markets.

But the GGFR report never mentions LNG or its current rapid growth. It had only to look at Nigeria—which it does mention—to see how effectively LNG has stepped into the equation for reducing flaring.

The timetable for the Algerian thermal generating project, on the other hand, is far too extended and the volumes that will feed it far too small for that project seriously to threaten supply for the country's LNG industry, the world's oldest.

The country's plans should, nonetheless, remind the global LNG industry, lest it become smug in its recent rapid growth and future bright prospects, that natural gas has lots of options, only one of which is LNG. **LNG**

warrent@ogjonline.com

China, US West Coast markets to push Pacific Rim LNG growth

Adrian John
Steve Robertson
Douglas-Westwood Ltd.
Canterbury

Pacific Rim LNG markets will see strong growth 2007-11 in expenditures on new LNG plants and terminals.

The LNG business has grown substantially in recent years with completion of some major high-profile LNG projects. While demand remains strong in traditional Asian markets, much attention is now being directed to opportunities arising from the potentially vast Atlantic Basin LNG market.

Meanwhile, the limits of domestic gas production in North America and Western Europe are becoming clear and gas import demand is rising. Increasingly, LNG is a choice in satisfying growing gas demand in these regions. Following the success of the plants recently established in Equatorial Guinea, Nigeria, and Trinidad and Tobago, a wave of new projects has emerged that demonstrate the potential for extensive market growth over the next 5 years.

Despite strong demand fundamentals, however, supply constraints are now affecting the business: EPC costs are rising; final investment decisions (FIDs) are being delayed or postponed as a result; and while major growth is still in prospect, the timing of operators' planned expenditures is likely to move significantly "to the right."

This article will focus on the general characteristics and development of the LNG industry in the Pacific Rim and present Douglas-Westwood's historical (2002-06) and forecast (2007-11) views of capital expenditures (capex) associated with LNG projects in the region. Particular attention will be given to development of the LNG industry in China and the US West Coast and Canada. For the present purposes, however, Southern Asian nations, such as India and Pakistan, are not considered part of the Pacific Rim.

Pacific Rim consumption, production

The historical trend of natural gas production and consumption in the Pacific Rim (excluding the US West Coast and Canada) shows that since 1980 the gap between consumption and production has been growing incrementally (Fig. 1). In 2006, that gap in the Pacific Rim was 7.3 bcfd, representing 17.3% of total consumption.[1]

LNG already plays a central role in Pacific Rim nations' meeting their natural gas consumption requirements. Japan, South Korea, and Taiwan, for example, almost entirely depend on LNG imports to fulfill domestic demand for natural gas. In 2006, 67.9% of all LNG imports in the Pacific Rim were from other Pacific Rim nations.[2] With exception of small volumes of LNG being exported from the Pacific Rim to India, all LNG produced in the Pacific Rim is consumed there.

These natural gas supply and demand dynamics in the Pacific Rim are driving the growth and development of LNG liquefaction capacity there.

Issues, Trends, Technologies

Left to right: Guangdong LNG terminal, China (photo from Guangdong Dapeng LNG Co. Ltd.); Northwest Swan (photo from Woodside); Karratha gas plant, Western Australia (photo from Woodside)

Development of liquefaction

The last 5 years have seen a 23.6% increase in Pacific Rim LNG liquefaction capacity, to 75.9 million tonnes/year

As of August 2007, the first LNG regasification terminal to operate on the western coasts of North America was more than 80% complete. Energía Costa Azul, under development in Baja California, Mexico, by Sempra Energy unit Sempra LNG, will open later this year or in first-quarter 2008. The terminal will initially be able to send out as much as 1 bcfd of Pacific Rim-produced natural gas to Mexican and US markets. Photograph from Sempra Energy.

(tpy) in 2006 from 61.4 million tpy in 2002.[3] Douglas-Westwood expects much larger growth over the forecast period 2007-11, with liquefaction capacity expected to reach 102.2 million tpy by 2011, a growth of 34.7% relative to 2006 capacity (Fig. 2).

Several factors are driving this growth on both demand and supply sides, including:

• Continuing growth in world gas consumption. The US Energy Information Administration has forecast world gas consumption growth at 2.4%/year out to 2030, compared to 1.4%/year for oil and 2.5%/year for coal.[4]

Gas will account for 26% of global energy use by 2030. In 2006, gas consumption in the Pacific Rim grew by more than 7.6% and has grown by 32% since 2002.[1]

• Strong import demand. Many of the major gas-consuming nations in the Pacific Rim have either very little gas production of their own (Japan, South Korea, for example) or have developed and drawn down their own reserves to the point where they are now past peak production and will have to rely increasingly on imported gas (US).

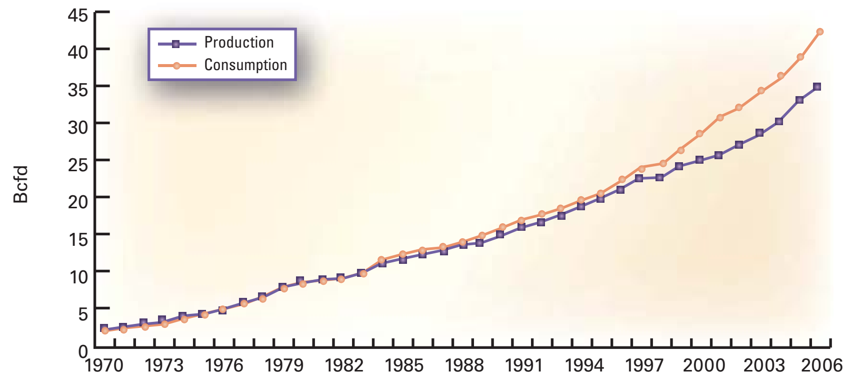
• Monetization of stranded gas reserves. Large natural gas reserves are

located a long distance from end-user markets or have no nearby access to takeaway pipelines. Without access to markets, produced gas is either flared or reinjected. LNG offers an access mechanism, a method of monetizing these gas reserves, and a way to reduce environmental harm from gas flaring.

• Technological advances. Advances in liquefaction technology had until recently led to a fall in the level of capex required to construct new plants. Nonetheless, development of larger liquefaction trains will create larger economies of scale, thus compensating somewhat for rising capex requirements and sustaining the economic viability of LNG as a solution for bringing gas to market.

Pacific Rim natural gas consumption, production

Fig. 1



*Excludes US West Coast, Canada
Source: BP Statistical Review

Capex trends, forecasts

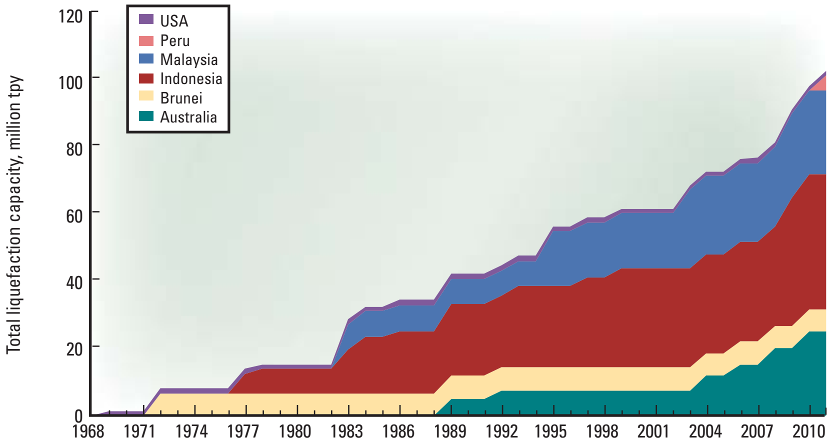
Douglas-Westwood forecasts that more than $62.1 billion of capex will be required to complete new LNG plants, vessels, and terminals in the Pacific Rim over 2007-11 (Fig. 3). The capex is accounted for in the year of start-up of the plant or terminal or delivery of the vessel.

In practice, however, contractual payments relating to the projects identified are often made in installments and will most likely be spread over years. For the sake of clarity and transparency, we do not attempt to try to reflect this situation in our forecasts. Instead, we focus on attempting to indicate the value of the new LNG facilities that come into use each year.

The overall trend is of strong market growth, with Pacific Rim capex on LNG

PACIFIC RIM LIQUIFICATION CAPACITY DEVELOPMENT

Fig. 2



Source: Douglas-Westwood Ltd.

developments over 2007-11 to total more than $62.1 billion–more than three times the $19.6 billion spent over the previous 5-year period.

LNG plants

Over 2002-06, Douglas-Westwood data indicate that 14.5 million tpy of liquefaction capacity was brought on stream by new LNG export plants and that the capex for constructing these plants (excluding upstream costs but including all site costs: plant, storage, marine facilities, etc.) totaled some $4.3 billion.

For 2007-11, new liquefaction plants coming on stream in the Pacific Rim will be a part of a massive increase in global LNG liquefaction capacity, requiring capex of more than $11.2 billion–almost 27% of global liquefaction capex for the period.

Key developments will include further development of the North West Shelf (Train 5) and the greenfield Pluto LNG project in Australia, the Tangguh LNG project in Indonesia, Sakhalin Trains 1 and 2 in Russia and Peru LNG in Peru.

Longer term, Australia is set to play a central role in liquefaction capacity additions in the Pacific Rim with more than 10 prospective developments announced. Of these prospects, seven had announced start-up dates during the 2007-11 forecast period. Projects such as Greater Gorgon, Browse LNG, and Pilbara LNG, however, have all experienced delays in project development, leaving NWS Train 5 and Pluto LNG as the only Australian liquefaction projects likely to come on stream during the forecast period.

Importantly, recent escalation of EPC costs has led to many proposed liquefaction projects delaying their FIDs. Until around 2005, technological advances, increased economies of scale, and increased competition between licensors, contractors, and suppliers within the LNG liquefaction industry had been driving the cost of construction down, to less than $200/tonne/year of capacity in several cases.

Escalating costs of labor and raw materials and the tight contractor market, however, have spurred large increases in the cost of new EPC contracts. By 2009 many projects coming on stream will have EPC costs of or greater than $300/tonne/year of capacity. The recent EPC contract award for Sonatrach's Skikda replacement trains, likely to come on stream in early 2012, exceeds $650/tonne.

In the Pacific Rim, this trend of increasing costs is exemplified by the increase to $1.8 billion from $1.4 billion for the 7.6-million-tpy Tangguh liquefaction project in Indonesia after an 18-month delay in FID. Larger EPC cost increases are likely for projects still awaiting their FIDs. The recent FID for Pluto LNG was the first to be made for a liquefaction plant in 2007.

LNG terminals

Douglas-Westwood also forecasts a large growth in spending for import terminals.

During 2002-06, more than $1.9 billion was spent on new LNG import and regasification terminals. Pacific Rim additions to import capacity over the forecast period will result in construction of around 29 new terminals at a total cost of almost $9.4 billion.

Despite strong energy demand in the US West Coast, none of the 29 terminals forecast to be constructed in the Pacific Rim will be there.

LNG carriers

Shipyards in the Pacific Rim have dominated activity in the newbuild LNG carrier market. In fact, the region has constructed nearly all the LNG carriers that entered service 2002-06. Over the next 5 years, we anticipate that more than 195 new carriers will be built in Pacific Rim nations. Capex associated with these new vessels will exceed $41.5 billion.

Douglas-Westwood data indicate the average price of an LNG vessel delivered over the previous 5 years fell to as low as $162 million in 2002. This decline in price over this period was largely due to intense competition among shipyards in the Far East, Korean ones in particular.

Although the market will remain competitive, however—with the entrance of Chinese yards into the market being a point of particular interest—demand in the shipping sector is at an all-time high with lead times for new orders stretching out 4-5 years. Prices for newbuilds now exceed $200 million/vessel again, with the trend towards increasingly larger vessels to continue.

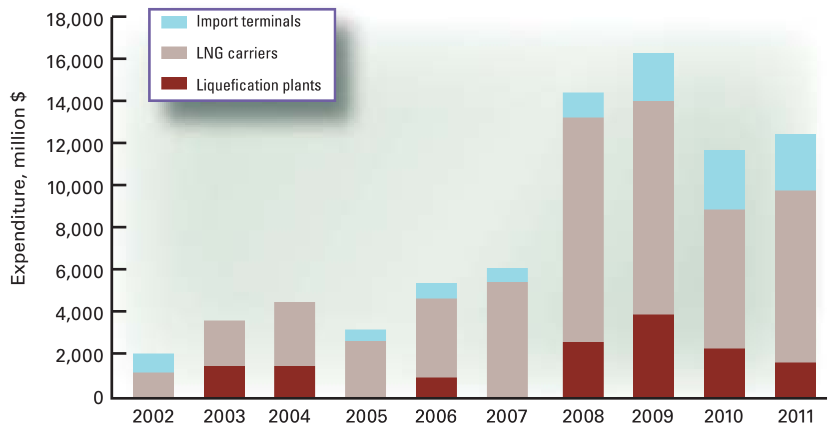
The main types of vessel design that have evolved are distinguished by type of containment system employed and are the Kvaerner-Moss Spherical System, the Gaz Transport Technigaz (GTT) membrane type, and IHI's Structural Prismatic design.

The membrane system is the most widely adopted, being used in more than half of LNG vessels in service as of 2007. It will be used in around 85% of vessels scheduled for delivery 2007-10. The Moss system is used in 45% of LNG vessels in service as of 2006 and will be used in more than 10% of vessels scheduled for delivery during 2007-10.

It is worth noting that in April 2007 Kogas signed a memorandum of understanding with the Korea Shipbuilder's Association to develop a membrane-type cargo containment system (called KC-1) to rival the GTT system. The successful development KC-1 would improve the competitiveness of the Korean shipyards in light of China's entrance into the LNG vessel construction market.

(Editor's note: See LNG Observer, July-September 2007, p. 12, for a fuller discussion of China's entry into the LNG carrier market. In addition, a complete listing of LNG carriers under construction, owners, commissioning dates, and trades, among other information can be found on p. 29 of this issue.)

PACIFIC RIM LNG CAPEX Fig. 3



Source: Douglas-Westwood Ltd.

Development in China

Although coal is China's main energy source, the country's gas consumption 2004-05 grew by 21% and a further 21.6% 2005-06. The Chinese government wants to increase the gas share of total energy production to 8% by 2010—more than doubling present volumes—to reduce reliance on coal, which is a much dirtier energy source than LNG.

A key reason for this policy is China's preparations for the 2008 Olympic games in Beijing. In years leading up to the games, Beijing is spending nearly $7 billion on environmental projects.[5]

This includes $800 million on preventing coal-burning pollution, with additional monies going to construction of natural gas pipelines and storage tanks, improving electricity distribution, and re-engineering the power supply structure.

Increased levels of domestic natural gas production and imports—the latter via pipeline or LNG—will meet the increase in gas demand in China. Most of the imported LNG will be used in southeast China, where six gas-fired power stations are being constructed in the Guangdong province.

Despite ambitious plans that originally proposed to construct 10 LNG import terminals (new and expansion projects) by 2008, only Guangdong Dapeng LNG Phases I and II have been completed thus far. China's second LNG import terminal at Putian, in the Fujian province, will be ready to receive its first cargo from Indonesia by yearend 2008.

Several reasons lie behind this failure of many projects to materialize. Chief among them has been China's insistence upon signing long-term LNG supply contracts at prices far below market value. Consequently, China has only signed two long-term contracts since a deal with North West Shelf Venture in 2002, owing to its insistence on a similarly low price (of $3.15/btu).

Recently, however, there have been indications that China may be moving away from this policy. In May 2007 the Guangdong Dapeng terminal received its first spot cargo from Oman (OGJ Online, May 10, 2007). The significance of this transaction lies in the willingness of local companies in China to pay market value for LNG, $8.30/MMbtu.

As a single cargo it did very little to overcome shortfalls in gas supply that many large cities in China were experiencing at the time, but this could be a sign that market forces are beginning to assert themselves in LNG and that China is going to be willing to pay a higher price for long-term contracts in future. Guangdong Dapeng has subsequently received more spot cargoes and has the spare capacity to receive one spot cargo per month.

Company officials recently suggested that Guangdong Dapeng might import close to 2.6 million tpy in 2007—more than trebling the 0.7 million tpy imported in 2006. In light of spot-cargo purchases, the Chinese government changed its LNG import permit system in order to reduce competition between local importers for cargoes and to avoid driving spot prices higher than they currently are.

These recent developments have created renewed optimism surrounding development of LNG as an industry in China. Douglas-Westwood estimates that some $4.4 billion will be spent on developing import terminals during 2007-11. Additionally (and as noted previously), China has entered the LNG vessel construction market through the Hudong-Zhonghua Shipbuilding Co., which has already secured contracts of more than $1 billion to build five vessels for China Shipping LNG and is likely to receive an order for an additional vessel by the end of this year.

LNG in US West Coast, Canada

Since 1991, EIA data show that there have only been 3 years when North America has produced more gas than it has consumed. The US currently depends on Canada for the vast majority of its gas imports, but since Canada's main producing areas are now mature and Canadian gas demand is increasing, both the US and Canada are now looking to LNG imports as an important source of gas.

A decade ago, an LNG export plant was proposed to export Canadian gas to markets in Asia. With gas supply in North America struggling to keep up with demand, however, all proposals are now for LNG import terminals.

Excluding Alaska, all US West Coast states import most if not all the gas they consume. California has the most in-state gas resources available but consumes almost 10 times as much natural gas each year as either Oregon or Washington. California produces about 15% of the 6.1 bcfd (2005 value) of natural gas that it consumes and imports the rest from Canada (about 24%), the Rocky Mountains (about 25%), and Southwest (about 36%).

This situation highlights the potential for LNG to be a substitute or complementary source of natural gas for West Coast states with easy access to Pacific Rim liquefaction capacity.

LNG import terminals have been proposed in all three US West Coast states, but thus far none has received regulatory approval, owing as much to public opposition as to failure to meet regulatory requirements. The LNG industry is renowned for its diligent standards and has an excellent safety record, albeit not entirely without incident.

Public perception about the risks of LNG, however, often appears to be misconceived. Consequently local opposition to new facilities is common and perhaps now more vigorous given continuing worries over terrorism. This seems to be a particular problem in California.

In recent years, three prospects for Californian LNG import terminals have been abandoned due to local opposition: Humbolt Bay (Calpine Corp.), Mare Island (Shell Corp. and Bechtel); and Cabrillo Port LNG (BHP Billiton). In the case of Mare Island, shipping scheduling was also a concern. The LNG tankers would have required escorting by the US Coast Guard under several major bridges including the Golden Gate Bridge and through San Francisco Bay.

Cabrillo Port LNG was the latest victim of strong local opposition to LNG projects in California. In May 2007, California Governor Arnold Schwarzenegger turned down BHP's applications for a floating storage and regasification unit (FSRU) some 35 km off Ventura County (OGJ Online, May 29, 2007; LNGO, July-September 2007, p. 23). The project reflects the difficulties involved in obtaining regulatory approvals and overcoming local opposition faced by all LNG terminal proposals located in California–offshore as well as onshore.

Although no import terminals are likely to be constructed on the US West Coast 2007-11, the Kitimat LNG (Galveston Energy) project on Canada's West Coast should be completed by yearend 2010. Also, commercial operations at the Sempra Energy's Energia Costa Azul LNG terminal in Baja California, on the Pacific Coast of Mexico, will begin by yearend 2008.

Baja California has seen a lot of interest for proposed LNG import terminals mainly due to the proximity of US markets and the region's isolation from the rest of Mexico's energy supply. Should proposed import terminals on the West Coast fail to gain approval, Kitimat and Energía Costa Azul may provide an alternate source for LNG supply if they are able to source sufficient volumes of LNG beyond the requirements of local markets. **LNG**

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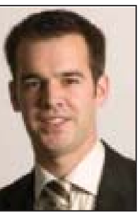

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Nuclear, LNG vie to meet Japan's energy needs

Tomoko Hosoe
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Japan's energy policy encourages an increased use of natural gas and nuclear power to mitigate climate change and diversify the energy mix away from oil. This would effectively reduce Japan's energy reliance on the Middle East. Accordingly, Japanese LNG buyers have significantly increased import volumes since their first imports in 1969, particularly after the two oil crises in the 1970s.

Today, Japan is the world's largest LNG importer at 62.1 million tpy, about 59% of total demand coming from the power industry and the rest from gas utilities. All of Japan's gas imports are in the form of LNG.

This article examines market fundamentals and how domestic factors such as power and gas industry reform and nuclear power policy and problems will influence Japan's LNG demand.

Current scene

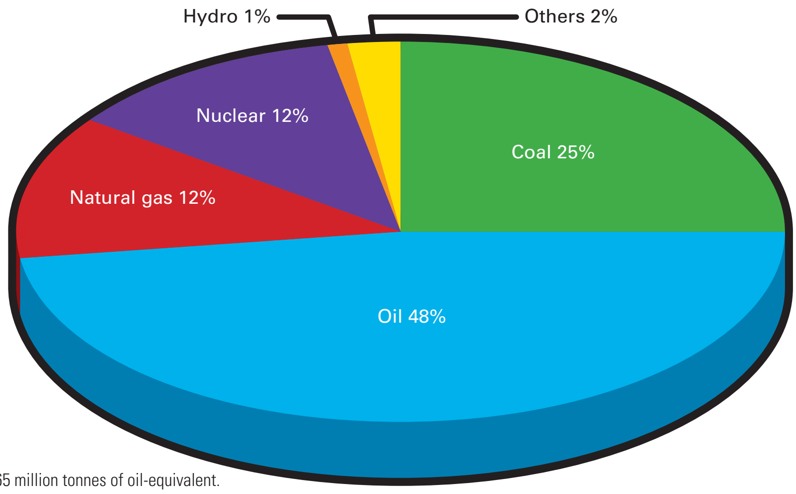
Until recently, Japan was considered a saturated market, but demand has started notably increasing again. LNG imports in 2006 were up by 7%, as Japan's economy continued to improve, increasing productivity, and the power sector continues to have nuclear power problems.

For the first half of 2007, the nuclear utilization rate was 61.9-72.9% and is likely to operate well below 70% for the second half. The main reason for Japan's additional LNG requirements is Tokyo Electric Power Co.'s (TEPCO) 8.21-Gw Kashiwazaki-Kariwa nuclear power plant shutdown (OGJ Online, July 24, 2007).

The Chuetsu offshore earthquake hit Niigata prefecture, where the nuclear power plant is located, on July 16, 2007. Complete plant closure will last at least through first-quarter 2008 and an additional year (or possibly longer) may be needed until the plant returns to normal operations.

JAPAN'S PRIMARY ENERGY CONSUMPTION: 2006*

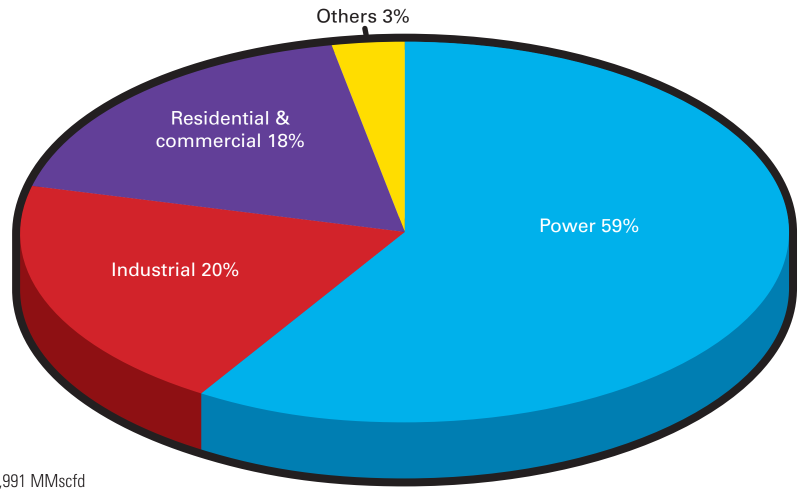
Fig. 1



*565 million tonnes of oil-equivalent.

JAPAN'S NATURAL GAS CONSUMPTION: 2006*

Fig. 2



*7,991 MMscfd

Primary energy consumption

In 2006, the share of natural gas in Japan's primary energy mix was 12%, in line with 2005 (Fig. 1). Oil (48%) continued to dominate the energy mix with coal's share at 25%. Japan's reliance on nuclear power increased to 12%, up from 11% in 2005.

For 2020, both nuclear and natural gas shares will likely increase to 18% and 19%, respectively. Japan's oil dependency will fall to 33%, given that the government continues to implement strict environmental and energy conservation and fuel-efficiency regulations at all levels.

Gas demand; LNG imports

In 2006, the power sector accounted for 59% of the total gas demand (nearly 8 bscfd), followed by the industrial sector (20%), the residential and commercial sectors (18%), and others (3%; Fig. 2).

The power sector's natural gas consumption (generally middle-load fuel) fell slightly from 2005, as a result of the increased share of nuclear power in total power generation. On the other hand, the industrial sector's gas consumption grew a significant 13% year-on-year in 2006, for the following reasons:

- Japan's economy continued to improve, increasing productivity significantly in areas such as Chubu where many large-scale, energy-intensive manufacturing industries are located.
- Industrial customers nationwide continued to switch from fuel oil to natural gas, supported by attractive gas prices relative to oil prices and also by government subsidy programs. The residential sector grew 2.6% year-on-year.

Accordingly, Japan's LNG imports increased to 62.1 tonnes in 2006 from 58.0 tonnes in 2005. As shown in Table 1, Japan has a diversified LNG supply portfolio with 72% of total imports coming from the Asia Pacific—Indonesia accounting for 22.5%, followed by Australia (19.6%), Malaysia (19.4%), Qatar (12.1%), Brunei (10.5%), Abu Dhabi (8.4%), Oman (3.8%), the US (1.9%), and others (1.8%).

Indonesia was unable to deliver the contracted volumes to Japanese buyers in 2005 and 2006, reducing the share of Indonesian LNG in Japan's portfolio of supplies.

Consequently, Australian supplies to Japan have been increasing over the past few years.

Middle East producing sources have also increased with the start of two new contracts with Oman. LNG from the Atlantic Basin accounted for nearly 2% of Japan's total LNG supplies.

JAPAN'S LNG IMPORTS Table 1

	2006	2005
	tonnes	
Indonesia	13.99	14.26
Malaysia	12.02	13.60
Australia	12.16	10.15
Qatar	7.48	6.33
Brunei	6.50	6.27
Abu Dhabi	5.19	5.13
US (Alaska)	1.17	1.25
Oman	2.37	0.97
Algeria	0.18	—
Trinidad/Tobago	0.33	—
Egypt	0.51	—
Nigeria	0.17	—
Total	**62.07**	**57.96**

Main consumers

The electric and gas utilities are key LNG consumers.

Japan has 10 private electric power utilities, of which six electric utilities (TEPCO, Chubu Electric Power, Kansai Electric Power, Tohoku Electric Power, Kyushu Electric Power, and Chugoku Electric Power) use LNG as their feedstock for power generation (Table 2). In the near future, Shikoku Electric Power and Okinawa Electric Power will start burning LNG.

In fact, four utilities (TEPCO, Kansai Electric, Chubu Electric, and Tohoku Electric) accounted for more than 90% of LNG consumption in the power sector in 2006. Generally speaking, TEPCO (Japan's largest electric power utility) remains the dominant LNG consumer, although Chubu Electric's demand has been growing robustly over the past 3 years.

TEPCO alone consumed 16.3 tonnes (45%) of the power industry's total consumption (36.2 tonnes), and Chubu Electric's consumption rose to 9.8 tonnes, up 8.8% from 9 tonnes in 2005. Demand in the Chubu area has been growing significantly, given the many large-scale, energy-intensive manufacturing industries in the region, such as Toyota Motor and its affiliated manufacturers.

Meanwhile, Japan has 212 city gas utilities, of which the "Big Four" gas utilities accounted for 77% of the total LNG consumption in the gas sector in 2006 (Table 3). Tokyo Gas accounted for 37% of the total 25.2 tonnes, followed by Osaka Gas (27%), Toho Gas (11%), Saibu Gas (2%), and others (23%).

The industrial sector's recent demand growth has been considerable, as industrial customers continue to switch to natural gas from fuel oil, supported by attractive gas prices relative to oil prices and government subsidiary programs. All of the "Big Four" utilities increased their sales volumes to their industrial customers in 2006, with their demand growth rates as follows on a year-on-year basis: Tokyo Gas (8%), Osaka Gas (8%), Toho Gas (20%), and Saibu Gas (17%).

LNG Imports: 2007

For first-half 2007, Japan's cumulative LNG imports totaled 32.7 tonnes (up 8.9% or 2.7 tonnes) from the same period a year ago. Electric utilities' cumulative LNG consumption for the period totaled 19.7 tonnes (up 3.5 tonnes), while gas utilities' cumulative consumption remained mostly unchanged at last year's 13.4 tonnes.

The demand increase was driven primarily by the following:

- Strong electricity and city

LNG CONSUMPTION BY ELECTRIC POWER UTILITIES Table 2

	2006	2005	2004
		tonnes	
Tokyo Electric	16.3	16.7	16.9
Chubu Electric	9.8	9.0	8.8
Kansai Electric	3.8	4.1	4.0
Tohoku Electric	2.8	3.2	3.2
Kyushu Electric	2.2	2.3	2.3
Chugoku Electric	1.3	1.2	1.3
Total	**36.2**	**36.5**	**36.4**

LNG CONSUMPTION BY GAS UTILITIES Table 3

	2006	2005	2004
		tonnes	
Tokyo Gas	9.3	8.9	8.5
Osaka Gas	6.7	6.3	6.1
Toho Gas	2.8	2.5	2.2
Saibu Gas	0.6	0.6	0.5
Others*	5.8	5.2	6.8
Total	**25.2**	**23.5**	**24.1**

*Japan has 212 gas utilities. "Others" includes the remaining utilities.

gas demand from the large-lot users, supported by Japan's continuous economic growth.

- A series of unexpected nuclear power plant shutdowns.
- Lower utilization of hydro power plants, due to Japan's record-high winter temperature (thus low winter snowfall) and low precipitation during the rainy season caused drought problems, particularly in western Japan.
- A series of unexpected hydro power plant shutdowns. Several hydro power plants had received penalties from the Ministry of Land, Infrastructure, and Transportation on May 16, 2007, as a result of maintenance and operational data manipulation. These penalties included: halting power plant operations; taking away the right to use water for power generation; and reducing their water intake, which is used for power generation. TEPCO's Shiobara plant (a 1.05-Gw pumped storage type plant), which is designed to meet their summer peak demand, was one of the plants penalized.

Fig. 3 illustrates Japan's LNG imports for first-half 2007.

For the second half of 2007, strong demand is expected primarily from TEPCO, as a result of its 8.21-Gw Kashiwazaki-Kariwa nuclear power plant closure in July.

The Chuetsu offshore earthquake (magnitude of 6.8) hit Japan's Niigata prefecture, where the Kashiwazaki-Kariwa nuclear power plant (consisting of seven nuclear reactors) is located. A fire broke out in a transformer at the Unit 3 reactor, while some water containing radioactive materials leaked from another unit into the sea.

At the time of the earthquake, three reactors out of the seven were operating normally and one was to commence operation after its maintenance shutdown. The other three reactors were not operating due to maintenance shutdowns. Due to the earthquake all reactors ceased operations.

The Kashiwazaki municipal government issued an emergency order to TEPCO to stop operating the power plant, stating that the plant can only resume operations after TEPCO receives permission from local municipalities. Similarly, Minister Akira Amari at the Ministry of Economy, Trade and Industry (METI) ordered TEPCO not to resume operations of the plant until safety is ensured.

Complete plant closure will last at least until the end of March 2008 and an additional year (or possibly longer) may be needed until the plant will return to its normal operation. Essentially, TEPCO will have to resolve two concerns:

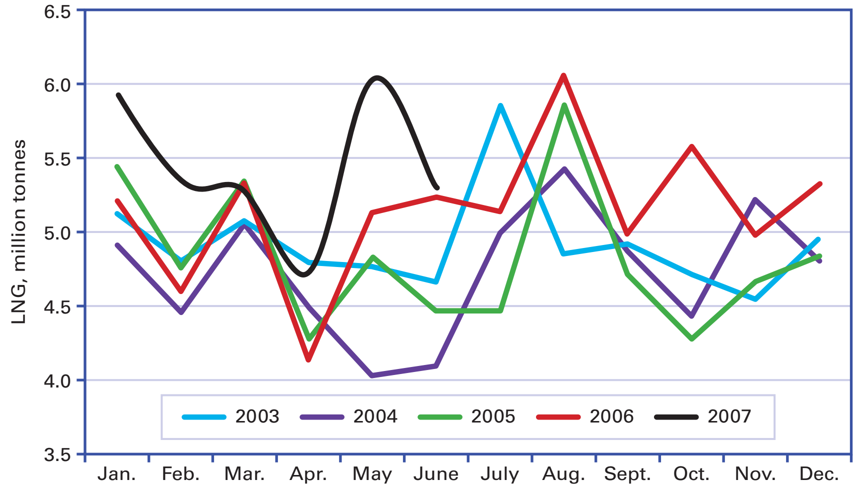
- Safety of the plant site, since various data suggest a fault line may run underneath the nuclear power plant.
- Earthquake resistance of the nuclear power plant, as it has already experienced an earthquake more severe than the plant was designed for.

It remains in question how long until the nuclear units can resume normal operation because Japan has never experienced nuclear power problems of this scale and has no way of assessing how long each step (e.g., investigation, geological survey, repair and construction works, government approval, and public approval) will take before TEPCO can resume plant operations.

From past experience, receiving permission from the local community

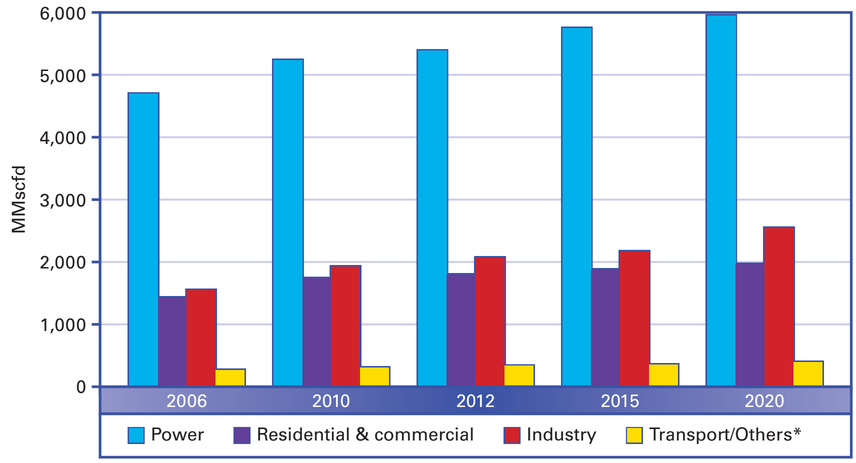
Japan's monthly LNG imports: 2003-07

Fig. 3



Japan's natural gas demand outlook

Fig. 4



*Includes agricultural use, field use, and unspecified others; excludes distribution losses.

and local municipalities is one of the most difficult and time-consuming processes in resolving nuclear-related problems. The general public's trust in nuclear power has been lost again and will damage TEPCO's attempts to resume plant operations.

The key difference between the 2003 nuclear crisis and the current Kashiwazaki-Kariwa problem is that by law, TEPCO is not allowed to resume plant operations, whereas in 2003 TEPCO could have resumed operations because the plants were operational. Without the 8.21-Gw baseload capacity today, TEPCO must increase its dependency on thermal power generation (fuels being LNG, fuel oil, and crude oil).

Assuming the power sector's LNG demand for 2007 is near 2003 level, when Tokyo experienced a nuclear power crisis, Japan's overall LNG demand in 2007 will likely increase to 65.2 tonnes, up from 62.1 tonnes in 2006. (See an accompanying sidebar on p. 14 Japan's 2003 nuclear power crisis.)

Long-term demand outlook

In the long term, LNG imports will likely reach 70.2 tonnes in 2010 and 82.0 tonnes in 2020 (Fig. 4). The industrial sector's demand will grow strongly at 7.0%/year until 2010, with a slowdown in growth thereafter. In fact, gas utilities have intentionally slowed down their marketing activities for beyond 2010 in the face of an uncertain LNG supply/price outlook.

The power sector's demand will likely grow at 2.0%/year until 2010, then at 1.3%/year towards 2020. Please note this outlook does not take into account a worst-case scenario—that the Kashiwazaki-Kariwa nuclear power plant may remain completely idle for more than 3 years.

The residential and commercial sector's demand will grow at 4.5%/year until 2010 and start slowing afterwards.

NUCLEAR POWER PLANTS IN JAPAN*

Table 4

Company	Plant	Unit no.	Capacity, 10 Mw
Japan Atomic Power	Tokaidaini		110.0
	Tsuruga	1	35.7
		2	116.0
Hokkaido		1	57.9
		2	57.9
Tohoku	Onagawa	1	52.4
		2	82.5
		3	82.5
	Higashi Dori	1	110.0
Tokyo (TEPCO)	Fukushima Daiichi	1	46.0
		2	78.4
		3	78.4
		4	78.4
		5	78.4
		6	110.0
	Fukushima Daini	1	110.0
		2	110.0
		3	110.0
		4	110.0
	Kasahiwazaki Kariwa	1	110.0
		2	110.0
		3	110.0
		4	110.0
		5	110.0
		6	110.0
		7	110.0
Chubu	Hamaoka	1	54.0
		2	84.0
		3	110.0
		4	113.7
		5	138.0
Hokuriku	Shika	1	54.0
		2	135.8
Kansai	Mihama	1	34.0
		2	50.0
		3	82.6
	Takahama	1	82.6
		2	82.6
		3	87.0
		4	87.0
	Oi	1	117.5
		2	117.5
		3	118.0
		4	118.0
Chugoku	Shimane	1	46.0
		2	82.0
Shikoku	Ikata	1	56.6
		2	56.6
		3	89.0
Kyushu	Genkai	1	55.9
		2	55.9
		3	118.0
		4	118.0
	Sendai	1	89.0
		2	89.0
Total		**55 units**	**4,958.0**

*as of 2007

POWER SECTOR DEREGULATION

Table 5

	Timing	Market share, %
Customers using 500 kw or more	April 2004	40
Customers using 50 kw or more	April 2005	63
Complete liberalization	Not decided	100

Nuclear energy policy

Despite the accidents and problems, nuclear power generation remains at the core of Japan's energy policy. Japan's Energy Policy and Strategy (announced by METI in 2006) set an ambitious target of increasing the share of nuclear power in total power generation to 40% or higher by 2030, up from the current 29-30%, in an effort to fulfill the country's obligations under the Kyoto Protocol and achieve energy security.

Currently, Japan has 55 nuclear units (totaling 49.6 Gw of capacity) and has two reactors (owned by Hokkaido Electric Power and Chugoku Electric Power) under construction. Additionally, 12 nuclear units are in planning stages, but there is no definite timetable for their construction (Table 4).

Inevitably, the recent disruption in nuclear power operations will make the government's ambitious energy policy target difficult to achieve. For example, TEPCO has delayed its plans to add two more nuclear units (1.38 Gw each) to the existing 4.70-Gw Fukushima Daiichi power plant several times and is unlikely to build them anytime soon.

Another essential issue for all electric utilities is that the financial burden of building nuclear power plants has become too heavy to bear—with the growing costs involved in running, maintaining, and decommissioning plants—when the potential market share is declining. This is especially true because, under deregulation, new entrants to the power market are building more cost efficient gas-fueled combined-cycle units.

As well as an energy security, economic, and political issue, the nuclear issue has become a social one. Among the reasons TEPCO's nuclear-related issues tend to be more controversial than other cases is that all of its nuclear power plants are located outside of TEPCO's service areas. TEPCO has no nuclear power plants in the Tokyo area.

Despite the accidents and problems, however, the core of Japan's energy policy remains in nuclear power to fulfill the country's obligation under the Kyoto Protocol and to achieve the "ideal" fuel mix for energy security that the government has planned. Further, for many villages and cities, a combination of employment and government subsidies relating to the nuclear industry plays an important role in their economic activities.

Power, gas industry reform

Japan has been opening the power market to competition on a step-by-step basis since 1999. In March 2000, the power retail market was partially liberalized to allow power producers and suppliers to sell electricity to extra-high voltage users whose demand exceeds 2 Mw (e.g., industrial complexes, large department stores). From April 2005, the scope was expanded to all users whose demand is more than 50 kw. Thus, about 63% of the market has already been liberalized.

The next stage is to include low-voltage users (e.g., residential customers), which will fully liberalize the market. The timing has not yet been decided, however, and it is unlikely that full liberalization will come about anytime soon because the government finds little merit in full liberalization at this time.

Recent high fuel prices have already hindered new participants from competing with established utilities. Nevertheless, the government's deregulation initiative is aimed at stimulating competition between the established electric utilities and new entrants to bring down electricity charges (Table 5).

Meanwhile, the gas industry in November 1999 opened the market to large-lot users with a minimum consumption of 1 million cu m/year. The market to customers using 500,000 cu m/year or more was opened in 2004; this segment accounts for about 44% of the gas market. As of April 2007, the market to customers using 100,000 cu m or more opened, liberalizing 50% of the entire market. The timing to open the rest of the market, customers using less than 100,000 cu m, has not yet been decided (Table 6).

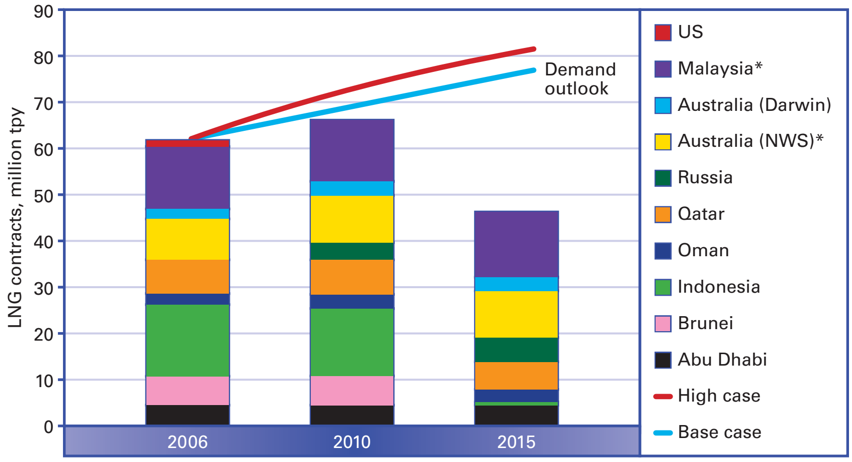
With liberalization, power and gas utilities have gone outside of their traditional markets, while oil refiners and others are entering the LNG retail and power markets. The market/price competition for large-volume users in the industrial sector has been especially fierce, as under deregulation, industrial users can choose utility suppliers.

About 8% of the gas market was taken by new market entrants, including the power utilities, Teikoku Oil (which produces domestic gas), Nippon Steel, and others, while about 2% of the power market was taken by the new entrants, mostly power producers and suppliers. Competition has been particularly fierce in the Kansai area due to its slow demand growth.

Industry deregulation has made it crucial that the established power and gas utilities find optimal ways to procure fuels and cut costs in order to compete in the increasingly liberalized market. City gas utilities, in particular, find it very difficult to remain competitive by offering low gas rates to their industrial clients, given the rising LNG prices beyond 2010-11 when their large volume contracts will be renewed with new price formulas.

Demand outlook exceeds contracts

Fig. 5



*Does not include optional volumes, upwards contractual flexibility.

Gas sector deregulation

Table 6

cu m/year	Timing	Market share, %
Customers using 500,000 or more	April 2004	44
Customers using 100,000 or more	April 2007	50
Complete liberalization	Not decided	100

Agreements with Australian greenfield projects

Table 7

Project*		Volume, million tpy	Buyer	Duration
Gorgon	HOA	1.5	Chubu Electric	2010-35
Gorgon	HOA	1.5	Osaka Gas	2011-36
Gorgon	HOA	1.2	Tokyo Gas	2010-35
Pluto	HOA	10.5 to 1.75	Tokyo Gas	2011-26
Pluto	HOA	1.75 to 2	Kansai Electric	2010-24

*HOA-heads of agreement.

LNG contracts

With market liberalization, "traditional" Japanese consortium LNG buyers have become competitors and ultimately abandoned the "one price fits all" consortium approach in LNG negotiations. Already, new contracts arranged since December 2005 (including North West Shelf Train 4 and Sakhalin II) have been signed without a consortium. The negotiations for NWS Trains 1 to 3 contracts have also been carried out separately by each of the eight initial buyers.

Japan has two large-volume contracts that will expire by 2010-11—the 7.33-million-tpy NWS Trains 1 to 3 and the 12.0-million-tpy Bontang contracts—which will supply reduced volumes to the buyers after renewal.

• NWS Trains 1 to 3. NWS was historically a Japan-focused project and the majority of the output is still destined for Japan. TEPCO was the consortium leader that negotiated the original contract for 7.33 million tpy on behalf of the eight utilities. The existing consortium contracts will expire by 2009.

Chugoku Electric and Toho Gas were the first to sign and have renewed contracted supplies from NWS. Chugoku Electric agreed to purchase 1.2—1.4 million tpy of LNG from the NWS venture. They increased the quantity purchased from the initial 1.1 million tpy, but the new contract is for a shorter duration (12 years). Toho Gas also raised the quantity purchased to a maximum of 0.76 million tpy from 0.23 million tpy and reduced the duration to 12 years. The prices agreed upon have no ceiling but do contain a clause to meet and discuss once JCC ("Japan Crude Cocktail") prices exceed $60/bbl.

Meanwhile, the rest of the eight original buyers participated in the allocation process launched by the Australian venture in April-May 2006 for the sale of up to 4 million tpy, consisting of volumes available for the renewal of Trains 1 to 3 contracts and Train 5's uncommitted volumes.

As a result of the allocation process, six buyers in the original consortium have signed preliminary agreements with the Australian venture for a total of 3 million tpy. The contracts' durations have been reduced to 6-8 years, depending on the buyer, and the extensions of the contracts' durations remain the seller's option.

The delivered ex-ship price agreed upon with these buyers was believed to be higher than prices agreed by Chugoku Electric and Toho Gas. When adding the contract renewals previously agreed during bilateral negotiations with Chugoku Electric and Toho Gas, total volume to Japan will be reduced to 5.12 million tpy from the original 7.33 million tpy.

• Indonesian Bontang. A total of 12 million tpy of Bontang contracts will expire by 2011. The consortium of Japanese buyers and Pertamina had supposedly reached an agreement during fourth-quarter 2005 for the renewal of 6 million tpy over 10 years, at a price significantly lower than the legacy contract. The contract is subject to the approval, however, of the Indonesian regulator BP Migas, which (as of August 2007) had still not approved the contract renewal and is concerned by the low price level.

Also, there is Indonesia's new focus on the domestic market instead of exports. After all, serious doubts remain about the volume of LNG potentially available for contract renewal after

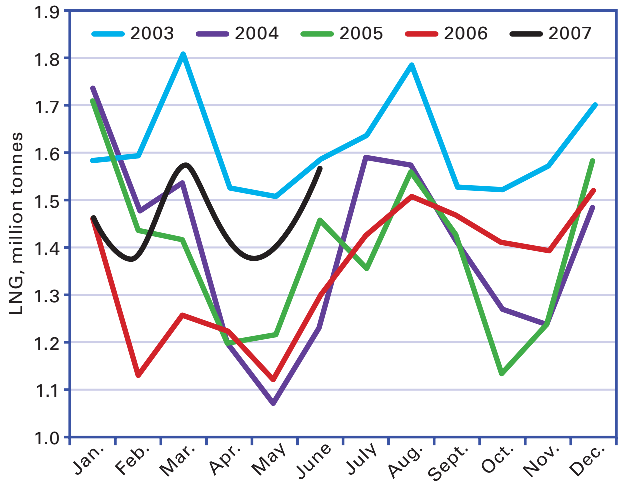
Nuclear power crisis in 2003

TEPCO's LNG consumption was abnormally high in 2003 due to unexpected nuclear power plant closures, which is remembered as the "nuclear power crisis." Beginning late August 2002, TEPCO began nuclear shutdowns for safety inspections as it admitted to having covered up the fact that there were cracks in several reactor parts that were not properly reported in routine plant inspection reports in the late 1980s and 1990s.

By March 2003, TEPCO had shutdown all 17 nuclear power units (17.3 Gw) for safety re-inspections. The company ramped up the existing units' utilization factors and started its backup oil-fired plants to make up for the loss of baseload electricity supply from nuclear shutdowns.

TEPCO's LNG demand remained higher than normal until early 2005.

TEPCO'S LNG CONSUMPTION



2010; thus we believe only a maximum of 3 to 4 million tpy will be renewed.

As a consequence of the reduced volumes of the two large-volume contracts, Japanese buyers have turned mainly toward greenfield projects (e.g., Australian and Russian projects) to meet the supply gap. Table 7 summarizes heads of agreement for Australian greenfield projects. In some cases, Japanese buyers have acquired equity shares in the projects, Tokyo Gas and Kansai Electric each owns 5% of the Pluto project.

Fig. 5 illustrates our base-case and high-case LNG demand outlooks vs. the existing Japanese LNG contracts until 2015. We take the difference between each forecast and the existing contracts to come up with an uncommitted demand figure. Note: Table 7 only includes supply-purchase agreements and selected HOAs, which we consider firm (e.g., NWS renewals and Sakhalin II) in terms of their start-up timing.

It is clear that Japan's contracted volumes are not forecast to meet demand by 2010. Supply could be even more insufficient if Pertamina does not solve its production problems by then. By 2015, Japan's uncommitted demand could reach 30.85 tonnes because the Bontang contracts and the Brunei contract are scheduled to expire by then.

Beyond 2015, expiration of the contracts with Malaysia Satu and Dua (from 2015 to 2018) and with ADGAS (2019) will also take place. If we take into account all the HOAs (e.g., Pluto and Gorgon), preliminary agreements, optional volumes, and potential renewals from Bontang, however, for a total volume of 3 million tpy (not included in the figure above), the volume of uncommitted demand is reduced to 15.6 tonnes by 2015.

Implications

Japan will face an LNG supply shortfall problem, unless the supply agreements for the greenfield projects materialize on schedule and more contracts will be signed. Clearly, those who have a higher dependency on Indonesian LNG are more exposed to future supply shortfalls, given that the Indonesian supply will be reduced after 2010-11. Also, the reduced supply volumes from NWS Trains 1 to 3 beyond 2009 cause added concerns over future supply.

In the long run, other supply reductions may come from ADGAS, as Abu Dhabi needs gas domestically. Meanwhile, buyers continue to hope that potential new supplies from Japan-operated and participated projects may be available, such as INPEX's proposed Ichthys LNG project off northwestern Australia. That's especially true now, as INPEX plans to build its first domestic LNG import terminal in the Niigata prefecture by 2013, where Teikoku Oil owns natural gas pipelines.

Apart from the global supply situation, Japan has domestic issues such as the Kashiwazaki-Kariwa plant shutdown and its effects on other utilities and on the industry as a whole. Under any scenario, Japan's utilization of nuclear power plants will remain reduced without the Kashiwazaki-Kariwa capacity. Without the 8.21 Gw of nuclear power generating capacity, Japan's commitments under the Kyoto protocol is unlikely to be reached.

The long-term answer to the problem involves revising Japan's nuclear safety regulations further and trying to keep the existing nuclear power plants, as well as those under construction, from closing indefinitely. Consequently, some nuclear power plants may need to be upgraded to meet the higher safety guidelines that METI will set.

Japan's nuclear problems have made it very difficult to forecast not only LNG demand, but also oil product balances. An additional some 2 tonnes of LNG, which need to be secured from the spot market in 2007-08 in a tight LNG market, is a serious problem. If the nuclear shutdowns last longer than anticipated, electric utilities will have to depend even more on LNG.

Meanwhile, oil refiners will produce or procure as much low-sulfur fuel oil as TEPCO requires. TEPCO will need a total 180,900 b/d of LSFO and crude oil combined for fiscal year 2007 (April 2007-March 2008). The utility's consumption volume in FY2006 was 69,600 b/d.

The emerging high LSFO demand could be a double-edged sword because it will produce more middle distillates and lighter products when domestic demand remains stagnant. Japanese refiners, especially those who have their own supply network, are expected to enhance their product exports.

Once again, Japan's nuclear power crisis has illustrated the fact that Japan's change in its energy-demand pattern rapidly affects the Asian oil and gas demand-supply picture in its entirety. **LNG**

The author

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Flexibility keys financing of Pacific Basin projects

Scott Flippen
Taylor-DeJongh
Washington

Current Pacific Basin market conditions appear to favor new liquefaction capacity. Considerable uncertainty exists, however, over the market's future. Financing decisions must be considered in light of a sponsor group's desire for flexibility, resources, and appetite for risk.

Access to US West Coast markets could alleviate some degree of market uncertainty, but committing to a regasification terminal that has yet to be constructed brings risks of its own.

A financing strategy that integrates terminal development into the LNG supply and marketing plan may be a viable option for tapping deeper liquidity within the Pacific Basin market.

Pacific Basin priorities

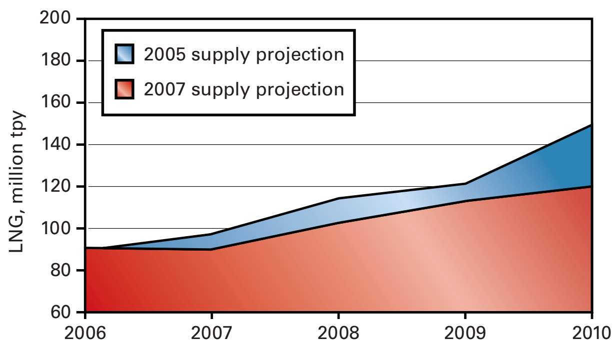
Despite the current global rise in LNG demand, the Pacific Basin will continue to be the largest market for the foreseeable future. Demand growth there is driven by economic recovery in Japan and Korea, concerns over global warming, and the growing need for new electricity-generating capacity in China and India.

LNG demand in this market is expected to grow at an estimated rate of 5-6%/year, to over 160 million tpy in 2014 from roughly 110 million tpy in 2007.

In response to this demand, a large number of Pacific Basin liquefaction projects are currently being developed. In fact, given the number of announced projects, the potential exists for the supply-demand balance to "flip"; that is, the current supply shortage could shift to a surplus by the middle of the next decade. Therefore, swift project execution has become a priority for many sponsors as they seek to lock in offtake contracts reflecting the current tight market.

The US West Coast market plays a prominent role in the plans of many sponsors as well. Access to it would provide additional depth to Pacific Basin demand and provide greater opportunities for arbitrage trade. The growing list of canceled projects, however, demonstrates that realizing a West Coast terminal is a difficult and uncertain task. Project sponsors must choose the financing that best equips them to meet the challenges of an uncertain market.

SUPPLY SLIPPAGE Fig. 1



Source: Taylor-DeJongh Research

Market conditions

Although Pacific Basin LNG demand is on the rise, supply is struggling to keep up. Companies have seized upon this opportunity to gain market share and are committing to invest tens of billions of dollars into building new capacity. There remain, however, considerable uncertainties about the future state of the market.

The current LNG supply crunch and resulting high natural gas prices have created the potential for some demand destruction. Traditional LNG importers (Japan, Korea, and Taiwan) may diversify their energy portfolios to emphasize other sources as a result of rising gas prices.

Demand destruction is an even bigger threat in China and India. Even though these countries have the potential to become significant importers of LNG in the future, neither is fully committed to pursuing this energy source at current market prices.

Finally, gaining access to the West Coast of North America has continued to prove difficult. Currently only one project on the West Coast, Sempra's terminal in Baja California, Mexico, is under construction. In comparison, on the other side of North America and along the Gulf Coast, six terminals are already in existence and five more are under construction.

Uncertain market conditions have been exacerbated by endemic project delays that are pushing back start-up dates for liquefaction projects worldwide. Fig. 1 illustrates how current estimates regarding upcoming Pacific Basin liquefaction capacity have slipped since 2005.

Although delays have placed current LNG supplies in high demand, the near simultaneous entry of several new liquefaction projects in the 2013-14 timeframe could result in region-wide overcapacity and downward pressure on long-term contract prices (currently averaging $8-10/MMbtu). The potential for lower prices as a result of overcapacity concerns many LNG project sponsors. Fig. 2 illustrates the prospects for a shift to a buyer's market as early as 2012.

It should be noted that in 2005, many experts predicted the shift to a buyer's market would occur by 2010-11, a prediction that now seems unlikely. The same schedule delays that have led to the current tightness in the market could continue, pushing the seller's window back further.

Corporate vs. project financing

Uncertainty regarding the future of the Pacific Basin market has already affected the financing strategy of some projects in the region. One example is Woodside's Pluto LNG project.

The single-train project will produce 4.3 million tpy of LNG and cost around $9 billion. Woodside has signed 15-year offtake agreements with Japanese utilities for 3.75 million tpy. The company announced that it will fund the project through corporate debt and the company's free cash flow.

In the current market, this decision appears to offer several advantages. First, "all-equity" financing avoids the longer schedule often associated with project financing. LNG project finance deals are extremely complex, often involving multilateral and export credit agency (ECA) lenders that can take a relatively long time to complete their extensive due-diligence process. Given the potential for future surplus capacity, speed to market can be a significant competitive advantage for a project.

Corporate financing can also provide greater flexibility in marketing strategy. In project financing, lenders will examine downside scenarios in which the value assigned to production volumes that are not under long-term offtake contracts is heavily discounted.

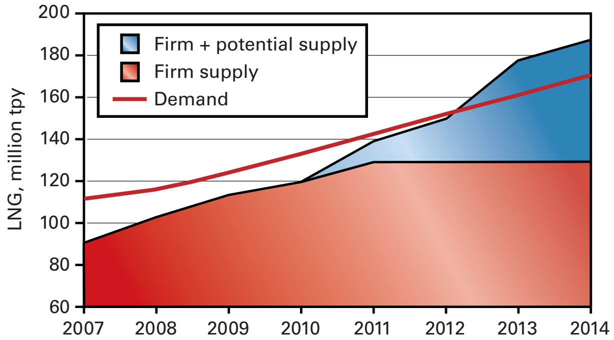
As a result, a sponsor that seeks to reserve a "merchant" tranche of supply, in hopes of increasing upside through more opportunistic sales, may find the project subject to reduced leverage and more stringent debt covenants. In corporate financing, a sponsor can take its own view on the risks associated with more flexible marketing arrangements and act accordingly.

Corporate financings are more widely considered in today's market than they were several years ago. One reason is that the huge surplus cash flows brought by high energy prices have made the option more widely available. If oil prices were at $35/bbl, Woodside and other companies like it might not have the resources even to consider balance-sheet financing for a $9-billion project. Sustained oil prices at $65/bbl and higher, however, have provided producing energy companies with a lot of choices.

All-equity financings have also become more attractive because sponsors have been assuming a greater share of project completion risk. A tight engineering-procurement-construction market has placed EPC contractors in high demand. Their ability to pick and choose the projects they undertake has made it less necessary for them to take on construction and completion price risk. These risks, therefore, have been pushed back on sponsors. As the exposure to overall completion risk increases, the construction-period risk profile of a project-financed project begins to look very similar to that of a corporate financing.

Even with the today's high energy prices, deciding to pursue balance-sheet financing is not without constraints and bears its own considerable risk. It is well understood that sponsors today are confronted by historically high capital costs. Global engineering services company Bechtel reports the cost of constructing a liquefaction facility has risen to as much as $600/tonne/year of production capacity. This figure is three times greater than it was just 6 years ago.[1]

A NARROWING WINDOW? Fig. 2



Source: Taylor-DeJongh Research

When current capital costs are combined with the growing scale of today's projects—generally a single train is designed to be at least 4-5 million tpy—the result is a capital outlay of $5 billion or more. Notwithstanding the huge profits that high energy prices have generated with the industry over the past couple of years, capital expenditures of this magnitude will be beyond the balance sheet for all but few corporations.

Pacific Basin liquefaction projects, as with most LNG projects, are also exposed to significant political and regulatory risks. Many of the countries in the Pacific Basin that have the potential to play host to an LNG project come with relatively high levels of country risk.

Host governments' actions can materially reduce a project's commercial viability, or at least add greater complication and uncertainty to a project's commercial structure. A project that is financed on the corporate balance sheet is fully exposed to this risk. Project-finance transactions, on the other hand, can be structured to mitigate country risk more effectively than a corporate financing.

ECA and multilateral lenders can be tapped to provide political risk instruments for both equity and debt. The involvement of these institutions in a project can also bring advantages through additional political leverage with the host government.

One overriding and obvious advantage of project financing is the boost to returns provided by the high level of leverage that can be attained, even in what are sometimes risky environments. The flexibility and speed of execution that can be achieved through corporate financing must be weighed against increased exposure to and reduced returns on the equity invested.

Higher labor costs forced Woodside in September 2006 to raise its project budget for Phase V expansion at the onshore gas plant near Karratha, WA, to $2.425 billion (Aus.) from $2 billion. Included is construction of a 4.2-million-tpy LNG processing train and a second loading berth. The expansion targets mid-2008 for completion. Photograph from Woodside.

A refinancing strategy that uses the corporate balance sheet to underwrite construction and then replaces equity with project debt at the beginning of operations can be a practical approach to combining the benefits of both options. The need for sponsor completion guarantees makes the construction-period risk profile of the two strategies appear very similar.

Once operations have begun, a non-recourse refinancing can reduce equity exposure and boost returns. If this approach is chosen, care must still be taken during project development to create a commercial structure that will protect the option for project financing, even though one may not be immediately at hand.

Cracking the West Coast code

Sponsors not only want to be first to market, they want to be first to the US West Coast market. The LNG market in the Pacific Basin is not as liquid as that of the Atlantic Basin. A higher degree of vertical integration within the natural gas industry and a relatively smaller number of industry participants make the Pacific Basin market less fluid.

Arbitrage opportunities also appear to be different than in the Atlantic Basin. Indexation to a 3-5 month rolling average of the regional oil price index–the Japanese Crude Cocktail–smoothes the Pacific Basin price curve somewhat, which in turn dampens volatility (Fig. 3). Unlike in the Atlantic Basin where price swings between North American and European markets open arbitrage opportunities throughout the year, price swings in the Pacific Basin tend to be much more seasonal and are met through shorter term contracts and spot sales of LNG cargoes. When spot sales arise, they generally are from supplies intended for the Atlantic Basin, with Japanese and Korean utilities seeking volumes from, for example, West Africa and the Middle East.

It is appealing to consider the impact of West Coast access. LNG terminal access to markets in California and the rest of the US West Coast would add significant depth and liquidity to the Pacific Basin market as a whole and provide new opportunities for arbitrage across the Pacific Ocean.

Nevertheless, financing regasification terminals on the West Coast poses problems of its own. First, these projects must clear domestic political and regulatory hurdles. In California, this has proven especially difficult, as evinced by the local government's rejection of a terminal proposed for the Port of Long Beach just south of Los Angeles and the state governor's veto of the Cabrillo Port, planned for off Malibu.

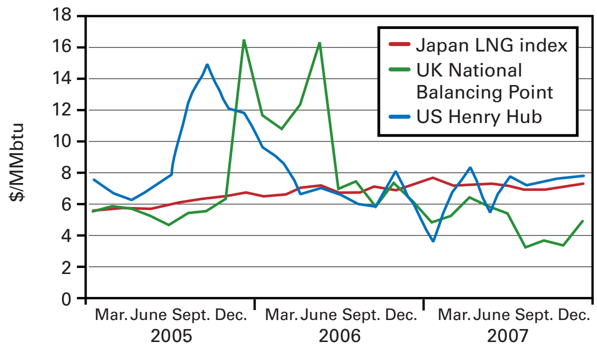
Woodside, however, appears to be making some progress with its terminal off Malibu. Good progress has also been made on permitting projects further north in Oregon that would serve Washington, Oregon, and Northern California markets.

Projects that are well-positioned from a regulatory standpoint face a second obstacle, a lack of readily available LNG supply. Current tightness in Pacific Basin LNG supply has left few creditable parties available to take firm capacity at any proposed West Coast terminal. For a terminal structured as a tolling facility, as are most of the proposed terminals, a long-term terminal-use agreement (TUA) for a majority of terminal capacity on a firm basis is essential. Without such an agreement a terminal will be unable to obtain debt financing.

From a lender's point of view, the largest risk in a tolling structure is the counterparty credit risk. An analysis of this risk should take into account not only the capacity holder's credit rating, but also the strength of its LNG procurement ar-

PACIFIC PRICES LESS VOLATILE

Fig. 3



Source: Bloomberg

rangements and its ability to market gas to the end customer.

One recent event that highlights the importance of a credit analysis of the full value chain concerns the Energía Costa Azul terminal in Baja California, Mexico. Sempra Energy, sponsor of the Costa Azul plant, has a 3.7-million-tpy offtake agreement with the BP-operated Tangguh LNG project in Indonesia. In June 2007, the Indonesian press reported that a significant portion of that volume would be diverted to other customers, including Indonesian state utility PLN. When the agreement was originally signed in 2004, BP characterized it as "highly flexible."[2] Therefore, the provision appears to have been part of the offtake agreement between the parties.

The situation, however, illustrates the importance of fully evaluating the risks up and downstream of a TUA, even when the counterparty brings an investment-grade credit rating. Issues such as the construction, operating, and country risks related to the source of the LNG supply, shipping arrangements, and natural gas marketing strategy all need to be carefully reviewed to assess the overall sustainability of the TUA.

Although a strong TUA with a creditworthy capacity holder may be sufficient to support the financing of a regas terminal, it may not be enough for the liquefaction plant. Take, for example, the situation in which the marketing plan for a given plant's LNG involves regasification at a terminal that has yet to begin construction.

Lenders to the supply plant will be reluctant to provide financing if offtake arrangements involve a regas facility that is still under development. Lenders will not want to assume the permitting, financing, and construction risks for the terminal and will pass them through to the sponsor's completion guarantee. If the sponsor is not the offtaker, the sponsor will probably pass the terminal completion risk to the offtaker through the LNG sales and purchase agreement.

In the end, whichever party is planning to offtake LNG and regasify it through its capacity at the terminal in question will be forced to bear completion risk for that terminal.

Under these circumstances it may make sense for the party bearing the terminal-completion risk to consider a significant equity investment, perhaps even a majority stake, in the terminal. Downsides to this approach include added capital budgeting requirements and reduced return on equity expected from an investment in regasification relative to a liquefaction project.

But there is considerable upside in owning a stake in the regas terminal, especially in terms of risk management. The ability to influence–or in the case of a majority stake, control–decisions throughout development and construction increases the ability to manage terminal-completion risk well beyond what is afforded through simply signing a TUA.

The impact on returns from investing in a less profitable regas facility is also small when viewed in the context of an overall investment in the LNG value chain. A regas terminal with a capacity of 1 bcfd can be expected to cost about $600 million to build. Assuming creditworthy agreements cover a majority of terminal capacity, project financing can achieve 80% leverage, leaving $120 million for sponsors to finance through equity. In this scenario, an investment of $75 million may be enough to secure a majority shareholding (51% of construction equity plus a premium).

Given the utility-style risk profile of a typical regas facility, returns to equity can be expected to be around 10—12%. This can be compared to a liquefaction plant that costs $5 billion, is 60% levered–thereby requiring $2 billion in equity–and is expected to provide an equity internal rate of return of 18%. Adding the regas cash flows to those of the liquefaction plant lowers liquefaction returns by less than 30 basis points. This relatively small reduction in expected returns is compensated by the ability to optimize risk management throughout the LNG supply chain.

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LNG construction projects, plans move ahead, buck cost pressures

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Despite escalating costs of materials and labor, LNG construction worldwide through mid-2007 has continued, with particular progress being made in Asia and the Americas.

While Australia has decided to move ahead with major project Pluto, China is on track in 2007 to import more than 6 million tonnes as it works to build additional terminals. In North America, the first receiving terminal on the West Coast is advancing towards start-up in the next 6 months.

In Europe, the much-delayed and discussed Barents Sea Schtokman project made a decisive step towards realization earlier this summer when Russia's Gazprom announced its first partner for the project. And in North Africa, plans to repair the damaged Skikda liquefaction plant in Algeria have finally begun to move ahead.

Australasia

Australia, already the world's fourth largest LNG exporter, is moving ahead with new projects that could help quadruple its LNG exports by 2010.

In late July, the board of Woodside Petroleum Ltd. approved development of the 4.3-4.8 million tonnes/year (tpy) Pluto LNG project at Karratha on Western Australia's Burrup Peninsula. It will use feedstock from the offshore Pluto and Xena fields, estimated to hold 5 tcf of reserves. Woodside has additional exploration acreage in the area. Start-up is set for 2010, pending receipt of still-needed regulatory and environmental approvals.

Participants are Woodside (owned 34% by Shell) with a 90% share and Tokyo Gas and Kansai Electric, each with 5%. Woodside also operates the North West Shelf project in which it has a 16.7% interest.

The project will be backed by 15-year contracts (with a 5-year option) for the sale of up to 3.75 million tpy of LNG to Tokyo Gas and Kansai Electric, which will each build and operate an LNG carrier. Woodside will lease another tanker and is evaluating additional shipping requirements.

Project cost will run an estimated

Project Updates

Images from BG Group and Statoil

$12 billion (Aus.), around 20% more than originally projected. Woodside's board also approved consideration of a one- and a two-train expansion.

Santos is proposing a 3-4 million tpy liquefaction plant at Gladstone in Queensland on Australia's East Coast that would be the first in the world to use coalseam methane as feedstock. The plant could cost as much as $7 billion (Aus.), half of it for upstream field development. A final investment decision will come by yearend 2009; deliveries could start in early 2014.

At least eight more LNG Australian projects have been proposed (accompanying table). Government officials say Australian LNG exports could quadruple to more than 50 million tpy within a decade.

Proposed Australian LNG export plants

Project name	Location or source of gas	Participants	Capacity, million tpy	Possible start-up
North West Shelf expansion: Train 5 (under construction)	Offshore fields, Withnell Bay	Woodside, Chevron, BHP Billiton, BP, Shell, Mitsubishi/ Mitsui	4.2	2008
Gorgon	Barrow Island	Chevron, Shell, ExxonMobil	10-17	2011
Pluto LNG	Burrup Peninsula	Woodside	6	2010
Browse LNG	Browse Basin	Woodside[1]	10	2013
Ichthys	Maret Islands, Browse Basin	Inpex	6	2012
Sunrise	Sunrise and Troubador fields, Timor Sea	Woodside, ConocoPhillips, Shell, Osaka Gas	5	2012+
Darwin LNG Train 2	Bayu-Undan field, East Timor	ConocoPhillips, Santos, ENI, Inpex, Tokyo Gas, Tokyo Electric[2]	6-7	2012-13
Pilbara LNG	Scarborough fields in Carnavon Basin	BHP Billiton ExxonMobil	5	2012+

[1]Partners in reserves are BP, Chevron, Shell, and BHP Billiton. [2]Partners in Train 1.

In September, in Australia's Gorgon project, Shell Eastern LNG signed binding heads of agreement with PetroChina International Co. to supply 1 million tpy of LNG for 20 years. The companies expect to conclude the sales and purchase agreement (SPA) by yearend 2008, contingent upon an FID by the Gorgon joint-venture Chevron (50%, ExxonMobil (25%), and Shell (25%). This agreement augments others to sell up to 2.5 million tpy to Mexico and 500,000 tpy to India.

The original $8.6 billion budget for the total Gorgon project—field development and LNG—has been pushed much higher by rising labor and materials costs. Fields holding more then 40 tcf backstop the liquefaction segment.

Also in early September, Gorgon received final approval from the Western Australian government, a major hurdle that had threatened the stop the project.

For approval, WA's Environment Ministry set "stringent" environmental conditions, among which Gorgon must establish a reservoir for a CO2 reinjection and expert panels to protect the biodiversity of Barrow Island surrounding marine environment. The sequestration plan proposes to reinject about 3 million tonnes of CO2/year under Barrow Island at a cost of about $850 million (Aus.) in the following 10 years.

The plan also includes a $60 million (Aus.) extra commitment by Gorgon to conserve rare flatback turtles and other endangered species.

In Browse LNG, another Australian project, PetroChina signed a preliminary agreement to buy 2-3 million tpy of LNG for 15-20 years from Woodside Petroleum's proposed project in what could be Australia's largest-ever export deal. Woodside said deliveries would begin 2013-15. PetroChina is developing three LNG terminals at Dalian on the northeast coast, Tangshan in Hebei Province, and Rudong in Jiangsu.

In Japan, following shutdown of its 8.2-Gw Kashiwazaki-Kariwa nuclear plant in western Japan after an earthquake in July, Tokyo Electric Power Co. Ltd. has projected that it will double its imports of crude oil and buy 18.8 million tpy of LNG (equivalent to 10-15 spot cargoes), up from its earlier projection of 17.5 million tonnes. The plant is expected to be shut through March 2008.

Taikoku Oil, subsidiary of Inpex Holdings Inc., announced plans to build a small LNG terminal at Joetsu, Niigata prefecture, in northwest Japan. Construction would start in 2009 and operations begin in late 2013 with an initial capacity of 600,000 tpy. The terminal would be the 28th in Japan.

Supplies could come from Indonesia, where Inpex has interests in the Tangguh project and a 50% share in the Mahakam block that supplies Bontang LNG, and from Australia, where Inpex participates in Darwin LNG and the proposed Ichthys project.

[*Editor's note*: See p. 14 of this issue for an extended analysis of Japan's energy and LNG present and future.]

In Indonesia, state-owned Pertamina signed an agreement with Mitsubishi and independent producer Medic Energi to build a $1.1 billion, 2-million-tpy liquefaction plant that will ship to Japan starting in 2010.

Mitsubishi will hold 51% in the project, Pertamina 29%, and independent producer Medco 20%. The feed gas will come from Senoro block, which is jointly operated by Pertamina and Medco, and from the Pertamina-operated Matindok Block.

Elsewhere in Asia, LNG World Shipping Journal reported that Guangdong Dapeng LNG Co., which operates China's only LNG terminal, was in

Ground clearing progresses in earnest near Karratha on Western Australia's Burrup Peninsula for Woodside Petroleum Ltd.'s Pluto LNG project. In mid-2007, the company announced it was moving ahead with the 4.3-4.8 million tpy, $12 billion (Aus.) project. Photograph from Woodside.

August bringing in LNG at a pace to import 2.6 million tonnes for 2007, up from 687,500 tonnes in 2006. The terminal came on stream in 2006 and is expanding to its nameplate capacity of 3.3 million tpy.

North West Shelf has contracted to send the terminal 3.3 million tpy over 25 years. And Guangdong had, in early August, taken its fourth spot cargo, according to Platts.

Guangdong Dapeng plans to double capacity at the terminal by 2010. And new terminals are under construction at Fujian and Shanghai.

[*Editor's note*: For more on China's LNG picture, see Oil & Gas Journal, Oct. 15, 2007.]

In Korea, Korea Gas Corp. announced in July plans to increase LNG storage capacity by 72% in the next 5 years to meet South Korea's growing demand for gas and to accommodate seasonal fluctuations in consumption (OGJ Online, July 31, 2007).

The company will construct 20 storage tanks by 2012, split among three LNG terminals—Incheon, Pyeongtaek, and Tongyoung.

The terminals currently contain a total of 40 storage tanks with total capacity of 5.18 billion cu m. The new tanks will provide 3.7 million cu m of additional LNG storage capacity, enough for 42 days of residential use, Kogas said.

Three tanks will be added in 2008, three in 2009, five in 2010, six in 2011, and three in 2012. Large tanks of 200,000 cu m will feature prominently in the program.

Kogas said it was considering construction of a fourth LNG terminal after 2012.

Dependent entirely on LNG for gas supply, South Korea is the world's second-largest LNG buyer after Japan. Kogas imported 24.27 million tonnes of LNG in 2006, up 8.6% over 2005. The country's gas consumption will likely increase by at least 50% in the next decade, and Kogas is lining up additional LNG supplies from Russia, Indonesia, Qatar, Yemen, and other suppliers.

Two thirds of the country's gas consumption occurs during winter months, and Kogas said it arranges LNG swap cargoes with utilities in Japan and Taiwan to ease annual December-March shortages.

The company also has formed a $10 million, 50-50 joint venture with Oman to provide Korea with additional LNG in case of winter supply disruptions. The storage tanks also provide buffer stocks during periods of peak demand.

Western Hemisphere

CB&I signed an engineering, procurement, and construction (EPC) contract for Chile's first LNG terminal at Quintero Bay, 70 miles northwest of Santiago. The 2.5-million-tpy terminal will be owned by GNL Quintero SA, a joint venture of BG Group PLC with a 40% share; Endesa Chile 20%; Chile's national oil and gas company ENAP 20%; and gas distribution company Metrogas Chile 20%.

BG will supply 1.7 million tpy of LNG to the project from its portfolio. The terminal is scheduled to start operations in second-quarter 2009.

In September, Marubeni Corp. signed an SPA with SK Energy to acquire 10% of the Peru LNG project, to be located in the Pampa Melchorita area south of Lima. The project's international consortium now consists of Hunt Oil Co. (US; 50%), SK Energy (Korea; 20%), Repsol YPF (Spain; 20%), and Marubeni (Japan).

CB&I holds an EPC contract for a single-train, 4.45-million-tpy LNG plant. LNG is to begin flowing in 2010 under an SPA with Repsol YPF. Total project cost is about $3.8b.

In Mexico, the nation's second LNG terminal and the first on the entire western coasts of the Americas is well on its way to opening later this year or early 2008. Energía Costa Azul, under development in Baja California, Mexico, by Sempra Energy unit Sempra LNG, will initially be able to send out as much as 1 bcfd of Pacific Rim-produced natural gas to Mexican and US markets.

In the US in late August, Waterborne Energy Inc., Houston, reported that cargoes to date and likely incoming shipments for the rest of 2007 will reach 19.3 million tonnes, setting a new annual record and nearly 60% ahead of the 12.3 tonnes received in 2006.

In early August 2007, construction teams raised the roof on a third LNG storage tank at Cheniere's Sabine Pass LNG regasification terminal in southwest Louisiana. These three tanks, of six to be finally built, will have 10.1 bcf of LNG storage capacity. The terminal will begin operations in second-quarter 2008 and have total regasification capacity of 4 bcfd when construction ends in 2009. Photograph from Cheniere Energy Inc. by Mike Kelly.

Imported LNG for the first 8 months of 2007 reached 14.5 tonnes, as much as came in through all of 2004, the previous record year for US LNG imports.

This year, the US is competing with Spain to be the world's third-largest LNG importer. Once expansions at three of the five existing US terminals and construction of four new terminals are completed, however, the US should easily outpace Spain in the next 3 years.

CB&I signed an EPC contract for expansion of Southern LNG Inc.'s terminal at Elba Island, Ga. CB&I will build a 200,000-cu-m storage tank—largest in North America—that will increase the terminal's LNG storage capacity by more than 50% to 11.5 bcf and add 540 MMcfd of sendout to increase capacity to 1.7 bcfd by 2010.

At the end of June, Dominion Cove Point resumed operations of its terminal at Cove Point, Md., following a month-long shutdown to allow tie-in work. The terminal's expansion will add two storage tanks, bringing the number to seven with a total capacity of 14.6 bcf; 800 MMcfd of sendout capacity for a total of 1.8 bcfd; and construction of 81 miles of new pipeline in Pennsylvania and 48 miles in Maryland. CB&I also holds this contract; it built the existing five storage tanks at Cove Point.

Along the Gulf Coast, the US Federal Energy Regulatory Commission staff has issued the final environmental impact statement for the proposed Calhoun LNG terminal and pipeline project at Port Lavaca-Point Comfort in Calhoun and Jackson Counties, Texas. The project, which is being developed by Gulf Coast LNG Partners LP, would have two 160,000-cu-m storage tanks and sendout capacity of around 1 bcfd. Operations would begin in 2009-10.

Similarly, on the West Coast, FERC has issued a favorable draft EIS for the proposed Bradwood Landing LNG terminal on the Columbia River in Oregon. Bradwood Landing's owner NorthernStar Natural Gas plans two 160,000-cu m, full-containment storage tanks to be augmented by a third if needed.

Europe

In July, OAO Gazprom named France's Total SA as its partner for the first phase of the much-discussed Shtokman project in the Barents Sea, ending years of discussions over a field that will ultimately supply gas to both Europe and North America. Gazprom intends to start shipments in 2013 through the Baltic Sea's Nord Stream pipeline and LNG deliveries in 2014 to North America.

Total will receive a 25% stake in a special-purpose company formed to plan, finance, and construct the project's infrastructure. Gazprom intends to award another 24% in the special company to one or more foreign partners but remain sole owner of the company holding license to develop the field.

The first LNG regasification terminal on the western coasts of the Americas will open later this year or in early 2008. Sempra LNG's Energía Costa Azul in Baja California, Mexico, shown here in August more than 80% complete, will initially be able to send out as much as 1 bcfd of Pacific Basin-produced natural gas to Mexican and US markets. Photograph from Sempra Energy.

Work progresses earlier this year on the Qatargas 2 expansion project, a joint venture between Qatar Petroleum, ExxonMobil, and Total. The company calls it the world's "largest integrated LNG project from wellhead to customer" and says it will start up next year. When fully operational, Qatargas 2 will supply up to 16 million tonnes of LNG to Europe, mainly to the UK, says the company. Photograph from Qatargas.

Gazprom estimates output from first phase of the project to be about 23.7 billion cu m/year and Shtokman's total reserves at some 3.7 trillion cu m (more than 129 tcf).

Also in the Barents Sea, Statoil has delivered first gas through a 90-mile pipeline from the Snøhvit field to its single-train 4.2-million-tpy Hammerfest liquefaction plant on Melkøya Island. The first cargo is expected to be shipped in October.

Statoil is operator with 33.53% interest; other participants are Petoro 30%, Total 18.4%, Gaz de France 12%, Hess 3.26%, and RWE Dea 2.81%.

The UK in July received its first LNG cargo in nearly 4 months when the Berge Arzew unloaded at Isle of Grain. Capacity in the terminal, operated by National Grid, is held by BP and Algeria's Sonatrach.

Higher prices in the US drew LNG away from the UK, especially after the opening of new pipelines from Norway and the Netherlands drove prices down. UK gas prices rose again, however, after a pipeline from Norway was closed.

In other UK developments, British Gas Trading Ltd., subsidiary of Centrica PLC, and Asean LNG Trading Co. Ltd., subsidiary of Malaysia's Petronas, terminated their 15-year LNG SPA signed in August 2004 "due to certain conditions precedent in the contract not having been satisfied." No details were disclosed.

Under the contract, Petronas would have delivered up to 3 billion cu m/year to the Dragon LNG terminal at Milford Haven in Wales starting in 2007. The 6-billion-cu m capacity terminal is owned by Petronas 30%, BG Group 50%, and Petroplus 20%. The LNG was to have come from Petronas's portfolio of supply sources, including Malaysia and Egypt, where Petronas has a 35.5% share in Train 1 and a 38% share in Train 2 of the Egyptian LNG plant at Idku.

In Belgium, Fluxys LNG announced in August it had received an €85-million loan from the European Investment Bank to double capacity of the Zeebrugge LNG regasification terminal to 6.6 million tpy. The company said the increased capacity has been fully booked on a long-term basis (OGJ Online, Aug. 9, 2007).

Fluxys is adding extra regasification infrastructure and a fourth LNG storage tank under a €165-million investment plan. Commissioning of the expansion was to begin by yearend.

Fluxys LNG, with a 93.20% stake, owns and operates the Zeebrugge terminal.

Zeebrugge may well be the site of the world's first fixed ship-to-ship transfer facility, if the Belgian shipping company Exmar NV can gain approval from the Brugge-Zeebrugge Port Authority. It filed its application in August to build the LNG transfer installation and high-pressure natural gas discharge connection (OGJ Online, Aug. 2, 2007).

The facility would resemble UK's Teesside Gas Port plant but also could handle transshipment of LNG between carriers, said Exmar. Currently, Zeebrugge has Belgium's only conventional jetty to discharge LNG, operated by Fluxys.

Exmar said its project aims to increase options for bringing natural gas to Belgium and strengthening the country's position as a supply and gas transit center.

Exmar is working with Ondernemingen Jan De Nul, Praxair Inc., Jacobs Engineering Group Inc., ERM Benelux in Belgium, and Ecolas NV in planning construction and development of the facility. The infrastructure is designed for the simultaneous berthing of two LNG carriers, either conventional or regasification vessels (LNGRV) capable of regasifying LNG on board and injecting gas directly into the national distribution grid.

In Germany, RWE Gas Midstream announced plans in July to develop an LNG import terminal at Wilhelmshaven in northern Germany. German GasPort will use Excelerate Energy's shipboard regasification technology to deliver the gas directly into the German grid (OGJ Online, July 9, 2007).

RWE, with Excelerate and Nord-West Oelleitung GMBH, plans to deliver as much as 600,000 cu m/hr of regasified LNG into the German network starting by yearend 2010.

The partners will carry out technical and financial studies over several months as they work to secure permits from various authorities concerning marine, environmental, and pipeline connections.

The company said German GasPort is a dockside regasification application, a land-based manifold that will connect to a high-pressure gas arm on Excelerate's Energy Bridge regasification vessels.

Africa, Middle East

In North Africa, Sonatrach awarded a $2.8 billion-EPC contract to KBR for a new 4.5-million-tpy LNG export train at the Skikda plant, associated LPG and condensate recovery, and precommissioning and commissioning. The new train will replace three units with a combined capacity of 2.7 million tpy destroyed in a January 2004 explosion.

In early September, however, Sonatrach terminated an agreement with Spain's Repsol YPC and Gas Natural to develop the integrated Gassi Touil project, citing delays in the investment plan, and now plans to develop it alone. Start-up for the project has been pushed back to 2001 from 2009.

So far $600 million has been invested in the project 39% of it from Repsol, 26 % from Gas Natural, and 35 % by Sonatrach. The initial agreement signed in November 2004 called for the drilling of 52 developmental wells, production of 22 MM cu m/day of gas, and construction of a 4-million-tpy liquefaction plant over 54 months.

The two European companies decried the action as unlawful and threatened international arbitration in response.

In West Africa in June, Brass LNG awarded Bechtel Corp. a contract for work on the proposed Brass LNG plant. Bechtel will prepare the site and construct a camp and construction dock, permanent operator housing and amenities, marine facilities, common facilities and support services, tankage, utilities and offsite, and others.

Brass LNG will process 10 million tonnes/year of LNG in two separate trains beginning late 2010 or first-half 2011 for export to the US and Europe.

Suez LNG Trading SA has signed a memorandum of understanding with Brass LNG to buy 2 million tpy of LNG for 20 years. BP PLC has also agreed to buy 2 million tpy of LNG starting in 2010.

Current partners are Nigerian National Petroleum Corp. 49%, Italy's Eni SPA 17%, Total SA 17%, and ConocoPhillips 17% (OGJ Online, June 7, 2007).

In Qatar, Qatargas Liquefied Gas Co. Ltd. has secured more than $4 billion in financing for its 7.8-million-tpy Qatargas 4 project, a joint venture of subsidiaries of QP (70%) and Royal Dutch Shell (30%). Project costs have risen to $8 billion from an initial estimate of $6-7 billion. When production starts up around 2010, the project will sell LNG to a Shell subsidiary for export, mainly to the North American market.

In a separate agreement, Shell was appointed shipping manager for 25 tankers owned by Nakilat (Qatar Gas Transport Co.) that will serve four Qatari LNG projects (Qatargas 2, 3, and 4 and RasGas 3). Operational management is to be transferred to Nakilat within 12 years. The ships, all under construction in Korea, will have capacities ranging from 210,000 to 266,000 cu m.

Ras Laffan Liquefied Natural Gas Co. Ltd. (RasGas 2) has signed a short-term agreement with India's Petronet LNG to supply 20 cargoes (around 1.25 million tpy) and a medium-term (around 4.5 years) agreement with EDF Trading Ltd. for interruptible deliveries of up to 3.4 million tpy delivered ex-ship at Belgium's Zeebrugge terminal. **LNG**

US LNG IMPORTS[1]

	Bcf											
	2006			2007								
Sources	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.
Algeria	—	—	—	2.52	—	8.67	24.45	23.61	11.30	—	3.08	5.81
Egypt	2.74	11.26	11.42	8.79	5.68	14.76	14.19	14.89	11.94	12.12	17.55	14.71
Equatorial Guinea	—	—	—	—	—	—	—	—	2.88	9.14	3.03	—
Nigeria	8.94	5.91	3.08	5.31	5.74	9.07	9.03	15.09	20.15	15.07	14.38	11.63
Qatar	—	—	—	—	—	—	—	3.04	5.76	—	6.06	—
Trinidad	24.48	29.93	36.62	36.63	31.14	54.33	50.87	37.56	36.20	59.60	45.55	29.40
Totals	**36.16**	**47.10**	**51.12**	**53.25**	**42.56**	**86.83**	**98.54**	**94.19**	**88.23**	**95.93**	**89.65**	**61.55**

	Bcf											
Daily[2,3]	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
2007	1.72	1.52	2.80	3.28	3.04	2.94	[4]3.09	[4]2.89	[4]2.05	—	—	—
2006	1.27	1.38	1.07	1.96	2.17	2.05	1.95	1.68	1.38	1.17	1.57	1.65
2005	1.94	1.88	1.49	1.58	1.82	1.87	1.63	1.39	1.72	1.92	1.94	1.65
2004	1.74	1.78	1.57	1.62	1.63	2.10	2.38	1.83	1.84	1.63	1.36	2.05
2003	0.75	0.75	1.00	1.09	1.48	1.54	1.83	1.61	1.69	1.96	1.63	1.32
2002	0.26	0.27	0.33	0.57	0.83	0.86	0.69	0.78	0.56	0.88	0.73	0.65
2001	0.59	0.72	0.75	0.73	0.88	0.89	0.77	0.58	0.73	0.38	0.26	0.43
2000	0.41	0.35	0.48	0.57	0.43	0.49	0.86	0.74	0.68	0.79	0.64	0.58
1999	0.42	0.37	0.42	0.34	0.30	0.39	0.46	0.48	0.57	0.35	0.38	0.41
1998	0.33	0.35	0.18	0.08	0.24	0.25	0.16	0.16	0.17	0.16	0.34	0.40
5-year avg.[5]	1.19	1.23	1.09	1.36	1.58	1.68	1.70	1.46	1.44	1.35	1.18	1.22
% of avg.	144	124	257	241	192	175	179	174	152	86	133	135

	Bcf											
Monthly[3]	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
2007	53.25	42.56	86.83	98.54	94.19	88.23	[4]95.93	[4]89.65	[4]61.55	—	—	—
2006	39.37	38.64	33.16	58.69	67.14	61.57	60.48	51.98	41.46	36.16	47.10	51.12
2005	60.28	52.70	46.22	47.43	56.36	56.07	50.48	43.10	51.57	59.47	58.09	51.10
2004	53.81	51.70	48.60	48.59	50.44	62.92	73.78	56.69	55.06	50.51	40.77	63.52
2003	23.11	21.01	31.00	32.68	45.81	46.14	56.74	50.02	50.77	60.79	49.00	41.04
2002	8.04	7.57	10.15	17.21	25.69	25.82	21.40	24.17	16.89	27.42	21.81	20.15
2001	18.21	20.10	23.25	22.01	27.14	26.59	23.91	17.91	21.83	11.73	7.85	13.21
2000	12.81	10.16	14.81	17.11	13.18	14.79	26.62	22.94	20.44	24.63	19.08	18.05
1999	13.01	10.33	13.09	10.13	9.39	11.56	14.12	15.03	16.97	10.98	11.46	12.67
1998	10.15	9.77	5.66	2.54	7.59	7.59	5.08	4.86	5.13	5.02	10.06	12.50
5-year avg.[5]	45.96	41.32	49.16	57.19	62.79	62.99	67.10	56.07	52.93	46.87	43.35	45.39
% of avg.	116	103	177	172	150	140	140	140	124	77	109	113

[1]Actual and projected as of Sept. 1, 2007. [2]Figures do not include Puerto Rico imports. [3]1998 through May 2003 values are derived from the US Energy Information Administration. [4]Incomplete data. [5]5-year average, 2000-04.

New liquefaction construction

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Country	Operator	Location	Capacity, million tpy	Status	Completion	Contractor	Notes
Algeria	Repsol YPF/Gas Natural/Sonatrach	Arzew	4.0	Planning	2010		New
	Sonatrach	Skikda	4.5	Engineering	2010	JGC/KBR/SNC-Lavalin/Black & Veatch	New. $700 million. Replaces plant destroyed in 2004.
Angola	Angola LNG Ltd.	Soyo	5.0	Engineering	2012	Bechtel/KBR/JGC/Technip	One train. $2 billion. Chevron Corp.(36.4%), Sonangol (22.8%), BP PLC (13.6%), Eni (13.6%), Total SA (13.6%).
Australia	Gorgon LNG	Barrow Island	10.0	Engineering	2010	KBR/JGC/Clough/Hatch/JGC	New. Two trains: 5.0 million tpy/train. Chevron Corp. (50%), ExxonMobil Corp. (25%), Shell (25%).
	Woodside Energy Ltd.	Withnell Bay	4.4	Under constr.	2008	Foster Wheeler/Worley Parsons/Clough Eng. Ltd.	Expansion. Train 5. $2.4 billion.
	Woodside Energy Ltd.	Burrup Peninsula	4.3-4.8	Engineering	2010	Foster Wheeler	New. Pluto LNG; one train.
Equatorial Guinea	Marathon Oil	Bioko Island	4.4	Engineering		Bechtel	Expansion. Train 2. Decision to proceed will be made in 2008. Marathon (60%), Sonagas (25%), Mitsui (8.5%), Marubeni (6.5%).
Indonesia	BP Tangguh	Berau Bay, Papua	7.6	Under constr.	2008-09	KBR/JGC Corp./Wood Group Indonesia	New. Two trains: 3.8 million tpy/train. $1.4 billion. BP (37.16%), CNOOC (16.96%), MI Berau BV (16.31%), Nippon Oil Exploration (12.23%), KG Cos. (10%), LNG Japan (7.35%).
	PT Pertamina	Sulawesi	2.0-2.5	Planning	2009		New. PT Medco Energi, Mitsubishi Corp.
Libya	National Oil Corp.	Marsa Al-Brega	3.2	Planning	2008		Expansion. $400 million. Shell and NOC.
Nigeria	Brass LNG Ltd.	Bayelsa State	10.0	Engineering	2011	Bechtel	New. Two trains: 5 milliion tpy/train. $3 billion. NNPC (49%), ConocoPhillips (17%), Eni (17%), Total SA (17%).
	Nigeria LNG Ltd.	Bonny Island	4.0	Under constr.	2007	KBR/JGC Corp./Technip/Snamprogetti SPA	Expansion. Train 6.
	Nigeria LNG Ltd.	Bonny Island	8.5	Engineering	2011-12	Foster Wheeler/Chiyoda Corp./KBR	Expansion. Train 7. SevenPlus project.
	Nigeria LNG Ltd.	Bonny Island	8.5	Engineering	2012	Foster Wheeler/Chiyoda Corp./KBR	Expansion. Train 8. SevenPlus project.

New liquefaction construction [continued]

Country	Operator	Location	Capacity, million tpy	Status	Completion	Contractor	Notes
	Olokola LNG	West Niger Delta	20.0	Planning	2011	KBR	New. Four trains. NNPC (49.5%), Chevron Corp. (18.5%), Shell (18.5%), BG (13.5%).
	Statoil ASA	Snohvit, Hammerfest, Melkoya Island	4.1	Under constr.	2007	Linde AG/ Statoil	New
Peru	Peru LNG	Pampa Melchorita	4.4	Under constr.	2010	CB&I	New. $3.8 billion. Hunt Oil (50%), SK Corp. (30%), Repsol YPF (20%).
Qatar	QatarGas II	Ras Laffan	15.6	Under constr.	2008-10	Chiyoda Corp./ Technip	New. Two trains: 7.8 million tpy/train. Train 1:1QTR 2008; Train 2: 2009-10. Export to UK, France, US, Mexico. Qatar Petroleum, ExxonMobil Corp., Total SA (16.7% in Train 2).
	QatarGas III	Ras Laffan	7.8	Under constr.	2009	Chiyoda Corp./ Technip	New. $4 billion. Qatar Petroleum (68.5%), ConocoPhillips (30%), Mitsui (1.5%).
	QatarGas IV	Ras Laffan	7.8	Under constr.	2010-11	Chiyoda Corp./ Technip	New. Qatar Petroleum (70%), Shell (30%).
	RasGas III	Ras Laffan	15.6	Under constr.	2008-09	Chiyoda Corp./Technip/ Snamprogetti SPA	Expansion. Two trains: 7.8 milliion tpy/train. Train 6: Aug. 2008; Train 7: Aug 2009. Train 6 to export to US, Europe, Asia. Qatar Petroleum (70%), ExxonMobil Corp. (30%).
Russia	Baltic LNG	Primorsk	5.0	Planning	2009-10		New. $3.7 billion.
	Repsol/Anadarko/ Tambeineftegaz	Yamal Peninsula	10.0	Planning	2011-13		New
	Sakhalin Energy	Prigorodnoye, Sakhalin	9.6	Under constr.	2008	CTSD Ltd.	New. Two trains: 4.8 million tpy/train. Train 1: July 2007; Train 2: Feb. 2008. Export to South Korea, Japan. Gazprom (50%), Royal Dutch Shell (27.5%), Mitsui (12.5%), Mitsubishi (10%).
Trinidad & Tobago	Atlantic LNG Ltd.	Point Fortin	3.0	Planning	2009		New. Train 5 (called Train X).
Venezuela	PDVSA	Gran Mariscal de Ayacucho, Sucre	4.7	Planning	2010		New. $2.7 billion.
	PDVSA	Jose, Anzoategui	2.1	Planning			New. $600 million.
Yemen	Yemen LNG Co. Ltd.	Bal Haf	6.7	Under constr.	2008-09	YEMGAS	New. Two trains. $2 billion. Export to South Korea, France, Belgium.

World LNG tankers under construction

Shipbuilder	Vessel name or hull number	Owner	Capacity, cu m	Commissioning date	Trading route	Propulsion	Containment
Daewoo	LNG Owdo	BW Group	148,300	Mar. 2008	Exports from Nigeria	S	GT No. 96
Daewoo	LNG IMO	BW Group	148,300	June 2008	Exports from Nigeria	S	GT No. 96
Daewoo	Tangguh Towuti	Sovcomflot	145,700	Oct. 2008	Tangguh exports	S	GT No. 96
Daewoo	Tangguh Bratan	Sovcomflot	145,700	Dec. 2008	Tangguh exports	S	GT No. 96
Daewoo	Al Ruwais	Qatar Gas & Pronav	210,000	Aug. 2007		DFDE	GT No. 96
Daewoo	Al Safliya	Qatar Gas & Pronav	210,000	Sept. 2007	Qatar-UK	DFDE	GT No. 96
Daewoo	Duhail	Qatar Gas & Pronav	210,000	Jan. 2008	Qatar-UK	DFDE	GT No. 96
Daewoo	Al Ghariya	Qatar Gas & Pronav	210,000	Dec. 2007	Qatar-UK	DFDE	GT No. 96
Daewoo	Al Aamriya	Qatargas	210,000	Mar. 2008	Qatar-US	DFDE	GT No. 96
Daewoo	Al Oraiq	Qatargas	210,000	Apr. 2008	Qatar-US	DFDE	GT No. 96
Daewoo	2251	Qatargas	210,000	May 2008	Qatar-US	DFDE	GT No. 96
Daewoo	2252	Qatargas	210,000	June 2008	Qatar-US	DFDE	GT No. 96
Daewoo	Umm Al Amad	Qatargas	210,000	July 2008	Qatar-US	DFDE	GT No. 96
Daewoo	Explorer[2]	Exmar	150,900	Feb. 2008		S	GT No. 96
Daewoo	2255	Qatargas	210,000	Sept. 2008	US imports	M	GT No. 96
Daewoo	2256	Qatargas	210,000	Nov. 2008	US imports	M	GT No. 96
Daewoo	2257	Qatargas	210,000	Dec. 2008	US imports	M	GT No. 96
Daewoo	2258	BW Group	156,100	May 2009	Yemen-US	DFDE	GT No. 96
Daewoo	2259	BW Group	156,100	Dec. 2009	Yemen-US	DFDE	GT No. 96
Daewoo	2260	Korea Line Corp.	151,800	Mar. 2008	Russia-Korea	S	GT No. 96
Daewoo	2261	Korea Line Corp.	151,800	Nov. 2008	Yemen-Korea	S	GT No. 96
Daewoo	Express[2]	Exmar	150,900	Apr. 2009	US imports	S	GT No. 96
Daewoo	2264	Qatargas	210,000	Feb. 2009	Qatar	M	GT No. 96
Daewoo	2265	Qatargas	210,000	Mar. 2009	Qatar	M	GT No. 96
Daewoo	2266	Qatargas	210,000	Apr. 2009	Qatar	M	GT No. 96
Daewoo	2267	Knutsen OAS	166,000	June 2010		DFDE	GT No. 96
Daewoo	2268	TMT	167,000	Oct. 2009		DFDE	GT No. 96
Daewoo	2269	Knutsen OAS	166,000	Dec. 2010		DFDE	GT No. 96
Daewoo	Exquisite[2]	Exmar	150,900	Aug. 2009		S	GT No. 96
Daewoo	Expedient[2]	Exmar	150,900	Dec. 2009		S	GT No. 96
Daewoo	Exemplar[2]	Exmar	150,900	June 2010		S	GT No. 96
Daewoo	2274	Knutsen O.A.S. Shipping	166,000	Nov. 2010		DFDE	GT No. 96
Daewoo	2278	TMT Co.	171,800	Aug. 2010		DFDE	GT No. 96
Daewoo	2283[2]	Qatargas	210,100	Sept. 2009	Qatar	DFDE	GT No. 96
Daewoo	2284[2]	Qatargas	210,100	Oct. 2009	Qatar	DFDE	GT No. 96
Daewoo	2285[2]	Qatargas	210,100	Nov. 2009	Qatar	DFDE	GT No. 96
Daewoo	2286[2]	Qatargas	210,100	Dec. 2009	Qatar	DFDE	GT No. 96
Hanjin Hi	192	STX Pan Ocean	155,000	Dec. 2008		S	Technigaz MK III

World LNG tankers under construction (continued)

Shipbuilder	Vessel name or hull number	Owner	Capacity, cu m	Commissioning date	Trading route	Propulsion	Containment
Hanjin Hi	193	STX Pan Ocean	155,000	Dec. 2009		S	Technigaz MK III
Hudong Zhonghua	Dapeng Sun	Guangdong Dapeng LNG	147,100	Nov. 2007	Australia-China	S	GT No. 96
Hudong Zhonghua	Dapeng Moon	Guangdong Dapeng LNG	147,100	May 2008	Australia-China	S	GT No. 96
Hudong Zhonghua	HI320A	Guangdong Dapeng LNG	147,100	Feb. 2008	Australia-China	S	GT No. 96
Hudong Zhonghua	HI378A	COSCO Dalian	145,000	Dec. 2008			GT No. 96
Hudong Zhonghua	HI379A	COSCO Dalian	145,000	Oct. 2009			GT No. 96
Hudong Zhonghua	HI401A	COSCO Dalian	145,000	Oct. 2007	Australia-China	S	GT No. 96
Hudong Zhonghua	HI402A	COSCO Dalian	145,000	Feb. 2008	Australia-China	S	GT No. 96
Hyundai	Grace Barleria	NYK	141,000	Nov. 2007	Australia-China	S	Technigaz MK III
Hyundai	Grace Cosmos	NYK	141,000	Mar. 2008	Australia-China	S	Technigaz MK III
Hyundai	Clean Force	Dynacom	149,700	Jan. 2008	Australia-China	S	Technigaz MK III
Hyundai	British Ruby	BP	155,000	June 2008	Indonesia-Korea/ China/others	DFDE	Technigaz MK III
Hyundai	British Sapphire	BP	155,000	Aug. 2008	Indonesia-Korea/ China/others	DFDE	Technigaz MK III
Hyundai	Tangguh Hiri	Teekay	155,000	Nov. 2008	Tangguh exports	DFDE	Technigaz MK III
Hyundai	Al Gattara	Qatar Gas & OSG	216,200	Oct. 2007	Qatar-UK	DFDE	Technigaz MK III
Hyundai	Al Gharrafa	Qatar Gas & OSG	216,200	Feb. 2008	Qatar-UK	DFDE	Technigaz MK III
Hyundai	Al Thumama	Qatargas	216,200	Feb. 2008	Qatar-US/UK	DFDE	Technigaz MK III
Hyundai	Al Sahla	Qatargas	216,200	June 2008	Qatar-US/UK	DFDE	Technigaz MK III
Hyundai	Al Utourma	Mitsui OSK	216,200	Sept. 2008		DFDE	Technigaz Mk III
Hyundai	1876	Mitsui OSK	155,000	Feb. 2009	Qatar-US/UK	DFDE	Technigaz MK III
Hyundai	Hyundai Ecopia	Hyundai Merchant Marine	150,000	Nov. 2008		S	Technigaz Mk III
Hyundai	1908	Qatargas	216,000	Feb. 2009	Qatar-US	DFDE	Technigaz MK III
Hyundai	1909	Qatargas	216,000	June 2009	Qatar-US	DFDE	Technigaz MK III
Hyundai	1910	Qatargas	216,000	Feb. 2008	Qatar-US	DFDE	Technigaz MK III
Hyundai Samho	British Diamond	BP	155,000	Oct. 2008	Indonesia-Korea/ China/others	DFDE	Technigaz MK III
Hyundai Samho	Tangguh Sago	Teekay	155,000	Mar. 2009	Tangguh exports	DFDE	Technigaz MK III
Hyundai Samho	S324	Mitsui OSK	155,000	Sept. 2009	Tangguh exports	DFDE	Technigaz MK III
Izar Sestao	Sestao Knutsen	Knutsen O.A.S. Shipping	138,000	Dec. 2007		S	GT No. 96
Kawasaki	Celestine River	K Line	145,000	Dec. 2007	US imports	S	Moss
Kawasaki	1588	Iino	145,000	June 2008	US imports	S	Moss
Kawasaki	1591	Osaka Gas - NYK	153,000	Dec. 2008	Oman-Japan	S	Moss
Kawasaki	1592	Osaka Gas - NYK	153,000	July 2009	Oman-Japan	S	Moss
Kawasaki	1593	Mitsui OSK	19,100	Sept. 2007	Japanese domestic trade	M	Moss

World LNG tankers under construction (continued)

Shipbuilder	Vessel name or hull number	Owner	Capacity, cu m	Commissioning date	Trading route	Propulsion	Containment
Kawasaki	1600	Tokyo LNG Tanker	145,000	Mar. 2008	Japanese domestic trade	S	Moss
Kawasaki	1601	Tokyo LNG Tanker	145,000	2010	Japanese domestic trade	S	Moss
Kawasaki	1611	Tokyo LNG Tanker	153,000	Mar. 2009		S	Moss
Kawasaki	1625	NYK	145,000	Dec. 2009		S	
Kawasaki	1626	NYK	145,000	Oct. 2010		S	
Koyo	Trinity Arrow	Shoei	154,200	Nov. 2007	US imports	S	GT No. 96
Koyo	2260	Shoei	154,200	Dec. 2008	US imports	S	GT No. 96
Koyo	2263	Mitsui OSK	154,200	June 2009		S	GT No. 96
Koyo	2265	Mitsui OSK	154,200	Dec. 2009		S	GT No. 96
Mitsubishi	2219	Tokyo Electric	145,000	Mar. 2008		S	Moss
Mitsubishi	Seri Begawan	Petronas (MISC)	152,900	Aug. 2007	Malaysian exports	S	GT No. 96
Mitsubishi	2222	Petronas (MISC)	152,900	Mar. 2008	Malaysian exports	S	GT No. 96
Mitsubishi	Seri Balhaf	Petronas (MISC)	152,900	Aug. 2008	Yemen exports	S	GT No. 96
Mitsubishi	Seri Balquis	Petronas (MISC)	152,900	Dec. 2008	Yemen exports	S	GT No. 96
Mitsubishi	Grand Elena	Sovcomflot - NYK jv	147,200	Oct. 2007	Russia-Japan	S	Moss
Mitsubishi	Grand Aniva	Sovcomflot - NYK jv	147,200	Dec. 2007	Russia-Japan	S	Moss
Mitsubishi	Pacific Hope	NYK	145,000	Jan. 2009		S	Moss
Mitsubishi	2236	Tokyo Electric	145,000	Mar. 2009	Russia-Japan	S	Moss
Mitsubishi	2241	Mitsui OSK - NYK	145,000	Sept. 2009	Qatar-Taiwan	S	Moss
Mitsubishi	2242	Mitsui OSK - NYK	145,000	Jan. 2010	Qatar-Taiwan	S	Moss
Mitsui	1681	Mitsui OSK	147,200	April 2008	Russia-Japan	S	Moss
Remontowa	Coral Methane	Veder, Anthony	7,500	Aug. 2008	Norway	M	
Samsung	LNG Borno	NYK	149,600	June 2007	Exports from Nigeria	S	Technigaz MK III
Samsung	LNG Ogun	NYK	149,600	Aug. 2007	Exports from Nigeria	S	Technigaz MK III
Samsung	Methane Alison Victoria	British Gas Corp.	145,000	Sept. 2008	Egypt-US	S	Technigaz MK III
Samsung	Methane Nile Eagle	British Gas Corp.	145,000	June 2008	Egypt-US	S	Technigaz MK III
Samsung	Seri Angkasa	Petronas (MISC)	145,000	Nov. 2007	Malaysia-Japan	S	Technigaz MK III
Samsung	Seri Ayu	Petronas (MISC)	145,000	Sept. 2007	Malaysia-Japan	S	Technigaz MK III
Samsung	Tembek	Qatar Gas & OSG	216,200	Aug. 2007	Qatar-UK	DFDE	Technigaz MK III
Samsung	Al Hamla	Qatar Gas & OSG	216,200	Oct. 2007	Qatar-UK	DFDE	Technigaz MK III
Samsung	1607	A.P. Moller	153,000	Oct. 2007	Qatar-UK	DFDE	Technigaz MK III
Samsung	Maersk Marib	A.P. Moller	153,000	June 2008	Qatar-UK	DFDE	Technigaz MK III
Samsung	Tangguh Foja	K Line	153,200	Aug. 2008	Tangguh exports	DFDE	Technigaz MK III
Samsung	Tangguh Jaya	K Line	153,200	Nov. 2008	Tangguh exports	DFDE	Technigaz MK III
Samsung	1625	A.P. Moller	153,000	Sept. 2008	Yemen exports	DFDE	Technigaz MK III
Samsung	1626	A.P. Moller	153,000	Apr. 2009	Yemen exports	DFDE	Technigaz MK III
Samsung	1632	A.P. Moller	153,000	Oct. 2009	Yemen exports	DFDE	Technigaz MK III
Samsung	1633	A.P. Moller	153,000	Dec. 2009	Yemen exports	DFDE	Technigaz MK III

World LNG tankers under construction (continued)

Shipbuilder	Vessel name or hull number	Owner	Capacity, cu m	Commissioning date	Trading route	Propulsion	Containment
Samsung	Tangguh Palung	K Line	153,000	Dec. 2008	Tangguh exports	S	Technigaz MK III
Samsung	1641	ChevronTexaco	154,800	June 2009	ChevTex projects	DFDE	Technigaz MK III
Samsung	1642	ChevronTexaco	154,800	July 2009	ChevTex projects	DFDE	Technigaz MK III
Samsung	1643	Teekay	217,000	May 2008	ChevTex projects	DFDE	Technigaz MK III
Samsung	1644	Teekay	217,000	Apr. 2008	ChevTex projects	DFDE	Technigaz MK III
Samsung	1645	Teekay	217,000	May 2008	ChevTex projects	DFDE	Technigaz MK III
Samsung	1646	Teekay	217,000	June 2008	ChevTex projects	DFDE	Technigaz MK III
Samsung	1675	Qatargas	216,200	Aug. 2008	Qatar-US/UK	DFDE	Technigaz MK III
Samsung	1676	Qatargas	216,200	Oct. 2008	Qatar-US/UK	DFDE	Technigaz MK III
Samsung	1677	Qatargas	266,000	Dec. 2008	Qatar-US/UK	DFDE	Technigaz MK III
Samsung	1686	NYK - Mitsui OSK - K Line	154,800	Sept. 2009	Qatar-US/UK	DFDE	Technigaz MK III
Samsung	1688[2]	Hoegh L. & Co.	145,000	Oct. 2009	Qatar-US/UK	DFDE	Technigaz MK III
Samsung	1689[2]	Hoegh L. & Co.	145,000	Apr. 2010	Qatar-US/UK	DFDE	Technigaz MK III
Samsung	1694	Qatargas	267,000	Jan. 2009	Qatar-US/UK	DFDE	Technigaz MK III
Samsung	1695	Qatargas	267,000	Feb. 2009	Qatar-US/UK	DFDE	Technigaz MK III
Samsung	1696	Qatargas	216,000	Mar. 2009		DFDE	Technigaz MK III
Samsung	1697	Qatargas	216,200	Apr. 2009	Qatar-US/UK	DFDE	Technigaz MK III
Samsung	1726	Qatargas	267,000	July 2009		DFDE	Technigaz Mk III
Samsung	1745	British Gas Corp.	170,000	Dec. 2009		DFDE	Technigaz MK III
Samsung	1746	British Gas Corp.	170,000	Sept. 2010		DFDE	Technigaz MK III
Samsung	1751[2]	Qatargas	267,000	Oct. 2009	Qatar	DFDE	Technigaz MK III
Samsung	1752[2]	Qatargas	266,000	Dec. 2009	Qatar	DFDE	Technigaz MK III
Samsung	1753[2]	Qatargas	266,000	Jan. 2010	Qatar	DFDE	Technigaz MK III
Samsung	1754[2]	Qatargas	267,000	Feb. 2010	Qatar	DFDE	Technigaz Mk III
Samsung	1761[2]	Flex LNG	90,000	Aug. 2010		DFDE	SPB
Samsung	1762[2]	Flex LNG	90,000	May 2011		DFDE	SPB
STX Shipbuilding	3008	Elcano	169,000	May 2010		M	unknown
Taizhou Zhongyuan	WZL0501	Skaugen I. M.	9,500	Dec. 2007	Chinese domestic trade	M	unknown
Taizhou Zhongyuan	WZL0502	Skaugen I. M.	9,500	Mar. 2008	Chinese domestic trade	M	unknown
Taizhou Zhongyuan	WZL0503	Skaugen I. M.	9,500	June 2008	Chinese domestic trade	M	unknown
Universal Tsu	Cheikh Bouamama	Sonatrach	75,500	July 2008	Intra Mediterranean	S	Technigaz MK III
Total capacities			**23,612,200**				

[1]S = steam; DFDE = dual-fuel diesel electric; M = motor. [2]Regasification vessel.

Source: EA Gibson Shipbrokers Ltd., London; www.eagibson.co.uk. List current as of Sept. 1, 2007.