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OIL&GAS JOURNAL®

May 25, 2009
Volume 107.20

ARCTIC DRILLING AND PRODUCTION

REGULAR FEATURES

COVER

World-class arctic drilling technology will go into ExxonMobil Corp.'s wells at the Point Thomson Unit on Alaska's North Slope 60 miles east of Prudhoe Bay. Penetrating a reservoir 2.5 miles deep at more than 10,000 psi and extending beneath the Beaufort Sea, they will be among the world's most complex wells. The ramp at the lower left corner of this image of Nabors Rig 27E on the PTU-15 well, spud in late April, runs downslope on the insulated permafrost drill pad to the Beaufort barge landing. The rig has been equipped with a new mud system and power generation and structural upgrades to safely drill the wells. Drilling water comes from a lake several miles inland at the end of the road at top right. The reservoir is estimated to contain 25% of the North Slope's known natural gas resource. OGJ's Arctic Drilling and Production special has an article about Alaska fiscal regimes starting on p. 20. Photo courtesy of ExxonMobil.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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May 25, 2009

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General Interest — Quick Takes

Indonesia, ExxonMobil disagree over tax debt

Indonesia is still in dispute with ExxonMobil Corp. and Kodeco Energy Co. Ltd. over the companies' alleged tax debts totaling $63 million, while three other firms have settled their outstanding bills. The two firms and Indonesian state auditors still hold different opinions about how the tax is calculated and the amount owed, according to R. Priyono, director of BPMigas, Indonesia's upstream oil and gas regulator.

Priyono told a hearing at the House of Representatives Commission VII for energy and mineral resources that ExxonMobil, based on an audit result from the State Development Finance Comptroller (BPKP), still owed the state $30.65 million in unpaid corporate taxes.

According to the BPMigas' report given to legislators, ExxonMobil claims it was to receive a tax reduction because of a royalty it paid to PT Asamera Oil Indonesia Ltd.

But Priyono said the royalty has nothing to do with the production-sharing contract between the government and ExxonMobil and "cannot be used as a tax reduction." Priyono added that the dispute still is being deliberated by a tax tribunal.

Meanwhile, Kodeco claims taxes that it owes are calculated on the basis of revenues and costs across all fields in one working area. But BPMigas and the BPKP argue that tax must be calculated separately for each field.

Under that formula, the BPKP says Kodeco owes $32.23 million in tax, while "Kodeco still disagrees with the BPKP," Priyono said.

Three other firms have agreed to settle their debts. BPMigas named them and their debts as Kangean Energy Indonesia Ltd., $45.06 million; Santos UK (Kakap 2) Ltd., $2.39 million; and Golden Spike Raja Blok, $10.62 million.

MEND threatens to block Nigeria's oil waterway

The Movement for the Emancipation of the Niger Delta (MEND) plans to block key channels for oil vessels to increase pressure on Nigeria's troubled oil and gas industry.

"We have ordered the blockade of key waterway channels to oil industry vessels both for the export of crude and gas and importation of refined petroleum products," MEND said. "This means vessels now ply such routes at their risk."

It claimed responsibility for blowing up two recently repaired pipelines near Escravos in the Niger Delta as retaliation for military attacks on its camps around Warri. The military launched its operations on May 15 following the hijacking of two oil vessels and assaults upon its soldiers. According to MEND, two hostages were killed during the fighting and it will return the bodies to the Red Cross charity. "The British hostage, Mathew Maguire has been relocated to Delta state and will be a guest of one the camps there," MEND added.

According to Nigerian press reports, there were also explosions at a manifold operated by Shell in the Bayelsa state, which the company is investigating.

MEND accused the military of "indiscriminate use of missiles and bombs on several defenseless Ijaw communities in Delta state," describing this "as the height of cowardice."

Ijaw's National Congress, which represents the region's largest ethnic group, said that the military has killed over 1,000 civilians, which the military has denied.

There have been conflicting reports on how many hostages were rescued last week and the number of civilians affected in the stand off between MEND and Nigerian troops.

MEND is fighting for a greater share of the revenue from oil and gas produced in the Delta and it pledged that for the Nigerian government to declare victory, troops must be able to secure every inch of pipelines and eliminate over 500 camps stretching from Ondo to Akwa Ibom.

The attacks on Nigeria's oil and gas facilities has cut oil production from 2.6 million b/d in January 2006 to about 1.8 million b/d. ✦

Exploration & Development — Quick Takes

JV confirms Poseidon find off W. Australia

The ConocoPhillips-Karoon Gas Australia Ltd. joint venture declared its Poseidon-1 wildcat a significant gas discovery despite being unable to carry out planned production tests.

The find is in Browse basin permit WA-315-P about 480 km north of Broome off Western Australian. It lies immediately north-northeast of and on trend with the Woodside Petroleum Group's Torosa gas-condensate field and north northwest of the Inpex group's Ichthys gas-condensate field.

A downhole mechanical failure when operator ConocoPhillips attempted to retrieve the liner-hanger setting tool irreparably plugged the well above the planned test interval.

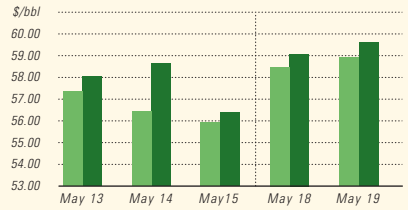
The consortium said the well penetrated a 317 m gross gas-bearing Plover Frmation reservoir between 4,795 m and 5,112 m containing three gross gas sands totaling 228 m thickness.

The gas-water contact was not penetrated, indicating the potential for additional gas below the well's total depth. Estimations of reservoir permeability based on log-derived porosity and four pressure data points suggest the reservoir section will flow gas.

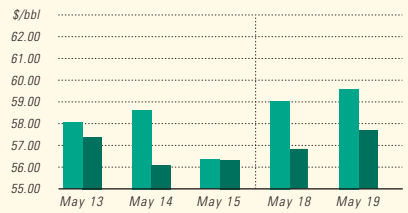
Current mapping indicates the well is more than 100 m be-

Industry Scoreboard

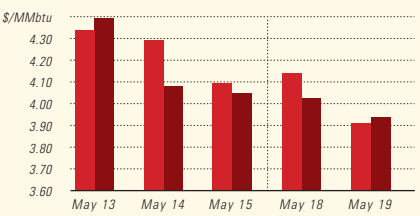
IPE BRENT / NYMEX LIGHT SWEET CRUDE



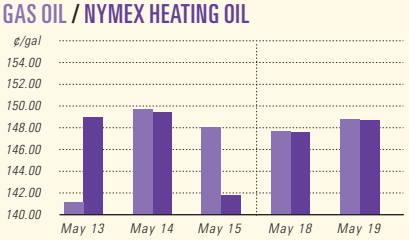
WTI CUSHING / BRENT SPOT



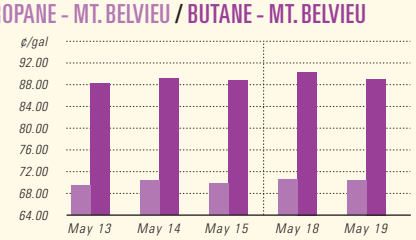
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



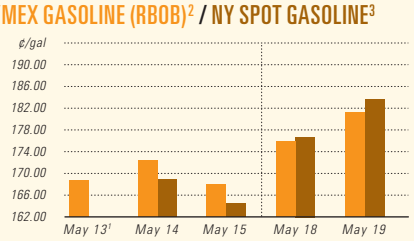
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

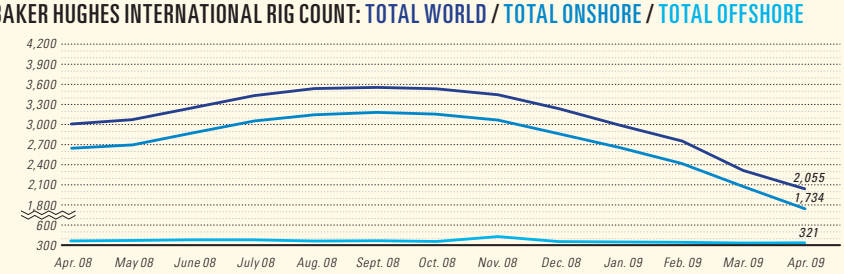
US INDUSTRY SCOREBOARD — 5/25

Latest week 5/8	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,030	9,142	–1.2	8,898	8,975	–0.9
Distillate	3,491	4,065	–14.1	3,831	4,163	–8.0
Jet fuel	1,422	1,585	–10.3	1,403	1,553	–9.7
Residual	456	678	–32.7	553	623	–11.2
Other products	3,795	4,288	–11.5	4,026	4,530	–11.1
TOTAL DEMAND	18,194	19,758	–7.9	18,711	19,844	–5.7
Supply, 1,000 b/d						
Crude production	5,319	5,163	3.0	5,314	5,129	3.6
NGL production[2]	1,823	2,247	–18.9	1,812	2,194	–17.4
Crude imports	9,577	9,834	–2.6	9,487	9,767	–2.9
Product imports	2,636	3,299	–20.1	3,017	3,191	–5.5
Other supply[3]	1,678	1,351	24.2	1,655	1,418	16.7
TOTAL SUPPLY	21,033	21,894	–3.9	21,285	21,699	–1.9
Refining, 1,000 b/d						
Crude runs to stills	14,272	14,744	–3.2	14,272	14,777	–3.4
Input to crude stills	14,604	15,292	–4.5	14,604	15,092	–3.2
% utilization	82.8	86.9	—	82.8	85.8	—

Latest week 5/8	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	370,629	375,258	–4,629	325,759	44,870	13.8
Motor gasoline	208,291	212,445	–4,154	210,168	–1,877	–0.9
Distillate	147,455	146,533	922	107,062	40,393	37.7
Jet fuel–kerosine	40,126	40,668	–542	40,384	–258	–0.6
Residual	36,680	35,927	753	39,320	–2,640	–6.7
Stock cover (days)[4]			Change, %		Change, %	
Crude	25.5	26.1	–2.3	22.0	15.9	
Motor gasoline	23.1	23.5	–1.7	22.7	1.8	
Distillate	42.2	41.5	1.7	25.5	65.5	
Propane	54.0	53.6	0.7	32.7	65.1	
Futures prices[5] **5/15**			**Change**		**Change**	**%**
Light sweet crude ($/bbl)	58.07	56.00	2.07	123.00	–64.93	–52.8
Natural gas, $/MMbtu	4.30	3.92	0.37	11.29	–7.00	–62.0

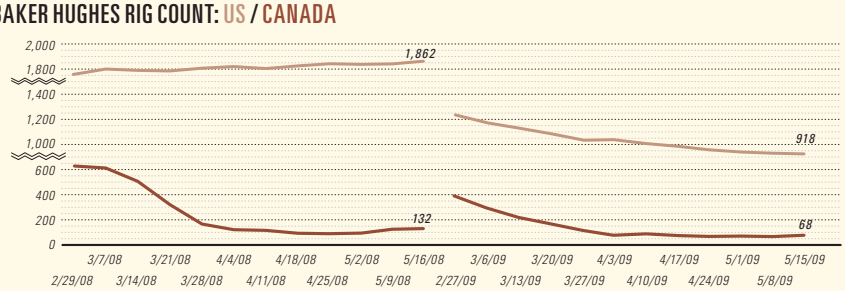
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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low the crest of the Poseidon trap, giving an interpreted gross gas column for the structure of more than 430 m. The aerial extent is mapped at around 280 sq km.

The JV estimates proved reserves to be 3 tcf of gas.

The joint venture has begun inquiries to secure a rig for further appraisal drilling on the discovery.

The Sedco 703 semisubmersible rig has been moved to the next well in the multiwell program called Kontiki-1.

Interests in WA-315-P are ConocoPhillips 51% and Karoon Gas 49%.

Firm to explore carbonate reefs in Palau

Palau Pacific Exploration, Brisbane, seeks to drill a 5,000-ft exploration well in 130 ft of water off northern Palau in the southwestern Pacific.

The company secured an option on a farmout covering a 1 million acre concession on the North Block in Kayangel state and sought investors to participate in a €30 million private placement to fund part of the drilling program.

By drilling the well, the company would earn a 75% working interest and a 66% net revenue interest in the block.

Palau Pacific defined the prospect by reprocessing in late 2007 about 140 miles of high-resolution seismic shot in 1997. Reprocessing with cutting edge frequency dependent processing resulted in the identification of multiple reefs and overlapping anomalies for drilling, the company said.

"Potential reservoirs, determined from seismic sequence stratigraphy, are thick Miocene age carbonate reef systems. Geochemical analysis confirms the presence of thermogenic hydrocarbons. Amplitude versus offset gradient analysis indicates shallow gas," the company said.

Consulting engineers suggest the existence of shallow Pliocene gas as a bailout option should oil not be found, and they estimated production lives of more than 20 years for Miocene oil and Pliocene gas if discovered. A power generation market exists for gas that would back out imported diesel.

Palau is formulating a hydrocarbon law and planning an exploration license round (OGJ Online, May 7, 2009).

EOG-Seneca gauge Marcellus shale gas

A Marcellus shale well operated by EOG Resources Inc., Houston, was flow-tested at an average rate of more than 3 MMcfd of gas for 7 days, said 50% interest owner Seneca Resources Corp., Buffalo, NY.

Seneca Resources, which holds a 60% net revenue interest, said the well "confirms our expectations for the potential of our Marcellus shale position, most of which is fee mineral acreage." A hydraulic fracture is under way at another well where flare tests should begin by the end of May.

Seneca Resources said it should soon be in a position to estimate the resource potential of its extensive acreage position. The company is the third largest acreage holder in the Marcellus play with more than 725,000 acres (OGJ Online, Jan. 15, 2009).

The EOG-Seneca acreage is centered 80 miles northeast of Pittsburgh. Seneca plans to operate 10 vertical wells and 2-3 horizontal wells in fiscal 2009 and participate in 8-10 wells to be operated by EOG Resources.

StatoilHydro eyes exploration off Bahamas

BPC Ltd., Perth, and Norway's StatoilHydro ASA formed a joint venture to explore for oil and gas off the Bahamas if the government approves licenses applications.

The companies propose to explore licenses in southwestern Bahamas waters that lie between Miami and central Cuba. The Bahamas commonwealth government could approve the license applications by yearend, BPC said.

The joint venture territory lies between four other Bahamas blocks wholly held by BPC southwest of Andros Island and six blocks in the Florida Straits off northwestern Cuba operated by Repsol YPF SA in which StatoilHydro holds 30% interest.

Meanwhile, BPC identified 22 exploration leads on its fully owned Bain, Cooper, Donaldson, and Eneas licenses 225-425 km southeast of Miami and the Miami license 85-150 km east of Miami. The licenses, awarded in 2007, total 3.874 million acres in 5-535 m of water on the southern Great Bahama Bank and have potential in a Jurassic-Cretaceous carbonate petroleum system.

BPC noted that five wells have been drilled in the Bahamas since 1947, the last one by Tenneco Oil Co. to 21,740 ft about 50 km off Cuba in 1986 that had oil shows in Lower Cretaceous. ✦

Drilling & Production — *Quick Takes*

Drilling activity continues to diminish

The US rig count continued to contract, down by 10 to 918 rotary rigs working the week ended May 15, less that half of the 1,862 units that were active in the same week a year ago, said Baker Hughes Inc.

Land operations showed the latest loss, down 13 rigs to 855 drilling. Inland-water activity remained unchanged with 7 rigs working. Offshore drilling increased by 3 to 55 rotary rigs working in the Gulf of Mexico out of a total of 56 on federal offshore leases.

Of the rigs still working, 728 are drilling for natural gas, down 2 from the previous week. The number drilling for oil fell by 9 to 181. There were 9 rigs unclassified. Horizontal drilling was down 1 to 379 rigs. Directional drilling totaled 160 rigs, 4 fewer than last week.

Texas continued to lead the decline among major producing states, down 13 rigs with 342 still working. Arkansas lost 4 rigs to 44. North Dakota and New Mexico laid down 3 rigs each, to respective counts of 33 and 31. California was down by 1 to 20. Oklahoma was unchanged at 84.

Wyoming and Alaska increased by 1 rig each to 36 and 6, respectively. Colorado was up 2 to 45 rigs working. Louisiana's rig count jumped by 8 to 146.

BP brings Dorado, King South fields on stream

BP PLC has begun production from Dorado and King South

fields in the Gulf of Mexico. Both are subsea tiebacks to BP's Marlin tension-leg platform.

The Marlin TLP is on Viosca Knoll Block 915. Dorado, 2 miles from the TLP, features three subsea wells operated by BP with a 75% working interest. Shell has 25% working interest.

King South, 18 miles from the TLP, features one subsea well and is 100% owned and operated by BP (OGJ, Oct. 8, 2007, p. 49).

Dorado utilizes dual completion technology enabling production from five Miocene zones, and King South is produced through the existing King field subsea pump.

BP installed the Marlin TLP in 1999 as a production hub for Marlin field. Since then, Marlin, King, Nile, and King West fields have been producing across the Marlin TLP.

With the addition of the four new wells, a total of 11 wells produce into the Marlin TLP with daily gross production of 60,000 b/d oil and 70 MMscfd of gas.

Jordan, Shell sign oil shale agreement

The Kingdom of Jordan has signed a concessionary agreement with Jordan Oil Shale Co. BV, a subsidiary of Royal Dutch Shell PLC, to explore for oil in the country's shale deposits, according to a senior government official.

Oil Minister Khaldoun Qteishat, who said the agreement will be sent to parliament for final approval next month, announced that the Shell subsidiary will invest up to $540 million in the project's preliminary exploratory and assessment phase.

Qteishat acknowledged that the "long-term concessionary agreement will take many years to prove and study" whether Jordan's reserves will produce the oil which his country needs.

The concession agreement will allow Josco to assess oil shale resources in an area spanning 22,500 sq km in the country's central, southern,/ and northwestern regions.

Shell Vice-Chairman Malcolm Brinded said Shell will examine the most promising of Jordan's 21 oil shale locations and then "hone in on the area that is most promising" of all for its pilot program.

The Jordanian government and Shell concluded an initial agreement on the contract in December, which sees production of oil from the shale within 12-20 years of the conclusion of the agreement.

The agreement between Jordan and Shell is the second in recent months. In April, the Jordanian cabinet approved memorandums of understanding between Inter Rao of Russia and Aqaba Petroleum for oil shale exploration and mining.

As reported by the Jordan Times, the areas that the two companies will explore are near Al Attarat in the southern part of the country.

Meanwhile, other companies seeking oil shale agreements are Estonia's Eesti Energei, Petroleo Brazileiro SA, Total SA, Jordan Energy & Mining, and a Jordanian-Saudi joint venture called International Corp. for Oil Shale Investment.

According to Jordanian figures, 40 billion tonnes of oil shale exist in the country's 21 locations near the Yarmuk River, Buwayda, Bayt Ras, Ruwayshad, Karak, Madaba, and Ma'an districts.

Premier to develop Gajah Buru gas field off Indonesia

Premier Oil Natuna Sea BV let an engineering, procurement, construction, and installation contract to a consortium led by Saipem SPA for a central processing platform and other equipment needed to develop Gajah Buru gas field off Indonesia.

First gas is expected in October 2011, and Premier estimates the field holds recoverable reserves of 325 bcf. It was discovered in 2004 with proved gas in stacked reservoirs in the Arang formation.

The deal is valued at $430 million, and the field is on the Natuna Block A in the West Natuna Sea. The central processing platform will weigh 12,900 tons. Saipem and its partner, PT SMOE Indonesia, will produce a wellhead platform, connecting bridge, and a 3-km, 16-in. subsea gas export pipeline to be laid in 80 m of water.

The pipeline will be linked to the existing export trunkline, with a capacity of 140 MMcfd to deliver gas to Sembgas in Singapore.

Facilities on the central processing platform will include compression, separation, glycol regeneration, gas metering, mechanical refrigeration, utilities, and living quarters for 60 staff. The wellhead platform has an estimated topside weight of 900 tons and a jacket weight of 1,400 tons. Construction is scheduled to commence in August.

The Central Processing Platform will be installed using the 'floatover' method, while other platform facilities and pipeline will be installed using Saipem's Castoro Otto derrick-lay barge, said Saipem.

Agip KCO awards Kashagan field contract

Agip KCO let a $2.6 billion contract to Saipem SPA and Aker Solutions to do the hook-up and commissioning of the offshore facilities, inshore completion, and prefabrication work for the first development phase of Kashagan field in the north Caspian Sea.

Saipem said the work would focus on oil and associated gas production by an artificial offshore facilities system called Block D and Block A. The inshore completion and prefabrication will happen in the Kuryk yard in Kazakhstan. All of the contracts will be completed by 2012.

"The very shallow water, the severe weather and the stringent environmental restrictions alongside the lack of infrastructure for the offshore industry make the project particularly complex and challenging," added Saipem. It will use five barges to carry out the work.

The hook-up contracts are the follow-ups of the letter of intent and preliminary agreements signed between Agip KCO, Aker Solutions, and Saipem in March 2007 for the early work for the hook-up.

Phase 1 of the project, dubbed the experimental program, is due online in late 2012 and will be under the responsibility of Eni SPA. Under Phase 1, oil production is expected to reach 300,000 b/d, increasing to 450,000 b/d during Phase 2 (OGJ Online, Feb. 2, 2009). The field, which is 80 km southeast of Atyrau, is expected to reach plateau production of 1.5 million b/d by the end of the next decade.

Saipem's portion of the contract is worth $1 billion while Aker Solutions' contract value is $1.6 billion.

Kashagan is one of the world's largest discoveries in the last 40 years and will cost $136 billion to develop, eventually doubling Kazakhstan's oil output to about 3 million b/d. ✦

Processing — Quick Takes

Kuwait, China to build Guangdong refinery

Kuwait and China have signed an agreement to establish a $9 billion, 300,000 b/d refinery at Zhanjiang, a city on the coast of Guangdong province in southwestern China.

Under terms of the agreement the refinery will be built in Zhanjiang instead of in Guangzhou, as originally planned, due to environmental concerns.

Sinopec will hold a 50% stake in the venture, which is scheduled to start operations in 2013, while state-owned Kuwait Petroleum International will hold 30%. The remaining 20% will be divided equally between Dow Chemical Co. and Royal Dutch Shell PLC.

PetroChina selects Chevron's RDS technology

PetroChina Sichuan has awarded a contract to Chevron Lummus Global to provide residual desulfurization (RDS) technology to the new processing facility in Pengzhou County, Chengdu City, in China's Sichuan province.

The RDS unit will process 3 million tonnes/year of resid and vacuum gas oil for pretreatment to a resid fluid catalytic cracker. The RDS unit will employ CLG's upflow reactor technology, an advanced guard bed technology that minimizes pressure drop build-up in the guard bed.

The facility will be designed to process heavy crudes and will meet modern environmental and industrial standards. ✦

Transportation — Quick Takes

Chevron LNG JV awards contract

Offshore Marine Services Alliance (OMSA), a joint venture of Skilled Group, Perth, Ezion Holdings, Singapore, and Pacific Basin Shipping, Hong Kong, secured a $350 million (Aus.) contract to supply marine vessels and labor to the Chevron Australia-led Gorgon-Jansz LNG project off Western Australia.

The contract is for a minimum 3 years beginning in the third quarter.

The Gorgon-Jansz development proposal involves linking two offshore gas fields by subsea pipelines to Barrow Island where a three-train LNG plant will be built with a total capacity of 15 million tonnes/year.

The plans also include a 300 terajoule/day domestic gas plant and a pipeline to the Western Australian mainland as well as a carbon dioxide geosequestration plant capable of separating the carbon dioxide content from Gorgon flow and pumping it down into deep formations below the island.

The project joint venturers are Chevron with 50%, and ExxonMobil and Shell, 25% each.

Oman LNG signs service agreement with GE-OG

Oman LNG and General Electric Oil & Gas (GE-OG) have signed a 16-year, $200 million contractual service agreement for the 12 GE gas turbines at Oman LNG's Qalhat complex.

Under the agreement, GE will supply a comprehensive range of services for the six critical gas turbines that drive the three LNG liquefaction trains and an additional six gas turbines that generate power for the Qalhat Complex.

Oman LNG is a joint venture comprised of the Omani government 51%, Royal Dutch Shell PLC 30%, Total SA 5.54%, Kogas 5%, Mitsubishi 2.77%, Mitsui 2.77%, Partex 2%, and Itochu 0.92%.

Southern Corridor Summit produces agreement

The Southern Corridor Summit on May 8 in Prague produced "an agreement on a common strategy and clear scheduling for the completion of relevant projects" contributing to diversification of energy sources and routes for the European gas supplies, said European Commission Pres. Jose Manuel Barroso.

The southern gas corridor is one of the European Union's highest energy security priorities to develop gas supplies from Caspian and Middle Eastern sources and possibly other countries in the longer term. The Prague summit brought together Barroso and the EU's revolving president, Czech Prime Minister Mirek Topolanek, with potential partners from Azerbaijan, Egypt, Georgia, Iraq, Kazakhstan, Turkey, Turkmenistan, and Uzbekistan.

It also was attended by Russia, the US, and Ukraine as observers as well as members of the international financial institutions.

A joint declaration was signed by the EU presidents and the leaders of Azerbaijan, Georgia, Turkey, and Egypt but not by gas-rich Kazakhstan, Turkmenistan, or Uzbekistan. Iraq's oil minister did not sign either, but Barroso indicated EU negotiations for a memorandum of understanding to export Iraqi gas to Europe.

Barroso declared, "Today we have commitments from producer, transit, and consumer countries. We now need to work quickly on the follow-up." Pending gas line projects were bolstered by the signing of the declaration.

By midyear, Barroso wants to see the signing in Turkey of the intergovernmental agreement on the Nabucco gas line slated to bring gas from Central Asia to the EU while avoiding Russia. By yearend, he also expects strong support for the Italy-Greece interconnector project as well as conclusion of a feasibility study on the possible shape of the Caspian Development Corp. initiative in cooperation with international financial institutions. This should lead to concrete proposals for obtaining sufficient gas volumes to be transported through the Southern Corridor including encouraging the market-based participation of public and private companies.

Barroso called the Southern Corridor "a new Silk Road" opening the potential for enhanced relations with the countries of the Southern Caucasus and Central Asia.

The memorandum of understanding between the EU and Iraq would receive strong support as well as cooperation between the EU and Egypt to determine specific projects to develop Egypt's gas reserves and the export potential for the EU via the Southern Corridor. ✦

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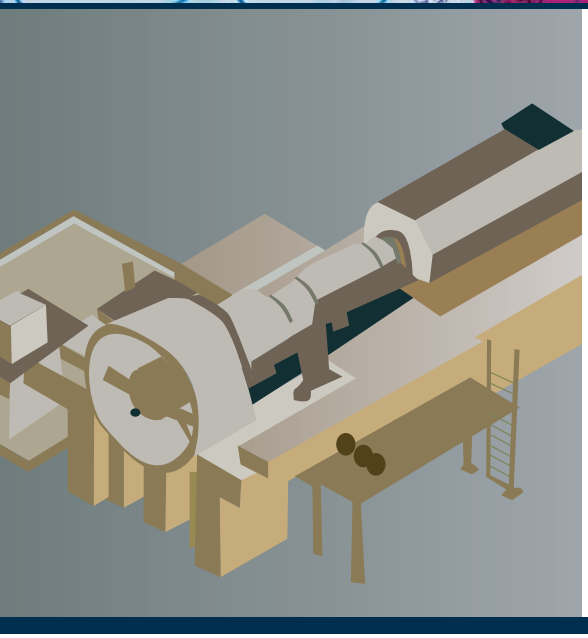


Two New Alstom 50-Hz Combined Cycle 140-MW Steam Turbine Generators Available for Immediate Shipment.

These steam turbine generators (STGs) are new, 140-MW Alstom two-cylinder (HP and IP/LP) reheat condensing steam turbine generator sets suitable for combined cycle outdoor operation with axial exhaust and air-cooled (TEWAC) generator. Initial steam conditions 1900 psia/1050°F/1050°F reheat. Units include manufacturer's performance guarantees and warranties. Units may be shipped directly to your site from Alstom's European manufacturing facility.

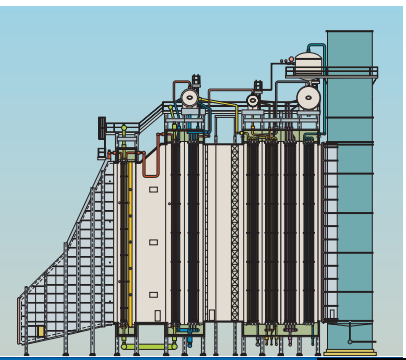
- Units come complete with all normally supplied auxiliaries and include factory warranties covering manufacturing defects and performance guarantees.
- Configured as a two-cylinder machine with an HP turbine and a combined IP/LP turbine with an axial exhaust.
- Steam inlet conditions are 1900 psia (nominal)/1050°F/1050°F.
- Air-cooled TEWAC generator rated 165 MVA, 15.75 kV, 3 phase, 50 Hz, 3000 rpm.

Four 58-MW Rolls-Royce Trent GTGs Available for Delivery Within 120 days

The Rolls-Royce Trent 60 is an advanced aeroderivative gas turbine that delivers up to 58 MW of electric power in simple cycle service. At 42% efficiency, the Trent 60 is highly fuel efficient. It offers operators fast delivery and installation times, and beneficial environmental performance. All or part of the following is available for immediate sale:

- Four Trent 60 Dual WLE GTGs rated at 58 MW with a gross heat rate of 8,592 BTU/kWe.hr (LHV)
- Dual fuel – natural gas and liquid
- Two left-handed units; two right-handed units
- Four generators rated at 13.8 kV, 3 phase, 60 Hz, 0.85 power factor
- Water injection system included
- SCR and carbon monoxide conversion systems with 80-ft stacks
- Acoustic abatement for SCR cladding and silencer
- Water wash system
- Special tools
- GSUs
- Two transformers able to handle two 58-MW units
- GE Prolec 90/120/150 MVA (2 units), with a low voltage 13.8 kV Delta, and a 115 kV Wye HV winding
- Price includes new transformer oil

Three New Vogt F-class HRSGs Now Available for Completion and Delivery by Vogt Within 14 Months



- Product type: natural circulation – unfired, triple pressure reheat heat recovery steam generators (HRSGs) designed for F class gas turbines.
- The HRSGs are designed for duct firing and feature a horizontal gas path; three pressure levels and reheat unfired.
- The buyer will have some flexibility to incorporate certain modifications before final completion by Vogt.
- Units come complete with all normally supplied auxiliaries.

Offered by THOMASSEN AMCOT INTERNATIONAL, LLC. exclusively through PennEnergy

For Info or Pricing Contact

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Letters

Quick to hire, fire

I read with interest your editorial in the Apr. 13 issue, which quite rightly pointed out the recruitment problems of the oil and gas industry and how these have shifted dramatically in recent months (OGJ, Apr. 13, 2009, p. 18). However, I think the article misses the more fundamental truth in focusing yet again on the industry's perceived "image" problem. Rather than banging the familiar drum about how the younger generation sees no future in the oil and gas industry, should we not worry that they see the industry only too clearly—as one that is quick to hire and even quicker to fire?

There is nothing more dispiriting to someone who has undergone 4 or 5 years of university training and been promised a glittering future than to see it all snatched away because the industry itself cannot plan its future sensibly. Nor is it any use in blaming it on the Obama administration and the move to a low carbon future since the oil and gas industry has been successfully shooting itself in the recruitment foot for many years before.

Sarah Beacock
Professional Affairs Director
Energy Institute
London

Shot in the foot

Again, the oil and gas industry has shot itself in the foot by not making an effort to explain to the public why gas prices have gone up 20¢/gal in the last 10 days or so. Even my wife is screaming collusion.

The industry continually wrings it hands over its public image but continues to ignore the obvious places to open a dialog with the public. Why was there so public explanation concerning the relationship to crude prices, the usage of summer-grade gasoline in places like Houston, etc.?

When will the titans of this industry realize they have to reach out to the public when there is an opportunity to open a dialog and make a point. The obvious answer is never.

Stan Thurber
Spring, Tex.

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.

2009

MAY

Gastech International Conference & Exhibition, Abu Dhabi, +44 (0) 1737 855000, +44 (0) 1737 855482 (fax), website: www.gastech.co.uk. 25-28.

APPEA Conference & Exhibition, Darwin, +61 7 3802 2208, e-mail: jhood@appea.com.au. website: www.appea2009.com.au. May 31-Jun. 3.

SPE Latin American and Caribbean Petroleum Engineering Conference, Cartagena, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. May 31-Jun. 3.

JUNE

Caspian International Oil & Gas/Refining & Petrochemicals Exhibition & Conference, Baku, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 2-5.

Asia Oil & Gas Conference, Kuala Lumpur, 65 62220230, 65 62220121 (fax), e-mail: info@cconnection.org, website: www.cconnection.org. 7-9.

AAPG Annual Meeting, Denver, (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 7-10.

PIRA Scenario Planning Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 8.

ILTA Annual International Operating Conference & Trade Show, Houston, (202) 842-9200, (202) 326-8660 (fax), e-mail: info@ilta.org, website: www.ilta.org. 8-10.

International Oil Shale Symposium, Tallinn, Estonia, +372 71 52859, e-mail: Rikki.Hrenko@energia.ee, website: www.oilshalesymposium.com. 8-11.

SPE EUROPEC/EAGE Conference and Exhibition, Amsterdam, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 8-11.

PIRA Understanding Global Oil Markets Seminar, Houston, (212) 686-6808, (212) 686-6628 (fax), website: www.pira.com. 9-10.

GO-EXPO Gas and Oil Exposition, Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 9-11.

Petro.t.ex Africa Exhibition & Conference, Johannesburg, +27 21 713 3360, +27 21 713 3366 (fax), website: www.fairconsultants.com. 9-11.

Oil and Gas Asia Exhibition (OGA), Kuala Lumpur, +60 (0) 3 4041 0311, +60 (0) 3 4043 7241 (fax), e-mail: oga@oesallworld.com, website: www.allworldexhibitions.com/oil. 10-12.

ASME Turbo Expo, Orlando, (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 13-17.

Society of Petroleum Evaluation Engineers (SPEE) Annual Meeting, Santa Fe, NM, (713) 286-5930, (713) 265-8812 (fax), website: www.spee.org. 14-16.

PIRA London Energy Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 15.

IPAA Midyear Meeting, Dana Point, Calif., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 15-17.

PIRA Scenario Planning Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 16.

Atlantic Canada Petroleum Show, St. John's, Newfoundland & Labrador, 403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 16-17.

IADC World Drilling Conference & Exhibition, Dublin, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 17-18.

PIRA Understanding Global Oil Markets Seminar, London, 44 1493 751 316, e-mail: miles@pira.com, website: www.pira.com. 17-18.

AAPL Annual Meeting, Clearwater Beach, Fla., (817) 847-7700, (817) 847-7704 (fax). e-mail: aapl@landman.org, website: www.landman.org. 17-20.

IAEE International Conference, San Francisco, (216) 464-2785, (216) 464-2768 (fax), website: www.usaee.org. 21-24.

Society of Professional Well Log Analysts Annual Symposium (SPWLA), The Woodlands, Tex., (713) 947-8727, (713) 947-7181 (fax), website: www.spwla.org. 21-24.

SPWLA Annual Symposium, The Woodlands, Tex., (713) 947-8727, (713) 947-7181 (fax), e-mail: webmaster@spwla.org, website: www.spwla.org. 21-24.

International Offshore and Polar Engineering Conference (ISOPE), Osaka, (650) 254-1871, (650) 254-2038 (fax), e-mail: meetings@isope.org, website: www.isope.org. 21-26.

Asia LPG Seminar, Singapore, (713) 331-4000. (713) 236-8490 (fax), website: www.purvingertz.com. 22-25.

API Exploration & Production Standards Oilfield Equipment and Materials Conference, Westminister, Colo., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 22-26.

Moscow International Oil & Gas Exhibition (MIOGE) & Russian Petroleum & Gas Congress, Moscow, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 23-26.

JULY

Rocky Mountain Energy Epicenter Conference, Denver, (303) 228-8000, e-mail: conference@epicenter2008.org, website: www.denverconvention.com. 7-9.

API Offshore Crane Operations and Safety Conference, Houston, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 14-15.

Calendar

Oil Sands and Heavy Oil Technologies Conference & Exhibition, Calgary, Alta., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilsandstechnologies.com. 14-16.

AUGUST

SPE Asia Pacific Health, Safety, Security and Environment Conference and Exhibition, Jakarta, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-6.

SPE 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. 4-6.

EnerCom's The Oil & Gas Conference, Denver, (303) 296-8834, email: kgrover@enercominc.com, website: www.theoilandgasconference.com. 9-13.

Oil Sands and Heavy Oil Technologies Conference & Exhibition, Calgary, Alta., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilsandstechnologies.com. 14-16.

ACS Fall National Meeting & Exposition, Washington, (202) 872-4600, e-mail: service@acs.org, website: www.acs.org. 16-20.

IADC Well Control Conference of the Americas & Exhibition, Denver, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 25-26.

Summer NAPE, Houston, (817) 847-7700, (817) 847-7704 (fax), e-mail: info@napeexpo.com, website: www.napeonline.com. 27-28.

SEPTEMBER

Oil & Gas Maintenance Technology North America Conference, New Orleans, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.ogmtna.com. 1-3.

EAGE Near Surface European Meeting, Dublin, +31 88 995 5055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 7-9.

IAEE European Conference, Vienna, (216) 464-5365, e-mail: iaee@iaee.org, website: www.iaee.org. 7-10.

Offshore Europe Conference, Aberdeen, +44 (0) 20 7299 3300, e-mail: nbradbury@spe.org, website: www.offshore-europe.co.uk. 8-11.

GPA Rocky Mountain Annual Meeting, Denver, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.gpaglobal.org. 9.

GITA's GIS Annual Oil & Gas Conference, Houston, (303) 337-0513, (303) 337-1001 (fax), e-mail: info@gita.org, website: www.gita.org/ogca. 14-16.

Turbomachinery Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), e-mail: inquiry@turbo-lab.tamu.edu, website: http://turbolab.tamu.edu. 14-17.

Annual IPLOCA Convention, San Francisco, +41 22 306 02 30, +41 22 306 02 39 (fax), e-mail: info@iploca.com, website: www.iploca.com. 14-18.

Polar Petroleum Potential 3P Conference, Moscow, (918) 584-2555, (918) 560-2665 (fax), website: www.aapg.org. 16-18.

ADC Drilling HSE Europe Conference & Exhibition, Amsterdam, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 23-24.

SPE Eastern Regional Meeting, Charleston, W.Va., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 23-25.

ERTC Sustainable Refining Conference, Brussels, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 28-30.

DGMK Production and Use of Light Olefins Conference, Dresden, 040 639004 0, 040 639004 50, website: www.dgmk.de. 28-30.

IADC Advanced Rig Technology Conference, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 29.

Unconventional Gas International Conference & Exhibition, Fort Worth, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.unconventional-gas.net. Sept. 29-Oct. 1.

ERTC Biofuels+ Conference, Brussels, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. Sept. 30-Oct. 2.

OCTOBER

Interstate Oil and Gas Compact Commission Annual Meeting (IOGCC), Biloxi, Miss., (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 4-6.

SPE Annual Technical Conference and Exhibition, New Orleans, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-7.

World Gas Conference, Buenos Aires, +54 11 5252 9801, e-mail: registration@wgc2009.com, website: www.wgc2009.com. 5-9.

ISA EXPO, Houston, (919) 549-8411, (919) 549-8288 (fax), e-mail: info@isa.org, website: www.isa.org. 6-8.

Kazakhstan International Oil & Gas Exhibition & Conference (KIOGE), Almaty, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 6-9.

NPRA Q&A and Technology Forum, Ft. Worth, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 11-14.

API Fall Petroleum Measurement Standards Meeting, Calgary, Alta., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 12-15.

GPA Houston Annual Meeting, Houston, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.gpaglobal.org. 13.

International Oil & Gas Exploration, Production & Refining Exhibition, Jakarta, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: ogti@oesallworld.com, website: www.allworldexhibitions.com. 14-17.

SPE/EAGE Reservoir Characterization and Simulation Conference and Exhibition, Abu Dhabi, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 18-21.

GSA Annual Meeting, Portland, (303) 357-1000, (303) 357-1070 (fax), e-mail: meetings@geosociety.org, website: www.geosociety.org. 18-21.

✦Oil Shale Symposium, Golden, Colo., (303) 384-2235, e-mail: jboak@mines.edu, website: www.mines.edu/outreach/cont_ed/oilshale/. 19-23.

SEG International Exposition and Annual Meeting, Houston, (918) 497-5500, (918) 497-5557 (fax), e-mail: register@seg.org, website: www.seg.org. 25-30.

SPE/IADC Middle East Drilling Conference & Exhibition, Manama, +971 4 390 3540, +971 4 366 4648 (fax), e-mail: spedal@spe.org, website: www.spe.org. 26-28.

Louisiana Gulf Coast Oil Exposition (LAGCOE), Lafayette, (337) 235-4055, (337) 237-1030 (fax), e-mail: lynette@lagcoe.com, website: www.lagcoe.com. 27-29.

Offshore Middle East Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshoremiddleeast.com. 27-29.

NOVEMBER

Deep Offshore Technology International Conference & Exhibition, Monte Carlo, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepoffshoretechnology.com. 3-5.

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Gen-Y oil and gas workers

Paula Dittrick
Staff Writer

Whether just or unjust, every generation has its stereotypes. Many assume Baby Boomers are ambitious corporate-ladder climbers.

A recent survey by Deloitte Consulting LLP of oil and gas professionals refutes the stereotype Generation-Y workers (born 1982-95) are most concerned about high salaries. Survey results conclude Gen Yers are focused on advancement rather than money.

Deloitte notes the oil and gas industry "suffered from such a low influx of new talent during the 1980s and 1990s that now only two generations are represented in a major way—Boomers and Gen Yers. This gap is tailor made for a generation that is widely known for wanting early advancement."

Gen-Y workers are attracted by long-term career development within a single organization, Deloitte said in its report entitled "Generation Y: a highly productive resource for oil and gas companies."

As a baby boomer journalist, I have listened to oil and gas executives talk at length about how to attract the attention and loyalty of Gen Yers, who Deloitte believes account for about 10% of today's work force.

Survey logistics

Deloitte surveyed 134 people working in oil and gas companies. They were part of 860 Gen-Y employees (age 19-27) of Fortune 500 companies across 20 industries who responded to an online survey during November through early January.

The survey results showed 83% of oil and gas workers reporting they are 'very satisfied' or 'somewhat satisfied' with their current jobs. Fewer than 70% of respondents in other industries said the same.

"Similarly, 75% of oil and gas Gen Yers reported being 'very satisfied' or 'somewhat satisfied' with the career paths offered by their employers, while barely two thirds of Gen-Y workers in other industries agreed. These higher satisfaction levels may be attributable to the fact that this is a remarkably high-tech industry," Deloitte said.

Gen Yers employed by the oil and gas industry also appear more loyal. While 70% of their peers in other industries expect to be with their current employers less than 5 years, almost half the Gen Yers in oil and gas plan to stay longer than that.

"Skills in this industry—for example, geology and petroleum engineering—are not necessarily transferable to other industries, which might contribute to both stronger loyalty and…higher anxiety about the prospects of layoffs," survey results said.

Advancement opportunities

When given a choice of actions that employers can take to retain them, oil and gas Gen Yers overwhelmingly (65% as opposed to 53% from other industries) selected opportunities for advancement. The top pick from survey respondents in other industries was a higher salary and bonus.

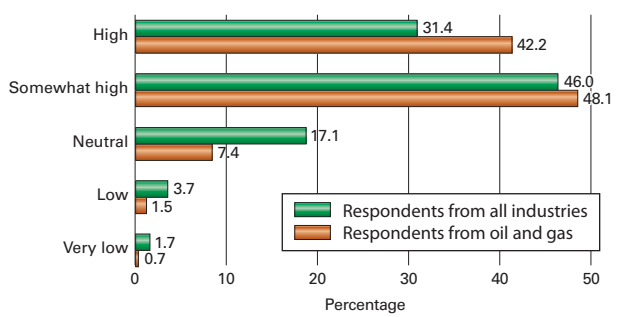
Deloitte concludes the oil and gas industry is offering the type of job opportunities and career paths that will attract and retain Gen Yers.

"This progress is critical for the industry, considering generation chasm created by layoffs during the past 2 decades, and the impact of that chasm on the industry's ability to maintain a strong recruiting pipeline of talent, both from universities and other industries," Deloitte said.

Gen-Y oil and gas workers believe their employers are committed to them and they perceive a high level of job security.

"This level of security may have to do with the significant talent gap between baby boomers and Gen Yers," Deloitte said. ✦

US GENERATION-Y WORKERS' PERCEIVED JOB SECURITY*



*Generation-Y (born between 1982-95)
Source: Deloitte Consulting LLP

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Editorial

A frosty political climate

Here's a tough question for the US oil and gas industry: How much of the nightmare forming in Washington, DC, must come true before companies begin to decamp? It's a global industry. Oil and gas companies based in the US don't have to stay where they are.

With Barack Obama in the White House and fellow Democrats firmly in control of both houses of Congress, the US government acts like it tolerates the oil and gas business only as a source of funding for economic and social reform. Even courts are getting into the act. From leasing to taxation, political hazards are accumulating for the industry responsible for 60% of US energy supply.

Reasons to sneer

When perpetrators of these follies claim to be pursuing "energy independence," new limits on industry access to federal land are reasons, by themselves, to sneer. In February, Interior Sec. Ken Salazar nixed 77 high bids worth $6 million from a December sale of leases in Utah. Then he delayed a 5-year program for leasing of the Outer Continental Shelf. Then he canceled preliminary work for an oil shale pilot program in Colorado and Utah.

Last month, the US Appeals Court for the District of Columbia vacated the current OCS leasing program, saying environmental impact statements prepared by the National Oceanic and Atmospheric Administration didn't sufficiently assess deepwater areas off Alaska. And that's just a sample of things to come. In March, Congress passed and Obama signed a lands bill that removed 2 million acres of land from federal leasing immediately and gave statutory authority to National Landscape Conservation System. For the 26 million affected acres, using lawsuits to block drilling on federal land will be easier than ever.

The federal budget proposed by Obama, meanwhile, would soak the oil and gas industry for $50 billion over 10 years. Some of the money would come from repeal of tax preferences that independent producers need for capital formation. Industry groups say the moves would cut drilling and production investment by 30-50%.

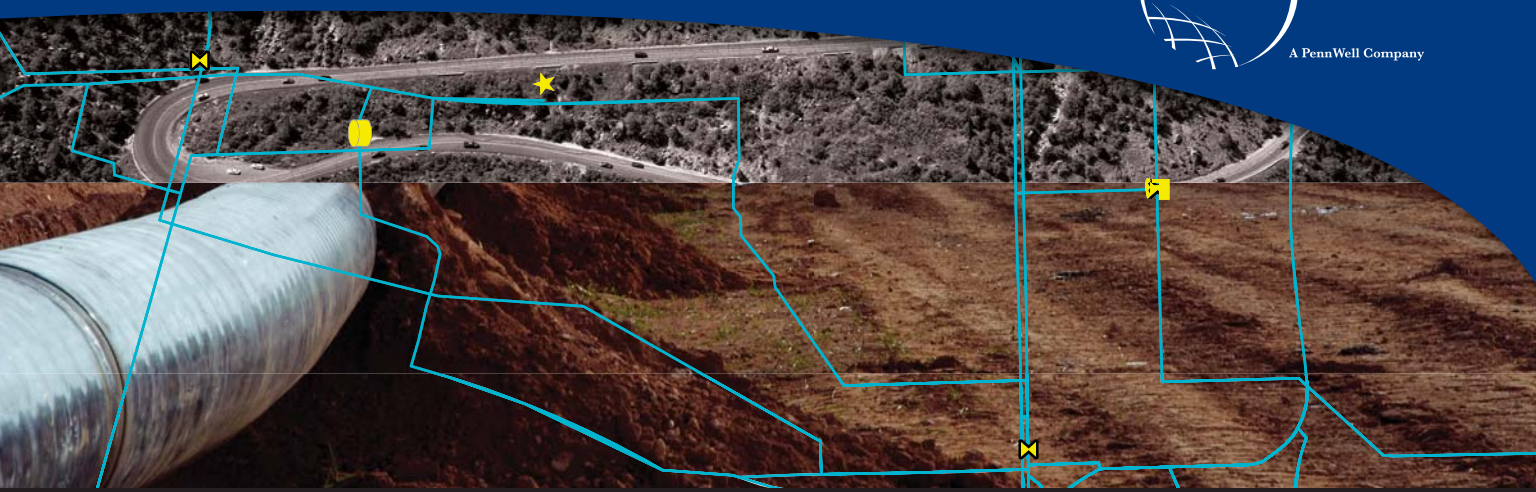
Larger oil and gas companies would take 10-year hits estimated by the administration at $17.2 billion from reinstated Superfund taxation, $13.3 billion from denial of the manufacturers' tax deduction available to other industries, $5.3 billion from repeal of deepwater royalty relief, and $1.2 billion from fees on "nonproducing" OCS leases in the Gulf of Mexico. That last fee is supposed to prod operators into drilling or relinquishing leases on the assumption that they otherwise would pay millions of dollars in bonuses and rentals for privilege of doing nothing. Since publication of the final budget proposal, the administration has revealed that it can't define "nonproducing lease" in any way that accommodates routine permitting and other administrative delays.

The budget also proposes to raise $650 billion from sales of allowances under a cap-and-trade program targeting emissions of greenhouse gases. The administration's plan would hit refiners harder than other manufacturers by excluding ultimate consumers of oil products from emission caps. It also relies in its revenue estimates on an auction of all emission allowances. In response to political pressure, the House Energy and Commerce Committee has softened that part of its cap-and-trade bill. Some energy-intensive industries would receive cost-free allowances. The refining industry isn't among them.

More to come?

Other venomous issues slither in the political grass. The most costly of them could be federal controls on drilling and frac fluids. The measures, under discussion at the Environmental Protection Agency and supported by key lawmakers, are environmentally unnecessary and threatening not only to drilling in general but to development of unconventional gas resources in particular. A wrong move in this area would stunt a crucial source of future energy supply.

This barrage of political setbacks and economic threats has developed in just 4 months. Hostility toward oil and gas, no doubt reflecting political payback to antipetroleum supporters of Obama and Democratic congressional leaders, is unmistakable. Oil and gas companies must wonder how bad things might become over 4 years in such a frosty political climate—and whether the atmosphere might be warmer somewhere else. ✦



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FIRST OF TWO PARTS

Alaskan tax reform: Intent met with oil

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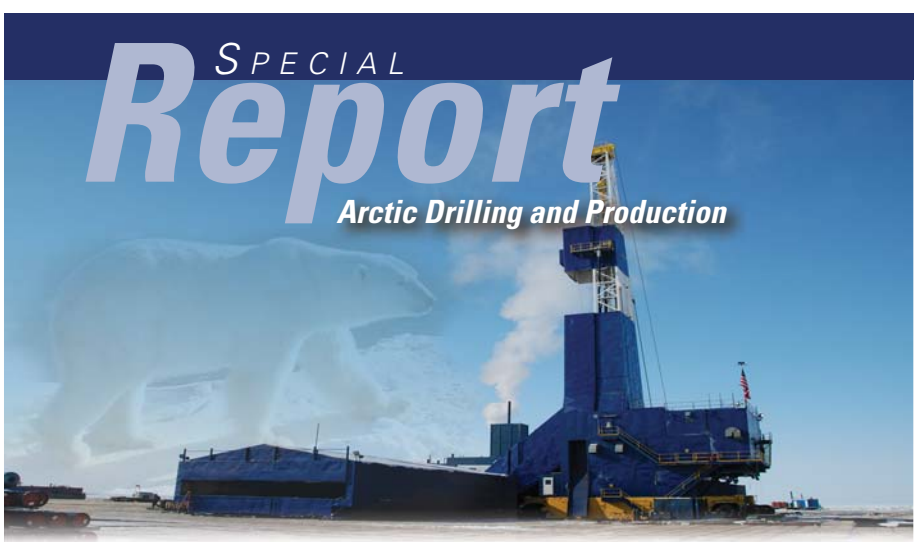


The two-part series beginning here takes a detailed look at a crucial element of Alaskan production: taxes. This week's installment argues that recent reforms have been successful from the state's perspective. But how will they affect efforts to encourage gas development? The authors address that question next week.

In 2006 and 2007 the State of Alaska undertook fundamental reforms to its oil and gas production tax, making it much more progressive. Among the goals of these reforms, two were key. One was to capture more value for the state at higher energy prices. As the legislature was debating the reforms in 2006, prices for Alaska North Slope (ANS) crude for the first time crossed the $40/bbl barrier.

An equal or more important goal was to improve the environment for attracting investments needed to slow or reverse the decline in the state's oil production. Forecast to average 701,000 b/d in the current state fiscal year of 2009, production had exceeded 2 million b/d in the late 1980s.

This article will show that the 2006-07 production tax reforms were phenomenally successful for the state. Alaska collected several billion dollars in additional oil production tax revenue as prices for ANS crude peaked above $140/bbl in the summer of 2008. The state's take from the tax hike was almost 500% higher than it would have been without the reforms.

However, as oil production declines from supergiant Prudhoe Bay field, which anchors the North Slope, the focus in the state has turned toward Alaska's immense reserves of unexploited natural gas.

If sufficient investment can be attracted to build a pipeline to transport gas from the North Slope to market, a feature of the state's production tax may limit performance under high oil prices similar to the 2008 spike. Although it is too early to tell how well the second goal of increased investment has been achieved, in this series we identify additional concerns about how some of the investment incentives might work if a new pipeline to export gas is added to the mix.

The fiscal system

State government in Alaska gets most of its general-fund revenue from four oil and gas mechanisms that are a mixture of progressive and regressive elements. Over the past decade, depending on prices, oil and gas have provided 68-93% of the state's general-fund revenues. The components of the state's fiscal system are summarized in Fig. 1.

Because most oil and gas production is from state land, royalty paid to the state averages just under 13% of gross value, less costs to get the commodity to market. This is regressive because it does not factor in the investment required or the expense of finding, developing, and producing the oil or gas. Alaska's fiscal design for oil and gas has evolved substantially in the past 3 years and consists of four mechanisms (Fig 1).

There also is a property tax of 2% of assessed value on oil and gas real property (though not on the lease or hydrocarbons). The tax is split between the state and the municipalities in which the property is located. This is relatively insensitive to the profits (or losses) generated by changes in the price of the oil or gas in the market.

There is a corporate net income tax (abbreviated here as CIT but defined by the Alaska Net Income Tax Act or ANITA) of 9.4% of that portion of an oil-and-gas producing taxpayer's worldwide income apportioned to Alaska. While this is an income-based tax, the link with specific Alaska investments, costs, and income is weakened by the apportionment mechanism—an

equal weighting of production, sales, and property. Higher operating costs in Azerbaijan or Alaska will have the same depressing effect on the income taxable in Alaska. Higher prices on out-of-state sales of ANS or Angola crude will increase the amount of Alaska CIT paid equally.

The final mechanism is the oil and gas production tax, which has changed substantially over the past 3 years. The next section sets out its history, politics, and mechanisms in more detail. These four mechanisms can be very different. For example, each approaches depreciation or the cost-allocation mechanism for upstream capital investment differently. For royalty there is no deduction driven by upstream investment, so no mechanism is needed. For the property tax, units of production essentially determine the rate of depreciation.

The corporate income tax preserves the pre-1980 asset depreciation range (ADR) system from federal income tax, while the production tax allows instantaneous depreciation or expensing of capital costs. Meanwhile, a producer in Alaska will be subject to US federal income tax (FIT) with its current modified accelerated cost-recovery system (MACRS).

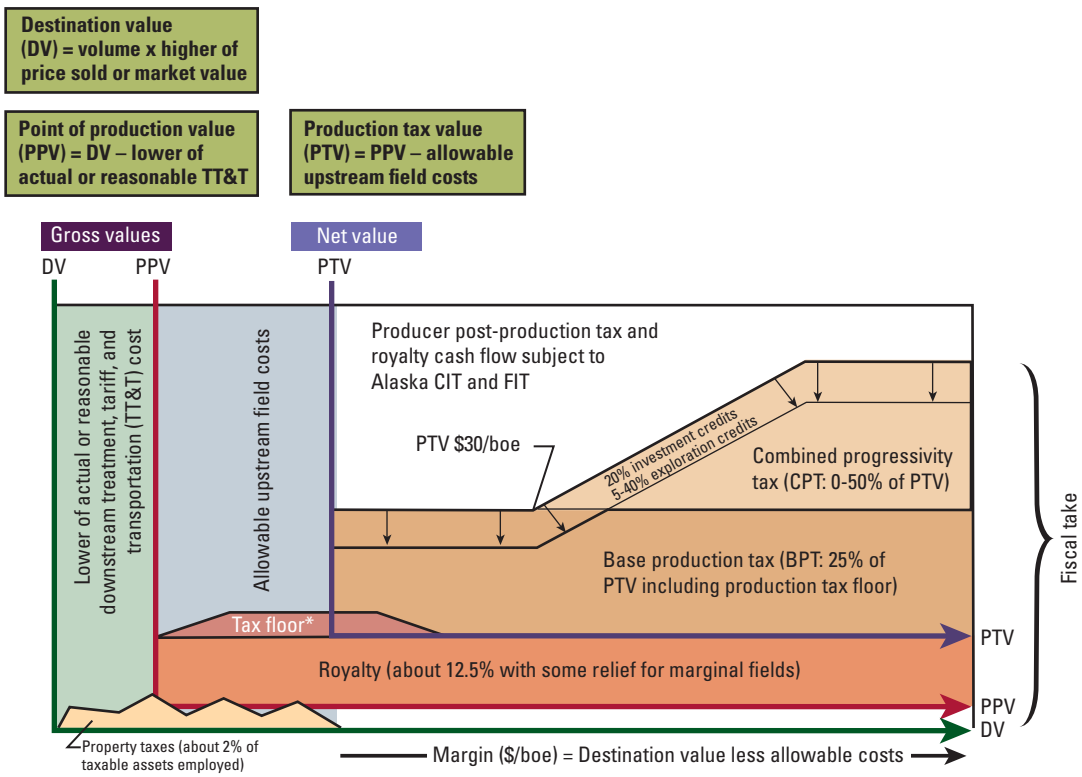
Alaska's hydrocarbon production comes primarily from the North Slope, with oil and some natural gas liquids sent through the trans-Alaska oil pipeline (TAPS) and tankers to US West Coast refineries.

North Slope oil production in FY 2008—including natural gas liquids mixed with crude and shipped through the pipeline—totaled roughly 261 million bbl, or 716,000 b/d. Annual average net gas recovery is closer to 500 MMcfd, although most of that is nontaxable gas used for enhanced oil recovery and as fuel to run North Slope production facilities.

Most taxable gas comes from a smaller production center in Alaska's Cook Inlet, now a gas province where the gas is used mostly in local population centers, with some export from an LNG facility. However, Cook Inlet accounts for less than 5 million bbl of the state's annual oil production. While other areas of the state and offshore show prospectivity for oil or gas, none has yet been commercialized. Major North Slope gas sales await a pipeline to carry the gas to markets, leaving a valuable resource stranded at the northern edge of North America.

Alaska upstream fiscal design for oil and gas

Fig. 1



Regressive fiscal elements

- Property taxes are levied on assets used in the upstream or TT&T services and shared between the state and local governments
- Royalty is levied at point of production value (PPV)
- *Tax floor refers to a production floor levied at 0-4% of PPV in place of BPT when that floor value is higher than the BPT value

Progressive fiscal elements

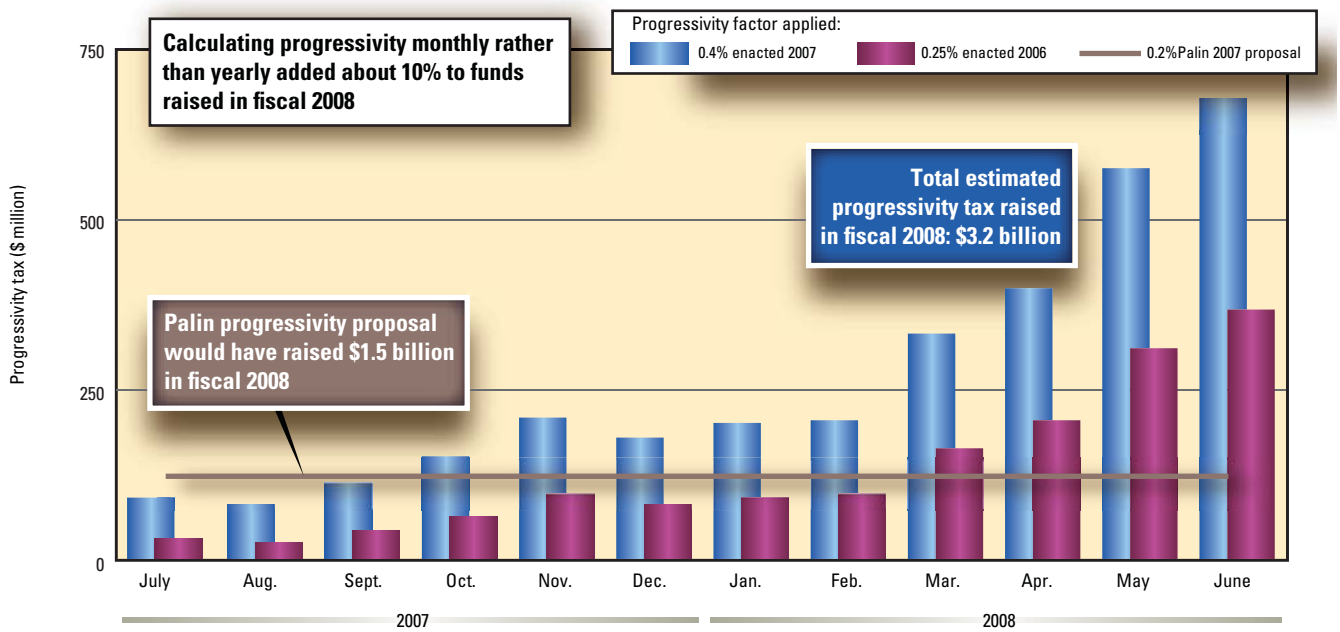
- Production taxes (BPT and CPT) are taxes paid on net value or margin
- Progressivity component of production tax (CPT) commences at PTV of $30/boe
- Alaska corporate income tax (CIT) of 9.4% is levied on producer's worldwide income apportioned to Alaska. CIT is deductible from federal income tax (FIT)

Tax before reform

Prior to reforms discussed in this article, Alaska's oil production tax was

ALASKA MONTHLY OIL PROGRESSIVITY TAX, 2008

Fig. 2



a maximum 15% of gross value (calculated under the same general principles as royalty), multiplied by the so-called economic limit factor (ELF). The ELF was 0.0 for small fields (hence leading to zero tax), and by 2006 averaged about 0.5 for fields with a positive ELF, for an effective tax rate of less than 8% of gross.

Although the nominal tax on gas was 10%, and the ELF mechanism involved a different calculation, by 2006 the effective rate on gas was also coincidentally around 8% of the gross. Price was not a factor in calculating the ELF multiplier. The ELF, adopted in 1979 and amended in 1989, was intended to reduce production taxes on smaller, less productive, older, and declining fields.

In 2006, then-Alaska Gov. Frank Murkowski proposed replacing the gross tax and ELF with a 20% tax rate (base production tax, referred to then as PPT but referred to in this article as BPT) applied to the net. The tax would be applied after allowing a deduction for upstream exploration, development, and production costs.

Furthermore, to make investment more attractive, capital investment could be deducted as a cost as spent and also would generate an additional 20% credit applicable against the BPT. The proposal came to be known as the 20:20 PPT proposal.

Murkowski introduced this oil tax reform to complement a gas pipeline fiscal contract negotiated under the Alaska Stranded Gas Development Act with the state's three largest holders of gas-rich

ALASKA'S FISCAL CHANGES BOOST TAX REVENUE IN 2007-08

Table 1

	Production taxes (BPT + CPT) applied from 2007		Production value					Royalty	
Fiscal year (July to June)	Production tax revenue PTV, million $	Year $/ 2004 $ C = current B/ 2004 B	West Coast ANS price, $/bbl	Production, million b/d	Production, million bbl/year	Value = price* volume	Year $/ 2004 $ H = current G/ 2004 G	Royalty revenue, million $	Year $/ 2004 $ J = current I/ 2004 I
A	B		D	E	F = E*days	G = D*F		I	
2004	642.7	1.0	32.36	0.999	365.6	11,831.9	1.0	1,042.8	1.0
2005	854.9	1.3	44.85	0.931	339.8	15,204.7	1.3	1,401.1	1.3
2006	1,191.7	1.9	62.12	0.858	313.2	19,454.1	1.6	1,772.2	1.7
2007	2,198.3	3.4	61.60	0.750	273.8	16,863.0	1.4	1,583.8	1.5
2008	6,867.3	10.7	96.51	0.730	267.2	25,785.5	2.2	2,420.6	2.3
Production tax revenue increase attributable to fiscal changes in 2006 and 2007 = 10.7/2.2 = 4.9									

Note: Because of Alaska Department of Revenue (DOR) methodological changes, historical data in the Fall 2008 Revenues Sources Book (RSB) may differ from same data presented in earlier RSBs. Table 1 uses total barrels, while Table 2 uses taxable barrels.
Sources: DOR, Fall 2008 RSB, December 2008 Appendices, A-5a, B-1a, C2a

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2008 PRODUCTION TAX REVENUES: ACTUAL VS. POTENTIAL UNDER ALTERNATIVE MECHANISMS*

Month	US West Coast oil price	Per barrel total costs	Per barrel production tax value PTV $/bbl	Progressivity threshold	PTV less progressivity threshold	PTV rate per dollar of adjusted PTV	Incremental progressivity rate %	Volume, million bbl	Combined progressivity tax (CPT), million $
A	B	C	D = (B+C)	E	F = (D+E)	G	H = (F*G)	I	J = (D*H*I)
1. Pre-2006 law—economic limit factor (ELF) mechanism									
Year	96.52	–6.05	90.47	—	—	0.00	0.00	228.7	0.00
2. Murkowski proposal: 20 20 PPT (2006), no progressivity									
Year	96.52	–22.88	73.64	—	—	0.00	0.00	228.7	0.00
3. Monthly analysis, $40 PTV $/boe threshold and 0.25% progressivity parameter under law as enacted in 2006									
July	75.93	–22.88	53.05	–40	13.05	0.25	3.26	19.4	33.6
Aug.	73.83	–22.88	50.95	–40	10.95	0.25	2.74	19.4	27.1
Sept.	79.92	–22.88	57.04	–40	17.04	0.25	4.26	18.8	45.7
Oct.	84.77	–22.88	61.89	–40	21.89	0.25	5.47	19.4	65.8
Nov.	92.98	–22.88	70.10	–40	30.1	0.25	7.53	18.8	99.1
Dec.	88.64	–22.88	65.76	–40	25.76	0.25	6.44	19.4	82.2
Jan.	91.16	–22.88	68.28	–40	28.28	0.25	7.07	19.4	93.7
Feb.	94.42	–22.88	71.54	–40	31.54	0.25	7.89	17.5	98.9
Mar.	105.06	–22.88	82.18	–40	42.18	0.25	10.55	19.4	168.3
Apr.	112.37	–22.88	89.49	–40	49.49	0.25	12.37	18.8	208.1
May	125.41	–22.88	102.53	–40	62.53	0.25	15.63	19.4	311.3
June	133.78	–22.88	110.90	–40	70.9	0.25	17.73	18.8	369.4
Total								228.7	1,603.3
4. Palin proposal (2007): yearly analysis $30 PTV $/boe adjustment and 0.2% progressivity parameter									
Year	96.52	–22.88	73.64	–30	43.64	0.20	8.73	228.7	1,469.8
5. Monthly analysis, $30 PTV $/boe threshold and 0.4% progressivity parameter under current law as enacted in 2007									
July	75.93	–22.88	53.05	–30	23.05	0.40	9.22	19.4	95.0
Aug.	73.83	–22.88	50.95	–30	20.95	0.40	8.38	19.4	82.9
Sept.	79.92	–22.88	57.04	–30	27.04	0.40	10.82	18.8	115.9
Oct.	84.77	–22.88	61.89	–30	31.89	0.40	12.76	19.4	153.3
Nov.	92.98	–22.88	70.10	–30	40.1	0.40	16.04	18.8	211.3
Dec.	88.64	–22.88	65.76	–30	35.76	0.40	14.30	19.4	182.7
Jan.	91.16	–22.88	68.28	–30	38.28	0.40	15.31	19.4	203.0
Feb.	94.42	–22.88	71.54	–30	41.54	0.40	16.62	17.5	208.5
Mar.	105.06	–22.88	82.18	–30	52.18	0.40	20.87	19.4	333.1
Apr.	112.37	–22.88	89.49	–30	59.49	0.40	23.80	18.8	400.2
May	125.41	–22.88	102.53	–30	72.53	0.40	29.01	19.4	577.7
June	133.78	–22.88	110.90	–30	80.9	0.40	32.36	18.8	674.5
Total								228.7	3,238.1

*Analysis based on actual US West Coast prices and cost data. Fiscal 2008 values: taxable North Slope production—626,456 b/d (228.7 million bbl); lease expenditures—$16.83/bbl; TT&T—$6.05/bbl; capital expenditure credits—$411.5 million. Table 2 uses taxable barrels, while Table 1 uses total barrels.
Sources: Alaska Department of Revenue, Fall 2008 Revenue Sources Book, December 2008; Alaska DOR web site

leases: BP, ConocoPhillips, and Exxon-Mobil. The administration hoped that the fiscal stability built into that contract would create a viable investment climate to enable financing and construction of a gas line to the Lower 48.

After extensive hearings consuming the better part of several special legislative sessions, the legislature passed a reformed oil and gas production tax in August 2006, retroactive to Apr. 1, 2006. Although the key ideas from Murkowski's proposal remained intact, the legislature imposed its own amendments to the administration's proposal and added a higher base tax rate and a progressivity mechanism.

This progressivity feature, called here the combined progressivity tax (CPT), added an extra 0.25% to the overall tax rate for every dollar the per-barrel net (production tax value, or PTV) was above $40 (until the CPT rate reached a maximum of 25%). For example, if per-barrel costs were $25 and that barrel could be sold for $85, an additional 5% CPT would be added to the base production tax rate.

How was this CPT calculated? For the sake of simplicity we will ignore royalty and start with $85/bbl oil and subtract $25 in costs to yield a PTV of $60. Subtracting the $40 progressivity trigger from the $60 yields $20. The CPT rate was calculated as 0.25% times $20, which equals 5% additional tax above the base rate. The legislature (along with many other changes) also increased the BPT to 22.5% from the proposed 20%, so in this example the nominal tax rate would be 27.5%, the sum of 22.5% BPT and 5% CPT.

Meanwhile, the legislature declined to take up Murkowski's controversial gas-line contract. Natural gas production taxes, however, were included in the oil-reform legislation. Under the new law, any taxable gas was converted to oil on an energy-equivalent basis at the rate of 6 MMbtu/bbl (which for a cubic foot of gas with a heating value of exactly 1,000 btu equals 6 Mcf/bbl). Then these energy-equivalent barrels of gas were added to the oil for the

Table 2

Base production tax (BPT) rate, %	Base production tax (BPT) value	CPT + BPT value	BPT less $400 in credits (except ELF)	~2% adjustment to RSB 2008 actual
	million $			
K	L = (D*I*K)	M = (J+L)	N = (M–411.5)	O = (N*0.977)
7.49	1,549.5	1,549.5	1,549.5	1,513.1
20.00	3,367.8	3,367.8	2,956.3	2,886.9
22.50	231.8	265.4	—	—
22.50	222.6	249.7	—	—
22.50	241.2	286.9	—	—
22.50	270.4	336.2	—	—
22.50	296.4	395.6	—	—
22.50	287.3	369.6	—	—
22.50	298.4	392.1	—	—
22.50	282.3	381.3	—	—
22.50	359.1	527.4	—	—
22.50	378.4	586.5	—	—
22.50	448.0	759.3	—	—
22.50	468.9	838.4	—	—
22.50	3,785.0	5,388.3	4,976.8	4,860.1
25.00	4,209.7	5,679.5	5,268.0	5,144.5
25.00	257.6	352.5	—	—
25.00	247.4	330.3	—	—
25.00	268.0	383.9	—	—
25.00	300.5	453.8	—	—
25.00	329.4	540.7	—	—
25.00	319.3	501.9	—	—
25.00	331.5	534.5	—	—
25.00	313.7	522.2	—	—
25.00	399.0	732.1	—	—
25.00	420.5	820.7	—	—
25.00	497.8	1,075.5	—	—
25.00	521.1	1,195.5	—	—
25.00	4,205.5	7,443.7	7,032.2	6,867.3

calculation of progressivity. We call this the combined progressivity tax (CPT) because oil and gas are taxed under a single combined formula.

The tax-reform legislation was created for oil but was applied to all hydrocarbon production. The consequences of this are explored in next week's article. To protect in-state consumers, the legislature capped the production tax on Cook Inlet gas at its existing ELF-calculated rates and values.

Reform approved

August 2006 was a pivotal month. On Aug. 10 the legislature voted to approve the production tax reform, including the reforms detailed above. On Aug. 19 Murkowski signed the legislation into law. On Aug. 22 Sarah Palin won the Republican gubernatorial primary with more than 50% of the vote, relegating Murkowski—with only 19% of the vote—to third place.

Then, on August 30, agents of the Federal Bureau of Investigation raided the offices of six legislators, carrying off in their gloved hands boxes of papers, documents, and computer hard drives. Publicly available warrants made clear the FBI was seeking information relating to votes on the PPT and the activities of VECO, an oil field services contractor active in the tax debate.

Palin went on to win the November 2006 election. She campaigned—in part—on returning the production tax from a net tax back to a gross tax. It was not until April 2007 that taxpayers had to file returns for 2006 under the new law. Although the state had predicted catch-up payments from North Slope producers of close to $1 billion, the checks totaled $880 million, and the new administration expressed concern over compliance.

In August 2007 indictments were finally brought against VECO officials and three of the legislators whose offices had been raided a year earlier (only one was still a sitting legislator). Subsequent VECO-related charges have been brought against one other legislator, a former legislator, US Sen. Ted Stevens (who later lost his reelection bid in November 2008) and Murkowski's chief of staff, resulting in three guilty pleas and Stevens's conviction, subsequently vacated.

Palin in September 2007 called a special legislative session to modify the production tax reforms and adopt a production tax that Alaska's citizens could believe was free of corruption. Her administration, after consulting widely with outside experts, did not propose a return to a gross tax and renewed its commitment to a net tax. Her proposal—tagged as ACES, or Alaska's Clear and Equitable Share—included raising the BPT from 22.5% to 25%.

The governor also proposed (1) that for purposes of administrative ease, progressivity be calculated on an annual basis instead of monthly, (2) the progressivity trigger would kick in at $30/boe instead of $40/boe, and (3) the rate of progressivity would increase more slowly at 0.2% per $1 above the trigger instead of 0.25%.

The legislature met in special session during October and November 2007 with oil prices in the $80/bbl range—about double where they had been during the 2006 special session. Just as it did when adopting the original reform under Gov. Murkowski's tenure, the legislature also imposed its own distinctive stamp on the law adopted under Gov. Palin—again focusing on progressivity.

The BPT was increased to 25%, as the governor had requested. However, the CPT remained on a monthly basis, and while the trigger dropped to the suggested $30/per boe, the rate was increased to 0.4%/$1 above the trigger. Using the example above of $85/bbl oil and $25/bbl costs, the total production tax rate becomes 37%. The BPT is 25%, and the CPT calculation is still $85 less $25 for a PTV of $60/bbl. But then subtracting the $30/bbl trigger and multiplying the resulting $30 times 0.4% yields a CPT of 12% and a total tax of 25% + 12%, or 37%. As detailed above, this example produced a 27.5% total tax rate under the 2006 law. The less simplified version that includes royalty

can be seen in Table 3. (At PTVs above $92.50, the progressivity increment fell to 0.1%/1 above the trigger, while total progressivity was capped at 50%.)

Capturing premiums?

In 2008, oil prices hit extraordinary levels. How did the legislature do at capturing those premiums? There are several ways of looking at this, and we present two.

The first looks at the increase in production taxes from fiscal 2004 through 2008 (Table 1).

While Column B of Table 1—annual production tax revenue—shows the increase is more than an order of magnitude from roughly $650 million to $6.9 billion, it doesn't tell how much of the change was due to the change in rules and how much was due to change in prices, production, or costs. At least the first two can be factored out in the following exercise. Column G of Table 1 shows that from fiscal 2004 to 2008 the product of market value times volume roughly doubled.

Similarly, Column J of Table 1 shows the royalty—rules for which didn't change—paid to the state over the same period doubled. Thus it appears the net effect of the change in tax was the tenfold increase divided by twofold increase caused mostly by rising oil prices. That is a fivefold increase caused by the change to the production tax fiscal mechanism. (More specifically 10.7 divided by 2.2 equals 4.9.)

Another way of comparing these is to look at the high prices that prevailed in fiscal 2008 and assuming both constant costs and volumes to evaluate them under the five different production tax designs discussed from 2005 to 2007. Table 2 summarizes such an analysis.

Table 2 also confirms a fivefold increase due to the tax reforms excluding oil price changes. Murkowski's proposal would have been a doubling of the production tax from the ELF-driven tax structure in 2006. That year, the legislature made that a tripling over the status quo. Palin's 2007 proposal would have had little effect under the prices that were realized in fiscal 2008, but the legislature pushed up the progressivity feature to achieve the nearly fivefold increase illustrated.

Methodology No. 5 is the prevailing regime, so we can compare this piece of the simplistic table with actual results. This simplified model produces a production tax liability of $7,032.2 million, about 3% different from the actual production tax liabilities for fiscal 2008, $6,867.3 million as seen in the last row of Column B of Table 1. Given that Table 2 uses a single average price, while the tax effects from deviation from the average are not symmetrical, and this analysis ignores other details such as the small producer tax credit, this is a surprisingly close match.

Fig. 2 illustrates the dollars flowing to the state from the three methods illustrated in Table 2 which incorporate a progressivity feature. Monthly increments from the original method enacted in 2006 (Methodology No. 3 on Table 2 with a 0.25%/$ factor and $40/boe PTV threshold) are compared to monthly increments from the revised method enacted in 2007 (Methodology No. 5 on Table 2 with a 0.4%/$ factor and $30/boe PTV threshold). The flat line on Table 2 illustrates the annual application of progressivity as proposed by the Palin administration in 2007 (Methodology No. 4 on Table 2 with a 0.2%/$ factor and a $30/boe PTV).

We do not have sufficient data to say whether the goals pertinent to increased investment are being achieved. Furthermore, whatever capital budgeting announcements made by producers when prices were high must be reexamined in the context of lower crude oil price environments. Pioneer brought on the new 90 million bbl Oooguruk field in August of 2008 under the new fiscal regime, but Eni in March 2009 announced it was delaying development at Nikaitchuq, a $1.5 billion project.

Acknowledgment

Dan E. Dickinson and David A. Wood have performed and continue to perform advisory and evaluation work for Alaska's Legislative Budget and Audit Committee on Alaska's oil and gas fiscal design. That work is now in the public domain. However, the ideas expressed here are the authors' own. Larry Persily provided extensive editorial assistance. ✦

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Alaska Point Thomson drilling under way, AOGA told

Alan Petzet
Chief Editor-Exploration

ExxonMobil Corp. expects the first well in Alaska's $1.3 billion Point Thomson condensate project to cost $209 million compared with $6-8 million for a typical well in Prudhoe Bay field.

The first well was drilling May 13 at 3,600 ft in 7½-in. surface hole, Craig Haymes, Alaska production manager for ExxonMobil, told 540 people at the Alaska Oil & Gas Association annual luncheon on May 13 in Anchorage. The Nabors rig, brought in over a 60-mile ice road from Deadhorse, Alas., underwent a $35 million upgrade. It now has a 172-ft derrick and a mud system that can pump 1,800 gal/min at 5,000 psi.

The well will turn horizontally under the Beaufort Sea from its coastal pad and reach a projected depth of 16,500 ft measured depth, Haymes said. Production at the gas cycling project is expected to start in 2014.

John Minge, president of BP Exploration (Alaska), said the company operates about 500,000 b/d or more than 60% of Alaska North Slope production. The net to BP is 204,300 boe/d.

One of BP's most important projects is Liberty, which involves the drilling from an existing island of an ultra-extended reach well 10,000 ft deep with an 8-mile lateral. BP Exploration plans to drill six wells in 2010.

Ken Sheffield, president of Pioneer Natural Resources Alaska and AOGA, said low oil and gas prices have led Pioneer to drop all but one drilling rig companywide, a unit drilling in Oooguruk field in northern Alaska. Pioneer was running 29 rigs a year ago.

Sheffield noted that Pioneer, which entered Alaska in 2002, produced its first barrel of oil in mid-2008 when Oooguruk field started up. The rig is drilling laterals in preparation for a frac program in mid-2009.

Resource potential of the area around Oooguruk is estimated at 120-150 million bbl, Sheffield said.

Rich Fox, Alaska asset manager for Shell, said the company will pursue its revised offshore plan to use one rig to drill two wells in a year starting in 2010. Shell shot more than 1,000 miles of 3D seismic in the Chukchi Sea in 2008 with encouraging results, he noted. He is optimistic about the program, having been involved in drilling wells in the Bering, Beaufort, and Chukchi seas earlier in his career. ✦

Nonproducing lease definition needed, DOI's Salazar told

Nick Snow
Washington Editor

US House Interior Appropriations Subcommittee leaders asked Secretary of the Interior Ken Salazar a basic question when he presented his department's fiscal 2010 budget request on May 13: How does Interior define a nonproducing lease?

Salazar couldn't supply an answer, but promised to develop one soon and consult with subcommittee members about it. He's already under pressure because the Obama administration's proposed federal budget includes $122 million of annual revenue from fees on nonproducing leases starting Oct 1.

Salazar doesn't question the idea behind the assessment. "I've practiced water law in the West. States' water laws have a similar use-it-or-lose-it feature. Oil and gas are similarly precious commodities," he told the subcommittee.

But Salazar also couldn't answer the question when Rep. Michael K. Simpson (R-Ida.), the subcommittee's ranking minority member, asked what DOI considers a nonproducing lease eligible for collection of the proposed $4/acre fee.

"I think this is important, particularly if someone could be penalized for bureaucratic or legal delays which aren't his fault," Simpson said. Officials from one of DOI's major agencies, the US Bureau of Land Management, told the subcommittee last year that it can take up to 4 years for a federal oil and gas lessee to simply get a drilling permit, he added.

'Would be unfair'

The subcommittee's chairman, Rep. Norman D. Dicks (D-Wash.), broke in. "I have to agree with my colleague. It does take time to go through the permitting process. I think it would be unfair to penalize someone starting the day they acquire the lease. You need to give them some time," he told Salazar.

Independent producers have been asking federal policymakers what would constitute a nonproducing lease since the US House Natural Resources Committee proposed instituting the charge last year in addition to bonus bids and rentals which the US Minerals Management Service and BLM already receive.

"We asked the committee's staff if their definition included leases where development was delayed by litigation. They said 'yes,'" said Daniel T. Naatz, vice-president of federal resources and political affairs at the Independent Petroleum Association of America.

The idea that a producer would lease a tract and not develop it doesn't make sense, Naatz said. "There isn't any company which will pay bonuses and bids and then sit on a lease. If they get a sense that a lease isn't working, they're

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Blog at www.ogjonline.com

Issues beyond cap-and-trade

In a sense, some pressure was off American Petroleum Institute Pres. Jack N. Gerard the morning of May 18.

The US House Energy and Commerce Committee was scheduled to begin marking up HR 2454 that afternoon. The bill, cosponsored by Reps. Henry A. Waxman (D-Calif.), the committee's chairman, and Edward J. Markey (D-Mass.), who chairs its Environment and Energy Subcommittee, aimed to address global climate change by establishing a carbon cap-and-trade system in the US.

But when API and Gerard originally planned to hold a teleconference with reporters that morning, they thought the US Senate also would be considering bills that would impose new taxes on domestic producers and refiners, and possibly further restrict access to US supplies.

The two committees with jurisdiction on those proposals delayed consideration until after Memorial Day. So Gerard and the reporters who questioned him concentrated on the reworked Waxman-Markey proposal, which its sponsors had released the afternoon of May 15.

'Rushed quickly'

Waxman remained determined to complete markup before the holiday weekend. Gerard disagreed. "Our hope is that now the legislation is finally on the street, people will be able to take a good look at it and fully analyze it. Right now, they've rushed quickly to try and complete the process which hasn't allowed anyone to do this," he said.

He also found it ironic that the bill did not recognize the industry's contribution to global climate change research so far.

"When you look closely at investments in greenhouse gas emission technology by all US industries and the federal government from 2000 to 2006, 45% came from the oil and gas industry. That makes us the leading investor," he said.

Cap-and-trade may have been more immediate, but Gerard suggested that taxes and access still mattered. "What the president talks about is reducing reliance on non-US sources. But he also has indicated the need to produce more oil and gas domestically," he said.

Not consistent

The proposed taxes in the administration's fiscal 2010 budget request are not consistent with that strategy, API's president continued. "It's very difficult to increase domestic production when you're taking away incentives to do so. The best thing for economic development and increasing government revenue is to encourage more domestic oil and gas development," he said.

When it came to access, Gerard said he has spoken personally with Senate Energy and Natural Resources Committee leaders and members. "We continue to push hard with them as well as the Interior secretary," he said.

"We emphasize that today is the day to plan for the future, and that we need to put processes in place to address needs 15-20 years down the road. Too often, we look at this through a political process with 2-year election cycles. These provisions are so important so we can make the necessary investments in the next decade," Gerard said. ✦

going to relinquish it," he told OGJ following the subcommittee's hearing.

"What we've always said is that even if they know what leases are not producing, they give lessees no credit for bureaucratic delays, environmental challenges, and other obstructions," said Independent Petroleum Association of Mountain States' government affairs director Kathleen Sgamma, who also was in Washington on May 13.

Sgamma said IPAMS members normally take 5-6 years to complete a comprehensive analysis for a federal environmental impact statement before drilling their first well on a federal onshore lease. Small projects of fewer than 10 wells which qualify for the less complicated environmental assessment take 2-3 years, she said.

'The only way'

"We've proposed working with Secretary Salazar to help him understand all the work that's done to comply with a lease's terms and requirements. That's the only way he can accurately determine if or why a lease isn't producing," Sgamma told OGJ.

She noted that Mary L. Kendall, DOI's acting inspector general, said in a Feb. 27 report to Salazar that BLM and MMS use different definitions for non-producing properties. "There are so many data inconsistencies and incompatibilities between the two agencies that it's not surprising DOI can't tell what leases are producing or not producing," she said.

In the report, which is posted online at the DOI IG's web site, Kendall said in a cover letter to the secretary that investigators "found numerous data integrity issues and confirmed that [DOI] cannot compel companies to develop their federal leases."

The examination, which the DOI IG's office began in July 2008 at Dicks's request, found that the department has no formal policy to compel companies to bring leases into production, and that BLM and MMS risk losing millions of dollars in royalties because their

tracking systems are not compatible. In one case, a communications breakdown between the two agencies could have resulted in nearly $6 million of royalties being lost over 5 years if the lessee had not sent its first production report to both bureaus and not just BLM. "The existing process is heavily reliant on companies doing the right thing," the report said.

In one inconsistency example, investigators found that BLM considers every lease contained in a unit producing, even though a well may not have been drilled on every lease and every lease within the unit is not paying royalties. Leases in a unit which are not required to pay royalties are categorized as "held by location in a producing unit," according to the report. It noted that MMS reports leases which are not paying royalties as nonproducing both onshore and offshore in areas it administers, regardless of whether they are part of a producing unit.

Definitions differ

"Consequently, leases that are identified as producing by BLM may be reported as nonproducing by MMS," it said, adding that BLM defines onshore leases determined to be capable of producing paying quantities as commercial as producing while MMS considers them nonproducing.

Investigators also learned during their examination that the lease development process has many variables that are not immediately apparent, it continued. "For example, due to inherent geologic uncertainties, there is no guarantee that any given lease contains oil and gas in commercial quantities. Also, because each lease property is unique, data from currently producing leases cannot be used to predict the volume of oil and gas that might be extracted from other leases," it said.

"Overall, DOI could do much more to track the status of nonproducing leases, but it may not be able to do much to promote production. Absent new policy or legislative direction, both industry and bureau officials cautioned that mandating production on all federal leases or increasing lease fees would not necessarily enhance production and could, in fact, reduce industry interest in federal leases," the report indicated.

Naatz said that the assessment would also be collected on offshore tracts, which could generate significant revenue because they are much larger than onshore tracts. But the impact would be greater on smaller independent producers who primarily work onshore, and who face a possible increase in fees for processing each drilling permit application to $6,500 from $4,000 and other expenses, he pointed out.

"It's the proverbial death-by-a-thousand-cuts for smaller operators who are facing hard economic times because of depressed commodity prices," he explained. ✦

API's Gerard: Allowances uneven in cap-and-trade bill

Nick Snow
Washington Editor

A carbon cap-and-trade bill before the US House needs to be reworked so allowances are distributed more evenly across the entire economy, American Petroleum Institute Pres. Jack N. Gerard said on May 18.

"We keep hearing about this legislation being a market-based proposal to begin the transition to a less carbon-based society. But it's not market-based if you give allowances to some segments and not to others," Gerard told reporters in a teleconference hours before the House Energy and Commerce Committee began marking up HR 2454, the American Clean Energy and Security Act.

Sponsors Henry A. Waxman (D-Calif.), the committee's chairman, and Edward J. Markey (D-Mass.), the chairman of its Environment and Energy Subcommittee, made several changes from their original Mar. 31 proposal before releasing the final bill on May 15. One or two responded to US oil industry concerns, Gerard acknowledged. But the measure is still badly flawed, he maintained.

"When you look at the way they distributed 85% of the allowances, some went to segments that aren't carbon bidders. We believe it should be equitable across all carbon sources. The Waxman-Markey approach isn't. Those who produce and use petroleum are receiving little and being asked to account for much," he said.

The bill's economic implications also have not been fully considered nor does it recognize that US refiners operate in a global industry, Gerard said. "There are tariff and rebate provisions in the legislation designed to offset impacts on the steel and other industries, but the refining sector is specifically excluded. There is no transition, no ability to stay competitive. There needs to be recognition of those industries which use petroleum products as well," he said.

'You look elsewhere'

"Clearly, the incentive and direction would be to push jobs overseas. If you can't succeed in a globally competitive environment because of costs in the United States, you start to look elsewhere. That means high-paying jobs would move overseas, which is what people who are leading this effort say they want to avoid," Gerard added.

A few constructive changes were made the past few weeks, notably elimination of a low-carbon fuel standard provisions which would have overlapped the federal renewable fuel standard, he noted. But the bill still has problems and should not be rushed, Gerard said. Waxman remained committed to having it ready to move to the House floor by Memorial Day.

"I'm not talking about years. I'm talking about weeks. There's plenty of time to get this right. It probably will be the most significant piece of legislation that will be enacted in our lifetime. We're going to stay at the table and continue to express our views," Gerard said.

Others also warned that committee members need to consider the bill's economic implications more fully. "Climate-change legislation will have a significant cost impact on every person and business and the economic competitiveness of the country. We must get it right or we can drive the country into a deeper recession and lose more high paying manufacturing jobs," said Paul N. Cicio, president of the Industrial Energy Consumers of America.

American Gas Association Pres. David N. Parker applauded the bill's provision which does not bring commercial or residential gas customers under the cap-and-trade system until 2016, however. "By using energy wisely and making smart choices every day, our customers have reduced their per-household consumption so dramatically that there has been virtually no growth in emissions in nearly three decades, despite a 70 percent increase in households using natural gas," he noted. ✦

EIA: US gas demand, supply to fall; prices to swing up

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

Total US natural gas consumption this year will drop by nearly 2%, according to the most recent Short-Term Energy Outlook from the US Energy Information Administration. Demand next year, said the agency, will increase slightly.

Total marketed US gas production also will decline slightly this year but more steeply in 2010. As a component of natural gas supply to US markets, LNG imports will increase in 2009 and 2010.

Working gas in storage in US reservoirs on May 1, said the report, was nearly 2 tcf, more than 360 bcf ahead of the average for the last 5 years and nearly 500 bcf more than the same week in 2008.

Finally, the report stated Henry Hub spot prices are likely to average about $4/Mcf this year, rising to more than $5/Mcf in 2010.

Consumption

Total gas consumption in the US will decline by 1.9% in 2009, then increase slightly in 2010 (Fig. 1). Weak economic conditions will depress gas consumption in the influential industrial sector, as the main source behind the dip in total consumption.

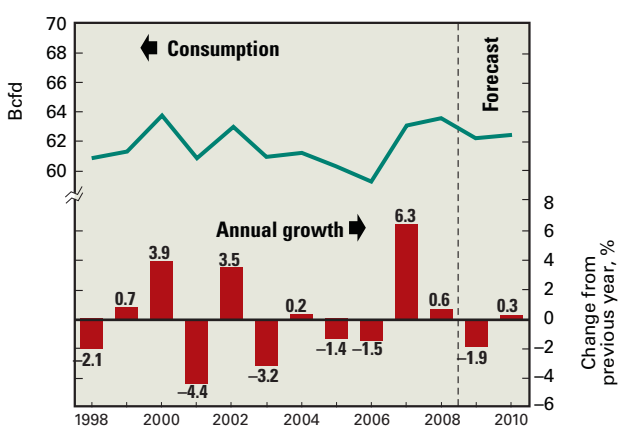
Projected increase in natural gas use for electric-power generation may offset some of this decline, said the report. Lower relative natural gas prices compared with coal, particularly in the Southeast, will induce higher use of gas-fired electric generation capacity near-term and drive up consumption by 2.1% in the electric-power sector this year. Gas consumption will decline only slightly in residential and commercial sectors this year.

For 2010, as for other fuels across energy markets, said the report, the outlook for natural gas consumption is "highly contingent upon the timing and pace of economic recovery."

Under EIA's current assumptions, demand growth in electric power and a slight recovery in the industrial sector will drive a small increase in total

US TOTAL NATURAL GAS CONSUMPTION

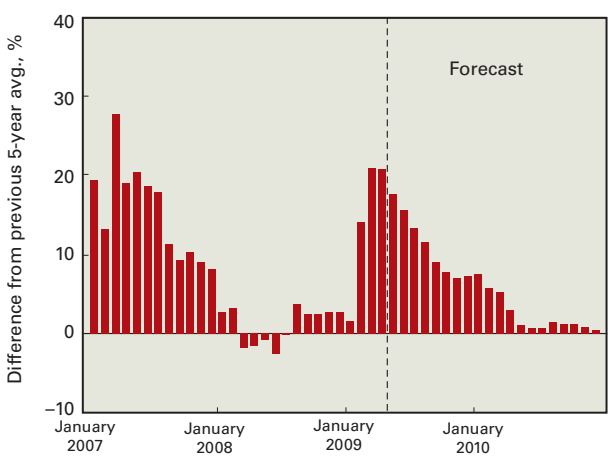
Fig. 1



Source: EIA Short-Term Energy Outlook, May 2009

US WORKING GAS IN STORAGE

Fig. 2



Source: EIA Short-Term Energy Outlook, May 2009

Barclays weighs in on LNG debate

Speculation about whether greater numbers of LNG spot cargoes will come to US terminals this summer was also the subject of a recent report from Barclays Capital Research.

The range of estimates for US LNG imports in 2009 is "unusually wide," said the report. It noted that higher prices in Europe may attract all spot LNG or, on the other hand, a paucity of storage capacity elsewhere in the world "will push most of the global oversupply into the US despite low prices."

"Both arguments have merit," it said, but neither accurately considers current LNG markets in their entirety.

Outside the US, storage capacity is limited. The size of liquefaction capacity additions coming online over the next 12-15 months and a "sharp contraction in [LNG] demand," the rest of the world is unlikely to be able to absorb all the excess.

There are, however, pockets of consumption strength, said Barclays, and the market might be underestimating Europe's ability to take more gas. That could be the case because of Europe's "low inventories, growing gas-fired power generation and expanding regasification capacity."

Also, the LNG spot market is at a "fledgling stage, with limited history to suggest how these factors may interact." This year, with an imminent global oversupply and more market participants "looking to arbitrage regional natural gas prices, the LNG industry is about to test just how global the gas market has become."

Barclays does believe US LNG imports will grow in 2009, just not as rapidly as "liquefaction additions and economic trends in Asia and Europe alone would suggest."

consumption for 2010. This will come despite minor consumption declines in residential and commercial sectors that will result from anticipated nearly 1% fewer heating degree-days than in 2009.

Production, imports

EIA expects total US marketed natural gas production to decline by 1% this year and by 2.8% in 2010.

Poor economic conditions and lower natural gas prices by May had reduced total working natural gas rigs by 54% since August 2008. The erosion of drilling activity combined with production curtailments in response to current and projected low prices and high inventory levels will push down gas production in the Lower 48

Loading piers at Cheniere Energy Inc.'s Sabine Pass LNG terminal, Cameron Parrish, La., stand empty as work on the terminal's expansion (foreground tanks) near completion. At 4 bcfd of sendout capacity, Sabine Pass will be the US largest LNG terminal when it is commissioned later this year. Many observers expect all US LNG terminals to be busy this year, despite low natural gas prices, as spot cargoes from new liquefaction capacity in the Middle East and elsewhere steer away from saturated, inflexible markets in Asia and Europe. Photo from Cheniere Energy.

non-Gulf of Mexico states by about 1.6% in 2009.

Marketed production from federal gulf waters, on the other hand, EIA expects to increase by 3.4% this year as production rigs damaged by Hurricanes Gustav and Ike as well as new production from offshore oil projects come on line. Despite expectations of higher prices in 2010, the "lagged effects of the downturn in drilling this year and the natural decline in productivity from existing wells" will contribute to lower production in both Lower-48 nongulf and federal gulf regions in 2010, said the report.

EIA has taken note of the considerable uncertainty among LNG observers over the outlook for global LNG balance (OGJ, May 4, 2009, p. 49). It says that expected weak gas demand in LNG-consuming countries of Asia and Europe, start-up of new liquefaction capacity (in Qatar, eastern Russia, Indonesia, Malaysia—2009; Peru and Australia—2010), and limited gas storage capacity in markets that typically rely on LNG will increase LNG available to the US.

With this in mind, EIA predicts the US will see an increase of about 500 bcf in supply via LNG imports in 2009 and another 650 bcf in 2010. But, as the debate among observers testifies, increased availability does not necessarily translate into imports. US natural gas prices have consistently been below those in Asia and Europe (see sidebar, p. 31).

Nevertheless, the highly liquid US market, with its extensive pipeline systems and burgeoning storage, may trump its low prices in attracting spot LNG cargoes by default from European and Asian markets with higher prices but less physical flexibility.

Pipeline imports, EIA said, mainly from Canada, will decline by about 7% this year as a result of suspended drilling and declining well productivity.

Inventories, prices

Working natural gas in US storage at May 1 stood at 1.9 tcf with that inventory 362 bcf above the 5-year average (2004-08; Fig. 2) and 491 bcf above the same week in 2008.

Natural gas working inventory will peak at more than 3.6 tcf at the end of October, said EIA, surpassing the previous record of slightly more than 3.5 tcf at the end of October 2007.

Working-gas inventory has typically reached maximum during the first 2 weeks of November, with the earliest seasonal peak reported the week ending Oct. 20, 2006, and the latest peak the week ending Nov. 30, 2001.

Henry Hub spot prices averaged $3.62/Mcf in April this year, $0.46/Mcf less than the average spot price in March and pushed down by slowing economic activity. EIA expects no significant rise in average spot prices before cooler temperatures arrive in the fall to increase demand for space heating.

Although the seasonal boost in gas consumption will strengthen prices, robust storage levels will dampen any upward price movement through winter 2009-10, said the report. As the expected economic improvement contributes to demand recovery in 2010, however, sustained lower production levels could lead to higher prices later in 2010.

The Henry Hub spot price will average $4.06/Mcf this year and $5.21/Mcf in 2010. ✦

CERA study says Canadian oil sands boost total GHG emissions 5-15%

Total emissions of greenhouse gases associated with Canadian oil sands exceed those related to average crude oil processed in the US by 5-15%, says a study by IHS Cambridge Energy Research Associates.

The comparison covers emissions from production and processing of the raw materials as well as consumption of the oil products.

IHS CERA said it based its estimates on an 8-month study that received contributions from 37 "stakeholder organizations"—including Canadian and US government agencies, oil companies, and environmental and commu-

nity groups.

It pointed out that 70-80% of total—or "wells-to-wheels"—emissions result from combustion of oil products for all sources of crude oil.

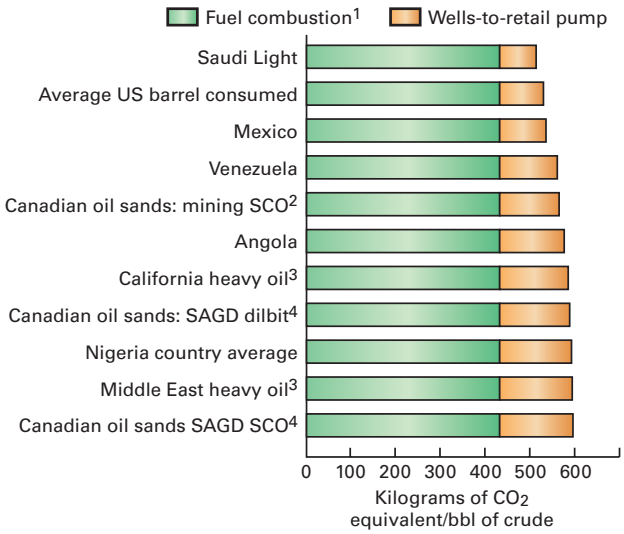
"The difference in total carbon emissions from oil sands to that of other crude oil sources occurs mainly in the extraction and processing phases—also called 'well-to-retail pump' or 'well-to-pump'," it said (see figure).

The study called Canadian oil sands "one of the most important sources of supply growth in the past decade," noting that production has increased to 1.3 million b/d at present from 600,000 b/d in 2000.

Depending on global economic conditions, oil prices, environmental regulation, and the pace of innovation, production from the Canadian oil sands will reach 2.3-6.3 million b/d by 2035, the study projected.

At the higher production rate, Canada's share of expected US oil imports would be 37%, compared with 19% in 2008. "The environmental and efficiency challenges for oil sands are classic cases for consistent, long-term government research and development spending," said James Burkhard, study director and managing director of IHS CERA's Global Oil Group. ✦

LIFE-CYCLE GREENHOUSE GAS EMISSIONS



[1]Based on a per-barrel of crude basis assuming an average carbon content. [2]SCO = synthetic crude oil. [3]Assumes steam-assisted gravity drainage (SAGD) is used for production. [4]Assumes steam:oil ratio of 3:1. Dilbit is bitumen diluted with light hydrocarbon liquids.
Source: Cambridge Energy Research Associates based on data from various sources

Americas to see LNG terminals commissioned in June

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

In June, three LNG terminals in the Americas will begin commissioning.

In North America, Repsol's Canaport LNG at St. John, NB, and Sempra Energy's Cameron LNG terminal near Lake Charles, La., will each accept commissioning cargoes. In South America, Chile's Quintero Bay LNG terminal will become the region's first land-based terminal.

North America

Irving Oil Ltd. (25%) and Repsol-YPF SA (75%) are partners in the 1-bcfd Canaport terminal, Canada's first LNG import terminal. It will have three 160,000-cu m full-containment tanks and a loading jetty that can handle carriers up to 200,000-cu m with four 16-in. liquid loading arms and one 16-in. gas-handling arm.

Estimated cost of the terminal is more than $750 million (Can.).

The commissioning vessel, whose name has yet to be released, is probably going to obtain its cargo from Atlantic LNG at Point Fortin on Trinidad and Tobago. The most likely vessel size will be the workhorse 138,000-cu m carrier in Repsol-YPF's fleet, according to LNG vessel watchers at Waterborne LNG, Houston, and EA Gibson Shipbrokers, London.

Sempra Energy's Cameron LNG terminal near Lake Charles anticipates commissioning next month with commercial operations starting in third quarter, according to Sempra Chairman Donald Felsinger speaking earlier this month.

Cameron is owned entirely by Sempra and lies 18 miles north of the Gulf of Mexico in Hackberry, La., on the Calcasieu Channel. It will the seventh land-based terminal for the US. Three other terminals are offshore, each using Excelerate Energy's EnergyBridge configuration.

Sempra began construction at Cameron in 2005. It has three 160,000-cu m full-containment tanks and two ship berths and will be able to send out up to 1.5 bcfd with room for expansion.

Capital investment, according to the company, will eventually reach about $850 million.

Sempra Energy spokesman Art Larson said Sempra does not "provide advance information re: the scheduling of anticipated shipment(s)." Waterborne Energy's Steve Johnson told OGJ that Cameron's "first two deliveries" are going to be on Q-Flex (216,000 cu m) vessels.

South America

Chile this year will become South America's third LNG importer but will boast the region's first and only conventional land-based terminal.

The consortium Quintero LNG will begin commissioning its 2.5-million tonne/year terminal north of Valparaiso

at Quintero Bay in June. The consortium consists of BG (40%), Chilean state-owned petroleum company Enap (20%), gas distributor Metrogras (20%), and Endesa (20%). Plateau demand from this terminal is 1.7 million tpy.

Source for the commissioning cargo will likely be a BG operation or one with which it can execute a swap. Given the terminal's location and the reluctance of most vessels to traverse Cape Horn, industry speculation has been that the commissioning cargo will be aboard a 145,000-cu m vessel from Asia, possibly Australia.

The first LNG carrier to negotiate Cape Horn was the 145,000-cu m Bluesky last year on its way to Sempra LNG's Costa Azul terminal at Baja California, Mexico.

A second, 1.4-million tpy Chilean terminal at Mejillones, owned by GDF Suez and copper producer Codelco, should also complete construction later this year, with start-up slated for January 2010. ✦

China plans host of domestic petrochemical plants

Eric Watkins
Oil Diplomacy Editor

China, concerned over forecasts of increased competition from Middle Eastern petrochemicals suppliers, reported plans to construct a host of domestic petrochemical plants.

China's new plans, however, are causing concern in Southeast Asia that production will outstrip demand and lead to lower prices, particularly after recently announced increases in the Middle East.

According to its 2009-11 industry support and development blueprint, China's State Council plans to raise the country's ethylene production capacity by 51.2% to 15.5 million tonnes/year.

Chinese refineries currently produce about 47.6% of the 21 million tpy of ethylene consumed in the country.

The new plants apparently are in addition to current Chinese efforts to increase output capacity, including plans by PetroChina to complete a 1 million tpy addition to its 220,000 tpy ethylene plant in Dushanzi, Xinjiang province.

PetroChina also is doubling the annual capacity of its ethylene plant in Daqing, Heilongjiang province, to 1.2 million tpy, while rival Sinopec is building two 1 million tpy ethylene plants, one in Ningbo and the other in Tianjin.

Competing with Middle East

Eyeing the substantial increase in the production of ethylene, industry observers said the government's plan is aimed largely at enabling the country to compete with Middle Eastern producers, who are boosting output.

Chinese concern over increased Middle Eastern production of petrochemicals emerged in April at Lnoppen's 4th Annual Petrochemical Summit held in Tianjin, China.

"A group of new ethylene and downstream petrochemical projects in the Middle East will be completed and put on stream from 2009 to 2010," said one Chinese oil and gas official, who declined to be named.

"As the demand for petrochemicals in the Middle East is limited, after the completion of these projects great quantities of petrochemicals will be likely to flow into the Chinese market," the official said.

"Petrochemicals from the Middle East have very strong price competitive edge and have great impact on the Chinese market," he said.

According to Hu Jie, the chief engineer of PetroChina Refining & Chemicals Co. Ltd., Middle Eastern refineries will more than double their production capacity of three major types of polyethylene (PE) to 14.81 million tpy in 2012 from 6.04 million tpy in 2007.

Hu said the buildup of ethylene production capacity in the Middle East scheduled to start operation in 2009 and 2010 will lead to "the flooding" of China's market with downstream petrochemicals.

"The Middle East has already exported several hundred thousand tonnes of PE products to the Chinese market in the first quarter of this year, but most of it is of low quality," Hu said.

However, Hu said a much larger volume of higher-quality products will enter the Chinese market in the second half of this year once the new Middle Eastern refineries start production.

As a result, he said, the next few months will be a challenging time for China's petrochemical producers as they attempt to clear inventories amid an influx of Middle Eastern PE products into the Chinese market.

Price competition

However, BOC International analyst Lawrence Lau said Beijing's aggressive expansion in ethylene could lead to keen price competition and low profits in the region, given the Middle East's major expansion plans with much of its output aimed at the Chinese mainland.

That view was shared and broadened by Gordon Kwan, head of regional energy research for Hong Kong-based Mirae Assets Securities.

"Given China is about half self-sufficient in ethylene, if PetroChina and Sinopec do realize Beijing's aggressive targets, it will be bad news for regional producers in Japan, Singapore, Taiwan, and Thailand as they rely on exports to China to keep utilization rates high," Kwan told the South China Morning Post.

Stan Park, deputy managing director of Petrochemical Corp. of Singapore, expressed similar concerns, saying that the key issue for the region's industry is new cracker capacity coming onstream in the second half in the Middle East

and China.

"We are in for volatile times, and we are all holding our breath," Park told Singapore's Business Times earlier this month, adding that additional facilities in the Middle East and China will affect plants in Singapore as well as Southeast Asia generally.

Still, he noted there has been a sustained recovery in China, with petrochemical demand back to about 90% of what it was before the global downturn. Continued Chinese demand—if it holds up—will offset the new Gulf and Chinese capacity, he said. If not, Park said, sales could fall by 10-20%. ✦

Brazil, China agree on $10 billion loan package

Brazil's Petroleo Brazileiro SA (Petrobras) completed negotiations with the China Development Bank for a 10-year, $10 billion bilateral credit line.

"The $10 billion is going to be used in our strategic plan that needs [the investment of] $174.4 billion from now until 2013," said Petrobras Chief Executive Jose Sergio Gabrielli de Azevedo.

The 10-year loan agreement was signed on the second day of a recent 3-day visit to Beijing by Brazil's President Luiz Inacio Lula da Silva between state visits to Saudi Arabia and Turkey.

The Brazilian firm said the loan, which includes funding for the purchase of goods and services from Chinese companies, also includes an increase in oil exports from Brazil to China.

"A long-term export agreement between Petrobras and Unipec Asia, a Sinopec subsidiary, was also foreseen," Petrobras said. The agreement calls for a sales volume of 150,000 b/d of oil during the first year and 200,000 b/d in the following 9 years.

The loan was not tied to the oil supply agreement or any other cooperation between Petrobras and Chinese refiners, Gabrielli said. He added that China would pay market prices for the oil shipments, and the $10 billion loan would be repaid in US dollars at an interest rate of less than 6.5%.

The loan agreement with Brazil is the latest of several similar arrangements that China has made with suppliers of oil, including a $10 billion oil-for-loan deal with Kazakhstan, and $25 billion to Russian oil and pipeline companies. ✦

Smallest Philippine block has shallow gas, deep reef potential

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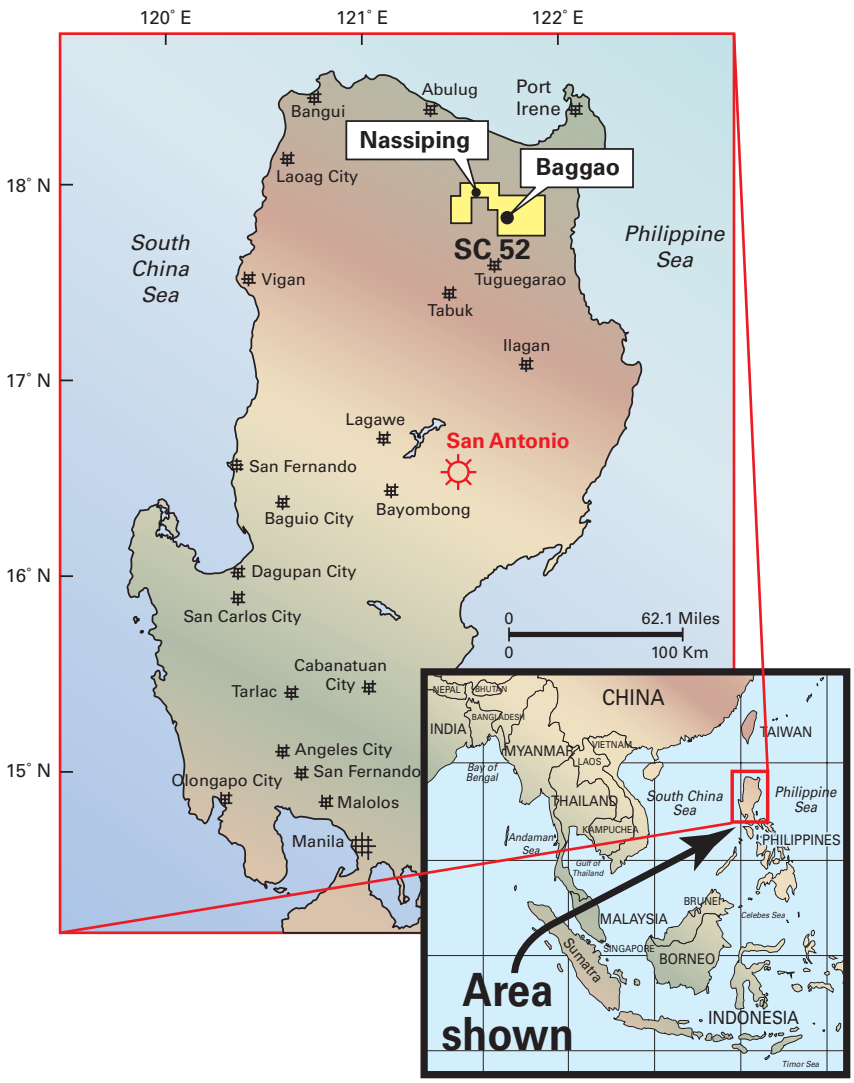
Record attendance levels experienced at the Apr. 20-24 Southeast Asia Petroleum Exploration farmout forum in Singapore signal an undiminished level of interest in regional exploration prospects.

The SEAPEX showing surprised many organizers and attendees in view of the world economic slump and the price of oil. Some 650 attended against the 550 expected. This bodes well for 2009-12 exploration in Southeast Asia. World class presentations, posters, and papers demonstrated the vast potential of the some 10 million plus sq km of onshore and offshore areas in the region.

The object of this article is not to dwell on the significance of the vast exploration licences and plays that can be enjoyed by majors and independent consortia in Southeast Asia. Rather, we have taken one of the smallest licenses in the region, SC 52 covering 960 sq km in northeast Luzon, Philippines, to demonstrate what can be done with careful research of existing data.

NORTHERN LUZON EXPLORATION AREA

Fig. 1



Economic woes

With the recent downturn in both oil prices and economic activity, low to midcap exploration companies have been hit particularly hard.

The prices these companies earn from production is now below 2005 levels, yet costs in association with drilling remain above double those of the same period. The consequent slashing of exploration budgets globally has limited the scope of junior exploration companies, but low-risk, low-cost plays, with an easy access to end-user markets still provide a way forward.

Southeast Asia stands out as a particularly attractive region in which to pursue such opportunities.

The lessons learned during the Asian financial crisis of the late 1990s have left middle-income countries such as Thailand, Malaysia, Indonesia, and the Philippines somewhat resilient to the economic downswing. A similar resistance can be seen in the lower-income countries in the region, with their underdeveloped financial markets providing a buffer against the adverse economic environment.

On the whole, Southeast Asia appears to have better economic parameters in view of the slump in other parts of the world, and as such it is likely a better place to explore.

Mabuhay Philippines

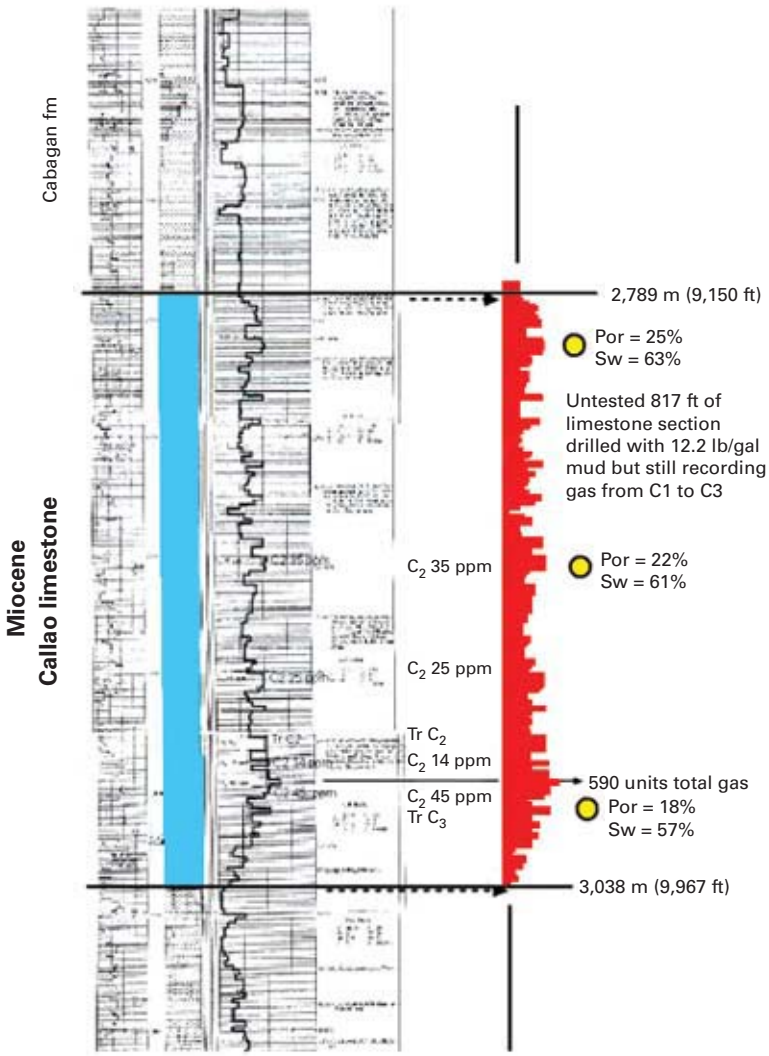
With its competitive fiscal regime, the Philippines stands out among Southeast Asian countries as a potential candidate for low-cost exploration and one that, until recently, has been largely ignored.

Boasting a low entry price, enticing incentives for collaboration with local partners, and a posttax contractor share of 30-45% of revenue, the Philippines has seen a resurgence of exploration activity in recent years.

The country has been largely abandoned since the mid-1970s, but the now-stable regulatory environment coupled with the successfully producing Malampaya gas project have paved the way for a revival. Most of the recent focus has been in the highly prospective Palawan basin, but this is just one of a number of potential oil and gas producing basins in the Philippines.

With an estimated resource potential of a few hundred million barrels of oil equivalent, and the only other producing gas field in the Philippines besides Malampaya, the Cagayan basin, Northern Luzon, is another "old haunt" now being revisited. It is a backarc basin of generally north-south orientation that covers about 28,000 sq km of Luzon Island with sedimentary fill estimated to be as thick as 9 km in some areas.

NASSIPING-2 BYPASSED GAS WELL Fig. 2



Service Contract 52

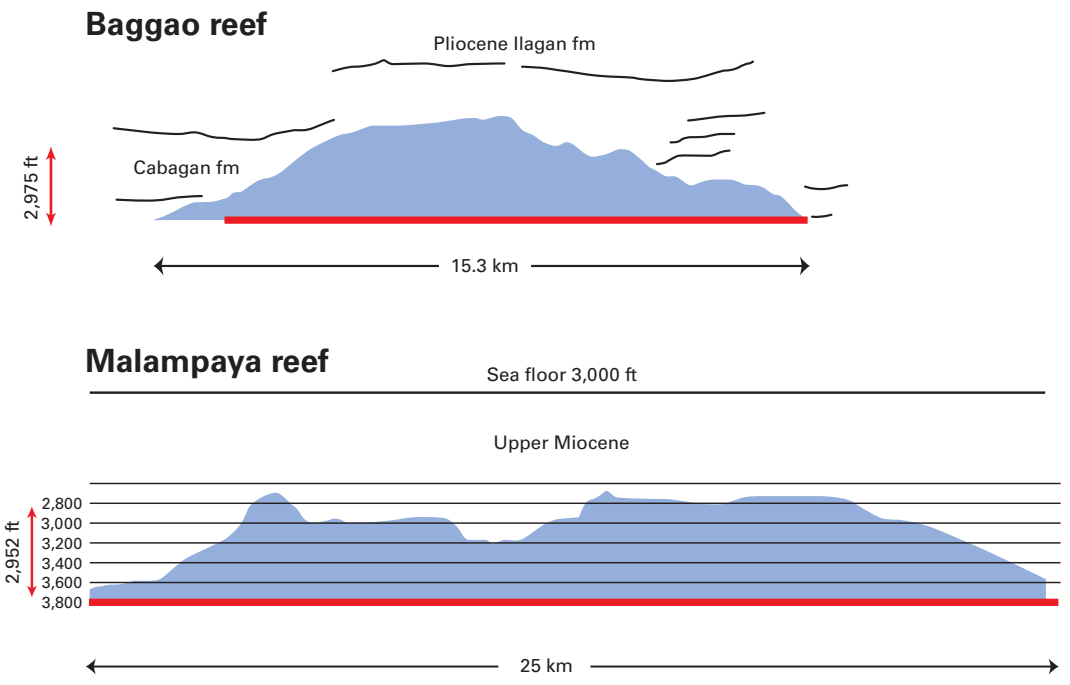
SC 52, in the northern Cagayan basin, is one of the smallest service contracts in the Philippines.

It was awarded to E.F. Durkee & Associates Inc. in mid-2005. After careful review of the existing data all indicators suggested that SC 52 was a highly prospective block with the Cagayan Valley providing a large onshore geological basin that has all the elements needed to perhaps provide important gas discoveries.

The oil and gas seeps found in the westerly foothills of the basin together with the San Antonio gas field (Fig. 1)

BAGGAO AND MALAMPAYA REEF CROSS SECTIONS

Fig. 3



This comparison of the profiles of the gas-producing Malampaya field reef-mound and the Baggao reef shows the two to be remarkably similar in height. Malampaya is long and narrow and embraces 10,500 acres at its base, whereas Baggao is quite broad and encompasses 30,700 acres at its base.

and producing well are pretty conclusive evidence that the Cagayan Valley has the potential to generate hydrocarbons from within its stratigraphic fill.

Several play concepts that have been identified in the basin include Early to Late Miocene reef buildups, fault block related traps, basement drapes, and stratigraphic traps. These aspects coupled with a good market potential for produced gas created by the area's position with respect to industrial developments, population centers, and electric power grids further enhanced the block's prospectivity.

Ready to blow?

The Nassiping dome is a nearly perfectly shaped, ovoid, domal surface anticline with good topographic and geomorphic expression.

It is about 8 km in diameter along its slightly longer northerly axis. Based on seismic data it has perhaps 2,000 ft of vertical closure in the younger strata.

The Nassiping-2 well drilled by Petro-Canada and Philippine National Oil Co. in 1984 has been shown until recently as a deep dry hole. Field work while searching for the wellhead uncovered gas leaking into the former cellar from beneath the steel plate that caps the 8⅝-in. pipe.

Often-ignored mud logs and geologic reports indicate that it was known that the well had penetrated 800 ft of gas-leaking strata. Uniquely, this well was cased to the top of the Miocene Callao limestone, which was only recently appreciated to be leaking gas. Hurrying on to other objectives estimated to be at 15,000 ft, the operator set pipe at the base of the limestone but never tested the Callao (Fig. 2).

The drillstring became stuck at 12,500 ft and was plugged and abandoned with no tests. Gas was apparently not of interest per the report.

Nassiping dome has an estimated resource potential of 35 to 350 bcf of gas and is strategically positioned less than 1 km from the local power grid.

Based on gas prices at Malampaya of around $8/Mcf, Nassiping appears to be a "freebie" to consider for testing. Durkee & Associates is seeking to farm down its equity position in SC 52.

Onshore giant reef

The Baggao-San Jose prospect on SC 52 is a Miocene-aged reef and possibly the largest onshore reef prospect yet identified in the Philippines (Fig. 3).

It has Malampaya-sized potential as a trap and has exceptional seismic evidence and surface geochemical methane anomalies. Drill depths vary on this tilted reef from 5,000 to 10,000 ft. It is 65 km from Port Irene, which in case of success will provide for export through that industrial zone to the Pacific region.

The Baggao reef is comparable with the 2-4 tcf reef at Malampaya off Palawan (Fig. 3).

Gas markets

Nassiping-2 is 0.7 km from the Northern Luzon Electric Grid and is a good candidate for a small gas-to-electricity project.

This type of development has already proved successful in the area, with PNOC having operated the one-well field at San Antonio. The well was tied to a 3-Mw generator that burned 1 MMcfd of gas and was on stream from 1992 until 2006.

Conclusion

SEAPEX's success as an exploration

forum indicates the interest in technical resources, financial resources, and human resources to evaluate Southeast Asia.

Two upcoming meetings to further this momentum are South East Asia Australia Oil Conference Sept. 9-11 in Darwin and the 2009 Association of International Petroleum Negotiators' Deal Making in the New Energy World international conference Oct. 18-21 in Bangkok. ✦

The authors

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E.F. Durkee has spent a lifetime largely in international exploration including Asia, Australia, Indonesia, Papua New Guinea, Europe, and the Middle East. He has BS and MA degrees from the University of Wyoming.

Algeria

Petroceltic International PLC resumed drilling on the Isarene permit in eastern Algeria for the first time since it shot almost 1,000 sq km of wide azimuth 3D seismic on the Ain Tsila ridge.

The INE-2 well, spud May 16, is first in a program of five to seven wells to test and appraise prior gas discoveries on the permit. The first two wells will be drilled before a rigless test crew is mobilized to the block.

Petroceltic is operator with 75% equity interest, and Algeria's Sonatrach has 25%.

India

Reliance Industries Ltd. and Niko Resources Ltd. reported exceptional reservoir performance as production has climbed to more than 900 MMscfd from 700 MMscfd in 7 days from the D6 development off eastern India.

Flow is expected to reach the target of 2.8 bscfd by yearend.

Meanwhile, the KG-D6 AR2 well in 1,844 m of water 5.7 km northwest of the KG-D6 R1 Late Miocene gas discovery went to TD 4,358 m and extended the R1 accumulation and enlarged its resource potential.

The KG-D6 BA2, at 80 km the farthest offshore well on the D6 block, targets the crest of a large anticlinal ridge feature that trends northeast-southwest across the entire block. The structure displays relatively late movement and trap closures that have formed in intervals that range from Early Pliocene to Cretaceous. The well is projected to 7,128 m in Upper Cretaceous.

The KG-D6 AS1 appraisal well is to go to 3,639 m in 1,791 m of water 11.2 km west of the KG-D6 R1 Late Miocene gas discovery.

Tanzania

Maurel & Prom, Paris, plans to spud an exploration well in August 2009 on the Delta Rufiji block in Tanzania.

The well is to probe the same formation in which the company discovered gas in the Mafia Deep well on the Bigwa Rufiji permit.

Meanwhile, the company drilled Mafia Deep ST-1 to 5,519 m and set a 360-m cement plug and 7-in. liner. Drilling will resume in order to evaluate the gas zone beneath the cement plug. Maurel & Prom operates the block with 70% interest.

Uganda

Tower Resources PLC said it is rigging up on 6,040 sq km Block 5 in northern Uganda using a rig transported from southern Sudan.

The Iti-1 exploration well in the Albert graben is expected to spud during the last week in May after the arrival of two further convoys of drill pipe and other equipment.

Yemen

Calvalley Petroleum Inc., Calgary, plans to drill six horizontal development wells in Hiswah field in 2009 and one exploration well each on the Ras Nowmah and Salmin prospects.

Both are projected to less than 1,500 m. Salmin is 5 km northwest of the Auqban discovery and targets a light oil carbonate structure. Ras Nowmah is between Hiswah and Al Roidhat fields.

The company is trying to resolve marketing issues to accelerate oil production from Block 9.

Mississippi

KFG Resources Ltd., Natchez, Miss., plans to redevelop Fayette field in Jefferson County, Miss.

The company is seeking permits for three wells to Eocene Wilcox at 4,000-5,500 ft based on results of 3D seismic shot in 2008.

The shallow development will precede the planned drilling of a 9,800-ft Lower Tuscaloosa well in the last quarter of 2009, KFG said.

The company holds 4,100 acres and has farmed out its working interests in all undeveloped acreage.

Texas

East

Goodrich Petroleum Corp., Houston, said its first horizontal Haynesville shale well tested at a rate of 7 MMcfd of gas on a $^{30}/_{64}$-in. choke with 2,800 psi pressure.

Goodrich is operator with 100% working interest in the Williams-7H well in the Beckville/Minden area of Panola County, Tex.

Goodrich also has 50% working interest in two Haynesville wells operated by Chesapeake Energy Corp. in Bethany-Longstreet field in Caddo and DeSoto parishes, La. Branch 2H-1 tested at 14.3 MMcfd with 6,750 psi on an $^{18}/_{64}$-in. choke, and ROTC 1H-1 tested at 14.1 MMcfd with 7,150 psi on an $^{18}/_{64}$-in choke.

New correlations calculate volatile oil, gas condensate PVT properties

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New correlations provide modified black-oil (MBO) pressure-volume-temperature (PVT) properties when fluid samples are unavailable.

One can use the correlations in generalized material balance calculations and MBO simulations. The new correlations match the fluid properties of a selected database and the authors also validated them with generalized material balance calculations.

To develop the new corrections, the authors modified existing solution gas-oil ratio, oil formation volume factor, and gas formation-volume factor correlations to increase their accuracy when used with gas condensates and volatile oils.

The new correlations have an accuracy within 10.4% for gas condensate and 15% for volatile oil samples used in this study.

Previous work

In 1973, Spivak and Dixon introduced the MBO simulation approach.[1] The MBO simulation considers three components; dry gas, oil, and water. The main difference between the conventional black-oil simulation and the MBO simulation, also called extended black-oil, lies in the treatment of the liquid in the gas phase.

The MBO approach assumes that the stock-tank liquid component can exist in both liquid and gas phases under reservoir conditions. It also assumes that one can define the liquid content of the gas phase as a sole function of pressure called vaporized oil-gas ratio, R_v, also referred to as r_{s2}. This function is similar to the solution gas-oil ratio, R_s, normally used to describe the amount of gas-in-solution in the liquid phase.

Whitson and Torp presented a procedure to calculate MBO properties from PVT experimental data of gas condensate.[2] Coats also presented a different procedure for gas condensate fluids.[3] Coats's procedure was extended by McVay for volatile oil fluids.[4] Walsh and Towler (OGJ, July 31, 1994, p. 83) also presented a procedure to calculate MBO PVT properties from constant volume depletion (CVD) experiment data.[5]

Fattah et al. (OGJ, Mar. 27, 2006, p. 35) showed that both Whitson and Torp's and Coats's procedures provide an excellent match with compositional simulation results when the analysis matches PVT experimental with an EOS model and then uses it to find the MBO PVT properties.[6]

El-Banbi et al. presented a field case where MBO PVT properties and the MBO approach helped speed a field development plan.[7] They presented evidence that the MBO approach adequate-

MBO approach

Several authors have shown that an MBO approach could replace compositional simulation in many applications for modeling gas condensate and volatile oil reservoirs.

This work developed a new set of MBO PVT correlations. The four PVT functions are:

1. R_v, oil-gas ratio.
2. R_s, solution gas-oil ratio.
3. B_o, oil formation volume factor.
4. B_g, gas formation volume factor.

To our knowledge, a correlation for calculating oil-gas ratio did not exist in the petroleum literature. Without this correlation, the analysis required for generating the oil-gas ratio required a combination of laboratory experiments and elaborate calculation procedures using equation of state models.

The new R_v correlation depends on only readily available parameters in the field and can have wide applications when representative fluid samples are unavailable.

EQUATIONS

$$\text{error} = \frac{1}{N}\sum_{i=1}^{N}\left|\frac{\text{Data} - \text{Model}}{\text{Data}}\right| \quad (1)$$

$$R_S = \gamma_g\left[\left(\frac{p}{A1} + A2\right)10^{X}\right]^{A3} \quad (2)$$

$$X = A4 \times API - A5\,(T - 460) \quad (3)$$

$$R_S = A1 \times \gamma_{gs} \times p^{A2} \times EXP\left[\frac{A3 \times API}{T}\right]$$

$$\gamma_{gs} = \gamma_g\left[1 + 5.192\,(10^{-5})\,(API)\,(T_{SEP} - 460)\log\left(\frac{P_{sep}}{114.7}\right)\right] \quad (4)$$

$$R_1 = \frac{A1 \times \rho_{gsc} \times (A2 \times p^2 + A3 \times p + A4)}{p_s} \times EXP\left[\frac{A5 \times CGR \times T_{sc}}{\rho_{osc} \times T \times P_{sc}}\right] \quad (5)$$

$$B_O = A1 + A2 * \left(R_S\sqrt{\frac{\gamma_{gsc}}{\gamma_{osc}}} + A3 * (T - 460)\right)^{A4} \quad (6)$$

$$p_{pc} = A1 + A2 \times \gamma_{gs} + A3 \times \gamma_{gs}^2 \quad (7)$$

$$T_{pc} = B1 + B2 \times \gamma_{gs} + B3 \times \gamma_{gs}^2 \quad (8)$$

$$B_g = \frac{5.04 \times z \times T}{p} \quad (9)$$

Nomenclature

B_g	=	Gas formation volume factor, bbl/Mscf
B_o	=	Oil formation volume factor, bbl/stb
CCE	=	Constant composition experiment
CVD	=	Constant volume depletion test
DL	=	Differential liberation test
EOS	=	Equation of state
MBO	=	Modified black oil
N	=	number of points or values
p	=	Pressure, psia
p_s	=	Saturation pressure, psia
p_{sc}	=	Standard pressure, psia
p_{sep}	=	Separator pressure, psia
PVT	=	Pressure-volume-temperature
R_s	=	Initial solution GOR, scf/stb
R_v	=	Volatile GOR, stb/Mcf
T	=	Reservoir temperature, °R
T_{sc}	=	Standard temperature, °R
T_{sep}	=	Separator temperature, °R
z	=	Gas compressibility factor, fraction
ρ_{gsc}	=	Gas density at standard conditions, lb/cc
ρ_{osc}	=	Oil density at standard conditions, lb/cc
γ_g	=	Gas gravity at the actual separator conditions of p_{sep} and T_{sep}
γ_{gs}	=	Gas gravity at reference separator pressure
γ_{gsc}	=	Specific gravity of gas at standard conditions
γ_{osc}	=	Specific gravity of oil at standard conditions

ly simulates gas condensate fluids above and below the dewpoint and with water influx.

Other authors also have presented different comparisons between the MBO and compositional approaches.[2 3 6]

In recent work, Fevang et al. presented guidelines to help engineers choose between MBO and compositional approaches.[8]

Fluid samples

The petroleum literature has reported many cases where the MBO approach replaced more expensive compositional simulation. Generating MBO PVT properties requires a representative fluid sample that undergoes enough laboratory experiments. Then, one usually constructs EOS models to match the laboratory experimental results, although there are other less accurate techniques.[6]

One can output the MBO properties at appropriate separator conditions using one of the procedures suggested in literature. This process requires the availability of a representative fluid sample in addition to the skills of EOS modeling.

The set of correlations presented in this article can generate MBO PVT properties without the need for fluid samples or an elaborate procedure for EOS calculations. The application of these correlations is of particular importance especially when a representative sample is unavailable.

Our study used 13 reservoir fluid samples (8 gas condensates and 5 volatile oils). The samples were from reservoirs at different locations and depth and covered a wide range of oil and gas fluid characteristics.

Table 1 shows the major properties of the 13 fluid samples. Reference 9 presented the PVT experiments for all these samples. Some samples represent near critical fluids (VO 2, VO 5, GC 1, and GC 2) as explained by McCain and Bridges.[10]

Approach

For every sample in Table 1, we constructed an EOS model that matched as best as possible the experimental results of all available PVT laboratory experiments that included constant composition expansion (CCE), constant volume depletion (CVD), differential liberation (DL), and separator tests.

For consistency, we developed all EOS models using the Peng and Robinson EOS with volume shift correction (three-parameter EOS).[11] We followed the procedure suggested by Coats and Smart to match the laboratory results.[12]

We then used the developed EOS model for each sample to output MBO PVT properties at different separator conditions using Whitson and Torp's procedure.[3]

The MBO PVT properties include the four functions required for MBO simulation: R_v, R_s, B_o, and B_g. For each of the four properties, we generated six curves, representing six different sepa-

Fluid sample characteristics

Table 1

Sample	VO 1	VO 2	VO 3	VO 4	VO 5	GC 1	GC 2	GC 3	GC 4	GC 5	GC 6	GC 7	GC 8
Reservoir temperature, °F.	249	246	260	190	197	312	286	238	256	186	312	300	233
Initial reservoir pressure, psig	NA	5,055	5,270	NA	13,668	14,216	NA	6,000	7,000	5,728	14,216	5,985	17,335
Initial producing GOR, scf/stb	1,991	2,000	2,032	2,24	2,416	3,413	4278	NA	4,697	5,987	8,280	6,500	6,665
Stock-tank oil gravity, °API	45.5	51.2	NA	36.8	34.1	45.6	NA	NA	46.5	58.5	50.7	45.6	4
Saturation pressure, psig	4,527	4,821	4,987	7,437	9,074	5,210	5,410	4,815	6,010	4,000	5,465	5,800	11,475
Components	Composition, mole %												
CO_2	2.14	2.18	2.4	0.1	0.34	2.66	4.48	0.14	0.01	0.18	2.79	6.98	0.36
N_2	0.11	1.67	0.31	0.16	0	0.17	0.7	1.62	0.11	0.13	0.14	1.07	0.31
C_1	55.59	60.51	56.94	69.84	72.47	59.96	66.24	63.06	68.93	61.72	66.73	65.25	81.23
C_2	8.7	7.52	9.21	5.37	4.57	7.72	7.21	11.35	8.63	14.1	10.22	8.92	5.54
C_3	5.89	4.74	5.84	3.22	2.79	6.5	4	6.01	5.34	8.37	5.9	4.81	2.66
iC_4	1.36	4.12	1.44	0.87	0.67	1.93	0.84	1.37	1.15	0.98	1.88	0.85	0.62
nC_4	2.69	0	2.73	1.7	1.33	3	1.76	1.94	2.33	3.45	2.1	1.75	1.06
iC_5	1.17	2.97	1.03	0.79	0.69	1.64	0.74	0.84	0.93	0.91	1.37	0.65	0.47
nC_5	1.36	0	1.22	0.88	0.82	1.35	0.87	0.97	0.85	1.52	0.83	0.69	0.52
C_6	1.97	1.38	1.96	1.41	1.52	2.38	0.96	1.02	1.73	1.79	1.56	0.83	0.84
C_{7+}	19.02	14.91	16.92	15.66	14.8	12.69	12.2	11.68	9.99	6.85	6.48	8.2	6.39

Modified standing correlation parameters

Table 2

Constant	Gas condensate	Volatile oil
A1	0.19408473	47.23306
A2	–3709.4214	–8.833514
A3	1.06052098	1.3251534
A4	–0.05022324	0.0091756
A5	–0.003771627	–0.000385524

Note: For gas condensates and volatile oil fluids, Equations 2 and 3.

Modified Vasques and Beggs correlation parameters

Table 3

Constant	Gas condensate	Volatile oil
A1	12.5849757	0.0005473
A2	1.343554054	1.607758566
A3	–105.486585	20.35993884

Note: For gas condensates and volatile oil fluids, Equations 4 and 5.

rator conditions for each sample.

Our database of PVT properties consisted of 1,850 points from eight different gas condensate samples and 1,180 points from five volatile oil samples.

We used PVTi program of Eclipse to generate the curves for the MBO PVT properties.[13]

For the three parameters commonly used for black-oil material balance and simulation (R_s, B_o, and B_g), we tested some known correlations to determine the one that fits our database and to see if we needed to modify the correlation constants.

For R_v, we had to develop a completely new correlation because we could not find one in the petroleum literature. Our approach was to start from a similar form to R_s correlations, then modify the correlation parameters using regression methods until we obtained the best fit to R_v data.

MBO PVT correlations

Our analysis used Equation 1 in the accompanying equation box to determine the average error for each of the four PVT parameters.

For R_s the analysis used several correlations for testing the database for both volatile oil and gas condensate samples. We found that the forms suggested by Standing and Vasques and Beggs gave the best results after we modified the correlation constants.[14,15] The average absolute error for both gas condensates and volatile oil samples was as high as 50% if we used the original correlation parameters. This probably results from the original Standing and Vasques and Beggs correlations being developed for black oils.[16]

Equations 2 and 3 show the modified Standing correlation, and Equations 4 and 5 show the modified Vasques and Beggs correlation. Table 2 lists five parameters for the modified Standing correlation, obtained from regression analysis for both gas condensate and volatile oil samples. Table 3 lists the new parameters for the modified Vasques and Beggs correlations.

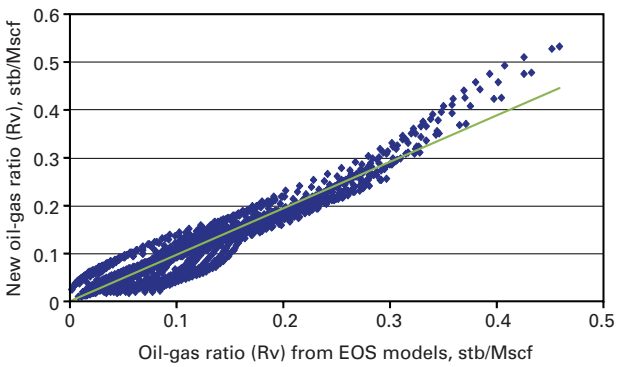
The average error calculated with Equation 1 was 20.5% for gas condensates and 23.2% for volatile oils. The modified Vasques and Beggs has higher errors of 27.7% for gas condensates and 29.2% for volatile oils.

For volatile oil above the bubblepoint, R_s, the analysis uses the same value as the bubblepoint value.

For calculating R_v, we needed a completely new form for the correlation. A useful correlation with a wide applicability has to have parameters with read-

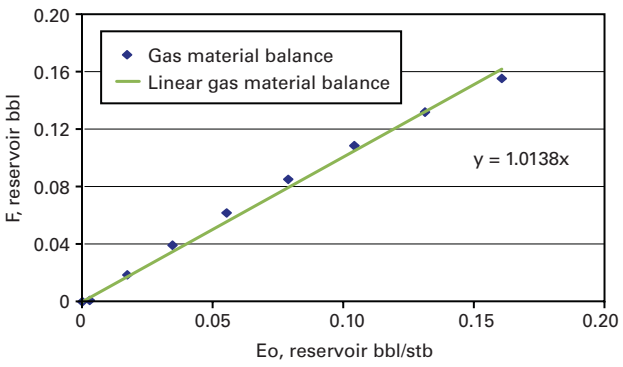
OIL-GAS RATIO FIT

Fig. 1



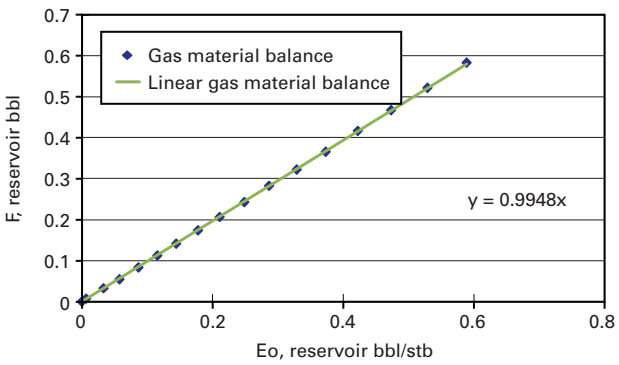
MATERIAL BALANCE GC 1

Fig. 2



MATERIAL BALANCE VO 1

Fig. 3



ily available values without the need for fluid samples or elaborate calculation procedures using EOS models.

Equation 5 is the derived correlation. The absolute average error with this form is 10.4% with a standard deviation of 0.0308 for gas condensates and 15.0% with a 0.1271 standard deviation for volatile oils.

Table 4 shows the correlation constants A1 to A5. Fig. 1 is a cross plot for all gas condensate points and shows the 45° line, as an indication of the goodness of fit for the calculated results vs. experimental results. Notice that initial condensate yield, which can be obtained from production data, depends on separator conditions in the field.

One can determine saturation pressure from a pressure vs. cumulative production plot. The saturation pressure is observed by change in slope in this plot due to the difference in depletion above and below the saturation pressure, or from constant composition expansion on a representative sample.

The R_v value is constant above the dewpoint for gas condensate samples.

For the oil formation volume factor, B_o, the analysis tested several correlations against the database of B_o points for both the gas condensate and volatile oil samples below the saturation pressure. It was found that one can use adequately both the Standing correlation and the Vasques and Beggs correlation (absolute average errors about 4%) without modifications. One can improve the error percentage of B_o with the constants listed in Table 5. Equation 6 gives the modified Standing correlation.

Equation 6 has an average absolute error of 2.7% for gas condensate samples and error of 1.6% for volatile oils. Further testing of the modified B_o correlation showed that it was not greatly affected by the accuracy of the R_s values used.

One can calculate B_g from the z-factor. We tested the use of the Sutton correlation to calculate pseudocritical properties and then used the Standing z-factor correlation in a calculation procedure suggested by Dranchuk and Abou-Kassem.[17 18] We found this procedure for calculating B_g adequate for both the gas condensate and volatile oil samples (absolute average error less than 8%). The correlation, however, improves with the use of different Sutton parameters, as in Equations 7 and 8.

OIL-GAS RATIO CORRELATION CONSTANTS

Table 4

Constant	Gas condensate	Volatile oil
A1	3.45841109	1.225537042
A2	6.89461E-05	0.000107257
A3	–0.03169875	–0.194226755
A4	251.0827307	240.549909
A5	4.174003053	8.32137351

Note: For gas condensates and volatile oil fluids, Equation 5.

OIL FORMATION VOLUME FACTOR CORRELATION CONSTANTS

Table 5

Constant	Gas condensate	Volatile oil
A1	0.965109778	0.839614826
A2	0.000342547	0.000460621
A3	1.303305644	2.013137024
A4	1.053171234	1.015821025

Note: For gas condensates and volatile oil fluids, Equation 6.

MODIFIED SUTTON CORRELATION PARAMETERS

Table 6

Constant	Gas condensate	Volatile oil
A1	670.958	608.520
A2	–188.078	–45.8495
A3	–3.7882	27.71169
B1	480.1142	29.70495
B2	–94.2128	871.57199
B3	9.398696	–502.6044

Note: For gas condensates and volatile oil fluids, Equations 7 and 8.

Error in fluid in place calculation Table 7

Fluid sample	Original fluid in place	Error, %
VO 1	0.9948	0.52
VO 2	1.0027	0.27
GC 1	1.0138	1.38
GC 2	0.9451	5.49
GC 3	1.0154	1.54
GC 4	1.0092	0.92
GC 5	1.1526	15.26
GC 6	1.0319	3.19

Note: From generalized material balance calculations using the new R_v correlation.

Table 6 lists the values for the modified Sutton equation. The analysis obtained these parameters by minimizing the error given by Equation 1.

We used the pseudocritical properties from Equations 7 and 8 to calculate the z-factor and then Equation 9 to obtain B_g.

The average absolute error in B_g, with this procedure, is 3.8% for gas condensate and 1.65% for volatile oil samples. Notice that the gas specific gravity used in the modified Sutton correlation is corrected for separator conditions with Equation 4.

Correlation validation

In addition to cross plots, such as Fig. 1, to see how the new correlation values compared to the values obtained from the EOS model, we validated the new corrections with reservoir simulation and material balance calculations.

We used the generalized material balance equation from Walsh to validate the new R_v correlations by performing the material balance calculations using the PVT properties from the new correlations to calculate original hydrocarbon in place.[19 20] We compared these values to the original hydrocarbon in place values obtained from compositional reservoir simulation for a tank model.

For simplicity, the analysis normalized the original fluid in place to 1.0 billion stock-tank bbl for oil cases and 1 bscf for gas cases.

Fig. 2 shows a plot of F vs. the expansion term, E_g, for a gas condensate sample (GC 1), based on the Walsh procedure. The slope of the line passing through the calculated points gives the original fluid in place volume. The plot shows that the slope of the line is 1.038, with the error in gas in place calculation of about 1.4%.

Fig. 3 is a similar plot for the volatile oil sample (VO 1). The plot shows a slope of 0.9948, which is equivalent to the error in the oil in place calculation of about 0.5%.

Table 7 shows the error in the calculated fluid in place for most of the fluid samples in our database. The error values show high accuracy and prove the validity of the new correlations.

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The authors thank Schlumberger Egypt for donating the Eclipse suite of software, used in this investigation, to the petroleum engineering department of Cairo University. In addition, A.H. El-Banbi also thanks Bill McCain for many valuable discussions that led to this research. ✦

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LIQUIDS ENTRAINMENT—2

On line liquid-entrainment testing confirms CFD model prediction

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Anchorage

Ralph Eguren
BP America Production Co.
Houston

This is the second of three articles that describes BP's experience with reciprocating compressor damage from liquids intrusion at two facilities, in Oklahoma and Alaska.

Part 1 of the series (OGJ, May 18, 2009, p. 46) discussed the role of changing operating conditions in leading to compressor damage and reviewed details of the Oklahoma incident.

This second article reviews the validation of CFD modeling by on line laser isokinetic probe sampling for liquid entrainment and the impact of NGL solubility in compressor lube oil.

The concluding article (OGJ, June 8, 2009) will examine the use of state-of-the-art in-line cyclonic separation technology to mitigate liquid entrainment.

BP owns and operates the Milne Point oil production facility on Alaska's North Slope where processing facilities are enclosed in heated, adjoining modules. The gas compression module houses two 3,450-hp reciprocating compressors.

Over time, the frequency and severity of compressor component failures increased. Intense examination identified both mechanical and process-related causes for the failures, including entrainment of water and NGLs in the compressor suction.

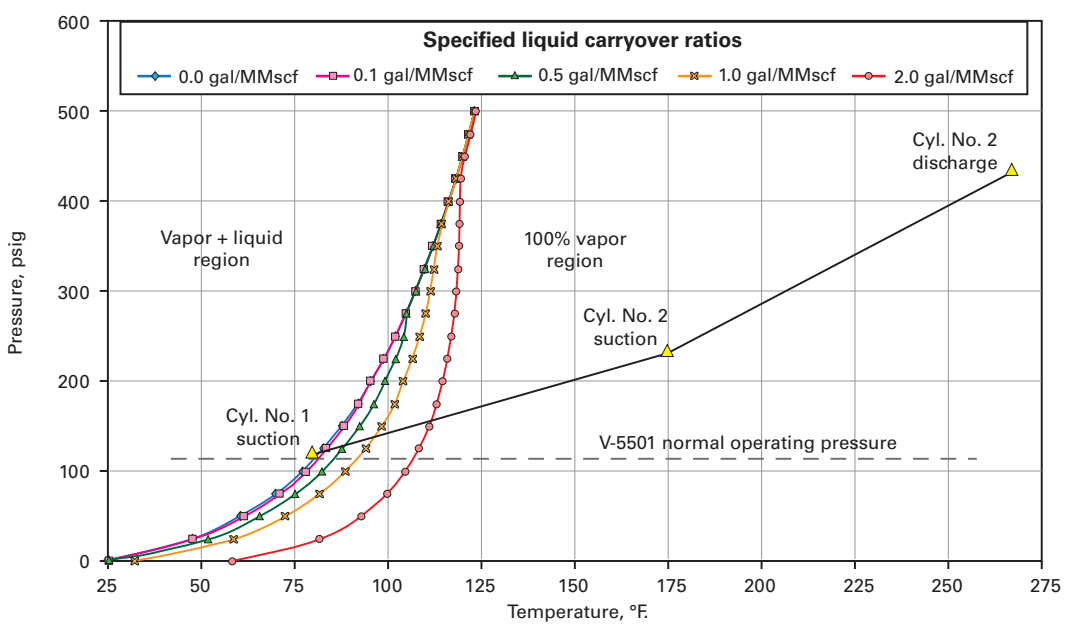
Damage caused or exacerbated by ingested liquids included bearing failures, damaged cylinder lining, sheared wrist pins, sheared cylinder attachment bolts, and cracked pistons.

At Milne Point, poor separation performance of existing suction scrubbers was predicted by computational fluid dynamics (CFD) modeling and confirmed by laser isokinetic probe sampling to quantify liquid entrainment. Analysis of operating data also indicated condensation of liquids in suction piping downstream of the scrubbers.

A process flow diagram for the Milne Point compression facility appeared in Part 1 and identifies the equipment tags and cylinder numbering sequence

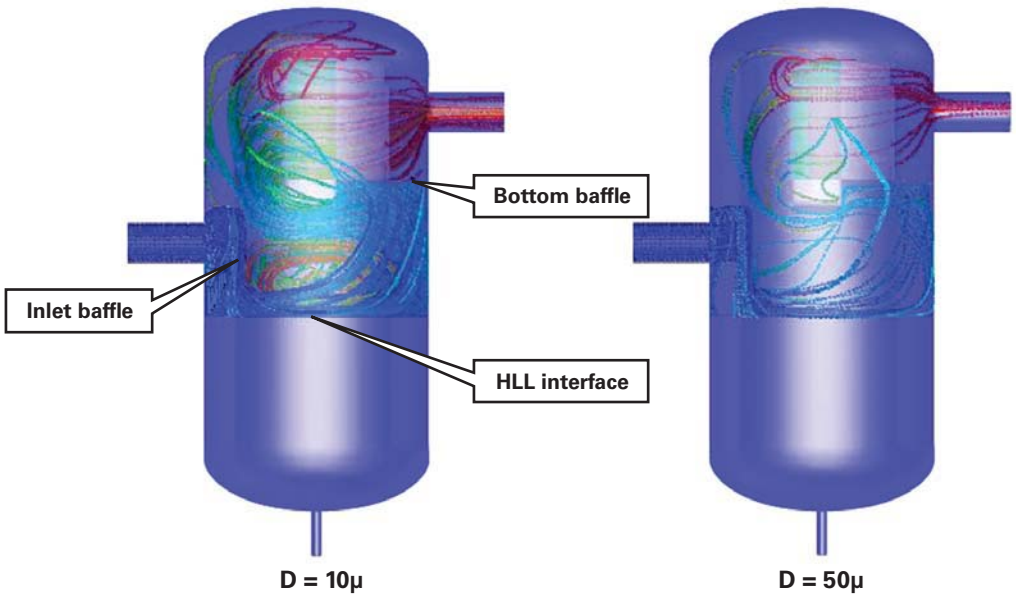
DEWPOINT CURVES

Fig. 1



V-5501 DROPLET TRAJECTORY

Fig. 2



Source: CDS Separation Technology, FMC Technologies

referred to in this second article and in the concluding article (OGJ, June 8, 2009).

Liquid source

The suction bottles on the Nos. 1 and 2 cylinders are immediately downstream of the suction scrubbers. The presence of water and NGL in these bottles clearly indicates that the source of these liquids is either scrubber liquid carryover, condensation in uninsulated suction piping and pulsation bottles, or a combination. Process analysis and operating data confirmed that both mechanisms contribute to the presence of condensate and water in the Big A/B suction streams.

As Fig. 1 shows, the gas entering the low-pressure No. 1 cylinders exhibits large dewpoint shift with liquid entrainment, even at low to moderate scrubber liquid carryover. This readily explains why the liquid dropout in the No. 1 suction bottles is so much greater than in the No. 2 suction bottles, which operate at a higher pressure where the dewpoint shifts are not so pronounced.

The suction bottles on the Nos. 3 and 4 cylinders are immediately downstream of the discharge bottles from the Nos. 1 and 2 cylinders, respectively. The only possible source of liquids in these suction bottles is carryover of liquids with the gas discharging from the upstream cylinders. As described earlier, lab analysis shows these liquids to be lube oil diluted with condensate.

From the accumulated evidence, the deleterious effects of liquids ingestion on Big A/B can be reasonably inferred. For clarity, this discussion focuses only on the Nos. 1 and 3 cylinders.

Entrained NGL enters the No. 1 suction bottle, located on top of the No. 1 cylinder. From there, it enters the No. 1 cylinder and dilutes the cylinder lube oil. This causes a loss of cylinder lubrication, which imposes disproportionate forces on the bearings, resulting in excessive wear and premature bearing failures.

Diluted lube oil is then carried with the compressed gas into the No. 1 discharge bottle, located beneath the No. 1 cylinder. Fluids enter this bottle from the top and exit upward through a nozzle oriented about 45° from vertical. The No. 1 discharge bottle connects by a 6-in. diameter vertical pipe to the No. 3 suction bottle, located on top of the No. 3 cylinder.

Before installation of a drain line from the No. 1 discharge bottle, diluted lube oil would accumulate there because it had no way to escape. Once the level of oil in this 100-gal bottle increased sufficiently, liquid slugs would intermittently be forced out with the gas into the No. 3 suction bottle.

If and when a large enough slug was pushed out of the discharge bottle, it would enter the No. 3 cylinder, damaging the piston. Calculations indicate that a slug of only 4 gal would nearly double the pressure generated inside the No. 3 piston.

With respect to the two instances of cracked No. 3 pistons, the scenario just described cannot be absolutely proven, but it is consistent with the evidence. Both cracked pistons were on Big A. As the table in Part 1 shows, the volumes of liquids drained from the Nos. 1 and 3 suction bottles on Big A are more than seven times the volumes drained from the corresponding bottles on Big B. Also, no further piston damage has occurred since installation and daily operation of bottle drains.

Visual scrubber inspection

After discovery of liquids in the Big A compressor, fouled or damaged scrubber internals were initially suspected of causing excessive liquid carryover. Suction scrubbers V-5501 and V-5511 had not been opened in 10 years and were due for inspection, which occurred in August 2007.

Both scrubbers were clean, with all internals in very good condition. New

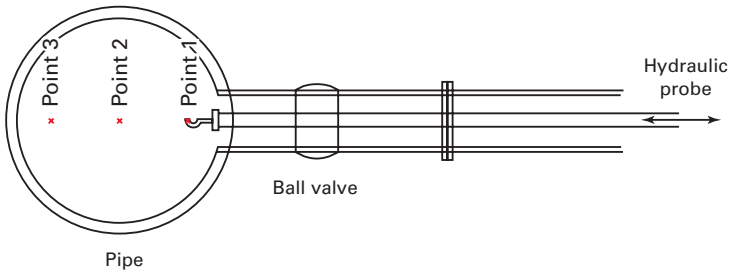
LISP HYDRAULIC PROBE

Fig. 3

V-5511 branch connection Fig. 3a

Source: Drawing from Peerless Manufacturing Co.

Probe insertion into vapor flowline Fig. 3b



mesh pads and vane packs were on site if needed. The existing vane packs were in nearly perfect condition and were not replaced. The existing mesh pads were only slightly worn, with no fouling or other damage. Because the mesh pads had to be removed to inspect the vane packs, new mesh pads were installed before the vessels were closed.

Scrubber inspections were performed by a Peerless Mfg. Co. representative. After no internal damage was found, Peerless recommended on line liquid carryover testing with a laser isokinetic probe. Specifications were provided for installation of 3-in. branch connections on the scrubber's vapor lines to allow for probe insertion. WorleyParsons designed a mechanical piping package to install the required branch connections.

CFD modeling

On line carryover testing could not be performed until the required connections were installed on the scrubber's vapor overhead lines during the next scheduled plant shutdown. In the interim, CDS Separation Technology, a subsidiary of FMC Technologies, was engaged to prepare CFD models to provide a better understanding of scrubber performance.

CFD model results indicate performance problems with both scrubbers. Scrubber V-5501 experiences significant recirculation and maldistribution of flow upstream of the mesh pad. This reduces volume utilization of the vessel, causing carryover of liquid droplets into the gas outlet.

Also, the inlet baffle plate diverts the feed stream downward onto the gas-liquid interface, which causes reentrainment of liquid particles and interferes with liquid level detection and control. Fig. 2, a snapshot from the V-5501 CFD model run, shows this inlet feed diversion and corresponding flow maldistribution. The model predicted that volume utilization for this vessel was 63.5% and that most liquid droplets smaller than 50µ were carried into the gas outlet nozzle.

Similar results were reported for V-5511. Volume utilization was 81%, higher than for V-5501 due to a lower mean vapor velocity that results in less internal turbulence. The overall liquid carryover rate, however, was predicted to be higher than for V-5501 due to a lower density difference between the liquid and gas phases.

The CFD models did not provide precise predictions of liquid carryover leaving the scrubbers. This would have required accurate modeling of the vane pack assemblies, which would have significantly increased both the complexity of the models and the time and computing resources required to run them.

Laser sampling

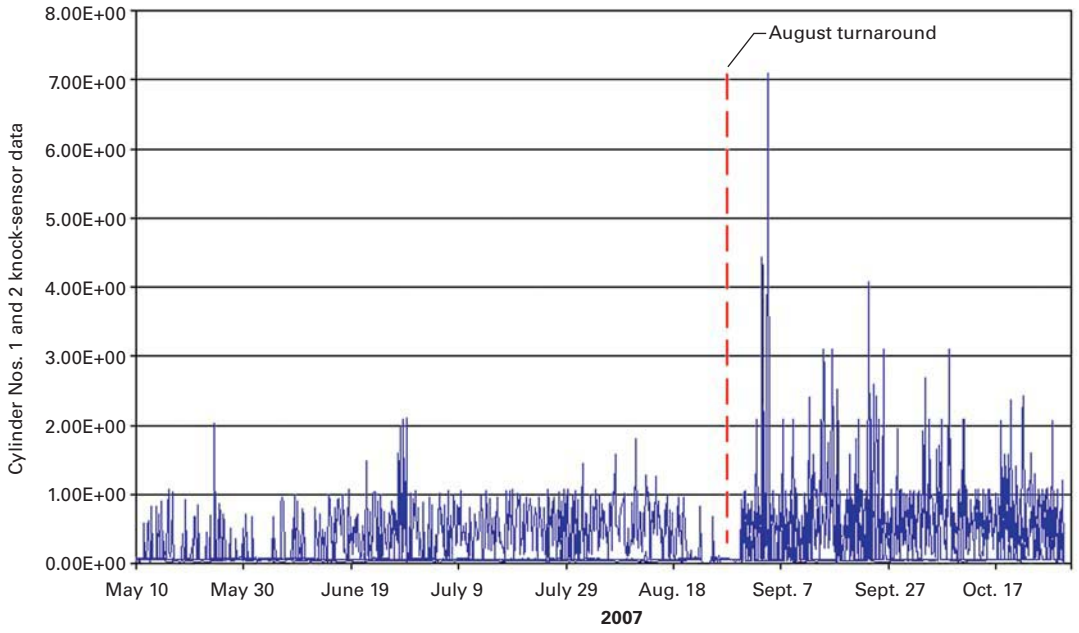
Branch connections for on line laser isokinetic sampling probe (LISP) carryover testing were installed during the summer 2008 plant shutdown. The test apparatus consists of a hydraulic sampling probe inserted through a 3-in. branch connection into the flowing vapor stream. Fig. 3 shows the actual branch connection for V-5511, alongside a Peerless sketch that illustrates insertion of the hydraulic sample probe into the vapor line.

A fluid sample flows through the hydraulic probe into an external LISP module, where two separate tests are performed. First, a laser-based particle counter yields particle size distribution and total liquid entrainment values. Second, the extracted sample flows through a coalescing filter that captures all entrained liquids and solids. Total entrainment is determined by weight difference of the filter elements.

Peerless Mfg. provided equipment and personnel to perform this testing in August 2008. Tests were conducted on each suction scrubber under two conditions, with only Big B running (half rate) and with both Big A and Big B running (full rate). Peerless issued final test reports in October 2008.

BIG A KNOCK-SENSOR VALUES

Fig. 4



With only Big B running, liquid carryover was 1.37 gal/MMscf for V-5501 and 4.32 gal/MMscf for V-5511. For comparison, the performance guarantee for these two vessels is 0.1 gal/MMscf, which is a typical industry guarantee. With both Big A and Big B running, liquid carryover was 0.11 gal/MMscf for V-5501 and 4.56 gal/MMscf for V-5511.

Each of the four test results reported a substantial volume of "solids" carryover. These are not necessarily solids but represent the total mass of entrained fluids that do not vaporize after the samples are cooked for 8 hr at 190° F. No analysis was done, but brown staining of the filters indicates these solids are most likely entrained lube oil, which does not vaporize at 190° F. Compressor lube oil gets into V-5501 with the Big A/B recycle stream and into V-5511 with the discharge stream from the No. 3 cylinders.

Results for V-5501 show substantially more liquid and solids carryover with Big B running alone than with both Big A/B on line. This most likely indicates the poor turndown performance typical of vane packs, which depend on the difference in momentum between gas and liquids for effective separation. At lower flow rates, the liquid particles have less momentum and tend to stay with the gas rather than be captured on the vane surfaces.

During the 1995 plant expansion, the original vane packs were replaced with new vane packs designed to handle 48 MMscfd. A rate of 19 MMscfd with only Big B running corresponds to a turndown ratio of 40%.

Results for V-5511 show slightly higher liquid carryover and considerably higher solids rate with only Big B running than with both compressors on line. This again is consistent with reduced separation efficiency for vane packs at lower flow rates, but the difference is substantially less than for V-5501. Also, the much higher carryover rates for V-5511, compared with V-5501, confirm the earlier CFD model prediction.

The V-5501 test with both compressors on line is the only one that even comes close to the vessel performance guarantee of 0.1 gal/MMscf. This result does seem strange, considering that substantially higher volumes of liquids are routinely drained from the suction bottles downstream of V-5501 than from the bottles downstream of V-5511.

On the other hand, the gas leaving V-5501 is richer than the gas leaving V-5511 and is more prone to condensation in the suction bottles and piping downstream of the suction scrubber. Regardless of this anomaly, this series of tests confirms that current scrubber performance is inadequate to provide clean, dry gas to the Big A/B compressors.

Lube oil replacement

Plugging of small-diameter lubricator lines led to replacement of the synthetic lube oil used for Big A/B cylinder lubrication with mineral oil during the August 2007 plant turnaround. This change stopped the line plugging but had an unintended consequence. Fig. 4 plots Big A knock-sensor values for several months before and after the turnaround. Because no other changes were made during the shutdown that could account for the step change in knock-sensor output, the lube oil change out was the prime suspect.

Samples of mineral oil and synthetic lube oil were sent to a local lab for solubility tests with n-pentane. At room temperature, both lube oil samples were found to be completely soluble in pentane over a wide range of pentane concentrations. Mixtures of 75% lube oil and 25% pentane were then placed in a ventilated oven for 1 hr at 113° F., which is 16° F. above the boiling point of pentane.

As expected, this caused evaporation

of pentane from the mixtures, but the total volume of pentane that evaporated was vastly different for each of the two lube oil samples. After heating, the synthetic oil mixture contained 4.96 wt % pentane, compared with 12.13 wt % pentane in the mineral oil mixture. This equates to a retention of 22% of the original pentane in the synthetic oil, compared with 59% retention of original pentane in the mineral oil.

In other words, at the lab test condition of 113° F., the mineral oil retained more than 2.5 times as much pentane as did the synthetic oil. At higher temperatures, this disparity in solubility between the two oils would be even greater. As a point of reference, the temperature inside the Nos. 1 and 2 cylinders on Big A/B ranges between 80-175° F.

The increased solubility of NGL in mineral oil compared with synthetic oil can be explained in terms of both chemical and thermodynamic properties. The relatively low solubility of pentane in the synthetic oil sample is largely due to its chemical formulation, which is proprietary. The particular oil formerly used at Milne Point, however, is primarily a mixture of poly-alpha-olefins and poly-isobutylene, the latter being responsible for the low NGL solubility.

From a thermodynamics standpoint, HYSYS process simulations confirm the lab test results. The existing Big A/B compressor suction scrubbers do not provide adequate vapor-liquid separation. This results in a mixed-phase compressor suction stream (gas plus entrained NGL). As shown previously in Fig. 1, this liquid entrainment shifts the dewpoint temperature of the gas-liquid mixture upward by an amount that depends entirely on the actual level of entrainment.

If there were no interaction between the entrained NGL and the cylinder lube oil, then these entrained liquids would vaporize early during each compression stroke as the cylinder temperature increased above the elevated gas dewpoint. In actuality, however, lube oil does interact with entrained NGL, as the lab tests showed that both synthetic and mineral oils dissolve and retain pentane.

Compared with the relatively minor dewpoint shift without NGL-lube oil interaction, whenever lube oil is dissolved in entrained NGL, even at low concentrations, the dewpoint temperature of the compressed gas shifts dramatically upward. This means that NGL components that would otherwise vaporize during the compression stroke will remain in the liquid state during the entire stroke.

The degree to which this phenomenon occurs largely depends on the type and concentration of dissolved lube oil. Because mineral oil has a much higher affinity for NGL than does synthetic oil, it can be expected to absorb and retain NGL to a much greater degree. This is consistent with the observed knock-sensor trends, which showed a step change increase after the August 2007 lube oil change.

In response to particularly high knock readings in November 2007, operators shut down Big A for inspection, which revealed a con rod bearing failure. This failure was almost certainly related to loss of cylinder lubrication caused by lube oil dilution with entrained NGL, exacerbated by the change from synthetic to mineral oil just 3 months earlier.

Research into the original plugging problem with synthetic oil indicates that a bad batch of oil from the manufacturer may have been responsible. Because in-line demisters will be installed to remove entrained liquids from the compressor suction streams, however, there are no immediate plans to switch back to synthetic oil for Big A/B cylinder lubrication.

Mineral oil is successfully used in reciprocating compressors all over the world and is expected to perform with no negative side effects at Milne Point once entrained liquids are no longer a problem. ✦

Study examines coating compatibility with CP

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Ennis, Tex.

For a pipeline coating to be truly compatible with cathodic protection (CP), the coating should allow CP protection to the pipe even if disbondment occurs and water penetrates between the coating and pipe. CP must be adequate to provide the needed current to significantly reduce or eliminate the corrosion under the nonshielding disbonded coating.

Coatings that shield CP when there is a disbondment are a major cause of external corrosion problems on pipelines. Even with proper application some coatings can disbond through soil stress and other methods.

Background

When applying CP to coated pipelines, end users must consider the problems faced if the coating disbonds. CP current is very effective when it has a path to the pipe metal. Disbonded coatings shielding CP, not lack of CP itself, cause most external corrosion on pipelines.

When disbondment or blistering occurs most coatings divert current from its intended path, preventing CP current from adequately protecting the external surfaces of a pipe. A coating must conduct CP current even when disbondment occurs to adequately protect underground pipelines.[1] Certain pipeline coatings will allow CP current to protect the pipe if disbondment occurs and water penetrates between the coating and the pipe.

This article discusses the differences between the two types of coating systems and how CP works with each.

Cathodic protection

The electrochemical process of cathodic protection causes the environment around the cathode (pipe, tank, etc.) to become alkaline, especially at the surface of the metal being protected. The pH of typical pipeline surfaces with adequate CP should be 9-13. This range protects steel and reduces or eliminates corrosion.

Cathodic disbondment (CD) testing, whether long or short-term, shows how well the adhesion of the coating will withstand the electrochemical process of cathodic protection. Coatings need to withstand the alkaline environment as well as hydrogen evolution and other potentially damaging electrochemical changes, making successful CD testing a requirement for pipeline coatings used in conjunction with CP.

Every coating system has finite life and eventually degrades, allowing oxygen, water, and chemicals to reach the substrate.[2] Increased CP often appears to be the best or only solution to prevent corrosion on a pipeline with poor or disbonded coatings. Increasing CP may help meet certain criteria and protect pipe exposed to electrolyte, but it does not always protect the pipe under disbonded coatings, allowing corrosion to continue unless the coatings are replaced.

Increasing CP creates other problems, including the possibility of further disbondment and coating deterioration, as well as adding potential interference to other systems and increasing costs.

Coating failure

Each coating manufacturer attempts to make coatings that will not fail. Poor surface preparation, application technique, soil stress, or selection of the wrong coating for the environment cause most failures. All coatings, however, experience disbondment, making behavior of a disbonded coating important in the overall performance of a coating system.[3 4]

Acidic and near neutral pH environments developed under disbonded shielding pipeline coatings can lead to corrosion and possibly environmentally assisted cracking. As the coating deteriorates, however, and its permeability to O_2 increases, the corrosion rate deep

Based on presentation to NACE Corrosion 2009, Atlanta, Mar. 22-26, 2009.

in the crevice (or blister) could become substantial given CP shielding.[5]

Any changes in the properties of a coating constitute a coating failure.[6] Soil stress and other mechanical damage can also create disbondment problems affecting pipeline coatings. Damage may lead to pipeline corrosion failure and costly repair (OGJ, Aug. 26, 1985, p. 63). Some coatings are more subject to this problem than others.

A large boulder sat on top of this 12-in. OD fusion-bonded epoxy coated pipe, shielding CP to it (Fig. 1).

All coatings have varying dielectric properties reducing the tendency of the electrolyte to complete the electrical circuit between the adjacent anodic and cathodic sites on a substrate, thereby mitigating corrosion.[2] The worst case coating failure prevents both the coating and the CP from protecting the pipeline.[6] Failure to understand coating's influence, especially on the CP system, has caused many premature pipeline failures.[7]

Many pipelines use fusion-bonded epoxy (FBE) coating. Running internal line inspection (ILI) tools in FBE coated pipelines rarely finds external corrosion, except at girth welds coated with a different coating that shields CP if the coating fails. FBE is a permeable coating and despite a high coating resistance current could pass directly through the FBE barrier to the underlying steel, developing a high pH environment in disbondment.[8]

ILI tools have shown corrosion under many types of non-FBE girth weld coatings after only a few years in service.

CP compatibility

Carefully selecting field-applied (girth weld and rehabilitation) coatings ensures their compatibility with CP should a coating failure or disbondment occur. Companies have performed expensive rehabilitations only to find their choice of coating material eventually disbonded, allowing further corrosion at additional expense. Certain coatings allow CP current to protect the pipe should the coating disbond, reducing or eliminating corrosion. These coatings are compatible with CP.

Field testing is the most effective way to determine a coating's CP compatibility. CP changes the pH of the electrolyte at the pipe surface to an alkaline pH, making pH testing an excellent way to determine the effectiveness of the CP under disbonded coating.

Laboratory tests can also establish a coating's effectiveness in allowing CP to protect the pipe under a disbondment. Testing whether a coating is truly compatible with CP requires a properly designed test apparatus.[9]

Articles written about testing to determine what happens under most disbonded coatings conclude it is difficult to achieve protection past the local holiday, much less under coatings without holidays in the disbonded area.[3 10 11]

Not all coating failures result in corrosion. Some coating failures have little or no effect on the corrosion rate of the pipe, including FBE.

External corrosion rarely occurs on pipelines coated with FBE if adequate cathodic protection is available. Pipe will remain protected and blistering and coating disbondment of FBE coatings will not present an integrity threat to a pipeline.[12]

Laboratory and field testing has also proven at least one geotextile mesh backed tape coating has this characteristic when adequate CP is available. These coating systems may not necessarily maintain protection in all conditions, but field and laboratory results have proven a tendency to mitigate corrosion even under disbonded coating.

FBE has experienced numerous failures over roughly 40 years, but these have very rarely led to corrosion or stress corrosion cracking (SCC). Low enough electrical resistance will allow cathodic protection to prevent corrosion on a pipe with disbonded or blistering coating since FBE is nonshielding.[13] Adequate CP reduces or eliminates corrosion, including SCC, if water penetrates under the coating. When CP-

Checking pH under this disbonded geotextile mesh backed coating yielded a measurement of roughly 10, showing the coating's nonshielding properties (Fig. 2).

Intentionally applying this geotextile mesh backed coating to a partially wet pipe surface and reexamining it 3 years later found a pH of 11 on the disbonded areas of the pipe, showing continued shielding. The coating did not adhere to the wet parts of the pipe surface but adhered well otherwise (Fig. 3).

compatible coatings degrade or ground water contacts the pipe, the surface remains protected from corrosion and SCC because the CP current can pass through the permeable coating.[14]

Other structures, however, can sometimes cause shielding, or interference from foreign DC or AC sources can cause corrosion not controlled by the pipeline CP or coating systems.

The documents referenced in this article include case histories and information about pipeline coatings that shield CP when disbondment occurs, allowing external corrosion. The references also discuss coatings that allow enough CP to reduce or eliminate corrosion on the structure even if the coating system adhesion fails and water penetrates between the coating and the pipe.

Case histories

Case histories of some coatings that are compatible with CP and some that are not follow.

• Case History 1. Though rare, external corrosion has been found on FBE coated pipelines. An ILI tool run in 1992 found a pit at the 12:00 o'clock position on this line (Fig. 1).

Excavation removed a 1-2 ton boulder from the top of the pipe, revealing several blisters in the FBE coating. The 12:00 o'clock pit was directly under the boulder, which had evidently shielded CP from the pipe. No corrosion was found under any of the other blistered FBE, reinforcing its typical nonshielding properties.

The damaged pipe was 12-in. OD coated with 22 mils of FBE and entered service in the early 1980s, operating at about 180° F. The "On" potential was –1,160 mv (cse) and the CP criterion used on this pipeline was an "ON" of –850 mv..

A large waste management pond also lay just above the pipeline and there were bacteria in the water around the pipe. Heat caused the failure of a variety of other coating systems used on pipelines in the area (extruded polyethylene, solid film-backed tapes, and coal tars), allowing water into the space between the solid film coatings, shielding the CP, and allowing corrosion.

• Case History 2; FBE-coated 16-in. OD diameter pipe laid in 1985 and internally inspected in 1999. The ILI run showed only internal corrosion, validating use of the FBE coating which remained in excellent condition. One area exposed for verification had blistering, but no external corrosion.

• Case History 3; FBE-coated 42-in. nominal pipe-size pipe examined after 8 years of service at ambient temperature. Excavation revealed several blisters. Blisters included:

—Medium-to-large with no holidays and bright steel under the coating.

—Medium-to-large with darkened steel.

—Small with liquid under the coating.

The excavated pipe was exposed to the atmosphere for an extended period before the coating was evaluated, perhaps allowing evaporation or runoff of the water under the large blisters.

Deionized water used to wash the surfaces under the larger blisters allowed analysis. Water from the blisters with darkened metal showed about three times the amount of sodium, with some chloride and sulfate, as blisters with bright steel. The pH of water under the small blisters was slightly >13, but still within the range of typical continued CP protection.

• Case History 4. Geotextile mesh backed coating has rarely failed. One pipe coated with this and excavated after 3 years of service showed minor wrinkling and water between the coating and pipe. Application occurred in a severe soil stress area without proper tension, without outer wrap, without stripping of the weld seams, incomplete primer application, and over a disbonded coal tar allowing water to migrate along the weld seam under the mesh-backed tape coating.

There was, however, no significant corrosion or metal loss. The pH of the water under the coating was 10, showing the coating's compatibility with CP even with disbondment and water penetration (Fig. 2).

• Case History 5. Several coatings applied to an excavated area on a 30-in. OD natural gas pipeline allowed for testing with geotextile mesh backed tape. The sunny side of the pipe was dry,

but the shady side had condensation. Testers intentionally coated the pipe while partially wet to evaluate the coating's performance, reexcavating the site after 3 years of service.

As expected, the coating did not bond to the wet surface, but was well bonded to the dry side of the pipe. The wet area, however, had a pH of 11 under the pipeline coating, showing continued CP even with adhesion loss and water penetration (Fig. 3).

This corrosion, found in 2006, lay under a shrink sleeve applied 9 years earlier. The shrink sleeve shielded the pipe from CP. Pipe potentials met all National Association of Corrosion Engineers criteria (Fig. 4).

- Case History 6; shrink sleeves applied to a 10-in. OD pipe as girth weld coating. FBE coated the main body of the pipe. An ILI run 9 years later only found corrosion at the girth welds under shrink sleeves wrinkled from soil stress and possible poor application. Corrosion under some sleeves required exposing the pipe and replacing the coating.
- Case History 7; solid film-backed tape coating used on girth welds of a 20-in. OD pipeline installed in 1980. A 1999 ILI tool run exposed many areas of corrosion under the tape coating on girth welds and other areas.
- Case History 8; 6-in. OD insulated pipeline installed in 1979 with a polyethylene (PE) tape anticorrosion barrier, roughly 1 in. of foam, and a PE-tape outer jacket. Poorly applied field joint coatings caused severe external corrosion at girth welds, making the pipeline unable to withstand axial and bending stress during excavation which caused the weld to crack. The line was not leaking prior to the dig.
- Case History 9; 6-in. OD, 27 km thermally insulated pipeline constructed in 1989. Coating consisted of an FBE anticorrosion barrier, 2 in. of foam, and an extruded PE outer jacket. Joint coatings included FBE, injection molded foam, and a shrink sleeve outer jacket. A pipeline inspection in 2005 discovered 209 anomalies only 3 of which were due to external corrosion.

All external anomalies measured <30% WT and were in the body of the pipe, not near the girth welds. External indications were not exposed and may have been steel defects and not corrosion. ✦

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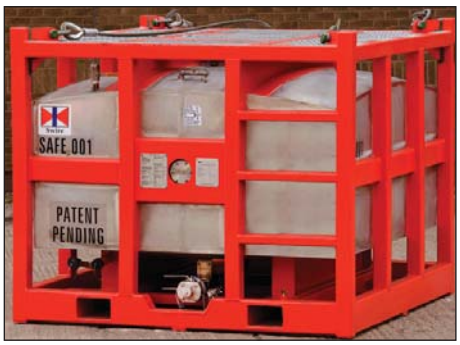

New tank for oil field chemicals

This new tank is designed to carry a full range of oil field chemicals, and it comes with a working pressure of 2.67 bar and a test pressure of 4 bar.

The design has a reduced height and footprint through using more of the empty space in the frame. The lower height minimizes the need for anyone to climb on top of the tank for operational or maintenance reasons.

The 1,000 gal capacity tank has dished ends and measures 2,300 mm by 2,300 mm. The overall height is 1,815 mm, with dip and vent valves 1,600 mm from the floor. It has slotted fork-lifting pockets, which help minimize the chances of dropping incidents, the firm points out.

Because of the partially dished ends, it uses fewer external frame stiffeners than other square tanks currently on the market and is relatively light, the firm adds. It also has a provision for a dial-type level gauge to be installed.

It is constructed of stainless steel and is suited for use in a marine environment. The new tank's height makes stacking plus working on top of the unit easier and safer, the company notes.

Source: **Swire Oilfield Services,** Swire House, Souter Head Rd., Altens, Aberdeen, Aberdeenshire, AB12 3LF, UK.

Sensor usable in extreme temperatures

A new extreme temperature version of the Rosemount 2130 vibrating fork liquid level switch is designed for use in temperatures of –94° to +500° F.

The new version has built-in fault monitoring/self-checking diagnostics, suiting it for a variety of uses.

The Rosemount 2130 level switch is already in use in high and low level alarm and pump control duties, the firm notes. The switch is simple and easy to use, reliable in a range of applications, and requires no on site calibration. Addition of the extreme temperature version allows site managers the possibility to standardize on the Rosemount 2130 across a range of process environments.

The Rosemount 2130 "heart-beat" LED gives an instant visual indication that the unit is operational. In addition, the built-in fault monitoring/self-diagnostics can detect any corrosion of the forks or any other internal or external damage or breaks in the internal electrical wiring, which triggers a warning LED and fail-safe handling of the load.

Source: **Emerson Process Management,** 8000 W. Florissant Ave., St. Louis, MO 63136.

Services/Suppliers

Petris Technology Inc.,

Houston, has formed a strategic partnership with Wipro Technologies, the IT services unit of Wipro Ltd., Bangalore, India, to accelerate the deployment of Petris's new PetrisWINDS OneTouch E&P knowledge portal. The goal of the alliance is to match Petris's experience in complex E&P data management with Wipro's global manpower, expertise, and technology services. OneTouch integrates the Microsoft Office SharePoint and ESRI geographic information system with the PetrisWINDS Enterprise framework, a Petris service-oriented architecture solution that provides open, accessible, and reliable information from any data source. Because many E&P companies already have SharePoint and ESRI, OneTouch adds significant value and increases the return on investment by offering an easy to use E&P domain-specific solution through an advanced web browser.

Founded in 1994, Petris is a leading supplier of data management solutions and geosciences applications providing practical, real-world solutions for the global oil and gas industry.

Wipro Technologies provides IT solutions and services, including systems integration, information systems outsourcing, package implementation, software application development, and maintenance services to corporations globally.

Smith International Inc.,

Houston, has announced that its drilling optimization solutions for Comstock Resources Inc., Frisco, Tex., enabled the operator to drill its first well in less than 30 days in the Haynesville gas shale play. Smith also reported a total drilling time reduction of more than 20% in a three-well Haynesville drilling program for Comstock. The integration of Smith services including i-DRILL, Smith's advanced drilling simulation technology, and PathFinder's drilling optimization team resulted in innovative drilling solution recommendations that led to efficiency gains. PathFinder is Smith's directional drilling and formation evaluation services company, acquired last year as part of the W-H Energy Services merger.

Smith International, Inc. is a leading global provider of products and services used by operators during the drilling, completion, and production phases of oil and natural gas development activities.

Honeywell Process Solutions,

Phoenix, has launched TheOptimizedPlant.com, a web site that delivers ideas, information, and tools to help manufacturers maximize plant performance and get the most out of existing assets. The site focuses on four key strategies: reducing maintenance costs, reducing risk and improving cash flow, implementing high-ROI solutions, and driving down operational costs. It includes a variety of tools, including videos, podcasts, white papers, case studies, and informational webinars, all of which offer practical advice for deriving faster returns.

Honeywell Process Solutions is part of Honeywell's Automation and Control Solutions group, a global leader in product and service solutions that improve efficiency and profitability, support regulatory compliance, and maintain safe, comfortable environments in homes, buildings, and industry.

Imports of crude and products

	Districts 1–4		District 5		Total US		
	5-8 2009	5-1 2009	5-8 2009	5-1 2009	5-8 2009	5-1 2009	*5-9 2008
	1,000 b/d						
Total motor gasoline	641	769	106	54	747	823	915
Mo. gas. blending comp.	403	583	40	34	443	617	627
Distillate	167	165	39	0	206	165	216
Residual	237	336	48	60	285	396	370
Jet fuel-kerosine	45	79	13	44	58	123	300
Propane-propylene	90	138	2	2	92	140	103
Other	637	277	(12)	(15)	625	262	929
Total products	**2,220**	**2,347**	**236**	**179**	**2,456**	**2,526**	**3,460**
Total crude	**7,789**	**8,157**	**919**	**1,763**	**8,708**	**9,920**	**9,933**
Total imports	**10,009**	**10,504**	**1,155**	**1,942**	**11,164**	**12,446**	**13,393**

*Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

Purvin & Gertz LNG netbacks—May 15, 2009

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	7.32	5.37	6.56	5.28	5.91	6.49
Everett	3.61	1.77	3.29	1.87	2.23	3.86
Isle of Grain	3.00	1.20	2.47	1.12	1.65	2.49
Lake Charles	2.06	0.25	1.87	0.42	0.64	2.59
Sodegaura	3.56	5.53	3.82	5.27	4.65	3.02
Zeebrugge	4.41	2.66	3.85	2.58	3.10	3.89

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		Jet fuel, kerosine	Fuel oils		Propane–propylene
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PADD 1	14,827	54,477	36,819	11,495	56,051	15,217	3,732
PADD 2	83,983	49,263	20,588	7,449	33,880	1,264	16,367
PADD 3	194,520	71,332	40,922	12,231	41,889	15,096	25,309
PADD 4	17,258	5,491	1,826	475	3,176	247	[1]874
PADD 5	60,041	27,728	22,200	8,476	12,459	4,856	—
May 8, 2009	**370,629**	**208,291**	**122,355**	**40,126**	**147,455**	**36,680**	**46,282**
May 1, 2009	**375,258**	**212,445**	**126,195**	**40,668**	**146,533**	**35,927**	**45,497**
May 9, 2008[2]	**325,759**	**210,168**	**106,687**	**40,384**	**107,062**	**39,320**	**31,303**

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

Refinery report—May 8, 2009

District	REFINERY OPERATIONS		REFINERY OUTPUT				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils		Propane–propylene
					Distillate	Residual	
	1,000 b/d						
PADD 1	1,292	1,233	2,402	80	409	80	59
PADD 2	3,209	3,186	1,996	210	902	32	233
PADD 3	7,263	7,112	2,610	704	2,163	279	661
PADD 4	545	540	317	26	170	12	[1]61
PADD 5	2,483	2,353	1,385	337	486	160	—
May 8, 2009	**14,792**	**14,424**	**8,710**	**1,357**	**4,130**	**563**	**1,014**
May 1, 2009	**15,077**	**14,754**	**8,918**	**1,432**	**4,207**	**421**	**973**
May 9, 2008[2]	**15,234**	**15,054**	**8,904**	**1,479**	**4,352**	**724**	**1,080**
	17,672 Operable capacity		**83.7% utilization rate**				

[1]Includes PADD 5. [2]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.

OIL&GAS JOURNAL online research center

OGJ crack spread

	*5-15-09	*5-16-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	66.11	138.60	–72.49	–52.3
Brent crude	56.32	123.44	–67.12	–54.4
Crack spread	9.79	15.16	–5.37	–35.4
FUTURES MARKET PRICES				
One month				
Product value	67.45	141.47	–74.02	–52.3
Light sweet crude	58.07	124.93	–66.86	–53.5
Crack spread	9.38	16.53	–7.15	–43.3
Six month				
Product value	66.83	137.25	–70.41	–51.3
Light sweet crude	62.18	123.97	–61.79	–49.8
Crack spread	4.65	13.27	–8.62	–64.9

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

OGJ GASOLINE PRICES

	Price ex tax 5-13-09	Pump price* 5-13-09	Pump price 5-14-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	176.3	222.8	372.9
Baltimore	176.9	218.8	359.4
Boston	174.9	216.8	354.4
Buffalo	162.9	223.8	376.8
Miami	168.2	219.8	381.9
Newark	188.0	220.6	346.7
New York	147.9	208.8	363.1
Norfolk	172.5	210.9	345.5
Philadelphia	174.2	224.9	363.9
Pittsburgh	177.2	227.9	362.7
Wash., DC	195.5	233.9	371.2
PAD I avg	174.1	220.8	363.5
Chicago	174.3	238.7	397.3
Cleveland	176.3	222.7	353.5
Des Moines	178.3	218.7	349.7
Detroit	165.3	224.7	363.3
Indianapolis	158.3	217.7	359.6
Kansas City	176.7	212.7	341.9
Louisville	177.8	218.7	370.5
Memphis	177.8	217.6	347.8
Milwaukee	171.4	222.7	375.9
Minn.-St. Paul	177.7	221.7	355.0
Oklahoma City	171.4	206.8	344.6
Omaha	167.3	212.6	352.6
St. Louis	172.7	208.7	359.0
Tulsa	172.3	207.7	339.7
Wichita	170.3	213.7	344.5
PAD II avg	172.5	217.7	357.0
Albuquerque	174.8	211.2	348.7
Birmingham	169.9	209.2	353.8
Dallas-Fort Worth	167.8	206.2	355.5
Houston	167.8	206.2	350.8
Little Rock	169.0	209.2	352.7
New Orleans	173.5	211.9	349.8
San Antonio	165.8	204.2	346.3
PAD III avg	169.8	208.3	351.1
Cheyenne	186.5	218.9	335.3
Denver	181.5	221.9	365.3
Salt Lake City	174.0	216.9	347.2
PAD IV avg	180.7	219.2	349.3
Los Angeles	159.2	226.3	390.4
Phoenix	177.9	215.3	340.1
Portland	192.9	236.3	367.3
San Diego	178.2	245.3	399.0
San Francisco	183.2	250.3	405.8
Seattle	180.4	236.3	376.3
PAD V avg	178.7	235.0	379.8
Week's avg.	**173.9**	**219.5**	**360.4**
Apr. avg.	**156.7**	**202.3**	**339.3**
Mar. avg.	**147.6**	**193.2**	**319.7**
2009 to date	**146.4**	**192.0**	—
2008 to date	**276.1**	**319.7**	—

*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

	5-8-09 ¢/gal		5-8-09 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	168.73	New York Harbor	148.32
Gulf Coast	161.73	Gulf Coast	146.57
Los Angeles	168.48	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	161.47	ARA	153.93
Singapore	160.12	Singapore	154.29
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	172.48	New York Harbor	124.88
Gulf Coast	166.23	Gulf Coast	139.21
Los Angeles	178.48	Los Angeles	133.80
		ARA	119.23
		Singapore	126.65

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

BAKER HUGHES RIG COUNT

	5-15-09	5-16-08
Alabama	4	6
Alaska	6	7
Arkansas	44	47
California	20	42
Land	19	40
Offshore	1	2
Colorado	45	122
Florida	0	0
Illinois	1	1
Indiana	1	2
Kansas	16	11
Kentucky	10	10
Louisiana	146	149
N. Land	79	50
S. Inland waters	7	23
S. Land	11	20
Offshore	49	56
Maryland	0	1
Michigan	0	1
Mississippi	9	10
Montana	1	10
Nebraska	1	0
New Mexico	31	76
New York	1	8
North Dakota	33	63
Ohio	7	12
Oklahoma	84	205
Pennsylvania	31	20
South Dakota	1	2
Texas	342	902
Offshore	4	10
Inland waters	0	2
Dist. 1	13	30
Dist. 2	12	35
Dist. 3	25	64
Dist. 4	37	90
Dist. 5	87	178
Dist. 6	53	118
Dist. 7B	9	35
Dist. 7C	9	68
Dist. 8	35	129
Dist. 8A	13	27
Dist. 9	21	39
Dist. 10	24	77
Utah	15	40
West Virginia	23	26
Wyoming	36	73
Others—NV-4; VA-5; WA-1	10	16
Total US	**918**	**1,862**
Total Canada	**68**	**132**
Grand total	**986**	**1,994**
US Oil rigs	181	381
US Gas rigs	728	1,471
Total US offshore	56	69
Total US cum. avg. YTD	**1,212**	**1,793**

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	5-15-09 Percent footage*	Rig count	5-16-08 Percent footage*
0-2,500	47	8.5	77	5.1
2,501-5,000	62	62.9	111	54.0
5,001-7,500	103	14.5	224	16.5
7,501-10,000	193	4.1	413	3.3
10,001-12,500	177	6.7	473	2.7
12,501-15,000	156	0.6	274	0.3
15,001-17,500	116	—	116	—
17,501-20,000	45	—	73	—
20,001-over	37	—	34	—
Total	**936**	**8.4**	**1,795**	**7.1**
INLAND	10		27	
LAND	882		1,708	
OFFSHORE	44		60	

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

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

OGJ PRODUCTION REPORT

	[1]5-15-09	[2]5-16-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	20	21
Alaska	690	691
California	649	653
Colorado	62	65
Florida	5	4
Illinois	27	26
Kansas	100	105
Louisiana	1,430	1,302
Michigan	15	17
Mississippi	60	59
Montana	93	86
New Mexico	164	160
North Dakota	193	154
Oklahoma	175	170
Texas	1,340	1,339
Utah	57	56
Wyoming	149	146
All others	66	78
Total	**5,295**	**5,132**

[1]OGJ estimate. [2]Revised.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

US CRUDE PRICES

	5-15-09 $/bbl*
Alaska-North Slope 27°	42.37
South Louisiana Sweet	55.75
California-Kern River 13°	49.05
Lost Hills 30°	57.85
Wyoming Sweet	45.84
East Texas Sweet	52.25
West Texas Sour 34°	46.75
West Texas Intermediate	52.75
Oklahoma Sweet	52.75
Texas Upper Gulf Coast	45.75
Michigan Sour	44.75
Kansas Common	51.75
North Dakota Sweet	43.50

*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]	5-8-09
United Kingdom-Brent 38°	53.89
Russia-Urals 32°	52.52
Saudi Light 34°	50.31
Dubai Fateh 32°	54.30
Algeria Saharan 44°	54.36
Nigeria-Bonny Light 37°	55.54
Indonesia-Minas 34°	57.84
Venezuela-Tia Juana Light 31°	54.88
Mexico-Isthmus 33°	54.77
OPEC basket	53.88
Total OPEC[2]	52.76
Total non-OPEC[2]	53.14
Total world[2]	52.92
US imports[3]	52.20

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume.
Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

US NATURAL GAS STORAGE[1]

	5-8-09	5-1-09	5-8-08	Change, %
	bcf			
Producing region	854	831	572	**49.3**
Consuming region east	827	768	735	**12.5**
Consuming region west	332	319	208	**59.6**
Total US	**2,013**	**1,918**	**1,515**	**32.9**
	Feb. 09	**Feb. 08**	**Change, %**	
Total US[2]	**1,761**	**1,465**	**20.2**	

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

Statistics

World oil balance

	2008 4th qtr.	2008 3rd qtr.	2008 2nd qtr.	2008 1st qtr.	2007 4th qtr.	2007 3rd qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	19.51	19.13	19.96	20.15	20.90	21.06
Canada	2.31	2.34	2.25	2.37	2.38	2.40
Mexico	2.04	2.11	2.16	2.10	2.16	2.06
Japan	4.67	4.30	4.59	5.41	5.25	4.70
South Korea	2.12	2.07	2.09	2.33	2.31	2.06
France	2.01	1.92	1.92	1.98	2.02	1.94
Italy	1.64	1.65	1.61	1.62	1.75	1.65
United Kingdom	1.71	1.64	1.72	1.72	1.73	1.73
Germany	2.64	2.72	2.41	2.47	2.54	2.55
Other OECD Europe	7.30	7.46	7.24	7.41	7.62	7.55
Australia & New Zealand	1.14	1.12	1.14	1.13	1.15	1.12
Total OECD	**47.09**	**46.46**	**47.09**	**48.69**	**49.81**	**48.82**
NON-OECD						
China	8.10	7.99	7.93	7.69	7.61	7.54
FSU	4.39	4.29	4.29	4.33	4.36	4.25
Non-OECD Europe	0.80	0.76	0.79	0.83	0.78	0.73
Other Asia	9.34	9.13	9.25	9.21	9.25	8.93
Other non-OECD	15.90	16.01	15.81	15.58	16.20	16.36
Total non-OECD	**38.53**	**38.18**	**38.07**	**37.64**	**38.20**	**37.81**
TOTAL DEMAND	**85.62**	**84.64**	**85.16**	**86.33**	**88.01**	**86.63**
SUPPLY						
OECD						
US	8.43	8.18	8.75	8.64	8.58	8.36
Canada	3.40	3.40	3.23	3.38	3.40	3.48
Mexico	3.12	3.15	3.19	3.29	3.33	3.46
North Sea	4.38	4.07	4.33	4.46	4.57	4.28
Other OECD	1.61	1.59	1.58	1.54	1.57	1.57
Total OECD	**20.94**	**20.39**	**21.08**	**21.31**	**21.45**	**21.15**
NON–OECD						
FSU	12.46	12.42	12.60	12.59	12.65	12.55
China	3.99	3.97	4.00	3.94	3.87	3.88
Other non–OECD	12.50	12.40	12.19	12.24	12.11	12.04
Total non-OECD, non-OPEC	**28.95**	**28.79**	**28.79**	**28.77**	**28.63**	**28.47**
OPEC*	**35.11**	**36.24**	**35.83**	**35.66**	**35.15**	**34.42**
TOTAL SUPPLY	**85.00**	**85.42**	**85.70**	**85.74**	**85.23**	**84.04**
Stock change	**–0.62**	**0.78**	**0.54**	**–0.59**	**–2.78**	**–2.59**

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

US petroleum imports from source country

	Jan. 2009	Dec. 2008	Average YTD 2009	Average YTD 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	1,000 b/d					
Algeria	720	484	720	636	84	13.2
Angola	543	562	543	578	–35	–6.1
Kuwait	242	219	242	239	3	1.3
Nigeria	509	939	509	1,191	–682	–57.3
Saudi Arabia	1,362	1,471	1,362	1,503	–141	–9.4
Venezuela	1,353	1,159	1,353	1,290	63	4.9
Other OPEC	947	845	947	976	–29	–3.0
Total OPEC	**5,676**	**5,679**	**5,676**	**6,413**	**–737**	**–11.5**
Canada	2,544	2,600	2,544	2,586	–42	–1.6
Mexico	1,430	1,228	1,430	1,307	123	9.4
Norway	90	80	90	86	4	4.7
United Kingdom	147	176	147	213	–66	–31.0
Virgin Islands	367	289	367	380	–13	–3.4
Other non-OPEC	2,918	2,548	2,918	2,507	411	16.4
Total non-OPEC	**7,496**	**6,921**	**7,496**	**7,079**	**417**	**5.9**
TOTAL IMPORTS	**13,172**	**12,600**	**13,172**	**13,492**	**–320**	**–2.4**

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

OECD total net oil imports

	Jan. 2009	Dec. 2008	Nov. 2008	Jan. 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	–1,367	–1,513	–1,427	–1,255	–112	8.9
US	11,246	10,736	11,123	11,869	–623	–5.2
Mexico	–1,213	–1,228	–1,309	–1,220	7	–0.6
France	1,739	1,876	1,753	2,081	–342	–16.4
Germany	2,275	2,267	2,454	2,392	–117	–4.9
Italy	1,368	1,531	1,422	1,509	–141	–9.3
Netherlands	974	1,116	1,127	1,033	–59	–5.7
Spain	1,360	1,618	1,509	1,677	–317	–18.9
Other importers	3,972	4,143	3,826	4,433	–461	–10.4
Norway	–2,052	–2,247	–2,372	–2,089	37	–1.8
United Kingdom	226	193	152	–129	355	–275.2
Total OECD Europe	**9,862**	**10,497**	**9,871**	**10,907**	**–1,045**	**–9.6**
Japan	4,580	4,839	4,527	5,444	–864	–15.9
South Korea	2,454	1,954	2,058	2,556	–102	–4.0
Other OECD	910	933	741	922	–12	–1.3
Total OECD	**26,472**	**26,218**	**25,584**	**29,223**	**–2,751**	**–9.4**

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

OECD* total gross imports from OPEC

	Jan. 2009	Dec. 2008	Nov. 2008	Jan. 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	549	441	401	581	–32	–5.5
US	5,676	5,652	5,779	6,366	–690	–10.8
Mexico	18	22	41	31	–13	–41.9
France	792	906	930	868	–76	–8.8
Germany	530	539	508	467	63	13.5
Italy	1,031	1,172	1,083	1,318	–287	–21.8
Netherlands	779	572	591	774	5	0.6
Spain	759	908	827	654	105	16.1
Other importers	1,068	1,095	1,149	1,337	–269	–20.1
United Kingdom	257	392	322	183	74	40.4
Total OECD Europe	**5,216**	**5,584**	**5,410**	**5,601**	**–385**	**–6.9**
Japan	3,712	4,116	3,797	4,575	–863	–18.9
South Korea	2,628	2,348	2,302	2,379	249	10.5
Other OECD	612	440	446	537	75	14.0
Total OECD	**18,411**	**18,603**	**18,176**	**20,070**	**–1,659**	**–8.3**

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

Oil stocks in OECD countries*

	Jan. 2009	Dec. 2008	Nov. 2008	Jan. 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million bbl					
France	179	179	179	182	-3	-1.6
Germany	280	277	273	281	-1	-0.4
Italy	136	128	127	136	--	--
United Kingdom	101	99	96	95	6	6.3
Other OECD Europe	720	724	701	690	30	4.3
Total OECD Europe	**1,416**	**1,407**	**1,376**	**1,384**	**32**	**2.3**
Canada	202	201	202	196	6	3.1
US	1,762	1,735	1,733	1,677	85	5.1
Japan	618	630	641	621	-3	-0.5
South Korea	149	135	139	155	-6	-3.9
Other OECD	114	113	116	109	5	4.6
Total OECD	**4,261**	**4,221**	**4,207**	**4,142**	**119**	**2.9**

*End of period.
Source: DOE International Petroleum Monthly Report
Data available in OGJ Online Research Center.

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The unspoken booms in some reform debate

The secret of aggressive reform is often just that: off-message information that reformist politicians don't want anyone to know.

Energy reform pushed by the administration of US President Barack Obama, for example, thunders with silence on the grotesque disproportion of cost relative to supply for "green energy," toward which public money now flows without restriction.

The Editor's Perspective

by Bob Tippee, Editor

Then there's health care. Some observers think the overhaul Obama proposes in this area would crush the economy and lead to rationing of medical services. Administration officials dispute those claims.

This writer has no expertise in health care beyond his life-long strategy of avoiding, to the extent possible, patient-provider interaction with doctors. But warnings about crushed economies and waiting lists for—heaven forbid—essential surgery get a person's attention. So who's right?

Two inexpert observations seem pertinent. One is what the administration assiduously avoids in its discussions about health care costs: medical malpractice litigation.

Theodore H. Frank, director of the American Enterprise Institute's Legal Center for the Public Interest, says the cost of "defensive medicine"—prescribed by doctors as an antidote for malpractice litigation—may be $30-180 billion/year. He made that estimate in a March presentation to the Senate Republican Conference, noting also that malpractice liability lowers the supply of medical service and thereby results in the loss of "hundreds of lives a year and perhaps even as high as 1,000 deaths and many more exacerbated injuries a year."

Those are indirect costs. Medical malpractice is a big part of the direct costs of excess tort liability, which Frank estimates, from analyses by Tillinghast-Towers Perrin, at $128 billion/year.

Costs like these deserve attention in the health-care debate. Yet tort reform appears nowhere on the Obama agenda.

Hence the other observation: Obama and other Democrats are politically indebted to the tort bar. According to the Center for Responsive Politics, the category "Lawyers/Law Firms" appears second behind "Retired" in a ranking of industry contributors to Obama's presidential campaign. Rankings were the same for contributions to congressional campaigns in the last election cycle. The lawyers favored Democrats 78% to 22% and Obama most of all.

(Online May 15, 2009; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Market fundamentals dampen optimism

Hope for economic recovery raised the front-month contract of benchmark US crudes briefly above $60/bbl for the first time this year on the New York Mercantile Exchange before it fell back to $56.34/bbl in the week ended May 15.

Although the worst may be over, said analysts at the Centre for Global Energy Studies (CGES), London, "The global economy is likely to scrape along the bottom for a while." They reported, "Investors' appetite for more risk seems to have made a muted comeback and more cash is flowing into equity markets and the commodities sector, while the current weakness of the US dollar has also played a part.... It is unlikely that oil will fall to $50/bbl again, but the optimism that has characterized the oil market since the end of March may well ebb."

At KBC Market Services, a division of KBC Process Technology Ltd. in Surrey, UK, analysts said, "However hard commentators try to talk up the economy, we cannot escape the fact that oil demand is showing no signs of improving." They noted "the harbingers of doom at the International Energy Agency" expect a 2.6 million b/d drop in world oil demand in 2009, which would be "larger even than the 2.5 million b/d fall seen in 1980."

For the ninth consecutive month, IEA in Paris reduced its previous forecast of oil demand, down 230,000 b/d in its latest adjustment to a total 83.2 million b/d, 3% below 2008 demand. "Continued oil demand weakness is premised on strong economic recovery later this year remaining elusive," EIA said. Only a day earlier, the Organization of Petroleum Exporting Countries reduced its 2009 demand growth forecast by 200,000 b/d to 1.6 million b/d to 84 million bbl.

KBC analysts said, "What is even more disturbing than the IEA's headline total is the fact that demand is down almost everywhere, with only India and Saudi Arabia of the world's top 10 oil markets showing any growth at all." They acknowledged "a small glimmer of hope" when rude inventories fell in the week ended May 8, the first decline in 10 weeks. "But this is straw-clutching," said KBC analysts. "Four-week average gasoline demand was down 1.2% on last year, and we might be optimistic in expecting much of a gasoline season this year."

'Sustainable' prices

CGES analysts said oil prices are "more or less" sustainable around $50-55/bbl under current conditions. They assume the drop in world demand for oil will be "much less drastic" than the IEA's forecast.

Adam Sieminski, chief energy economist, Deutsche Bank, Washington, DC, said, "Oil analysts should stay focused on the potential for lower equity markets given the very strong positive correlation recently between oil prices and the Standard & Poor's 500 [an index of the 500 largest US companies]. We estimate that since September every 50-point move in the S&P 500 has been worth a $7/bbl move in the West Texas Intermediate crude price."

Meanwhile, Olivier Jakob at Petromatrix, Zug, Switzerland, noted "a general consensus" that the recent oil rally "was purely a correlation to the equity markets and not linked to oil fundamentals." However, he said, "With industrial demand down more than driving demand and with the combination of a contango in distillates and a backwardation in gasoline, distillates is driving gasoline out of storage capacity, and this is then making the day-of-cover picture in gasoline not very different from previous years. This then makes gasoline still exposed, like in previous years, to supply glitches." Only recently, he said, reports of "a few cracker problems" had "a direct impact" on gasoline prices.

Meanwhile, Jakob maintained "a Nigerian risk premium" on the price of crude due to long-term civil unrest in that oil-producing country. "If nothing happens in Nigeria, we will then transfer it to a Middle East premium," he said in connection with Israel Prime Minister Binyamin Netanyahu's visit to Washington, DC, beginning May 18.

Jakob noted "leaks" earlier this month about the Israeli air force training on refueling missions between Israel and Gibraltar. He reported on May 14 another leak "that Israel has rented MIG-29 fighter jets (the type owned by Iran) to train its pilots in 'dog-fights' against them; and it was leaked...that the US Central Intelligence Agency director was sent to Jerusalem 2 weeks ago to gain reassurances that Israel would not strike Iran without a green light from Washington." Jakob said, "All of this is part of psychological warfare, but we have been there before, and we can't fully ignore it."

(Online May 18, 2009; author's e-mail: samf@ogjonline.com)

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